Manitoba Hydro
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2003 08 08

Mr. Trent Hreno
Chair, Technical Advisory Committee
Manitoba Conservation
169 - 123 Main Street
Winnipeg, MB R3C 1A5

Dear Mr. Hreno:

FILING OF SUPPLEMENTARY FILING ON NEED FOR AND ALTERNATIVES TO (NFAAT) THE WUSKWATIM PROJECT

We are pleased to submit for your consideration the *Supplementary Filing On Need For and Alternatives To the Wuskwatim Project*, August 2003. Forty two print copies of this filing are enclosed as advised by Mr. L. Strachan. We understand you will distribute these, as required, to Technical Advisory Committee (TAC) members and the Public Registeries.

Under separate letter, Manitoba Hydro and Nisichawayasihk Cree Nation are submitting the Supplementary filings for the:

- *Environmental Impact Statement for the Wuskwatim Transmission Project, and the Environmental Impact Statement for the Wuskwatim Generation Project, April 2003.*

This NFAAT supplemental filing is provided in response to the adequacy comments received on July 10, 2003. It also includes supplemental information in response to comments and questions arising at the June TAC Technical Workshop, the July Participant technical workshops and subsequent informal discussions.

An electronic copy of the NFAAT supplemental filing will be provided in conjunction with the supplemental filing for the two EIS's.

Copies are being provided directly to the contact lists for the Wuskwatim Clean Environment Commission review to assist in the CEC pre-hearing process.

The information in this filing is presented according to content in the original NFAAT submission on a chapter by chapter basis. There is an index listing responses.

Manitoba Hydro acknowledges with appreciation, the thorough review of the NFAAT, as demonstrated by the extent and quality of the many questions raised for our consideration. These questions and our responses will assist in a rigorous, comprehensive review of our proposals.

We will be pleased to answer any other questions you may have on this filing.

Sincerely,

"Ed Wojczynski"

Ed Wojczynski
Division Manager
Power Planning and Development

EW/tb /2003 08 06.1

C. Councillor W.E. Thomas, NCN Future Development
Clean Environment Commission Contact Lists:
- Funded Participants
- Non-Funded Participants
- Others

Enclosures

SUPPLEMENTAL FILING

on

Need For and Alternatives to the Wuskwatim Project (NFAAT)

August 8, 2003

NFAAT Supplemental Filing- August 8, 2003

Supplemental Response	Associated Attachment(s)	Main Submission Chapter Reference	Subject	Origination*
CAC/MSOS/NFAAT/S/1	CAC/MSOS/NFAAT/S/1a	4	Detailed levelized cost calculations for the main resource alternatives	CAC/MSOS item 5 & 6
CAC/MSOS/NFAAT/S/2		4	Appropriateness of using 2001 PowerSmart Plan under current export prices and market opportunities	CAC/MSOS item 4
CCC/NFAAT/S/1		5	Potential impact of standard market design (SMD) on electricity markets and on Manitoba Hydro's export market	CCC Page 4 comments
CAC/MSOS/NFAAT/S/3		5	Further information on High and Low export price forecasts and historic average prices	CAC/MSOS item 1
CAC/MSOS/NFAAT/S/4	CAC/MSOS/NFAAT/S/4a	5	Recent load growth projections in MAPP-US and supply forecasts	CAC/MSOS item 1
CCC/NFAAT/S/2	CCC/NFAAT/S/2a	6	Summary of new information from the 2003 Power Resource Plan and sensitivity analysis regarding its implications on Wuskwatim evaluations	CCC Page 2 Comments
CCC/NFAAT/S/3		6	Assessment of the decrease to Low Export Prices that would be needed to have the project breakeven with WACC (6.08%) and Cost of Debt (5.34%)	CCC page 3 comments
CCC/NFAAT/S/4; CAC/MSOS/NFAAT/S/5		6	IRR Sensitivity on the impact of a drought of record occurring coincident with the advanced in-service date of the project	CCC page 3 comments & CAC/MSOS item 2
MH/NCN/NFAAT/S/1	MH/NCN/NFAAT/S/1a	6	Social Benefit Cost Analysis- Low & High export prices	MH initiated
CAC/MSOS/NFAAT/S/6		6	Sensitvity on Wuskwatim Project economics to development of twice the current forecast of DSM, 250 MW of wind and a combination of these two sensitivities	CAC/MSOS item 4
MH/NCN/NFAAT/S/2	MH/NCN/NFAAT/S/2a	6	Summary of Economic Evaluations and Sensitivities	MH initiated
CCC/NFAAT/S/5; CAC/MSOS/NFAAT/S/7		7	Financial Sensitivity - 5 year low water flow conditions coinciding with advanced in-service	CCC Page 3 comments & CAC/MSOS item 2
CCC/NFAAT/S/6		7	Finanical Stability	CCC page 3 comments
CCC/NFAAT/S/7	CCC/NFAAT/S/7a	7	Projected balance sheets and financing requirements statements	CCC page 3 comments
CCC/NFAAT/S/8; CAC/MSOS/NFAAT/S/8		7	Consolidation Accounting	CCC page 3 comments
CCC/NFAAT/S/9; CAC/MSOS/NFAAT/S/9		7	Financial Sensitivity - 15% capital increase/decrease in base capital costs	CCC page 3 comments
CCC/NFAAT/S/10		7	Finanical impact of 2003 Power Resource Plan Update	CCC Page 2 Comments
CAC/MSOS/NFAAT/S/10		7	Impact of Partnership Dividend Policy on Manitoba Hydro	CAC/MSOS Informal Meeting
CAC/MSOS/NFAAT/S/11	CAC/MSOS/NFAAT/S/11a	7	Summarized Partnership Projected Income Statements	CAC/MSOS Informal Meeting
CCC/NFAAT/S/11		Appendices	Document Updates & Summary of changes	CCC page 1 comments
CCC/NFAAT/S/12		Appendix 2	CSP	CCC page 1 comments
CCC/NFAAT/S/13		Appendix 4	Newsletter #4	CCC page 1 comments
CCC/NFAAT/S/14		Appendix 7	Economic Outlook	CCC page 1 comments
CCC/NFAAT/S/15		Appendix 8	Load Forecast Report 2003	CCC page 1 comments

*Origination refers to comments provided by:
CAC/MSOS in their letter to Manitoba Conservation of June 30, 2003;
Crown Corporations Council in their letter to Manitoba Conservation of June 27, 2003; and
informal discussions during and after the July 9, 2003 workshop.

CAC/MSOS/NFAAT/S/1

Request: CAC/MSOS requested detailed levelized cost calculations for the main resource alternatives

Response: Attached are detailed levelized cost calculations for the main competing resource alternatives of interest to Manitoba Hydro. The levelized costs provided are for upper and lower bounds of the ranges of costs indicated in Figure 4.5 in the "Need For and Alternatives to the Wuskwatim Project".

Detailed levelized costs included here are for:

- Wuskwatim
- Conawapa
- Gull
- Wind
- SCCT
- CCCT
- Coal
- DSM

See attached (CAC/MSOS/NFAAT/S/1a)

For more information on economic levelized costs, refer to Section 4.2.4 "Need For and Alternatives to the Wuskwatim Project".

Levelized Costs of : **Wuskwatim-09** **66.1** $/MW.h

- Referenced to Southern Bus

Includes Capital Tax & Development Fund

In-Service-Date = **2009**

RATES

Discount Rate: 10.00%

Water Rental = 3.341 2002 $ / MW.h

Capacity (MW)
Summer = 200
Average = 200
Winter = 200

Energy (GW.h)
Dependable = 1250
Average = 1520
High = 1700

	Fiscal Year Beg. April	Capacity (MW)	Ave GW.h @ gen	Generation Costs (millions of 2002 base dollars): Generating Station 67	Water Rental	Generation O&M Costs	Generation Capital Tax 0.50%	Generation TOTAL COST	Transmission Costs (millions of 2002 base dollars): TL Capital Cost 50	TS Capital Cost 35	Trans O&M Costs	Trans Capital Tax 0.50%	Trans Development Fund	Transmission TOTAL COST
	2002	0	0	0.00	0.00	0.00	0.08	0.08	0.00	0.00	0.00	0.01	0.00	0.01
	2003	0	0	16.55	0.00	0.00	0.08	16.64	0.46	0.84	0.00	0.01	0.00	1.31
	2004	0	0	69.36	0.00	0.00	0.43	69.79	5.32	2.57	0.00	0.05	0.00	7.94
	2005	0	0	110.53	0.00	0.00	0.98	111.51	5.15	6.88	0.00	0.11	0.00	12.15
	2006	0	0	108.62	0.00	0.00	1.53	110.14	25.44	11.03	0.00	0.29	0.00	36.76
	2007	0	0	115.41	0.00	0.00	2.10	117.51	23.60	15.64	0.00	0.48	0.00	39.73
	2008	0	0	77.70	0.00	0.00	2.49	80.19	15.50	16.16	0.00	0.64	0.00	32.30
1	2009	150	1015	21.86	3.39	1.64	2.60	29.49	-9.00	0.60	0.60	0.60	5.58	-1.62
2	2010	200	1520	0.00	5.08	1.64	2.60	9.32	-9.46	-1.79	0.60	0.54		-10.11
3	2011	200	1520	0.00	5.08	1.64	2.60	9.32	-0.17	-0.23	0.60	0.54		0.74
4	2012	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
5	2013	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
6	2014	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
7	2015	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
8	2016	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
9	2017	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
10	2018	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
11	2019	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
12	2020	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
13	2021	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
14	2022	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
15	2023	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
16	2024	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
17	2025	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
18	2026	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
19	2027	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
20	2028	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
21	2029	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
22	2030	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
23	2031	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
24	2032	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
25	2033	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
26	2034	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
27	2035	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
28	2036	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
29	2037	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
30	2038	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.84	0.60	0.54		1.99
31	2039	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	2.57	0.60	0.54		3.72
32	2040	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	6.88	0.60	0.54		8.03
33	2041	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	11.03	0.60	0.54		12.17
34	2042	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	15.64	0.60	0.54		16.78
35	2043	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	16.16	0.60	0.54		17.31
36	2044	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.60	0.60	0.54		1.74
37	2045	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	-1.79	0.60	0.54		-0.65
38	2046	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	-0.23	0.60	0.54		0.91
39	2047	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
40	2048	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
41	2049	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
42	2050	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
43	2051	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
44	2052	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
45	2053	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
46	2054	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
47	2055	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
48	2056	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
49	2057	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
50	2058	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
51	2059	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
52	2060	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
53	2061	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
54	2062	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
55	2063	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
56	2064	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
57	2065	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
58	2066	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
59	2067	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
60	2068	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
61	2069	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
62	2070	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
63	2071	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
64	2072	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
65	2073	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
66	2074	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
67	2075	200	1520	0.00	5.08	1.73	2.60	9.41	0.00	0.00	0.60	0.54		1.14
	2076	50	505	0.00	1.69	0.09	2.60	4.38	0.00	0.00	0.00	0.54		0.54
	2077	0	0	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00		0.00
	Total 2002 Base	13,400	101,840	520.02	340.25	116.02	184.50	1,160.79	56.85	103.42	40.20	38.55	5.58	244.59
	Total 2002 P.V.	1,101	8,307	356.33	27.75	9.64	19.66	413.39	40.36	35.01	3.38	4.08	2.86	85.70

Adjusted for Losses @ 10%

Levelized Energy Cost (2002 $/MW.h) @ SOUTH:	
Generation (capital, O&M, water rentals):	54.7
Transmission (capital, O&M):	11.3
(Cost NPV / Energy NPV) Total:	66.1

Adjusted for North - South Losses 10.000%

Discount Rate 10.000%

Levelized Energy Cost (2002 $/MW.h) @ SOUTH:	
Generation (capital only):	47.2
Transmission Line (capital only):	5.3
Transmission Station (capital only):	4.6
Total Capital:	57.2
O&M:	1.7
Water Rental:	3.7
Capital Tax:	3.1
Development Fund:	0.4
(Cost NPV / Energy NPV) Total:	66.1

CAC/MS0S/NFAAT/S/1a

Levelized Costs of : **Gull-12** **75.7** $/MW.h

- Referenced to Southern Bus In-Service-Date = **2012**

Includes Capital Tax & Development Fund, Full Converters Costs less 500 kV HVDC line

RATES
Discount Rate: **10.00%**
Water Rental = **3.341** 2002 $ / MW.h

Capacity (MW)
Summer = **630**
Average = **623**
Winter = **615**

Energy (GW.h)
Dependable = **2900**
Average = **4430**
High = **5320**

				Generation Costs (millions of 2002 base dollars)					Transmission Costs (millions of 2002 base dollars)					
	Fiscal Year Beg. April	Capacity (MW)	Ave GW.h @ gen	Generating Station **67**	Water Rental	Generation O&M Costs	Generation Capital Tax 0.50%	Generation TOTAL COST	TL Capital Cost **50**	TS Capital Cost **35**	Trans O&M Costs	Trans Capital Tax 0.50%	Trans Development Fund	Transmission TOTAL COST
	2002	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	2003	0	0	17.10	0.00	0.00	0.09	17.18	0.00	0.00	0.00	0.00	0.00	0.00
	2004	0	0	28.77	0.00	0.00	0.23	29.00	0.00	0.00	0.00	0.00	0.00	0.00
	2005	0	0	25.97	0.00	0.00	0.36	26.33	0.52	2.33	0.00	0.01	0.00	2.87
	2006	0	0	54.59	0.00	0.00	0.63	55.23	1.04	3.50	0.00	0.04	0.00	4.57
	2007	0	0	112.19	0.00	0.00	1.19	113.38	6.24	7.00	0.00	0.10	0.00	13.33
	2008	0	0	245.83	0.00	0.00	2.42	248.25	6.24	11.66	0.00	0.19	0.00	18.09
	2009	0	0	282.73	0.00	0.00	3.84	286.57	31.18	69.96	0.00	0.70	0.00	101.84
	2010	0	0	303.57	0.00	0.00	5.35	308.92	29.10	95.62	0.00	1.32	0.00	126.04
	2011	0	0	241.29	0.00	0.00	6.56	247.85	29.10	152.75	0.00	2.23	0.00	184.08
1	2012	217	1371	209.69	4.58	1.84	7.61	223.72	0.52	111.94	1.96	2.79	16.11	133.32
2	2013	571	3955	57.09	13.21	1.84	7.89	80.04	0.00	11.66	1.96	2.85		16.47
3	2014	623	4430	0.00	14.80	1.84	7.89	24.53	0.00	0.00	1.96	2.85		4.81
4	2015	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
5	2016	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
6	2017	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
7	2018	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
8	2019	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
9	2020	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
10	2021	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
11	2022	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
12	2023	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
13	2024	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
14	2025	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
15	2026	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
16	2027	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
17	2028	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
18	2029	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
19	2030	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
20	2031	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
21	2032	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
22	2033	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
23	2034	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
24	2035	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
25	2036	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
26	2037	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
27	2038	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
28	2039	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
29	2040	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	2.33	1.96	2.85		7.14
30	2041	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	3.50	1.96	2.85		8.31
31	2042	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	7.00	1.96	2.85		11.81
32	2043	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	11.66	1.96	2.85		16.47
33	2044	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	69.96	1.96	2.85		74.77
34	2045	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	95.62	1.96	2.85		100.43
35	2046	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	152.75	1.96	2.85		157.56
36	2047	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	111.94	1.96	2.85		116.75
37	2048	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	11.66	1.96	2.85		16.47
38	2049	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
39	2050	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
40	2051	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
41	2052	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
42	2053	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
43	2054	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
44	2055	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
45	2056	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
46	2057	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
47	2058	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
48	2059	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
49	2060	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
50	2061	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
51	2062	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
52	2063	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
53	2064	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
54	2065	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
55	2066	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
56	2067	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
57	2068	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
58	2069	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
59	2070	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
60	2071	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
61	2072	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
62	2073	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
63	2074	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
64	2075	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
65	2076	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
66	2077	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
67	2078	623	4430	0.00	14.80	2.00	7.89	24.70	0.00	0.00	1.96	2.85		4.81
	2079	406	3059	0.00	10.22	0.16	7.89	18.28	0.00	0.00	0.00	2.85		2.85
	2080	52	475	0.00	1.59	0.16	7.89	9.64	0.00	0.00	0.00	2.85		2.85
	2081	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.85		2.85
	Total 2002 Base	41,708	296,810	1,578.82	991.64	134.07	565.08	3,269.62	103.92	932.84	131.33	204.16	16.11	1,388.37
	Total 2002 P.V.	2,461	17,412	794.43	58.17	8.31	43.65	904.56	50.61	214.99	8.30	14.19	6.21	294.29

Adjusted for Losses @ 10%

Levelized Energy Cost (2002 $/MW.h) @ SOUTH:	
Generation (capital, O&M, water rentals):	57.1
Transmission (capital, O&M):	18.6
(Cost NPV / Energy NPV) Total:	75.7

Adjusted for North - South Losses 10.000%
Discount Rate 10.000%

Levelized Energy Cost (2002 $/MW.h) @ SOUTH:	
Generation (capital only):	50.2
Transmission Line (capital only):	3.2
Transmission Station (capital only):	13.6
Total Capital:	67.0
O&M:	1.0
Water Rental:	3.7
Capital Tax:	3.7
Development Fund:	0.4
(Cost NPV / Energy NPV) Total:	75.7

Levelized Costs_July 24 2003.xls
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CAC/MS0S/NFAAT/S/1a

67.4 $/MW.h

Levelized Costs of : **Conawapa - 2015, 10 unit scheme**

- Referenced to Southern Bus — In-Service-Date = **2015**

Includes Capital Tax & Development Fund, Full Converters Costs less 500 kV HVDC line

RATES
Discount Rate: **10.00%**
Water Rental = **3.341** 2002 $ / MW.h

Capacity (MW): Summer = **1290**; Average = **1260**; Winter = **1230**

Energy (GW.h): Dependable = **4550**; Average = **7000**; High = **9000**

				Generation Costs (millions of 2002 base dollars)					Transmission Costs (millions of 2002 base dollars)					
	Fiscal Year Beg. April	Capacity (MW)	Ave GW.h @ gen	Generating Station 67	Water Rental	Generation O&M Costs	Generation Capital Tax 0.50%	Generation TOTAL COST	TL Capital Cost 50	TS Capital Cost 35	Trans O&M Costs	Trans Capital Tax 0.50%	Trans Development Fund	Transmission TOTAL COST
	2002	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	2003	0	0	3.31	0.00	0.00	0.02	3.33	0.00	0.00	0.00	0.00	0.00	0.00
	2004	0	0	26.34	0.00	0.00	0.15	26.49	0.00	0.00	0.00	0.00	0.00	0.00
	2005	0	0	40.91	0.00	0.00	0.35	41.26	0.00	0.00	0.00	0.00	0.00	0.00
	2006	0	0	43.48	0.00	0.00	0.57	44.05	0.00	0.00	0.00	0.00	0.00	0.00
	2007	0	0	71.85	0.00	0.00	0.93	72.78	0.00	0.00	0.00	0.00	0.00	0.00
	2008	0	0	125.75	0.00	0.00	1.56	127.31	0.30	3.83	0.00	0.02	0.00	4.14
	2009	0	0	139.98	0.00	0.00	2.26	142.24	0.60	5.74	0.00	0.05	0.00	6.39
	2010	0	0	221.77	0.00	0.00	3.37	225.13	3.57	11.48	0.00	0.13	0.00	15.18
	2011	0	0	287.38	0.00	0.00	4.80	292.19	3.57	19.13	0.00	0.24	0.00	22.94
	2012	0	0	284.26	0.00	0.00	6.23	290.49	17.87	114.76	0.00	0.90	0.00	133.54
	2013	0	0	235.70	0.00	0.00	7.40	243.10	16.68	156.85	0.00	1.77	0.00	175.30
	2014	0	0	234.07	0.00	0.00	8.57	242.65	16.68	250.57	0.00	3.11	0.00	270.36
1	2015	150	2200	173.32	7.35	3.21	9.44	193.32	0.30	183.62	2.93	4.03	19.56	210.44
2	2016	955	6600	50.02	22.05	3.21	9.69	84.97	0.00	19.13	2.93	4.12		26.18
3	2017	1260	7000	9.39	23.39	3.21	9.74	45.72	0.00	0.00	2.93	4.12		7.05
4	2018	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
5	2019	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
6	2020	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
7	2021	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
8	2022	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
9	2023	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
10	2024	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
11	2025	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
12	2026	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
13	2027	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
14	2028	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
15	2029	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
16	2030	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
17	2031	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
18	2032	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
19	2033	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
20	2034	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
21	2035	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
22	2036	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
23	2037	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
24	2038	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
25	2039	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
26	2040	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
27	2041	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
28	2042	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
29	2043	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	3.83	2.93	4.12		10.88
30	2044	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	5.74	2.93	4.12		12.79
31	2045	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	11.48	2.93	4.12		18.53
32	2046	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	19.13	2.93	4.12		26.18
33	2047	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	114.76	2.93	4.12		121.82
34	2048	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	156.85	2.93	4.12		163.90
35	2049	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	250.57	2.93	4.12		257.62
36	2050	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	183.62	2.93	4.12		190.68
37	2051	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	19.13	2.93	4.12		26.18
38	2052	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
39	2053	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
40	2054	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
41	2055	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
42	2056	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
43	2057	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
44	2058	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
45	2059	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
46	2060	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
47	2061	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
48	2062	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
49	2063	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
50	2064	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
51	2065	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
52	2066	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
53	2067	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
54	2068	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
55	2069	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00	0.00	2.93	4.12		7.05
56	2070	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00		2.93	4.12		7.05
57	2071	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00		2.93	4.12		7.05
58	2072	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00		2.93	4.12		7.05
59	2073	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00		2.93	4.12		7.05
60	2074	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00		2.93	4.12		7.05
61	2075	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00		2.93	4.12		7.05
62	2076	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00		2.93	4.12		7.05
63	2077	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00		2.93	4.12		7.05
64	2078	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00		2.93	4.12		7.05
65	2079	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00		2.93	4.12		7.05
66	2080	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00		2.93	4.12		7.05
67	2081	1260	7000	0.00	23.39	3.44	9.74	36.57	0.00		2.93	4.12		7.05
	2082	1110	4800	0.00	16.04	0.23	0.00	16.27	0.00		0.00	0.00		0.00
	2083	305	400	0.00	1.34	0.23	0.00	1.57	0.00		0.00	0.00		0.00
	2084	0	0	0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00		0.00
	Total 2002 Base	84,420	469,000	1,947.55	1,566.93	230.27	688.29	4,433.05	59.58	1,530.20	196.34	282.40	19.56	2,088.07
	Total 2002 P.V.	3,607	20,773	830.40	69.40	10.76	45.62	956.18	21.80	264.96	9.32	15.25	5.66	316.99

Adjusted for Losses @ 10%

Levelized Energy Cost (2002 $/MW.h) @ SOUTH:	
Generation (capital, O&M, water rentals):	50.6
Transmission (capital, O&M):	16.8
(Cost NPV / Energy NPV) Total:	67.4

Adjusted for North - South Losses 10.000%
Discount Rate 10.000%

Levelized Energy Cost (2002 $/MW.h) @ SOUTH:	
Generation (capital only):	44.0
Transmission Line (capital only):	1.2
Transmission Station (capital only):	14.0
Total Capital:	59.2
O&M:	1.1
Water Rental:	3.7
Capital Tax:	3.2
Development Fund:	0.3
(Cost NPV / Energy NPV) Total:	67.4

Levelized Costs_July 24 2003.xls
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CAC/MS0S/NFAAT/S/1a

Upper Bound Levelized Cost of : **Wind Generation in Manitoba**

Discount Rate: 10.00%

10.05	(cents/kW.h)
100.5	($/MW.h)

Average Energy: 110 GW.h

Generating Costs:
$80.5 M (1 610.25 $/kW)
Cdn 2002 Constant Dollars

O&M Costs:
Variable Costs = 14.50 2002 $ / MW.h (includes $1/MWhr for land leases)
Fixed Costs = 2002 $ Millions $/yr

In-Service-Date = 2004
Life= 21 yrs

Plant Characteristics:
MW (net output) 50.000 MW
Capacity Factor 25.00%

Year	Capacity (MW)	Average Energy (GW.h)	Generating Station ($M) 21	Capital Tax ($M)	Variable O&M Costs ($M)	Generation TOTAL COST ($M)
2003			20.13	0.10		20.23
2004	50.000	63.800	60.38	0.40	0.93	61.71
2005	50.000	110.000		0.38	1.60	1.98
2006	50.000	110.000		0.36	1.60	1.96
2007	50.000	110.000		0.34	1.60	1.94
2008	50.000	110.000		0.32	1.60	1.92
2009	50.000	110.000		0.30	1.60	1.90
2010	50.000	110.000		0.28	1.60	1.88
2011	50.000	110.000		0.26	1.60	1.86
2012	50.000	110.000		0.24	1.60	1.84
2013	50.000	110.000		0.22	1.60	1.82
2014	50.000	110.000		0.20	1.60	1.80
2015	50.000	110.000		0.18	1.60	1.78
2016	50.000	110.000		0.16	1.60	1.76
2017	50.000	110.000		0.14	1.60	1.74
2018	50.000	110.000		0.12	1.60	1.72
2019	50.000	110.000		0.10	1.60	1.70
2020	50.000	110.000		0.08	1.60	1.68
2021	50.000	110.000		0.06	1.60	1.66
2022	50.000	110.000		0.04	1.60	1.64
2023	50.000	110.000		0.02	1.60	1.62
2024		46.200		0.00	0.67	0.67
2025						
2026						
2027						
2028						
2029						
2030						
2031						
2032						
2033						
2034						
2035						
Total 2002 Base	$1,000.00	$2,200.00	$80.51		$31.90	$116.74
Total 2002 P.V.	387	819	68.203	2.193	11.873	82.269

Lower Bound Levelized Costs of : **Wind Generation in Manitoba**

Discount Rate: 10.00%

6.85	(cents/kW.h)
68.5	($/MW.h)

Average Energy: 175 GW.h

Generating Costs:
$80.5 M (1 610.25 $/kW)
Cdn 2002 Constant Dollars

O&M Costs:
Variable Costs = 14.50 2002 $ / MW.h (includes $1/MWhr for land leases)
Fixed Costs = 2002 $ Millions $/yr

In-Service-Date = 2004
Life= 21 yrs

Plant Characteristics:
MW (net output) 50.000 MW
Capacity Factor 40.00%

Year	Capacity (MW)	Average Energy (GW.h)	Generating Station ($M) 21	Capital Tax ($M)	Variable O&M Costs ($M)	Generation TOTAL COST ($M)
2003			20.13	0.10		20.23
2004	50.000	101.500	60.38	0.40	1.47	62.26
2005	50.000	175.000		0.38	2.54	2.92
2006	50.000	175.000		0.36	2.54	2.90
2007	50.000	175.000		0.34	2.54	2.88
2008	50.000	175.000		0.32	2.54	2.86
2009	50.000	175.000		0.30	2.54	2.84
2010	50.000	175.000		0.28	2.54	2.82
2011	50.000	175.000		0.26	2.54	2.80
2012	50.000	175.000		0.24	2.54	2.78
2013	50.000	175.000		0.22	2.54	2.76
2014	50.000	175.000		0.20	2.54	2.74
2015	50.000	175.000		0.18	2.54	2.72
2016	50.000	175.000		0.16	2.54	2.70
2017	50.000	175.000		0.14	2.54	2.68
2018	50.000	175.000		0.12	2.54	2.66
2019	50.000	175.000		0.10	2.54	2.64
2020	50.000	175.000		0.08	2.54	2.62
2021	50.000	175.000		0.06	2.54	2.60
2022	50.000	175.000		0.04	2.54	2.58
2023	50.000	175.000		0.02	2.54	2.56
2024		73.500		0.00	1.07	1.07
2025						
2026						
2027						
2028						
2029						
2030						
2031						
2032						
2033						
2034						
2035						
Total 2002 Base	$1,000.00	$3,500.00	$80.51		$50.75	$135.59
Total 2002 P.V.	387	1,303	68.203	2.193	18.889	89.285

LEVELIZED COST OF: CCCT CAC/MSOS/NFAAT/S/1a

1. PLANT CHARACTERISTICS

Discount Rate = 10.00% Capacity Factor = 65%
Annual Av. Capacity (@ South) = 248 MW In-Service-Date = 2009
Life = 30 years Present Value Year = 2002

2. LEVELIZED COST BY ITEM

	Generation & Transmission Capital	Fixed Costs	Variable Costs w/ low NG scen	**Base Cost**	Incremental High NG Price scenario	Incremental High Environ. Premium	**TOTAL**
$/MWh	22.06	1.01	37.56	**60.63**	8.32	10.24	**79.19**
c/kWh	2.21	0.10	3.76	**6.06**	0.83	1.02	**7.92**

3. CASHFLOW (mm CDN 2002 Base Dollars)

Fiscal Year Beg. April	Plant Outputs @ South Average MW	Average GW.h	Generation & Transmission Capital	Fixed Costs	Variable Costs (w/ low NG scen)	Base Cost	Incremental High NG Price scenario	Incremental High Environ. Premium	TOTAL
2001									
2002									
2003									
2004									
2005									
2006			28.15			28.15			28.15
2007			188.31			188.31			188.31
2008			52.25			52.25			52.25
2009	248	1416	1.03	1.43	50.01	52.47	10.05	6.30	68.81
2010	248	1416		1.43	50.53	51.97	10.98	7.91	70.85
2011	248	1416		1.43	50.87	52.30	11.36	9.47	73.13
2012	248	1416		1.43	51.23	52.66	10.41	11.02	74.09
2013	248	1416		1.43	51.58	53.02	10.05	12.57	75.64
2014	248	1416		1.43	51.95	53.38	9.69	14.13	77.20
2015	248	1416		1.43	52.31	53.74	9.62	15.68	79.05
2016	248	1416		1.43	52.68	54.11	10.45	16.46	81.02
2017	248	1416		1.43	53.05	54.48	11.12	17.23	82.84
2018	248	1416		1.43	53.42	54.86	12.83	18.01	85.70
2019	248	1416		1.43	53.80	55.23	14.24	18.79	88.26
2020	248	1416		1.43	54.18	55.61	14.61	19.57	89.79
2021	248	1416		1.43	54.56	55.99	14.97	19.57	90.53
2022	248	1416		1.43	54.95	56.38	15.33	19.57	91.28
2023	248	1416		1.43	55.34	56.77	15.84	19.57	92.17
2024	248	1416		1.43	55.73	57.16	15.44	19.57	92.17
2025	248	1416		1.43	56.12	57.55	15.05	19.57	92.17
2026	248	1416		1.43	56.52	57.95	14.65	19.57	92.17
2027	248	1416		1.43	56.92	58.35	14.25	19.57	92.17
2028	248	1416		1.43	57.33	58.76	13.85	19.57	92.17
2029	248	1416		1.43	57.73	59.17	13.44	19.57	92.17
2030	248	1416		1.43	58.15	59.58	13.03	19.57	92.17
2031	248	1416		1.43	58.56	59.99	12.61	19.57	92.17
2032	248	1416		1.43	58.98	60.41	12.20	19.57	92.17
2033	248	1416		1.43	59.40	60.83	11.77	19.57	92.17
2034	248	1416		1.43	59.82	61.25	11.35	19.57	92.17
2035	248	1416		1.43	60.25	61.68	10.92	19.57	92.17
2036	248	1416		1.43	60.68	62.11	10.49	19.57	92.17
2037	248	1416		1.43	61.12	62.55	10.06	19.57	92.17
2038	248	1416		1.43	61.12	62.55	10.06	19.57	92.17

LEVELIZED COST OF: 2x NEW FUTURE SCCT

1. PLANT CHARACTERISTICS

Discount Rate = 10.00%   Capacity Factor = 65%
Annual Av. Capacity (@ South) = 240 MW   In-Service-Date = 2009
Life = 40 years   Present Value Year = 2002

2. LEVELIZED COST BY ITEM

	Generation & Transmission Capital	Fixed Costs	Variable Costs w/ low NG scen)	**Base Cost**	Incremental High NG Price scenario	Incremental High Environ. Premium	**TOTAL**
$/MWh	12.43	0.80	59.24	**72.47**	13.49	16.89	**102.85**
c/kWh	1.24	0.08	5.92	**7.25**	1.35	1.69	**10.29**

3. CASHFLOW (mm CDN 2002 Base Dollars)

Fiscal Year Beg. April	Plant Outputs @ South Average MW	Average GW.h	Generation & Transmission Capital	Fixed Costs	Variable Costs (w/ low NG scen)	Base Cost	Incremental High NG Price scenario	Incremental High Environ. Premium	TOTAL
2001									
2002									
2003									
2004									
2005									
2006			15.60			15.60			15.60
2007			65.79			65.79			65.79
2008			70.17			70.17			70.17
2009	240	1367	5.27	1.10	75.57	81.93	15.81	9.92	107.66
2010	240	1367		1.10	76.40	77.49	17.28	12.45	107.23
2011	240	1367		1.10	76.92	78.02	17.89	14.90	110.81
2012	240	1367		1.10	77.48	78.58	16.39	17.35	112.32
2013	240	1367		1.10	78.05	79.15	15.82	19.79	114.76
2014	240	1367		1.10	78.62	79.72	15.25	22.24	117.21
2015	240	1367		1.10	79.19	80.29	15.15	24.68	120.12
2016	240	1367		1.10	79.77	80.87	16.45	25.91	123.22
2017	240	1367		1.10	80.35	81.45	17.51	27.13	126.09
2018	240	1367		1.10	80.94	82.04	20.20	28.35	130.59
2019	240	1367		1.10	81.53	82.63	22.42	29.58	134.63
2020	240	1367		1.10	82.13	83.23	23.00	30.80	137.03
2021	240	1367		1.10	82.73	83.83	23.57	30.80	138.20
2022	240	1367		1.10	83.34	84.44	24.14	30.80	139.37
2023	240	1367		1.10	83.95	85.05	24.93	30.80	140.78
2024	240	1367		1.10	84.57	85.67	24.31	30.80	140.78
2025	240	1367		1.10	85.19	86.29	23.69	30.80	140.78
2026	240	1367		1.10	85.82	86.92	23.07	30.80	140.78
2027	240	1367		1.10	86.45	87.55	22.43	30.80	140.78
2028	240	1367		1.10	87.09	88.18	21.80	30.80	140.78
2029	240	1367		1.10	87.73	88.83	21.16	30.80	140.78
2030	240	1367		1.10	88.38	89.47	20.51	30.80	140.78
2031	240	1367		1.10	89.03	90.13	19.86	30.80	140.78
2032	240	1367		1.10	89.69	90.78	19.20	30.80	140.78
2033	240	1367		1.10	90.35	91.45	18.54	30.80	140.78
2034	240	1367		1.10	91.02	92.11	17.87	30.80	140.78
2035	240	1367		1.10	91.69	92.79	17.19	30.80	140.78
2036	240	1367		1.10	92.37	93.46	16.52	30.80	140.78
2037	240	1367		1.10	93.05	94.15	15.83	30.80	140.78
2038	240	1367		1.10	93.05	94.15	15.83	30.80	140.78
2039	240	1367		1.10	93.05	94.15	15.83	30.80	140.78
2040	240	1367		1.10	93.05	94.15	15.83	30.80	140.78
2041	240	1367		1.10	93.05	94.15	15.83	30.80	140.78
2042	240	1367		1.10	93.05	94.15	15.83	30.80	140.78
2043	240	1367		1.10	93.05	94.15	15.83	30.80	140.78
2044	240	1367		1.10	93.05	94.15	15.83	30.80	140.78
2045	240	1367		1.10	93.05	94.15	15.83	30.80	140.78
2046	240	1367		1.10	93.05	94.15	15.83	30.80	140.78
2047	240	1367		1.10	93.05	94.15	15.83	30.80	140.78
2048	240	1367		1.10	93.05	94.15	15.83	30.80	140.78

LEVELIZED COST OF: <u>Coal</u>

CAC/MS0S/NFAAT/S/1a

1. PLANT CHARACTERISTICS

Annual Av. Capacity (@ South) = 400 MW
Life = 30 years

Discount Rate = 10.00%
In-Service-Date = 2009
Present Value Year = 2002

Capacity Factor = 65%

2. LEVELIZED COST BY ITEM

	Generation & Transmission Capital	Fixed Costs	Variable Costs	**Base Cost**	Incremental Technology Cost (IGCC-PC)	Incremental High Environ. Premium	**TOTAL**
$/MWh	37.56	7.77	19.52	**64.86**	4.00	28.50	**97.36**
c/kWh	3.76	0.78	1.95	**6.49**	0.40	2.85	**9.74**

3. CASHFLOW (mm CDN 2002 Base Dollars)

Fiscal Year Beg. April	Plant Outputs @ South Average MW	Plant Outputs @ South Average GW.h	Generation & Transmission Capital	Fixed Costs	Variable Costs	Base Cost	Incremental Technology Cost (IGCC-PC)	Incremental High Environ. Premium	TOTAL
2001									
2002									
2003									
2004									
2005									
2006									
2007			129.42			129.42	63.12		192.54
2008			408.83			408.83	210.14		618.97
2009	400	2279	281.41	17.71	44.29	343.41	178.95	32.43	554.79
2010	400	2279		17.71	44.40	62.11	31.96	41.47	135.55
2011	400	2279		17.71	44.38	62.09	31.96	47.09	141.14
2012	400	2279		17.71	44.38	62.09	31.96	52.71	146.76
2013	400	2279		17.71	44.38	62.09	31.96	58.33	152.38
2014	400	2279		17.71	44.38	62.09	31.96	63.95	158.00
2015	400	2279		17.71	44.38	62.09	31.96	69.57	163.62
2016	400	2279		17.71	44.44	62.16	31.98	72.38	166.51
2017	400	2279		17.71	44.51	62.22	32.00	75.19	169.40
2018	400	2279		17.71	44.57	62.28	32.01	78.00	172.30
2019	400	2279		17.71	44.63	62.34	32.03	80.81	175.19
2020	400	2279		17.71	44.70	62.41	32.05	83.62	178.08
2021	400	2279		17.71	44.70	62.41	32.05	83.62	178.08
2022	400	2279		17.71	44.70	62.41	32.05	83.62	178.08
2023	400	2279		17.71	44.70	62.41	32.05	83.62	178.08
2024	400	2279		17.71	44.70	62.41	32.05	83.62	178.08
2025	400	2279		17.71	44.70	62.41	32.05	83.62	178.08
2026	400	2279		17.71	44.70	62.41	32.05	83.62	178.08
2027	400	2279		17.71	44.70	62.41	32.05	83.62	178.08
2028	400	2279		17.71	44.70	62.41	32.05	83.62	178.08
2029	400	2279		17.71	44.70	62.41	32.05	83.62	178.08
2030	400	2279		17.71	44.70	62.41	32.05	83.62	178.08
2031	400	2279		17.71	44.70	62.41	32.05	83.62	178.08
2032	400	2279		17.71	44.70	62.41	32.05	83.62	178.08
2033	400	2279		17.71	44.70	62.41	32.05	83.62	178.08
2034	400	2279		17.71	44.70	62.41	32.05	83.62	178.08
2035	400	2279		17.71	44.70	62.41	32.05	83.62	178.08
2036	400	2279		17.71	44.70	62.41	32.05	83.62	178.08
2037	400	2279		17.71	44.70	62.41	32.05	83.62	178.08
2038	400	2279		17.71	44.70	62.41	32.05	83.62	178.08

DSM Costs from 2003

Net Present Value Year = 2001
Discount 10%
(2002 G911)

01 to 02 Convers 1.015

	Support & Contingency			Lowest Cost Program			Highest Cost Program		
				Program Lev Cost	1.52	02$	Program Lev Cost	6.85	02$
				Support & Contin +	0.31	02$	Support & Contin +	0.31	02$
				Total Low	**1.83**	**02$**	Total High	**7.16**	**02$**
	@ generation			***@ meter***			***@ meter***		
	Levelized($/MWh)	2.80	01$	Levelized($/MWh)	15.53	01$	Levelized($/MWh)	70.15	01$
	Levelized(c/kWh)	0.28	01$	Levelized(c/kWh)	1.55	01$	Levelized(c/kWh)	7.01	01$
	Levelized(c/kWh)	0.28	02$	Levelized(c/kWh)	1.58	02$	Levelized(c/kWh)	7.12	02$
	Gener to S. Bus	10%		Meter to S. Bus	4%		Meter to S. Bus	4%	
@ South Bus	Levelized(c/kWh)	**0.31**	**02$**	Levelized(c/kWh)	**1.52**	**02$**	Levelized(c/kWh)	**6.85**	**02$**

Original Values

	Support & Contingency: Total Contrib to Annual Energy (GW.h) @ generation	Support & Contingency: Total Cost	Lowest Cost Program: Total Contrib to Annual Energy (GW.h) @ meter	Lowest Cost Program: Total Cost	Highest Cost Program: Total Contrib to Annual Energy (GW.h) @ meter	Highest Cost Program: Total Cost
2001	0.00		0.00		0.00	
2002	0.00		0.00		0.00	
2003	59.52	$2,002,626	2.32	$348,603	0.45	$321,838
2004	124.04	$2,017,363	4.65	$348,603	0.93	$333,992
2005	189.91	$2,024,648	5.07	$50,060	1.42	$346,147
2006	241.88	$1,254,167	5.49	$34,797	1.66	$150,856
2007	290.63	$1,092,515	5.90	$34,797	1.89	$145,856
2008	337.36	$1,041,258	6.28	$31,228	2.13	$145,856
2009	377.09	$775,365	6.66	$31,228	2.37	$145,856
2010	413.20	$765,436	7.03	$31,228	2.62	$158,011
2011	445.12	$551,434	7.41	$31,228	2.88	$158,011
2012	468.71	$524,934	7.78	$31,228	3.13	$158,011
2013	492.47	$524,934	8.16	$31,228	3.39	$158,011
2014	518.31	$524,934	8.54	$31,228	3.67	$170,166
2015	543.09	$488,380	11.45	$241,798	3.94	$170,166
2016	568.39	$488,380	12.03	$241,798	4.22	$170,166
2017	596.86	$487,880	12.62	$241,798	4.50	$170,166
2018	617.59	$487,880	11.15	$70,487	4.78	$177,458
2019	637.36	$487,880	9.67	$70,487	5.07	$177,458
2020	656.91	$487,880	10.10	$70,487	5.36	$177,458
2021	649.10	$487,880	10.53	$70,487	5.65	$177,458
2022	632.95	$487,880	10.96	$70,487	5.93	$177,458
2023	609.74	$487,880	11.33	$62,160	6.23	$182,320
2024	584.89	$487,880	11.70	$62,160	6.53	$182,320
2025	560.16	$487,880	12.08	$62,160	6.82	$182,320
2026	544.68	$487,880	12.45	$62,160	6.72	$182,320
2027	533.23	$487,880	12.82	$62,160	6.59	$182,320
2028	525.37	$487,880	13.19	$62,160	6.43	$182,320
2029	526.75	$487,880	13.57	$62,160	6.25	$182,320
2030	530.61	$487,880	13.57	$62,160	6.05	$182,320
2031	530.61	$487,880	13.57	$241,798	6.05	$182,320
2032	530.61	$487,880	13.57	$241,798	6.05	$182,320
2033	530.61	$487,880	13.57	$70,487	6.05	$182,320
2034	530.61	$487,880	13.57	$70,487	6.05	$182,320
2035	530.61	$487,880	13.57	$70,487	6.05	$182,320
2036	530.61	$487,880	13.57	$70,487	6.05	$182,320
2037	530.61	$487,880	13.57	$70,487	6.05	$182,320
2038	530.61	$487,880	13.57	$62,160	6.05	$182,320
Totals	17,520.79	$ 24,809,733	373.02	$ 3,508,755	166.03	$ 6,707,524
PV Totals	3,269.38	$ 9,155,589	66.38	$ 1,030,616	25.90	$ 1,816,915

CAC/MSOS/NFAAT/S/2

Comment on Appropriateness of using 2001 PowerSmart Plan under current export prices and market opportunities.

Current DSM Plan

Manitoba Hydro's current approved DSM plan, the 2001 PowerSmart Plan, was developed based upon marginal cost values current in 2001, of which export prices are a component. Under this analysis, a number of economically feasible market attainable opportunities were identified and market/program strategies proposed, resulting in the current DSM targeted savings of 356 MW and 1272 GW.h by 2011/12.

Changes within electricity markets throughout North America, as well as increasing environmental concerns, have led to increased interest in, and increased value of, potential DSM savings. In light of these changes, in 2002 Manitoba Hydro initiated a DSM Market Potential Study to reassess the maximum economically feasible market attainable DSM savings within Manitoba. This assessment values DSM savings according to Manitoba Hydro's latest export price assumptions used in the economic evaluation of Wuskwatim and all other resource options. While higher values on the export market will mean that previously uneconomic technologies may now become more economically feasible, this change does not necessarily result in a proportionate increase in the number of economic opportunities, nor will it necessarily result in an equivalent percentage increase in the market attainable savings. A technology may be theoretically economic and therefore worthwhile developing within the marketplace; however, there are a number of market barriers that these technologies may face and that will need to be addressed through individual program design (e.g. awareness, availability of qualified trade allies, etc.). The additional costs associated with this market intervention (e.g. program delivery, education, verification/quality control) will increase the economic cost of the DSM opportunity and in some cases may make it less attractive as a resource option.

Once the DSM Market Potential Study is finalized, a new formal DSM plan will be prepared. For the interim, Manitoba Hydro continues to use the 2001 DSM plan for operational purposes. Throughout detailed program design and implementation, projected DSM savings have not deviated substantially from the overall targets identified under the 2001 DSM plan as forecasted market adoption for some opportunities were slightly overstated and others slightly understated. In addition to the opportunities identified under the 2001 DSM plan, Manitoba Hydro has continued to explore additional economic opportunities as they emerge and add them to the DSM product mix (.e.g. recently launched Commercial Chiller Program).

Manitoba Hydro will continue to pursue all economically feasible, market attainable DSM opportunities which can be achieved without unacceptable rate impacts. The development of additional DSM, beyond levels currently forecast and used in the evaluation of Wuskwatim economics, is not incompatible with the development of Wuskwatim for 2009. Even if future levels of DSM were doubled from those currently forecast, the impact on Wuskwatim's IRR is only a reduction of 0.05%. See CAC/MSOS/NFAAT/S/6 for more details on the sensitivity of Wuskwatim economics to higher levels of DSM.

CCC/NFAAT/S/1

Potential Impact of Standard Market Design (SMD) on Electricity Markets and on Manitoba Hydro's Export Market

This section provides an update on recent developments in the U.S. Federal Energy Regulatory Commission (FERC) relating to its proposal on Standard Market Design (SMD). The implications of this initiative to Manitoba Hydro's export market potential and the expected accessibility of this market are assessed.

Background

On July 31, 2002, FERC issued a Notice of Proposed Rulemaking (NOPR) which would substantially alter the regulations governing the nation's wholesale electricity markets by establishing a common set of rules -- the Standard Market Design or SMD – applicable to all U.S. public utilities that own, operate or control transmission facilities. FERC contended that these changes were necessary to remedy undue discrimination which lingers despite FERC's Order No. 888 (which initiated open access transmission) and subsequent related orders.

Manitoba Hydro's export power business benefited significantly from open access transmission under Order No. 888 as it allowed many more U.S. customers to access Manitoba's surplus hydro resources. Any further changes in the regulation of U.S. electricity markets that facilitate a more competitive market, such as the Standard Market Design is intended to be, are expected to benefit low cost suppliers such as Manitoba Hydro.

FERC's SMD proposal generated loud and somewhat unexpected opposition in a number of areas, such as FERC attempting to assert jurisdiction over areas traditionally under state responsibility. Lawmakers listened to the concerns, and Congress commissioned the U.S. Department of Energy (DOE) to do an independent study of the costs and benefits of SMD to the electricity markets. Insight into the impacts of the SMD proposal on the electricity markets for potential future hydro developments in Manitoba can be determined from the DOE study. Note that the DOE study was conducted before FERC's April 28, 2003 White Paper on the new wholesale power market platform. While the White Paper softens some of the SMD proposals in a few areas, it does not materially alter the conclusions of the study. The Midwest Independent System Operator (MISO) is already well along in the process of developing its market rules consistent with the SMD proposal, and for the most part will continue to proceed on its current path regardless of the White Paper. Further information on recent developments relating to the White Paper are provided at the end of this section.

The DOE Study on SMD

On April 30, 2003, the U.S. Department of Energy released its Report to Congress: Impacts of the Federal Energy Regulatory Commission's Proposal for Standard Market Design. Quantitative and qualitative approaches were used in the analysis of the impacts. The analysis consists of Non-SMD and SMD cases. The Non-SMD case projected a continuation of existing conditions, in which some large areas of the country had established centralized wholesale electricity markets and others do not. In the SMD case, FERC's SMD rulemaking would be finalized and all areas under FERC jurisdiction would establish fully competitive regional markets with SMD's basic features.

Following are the most relevant conclusions of the DOE study.

1. Impacts on Wholesale Prices

- The average U.S. wide wholesale prices under SMD are estimated to decrease by about 1% in 2005 through 2010 and by about 2% from 2011 through 2015 relative to the Non-SMD case. However, the impacts vary significantly among regions.

For the MAPP Region (North Dakota, most of Minnesota, most of South Dakota, Western Iowa, Nebraska, and Eastern Montana – which is a good proxy for Manitoba Hydro's U.S. marketplace), average wholesale prices are estimated to increase by 10% in the near term (2005-2010), from Non-SMD to the SMD Case. In the mid- term (2011–2015), wholesale electricity prices for the Non-SMD and SMD cases are expected to be the same. For the long term (2016-2020), wholesale prices in MAPP are expected to be 1% lower for the SMD Case in comparison with the Non-SMD Case.

In commenting on the MAPP Region, the DOE study stated:

- "MAPP is a net exporter. In the Non-SMD case, market inefficiencies prevent some of the available low-cost power from reaching more distant load centers. As a result, net exports increase in the SMD case, especially in the early years.

- In the non-SMD case, MAPP is among the regions with the lowest wholesale prices. Wholesale prices rise in the near term with SMD due to the ability to reach higher priced markets, but the effect moderates within a few years."

2. <u>Impacts on Security and Reliability of Generation and Transmission Infrastructure</u>

The DOE study concluded that overall the U.S. electric system is very reliable today and would continue to be reliable under SMD. SMD would be unlikely to have adverse effects on reliability and could have several positive effects. In particular, a regional approach to transmission planning and related planning issues under SMD would improve the coordination among the State and regional resource agencies, which should result in investments to relieve transmission bottlenecks. Any improvements in the transmission grid within Manitoba Hydro's marketplace should benefit low cost suppliers such as Manitoba Hydro because they expand the marketplace, thus creating new opportunities for export sales and purchases.

3. <u>Implications for Future Hydro Development:</u>

<u>Near term (2005-2010)</u>: The increase in wholesale electricity price in the MAPP region under SMD as forecast by DOE in the near term period will have a positive impact on Manitoba Hydro's export revenues from existing facilities.

Mid and Long term (2011-2020): The DOE forecast indicates SMD will have minimal impact on wholesale electricity prices in MAPP in the mid to long term. A potential 1% decline in wholesale prices in the MAPP region in the long term is expected to be offset by the positive effect of new transmission investment and expanded opportunities in the marketplace. No discernable effect on prices from SMD is expected on Manitoba Hydro's U.S. marketplace in the long term.

Manitoba Hydro's perspective on these DOE conclusions is that MAPP prices may be slightly less with SMD due to enhanced market efficiency. However, reduction in transmission bottlenecks and greater access to further markets will work in the opposite direction and may even more than affect the small 1% decline to yield an increase in MAPP prices due to SMD. Regardless of the uncertainty as to whether SMD will cause a small increase or decrease, it is expected by Manitoba Hydro that SMD will decrease the risks to Manitoba Hydro. SMD would reduce risks by reducing the chance of not being able to access higher price markets.

The FERC White Paper on SMD and Update on Recent Developments

As noted in the Wuskwatim NFAAT submission, the U.S. Federal Energy Regulatory Commission's ("FERC") July 2002 Notice of Proposed Rulemaking ("NOPR") on Standard Market Design ("SMD") has caused much controversy in the U.S., particularly with regard to federal intrusion into traditional state authority. In the months following the issuance of the NOPR, considerable opposition was voiced by officials and elected representatives from western and southern U.S. states claiming that the net effect of the proposal would be to raise power prices in low-cost states.

In addition, political pressure was applied at high levels in the U.S. Congress throughout the early months of 2003 leading to U.S. Senate Energy Committee Chairman Pete Domenici threatening to cut FERC's appropriations from Congress if the Commission did not soften its insistence on national standards.

The original Wuskwatim NFAAT submission had already anticipated that FERC would be pressured into stepping back from its original proposals of prescriptive national rules, and would be forced to modify its design to one that was regionally flexible, both in terms of details as well as the timing of implementation. This adjustment in approach by FERC has in fact occurred since the original submission was prepared.

On April 28, 2003, FERC issued a White Paper which effectively ended the controversial standard market design in favour of a set of revisions now dubbed the “wholesale power market platform.” Regional flexibility and increased participation from state and local authorities are heavily emphasized in the new document.

In its final rule, according to the White Paper, the Commission will focus on the formation of regional transmission organizations (“RTOs”) and ensuring that they have sound wholesale market rules. Implementation schedules will vary to allow for regional differences. The Commission will now rely on regional state committees to shape the market design features and give State commissions flexibility and decision-making power on issues such as transmission planning and resource adequacy. The document notes that FERC will not require that firm transmission rights be auctioned, and further notes that FERC no longer plans to extend its jurisdiction over the transmission rate component of bundled retail sales.

Industry observers note that this compromise on the part of FERC still goes only part of the way to satisfying SMD’s harshest critics. A Standard & Poor’s survey of state utility commissioners recently noted that, although commissioners from the Midwest and states offering a degree of choice in electricity markets express guarded to neutral assessments of FERC’s latest proposals, regulators from the U.S. south and west, plus regulated states, register opposition by margins as great as 10-1. The Alliance of State Leaders Protecting Electricity Consumers, which represents state regulators from the U.S. south and west, continue to insist that reliable service and affordable rates enjoyed by consumers in their regions remain at risk. The Alliance is adamant that the U.S. Congress must reaffirm states’ authority to protect consumers, perhaps through comprehensive energy legislation being considered by both the U.S. House of Representatives and the U.S. Senate.

The U.S. Congress has been pursuing development of comprehensive legislation for a number of years, and the process continues in the current Congress. The U.S. House of Representatives finished its version of an energy bill in April 2003.

The timing of a U.S. Senate energy bill is still in doubt, with numerous postponements occurring throughout spring and summer 2003. Senator Domenici has stated that FERC's White Paper "was not clear enough to be helpful" and raised more concerns than it allayed. The current Senate bill contains language which would bar FERC from completing its final rules before July 2005, about two years later than FERC originally wanted. Assuming the completion of a Senate energy bill, the next step would see negotiators from both chambers of the Congress attempt to develop compromise legislation.

In any event, it is likely that the final design for electricity markets in the United States will now be fashioned in gradual steps, by FERC and Congress encouragement of individual regional contributions.

One example of these regional contributions would be the continued development of an electricity market under the auspices of the Midwest Independent Transmission System Operator ("MISO"), the RTO with which Manitoba Hydro maintains a coordination agreement. In late April 2003, MISO announced that its planned start-up date to open day-ahead and real-time energy markets in the U.S. Midwest was being postponed to March 31, 2004. The revised timeline is designed to accommodate additional training for market participants, as well as additional time to review and confirm the proposed market rules.

CAC/MSOS/NFAAT/S/3

Further Information on High and Low Export Price Forecasts and Historic Average Prices

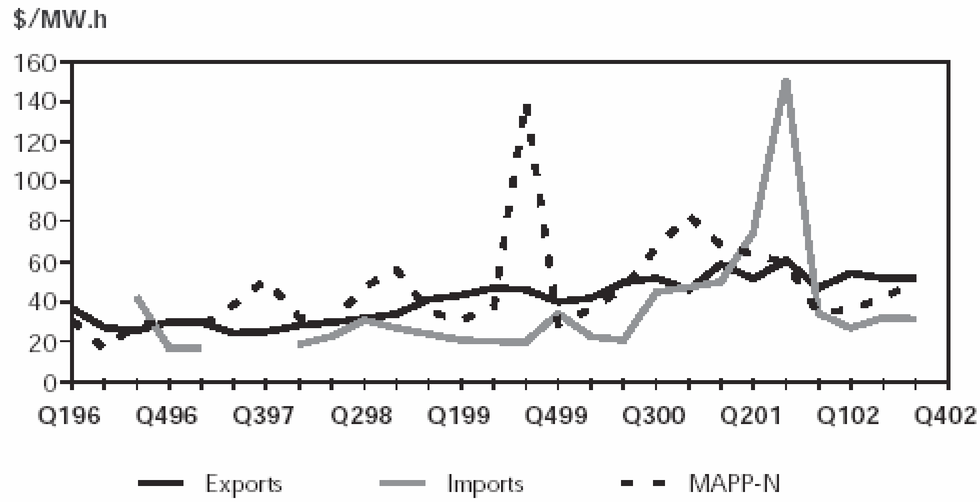
This section provides further information on the High and Low export price forecasts and historic average export prices and how they compare to market prices as measured by an index of electricity prices in the U.S. In addition, equivalent natural gas prices corresponding to the Low and High forecasts is determined under the assumption that a combined cycle combustion turbine is utilized to produce electricity of the same characteristics as export power. A comparison of these natural gas prices to several forecasts of natural gas price is made. It is concluded that the Low and High electricity price forecasts are generally consistent with forecasts of equivalent natural gas prices.

<u>Forecasts and Historic Export Prices Compared to an Index for MAPP-North</u>

The National Energy Board (NEB) of Canada has published a report "Canadian Electricity Exports and Imports - An Energy Market Assessment January 2003" that provides information on Manitoba Hydro's export and imports. This report states that "Manitoba export and import prices are generally in the same range as wholesale prices in MAPP-North, the northern part of the Mid-Continent Area Power Pool (Figure 3.5.2). Approximately 95 percent of exports from Manitoba are transacted through bilateral contracts. The long-term nature of these contracts results in Manitoba missing the highs and lows that tend to occur on the spot market, so Manitoba's average prices exhibit more stability than MAPP-N prices." The figure depicts the prices of Manitoba Hydro exports and imports from the first quarter of 1996 to the fourth quarter of 2002 all in current Canadian dollars. The figure also depicts the MAPP-North index, which is established by Power Markets Week and is for on-peak sales of 5x16 blocks of power.

FIGURE 3.5.2

Manitoba Export and Import Prices vs. MAPP North*



* Mid-Continent Area Power Pool - North
Source: NEB, PIRA. MAPP-North prices are average on-peak prices (7:00 a.m. - 11:00 p.m., Monday to Saturday).

The NEB report also states "Manitoba's export prices have increased from an average of $18 per MWh in 1990 to approximately $51 per MWh in 2002." This price of $51 in 2002 is consistent with the historic price provided in Figure 5.9, Chapter 5, Volume 1 of Need for and Alternatives to the Wuskwatim Project (NFAAT). As shown in Figure 3.5.2 above, the MAPP-North index of on-peak prices is a good indicator of Manitoba Hydro's average export prices.

The Low export price forecast was developed on the assumption that there would be no further increases in export prices into the long term. In this scenario all fundamental factors that drive up power prices would not occur into the long term. This assumption is considered to be conservative since all forecasts obtained by Manitoba Hydro projected that power prices would increase in real terms due to a variety of factors such as environmental considerations, use of more costly generation sources and expected real escalation in fuel.

The High export price forecast was developed on the assumption that a combination of fundamental factors that drive up power prices could occur concurrently into the long term. This forecast is higher than the scenario with the highest environmental export premiums added to the reference price. The high forecast can result from factors such as high and volatile natural gas prices, extremely high environmental premiums, and high economic growth resulting in supply shortages.

<u>Natural Gas Prices Corresponding to Export Price Forecasts for Electricity</u>

It is judged that there is a 5% probability that the export prices will equal or exceed the High export price forecast. Similarly, export prices can be expected to be equal or lower than the Low price forecast with a probability of 5%. In order to provide some context to the range of forecasts for electricity prices, the equivalent natural gas price was calculated assuming that a combined cycle combustion turbine is utilized to produce electricity of the same characteristics as export power.

It was found that a natural gas price of $3.10 per mmbtu (2002 U.S. $) with no real escalation over time was required to produce a forecast similar to the Low. This price is lower than publicly available price forecasts for the post-2010 period. The National Energy Board's recent report entitled "Scenarios for Supply and Demand to 2025" published in July 2003, predicts natural gas prices of $3.45 in 2010 with real escalation thereafter in the Supply Push Scenario (which is the scenario that results in low natural gas prices). The US Energy Information Administration in its Annual Energy Outlook 2003 predicts natural gas prices in excess of $3.10. Even in its low economic growth case (which results in lower natural gas prices), prices are forecast to be $3.18 in 2010 and reach $4.09 (in $2002) by 2025. Most forecasts have real increases in natural gas prices over time because of increasing demand and the requirement to meet that demand from more remote supply basins or from offshore in liquid form, thus resulting in higher cost. Based on the above comparisons, a natural gas price forecast of less than $3.10 per mmbtu with no real escalation for the next 25 years can be considered to be consistent with a 5% probability that was estimated for the low export price forecast.

Similar to the Low export price forecast, a natural gas price was determined for the High export price forecast. This comparison may not be as meaningful since the high electricity price is largely influenced by premiums for environmental considerations. If the high scenario of environmental premiums is removed from the high forecast, it was determined that a natural gas price of $5.15 per mmbtu (2002 U.S. $) in the long term would be required for a combined cycle combustion turbine to be utilized to produce electricity of the same characteristics as export power. This price is well above the range of natural gas forecasts available to Manitoba Hydro and is consistent with a 5% probability of being exceeded that was estimated for the high export price forecast.

Based on the above observations, it is concluded that the Low and High electricity price forecasts are generally consistent with forecasts of equivalent natural gas prices. In addition, it is concluded that the MAPP-North index is a reasonable indicator of Manitoba Hydro's average export prices.

CAC/MSOS/NFAAT/S/4

Recent Load Growth Projections in MAPP-US and Supply Forecasts

The following table compares load growth projections contained in the July 2002 MAPP Load and Capability Report with projections contained in the May 2003 2nd Draft of the 2003 MAPP Load and Capability Report. An extract of the Draft 2003 MAPP Load and Capability Report is provided in this Supplemental Filing (CAC/MSOS/NFAAT/S/4a). It provides information on future load growth, generation retirements and additions and transmission enhancements in the region central to Manitoba Hydro exports. The full report can be found on MAPP's website at www.mapp.org/content/eia.shtml.

Table 1

Forecasted Annual Net Energy Requirements and Seasonal System Demand In MAPP-US (2002 Load and Capability Report vs. 2003 Draft Load and Capability Report)

	Net Energy Requirements (GWh)		Summer System Demand (MW)	
	2002 L&C*	**2003 L&C**	**2002 L&C**	**2003 L&C**
2001[1]	*144,893*	*144,893*	*28,321*	*28,321*
2002[1]	*150,058*	*150,058*	*29,119*	*29,119*
2003	150,595	157,518	28,382	29,957
2004	157,110	162,091	29,013	30,555
2005	159,886	165,604	29,507	31,156
2006	163,170	169,315	30,035	31,763
2007	165,193	172,163	30,604	32,413
2008	167,768	175,777	31,185	33,022
2009	170,215	178,570	31,866	33,640
2010	172,696	181,736	32,459	34,228
2011	175,255	184,702	33,022	34,811
2012		187,878		35,383
Increase (01 – 11)	30,362	39,809	4,701	6,490
AAC**: (01 – 11)	1.9%	2.4%	1.5%	2.1%

*L&C = Load and Capability

**AAC = Average Annual Change

[1] Values for 2001 and 2002 are actuals

The table illustrates that currently forecasted annual net energy requirements and seasonal system demand in MAPP-US have increased over the 2002 report. The 2003 draft report illustrates that both projected energy and demand requirements are 5.4% higher for 2011 than the projections for 2011 in the 2002 report. This increase in load is favourable to Manitoba Hydro since this provides more opportunity to export power. In order to obtain additional insight into the opportunity for export sales, it is necessary to investigate the expected resource additions in MAPP and the resulting surplus or deficit of power.

The MAPP Load and Capability Report includes an estimate of resources that are reported by the utilities as expected to be available in the future. Table 2 below provides a summary of supply and demand along with surplus or deficit for the period to 2012.

Table 2

Forecasted Seasonal (Summer) Capability and Capacity Obligation in MAPP-US (MW)
(2002 Load and Capability Report vs. 2003 Draft Load and Capability Report)

	2002 L&C			2003 L&C		
Summer	**Adjusted Net Capability (MW)**	**Total Firm Capacity Obligation (MW)**	**Surplus or Deficit (MW)**	**Adjusted Net Capability (MW)**	**Total firm Capacity Obligation (MW)**	**Surplus or Deficit (MW)**
2002	32,196	29,948	2,248			
2003	32,173	30,538	1,635	34,668	32,764	1,904
2004	31,997	31,301	696	34,229	33,414	815
2005	31,635	31,845	-210	34,503	33,991	512
2006	31,963	32,455	-492	34,456	34,659	-203
2007	32,488	33,136	-648	35,760	35,377	383
2008	32,384	33,710	-1,326	35,895	35,969	-74
2009	33,144	34,492	-1,348	36,413	36,658	-245
2010	33,093	35,171	-2,078	36,407	37,312	-905
2011	33,172	35,740	-2,568	36,542	37,888	-1,346
2012				36,557	38,524	-1,967

Sources:
MAPP Load and Capability Report 2002 – Section III-3
MAPP Load and Capability Report 2003 (Draft 2) – Section III-3

However, the usefulness of this information more than several years out in time is limited because long-term plans are not usually provided by the reporting utilities and such information is often considered proprietary. For example, the summary of supply/demand balance indicates that deficits in MAPP begin as early as 2006 and are as high as 2000 MW by 2012 for the 2003 report.

An alternative approach to using the MAPP Load and Capability Report is to assess what projects are likely to be developed in the future. An example of such an assessment is a Henwood Energy Services estimate that about 7500 MW of generating capacity is expected to be added to the MAPP area between 2002 and 2006. This has the effect of creating reserve margins as high as 25% in 2003 and reducing to 15% over this time period. This is generally consistent with the supply/demand MAPP Load and Capability Report for these early years. The significant additional resources in the early years results in an oversupply in the short term, but it is expected that load growth will overtake supply additions after this period of excess capacity and new resource additions will continue to be required.

In general, the MidWest electricity markets have recently experienced significant new development of merchant power plants and this has resulted in significant excess capacity for the next several years. However, most of this excess is not in the MAPP region, but interconnectivity has the effect of suppressing prices in the entire region. As a result of the above conclusions, Henwood Energy Services has market price forecasts that do not increase significantly until about 2006 when the excess capacity due to oversupply is offset by load growth. In the longer term, electricity markets are forecast to move to an equilibrium situation in which new combined cycle entrants are able to recover all investment costs including debt costs and return on equity.

Table 1 illustrates that the projected capacity and energy of the proposed Wuskwatim Generating Station (200 MW, 1520 GWh) is small relative to the projected size of the MAPP-US market of 33,000 MW and 180,000 GWh. The annual load growth in 2010 is about 600 MW and 3000 GWh. Therefore, the output of the Wuskwatim Generating Station is less than the load growth for half of one year in MAPP.

Load Growth in Nearby NERC Regions

Because the various electricity markets are somewhat interconnected, it is appropriate to obtain market information from neighbouring areas. Table 3 illustrates projected load growth for the North American Electric Reliability (NERC) regions Mid-Continent Area Power Pool (MAPP-US), Mid-American Interconnected Network (MAIN), and Southwest Power Pool (SPP). The total growth in the joint market area from 2001 – 2011 is 117,855 GW.h. or approximately 77 times the projected average annual generation of Wuskwatim of 1520 GW.h.

Table 3

Net Energy Requirements (GWh)

	Actual (2001)	Projected (2011)	Projected Average Annual Growth	GW.h Increase 2001 - 2011
MAPP-US	144,893	175,255	1.9%	30,362
MAIN	271,053	311,483	1.4%	40,430
SPP	193,590	240,653	2.2%	47,063
TOTAL	609,536	727,391	1.8%	117,855

Sources:
NERC Reliability Assessment 2002-2011 (October 2002)
MAPP Load and Capability Report (July 2002)

CAC/MSOS/NFAAT/S/4a

MID-CONTINENT AREA POWER POOL

LOAD AND CAPABILITY

REPORT

May 28, 2003
2nd DRAFT

QUESTIONS REGARDING THIS REPORT MAY BE DIRECTED TO:

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St. Paul, MN 55108-5001
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INTRODUCTION

GENERAL COMMENTS

The MAPP Load and Capability Report May 2003 is prepared in response to the requirement set forth in the MAPP Agreement and the MAPP Reliability Handbook for a two-year monthly and a ten-year seasonal load and capability forecast from each MAPP Participant. The report contains forecasts of monthly load and capability data for the period of May 2003 through December 2005 and seasonal load and capability data for the ten-year period Summer 2003 through Summer 2012.

The information in the report is dated May 31, 2003 and is prepared in conjunction with the May 1, 2003 MAPP Regional Reliability Council Report on Coordinated Bulk Power Supply Program (EIA-411) submitted to the North American Electric Reliability Council.

MAPP RELIABILITY COUNCIL

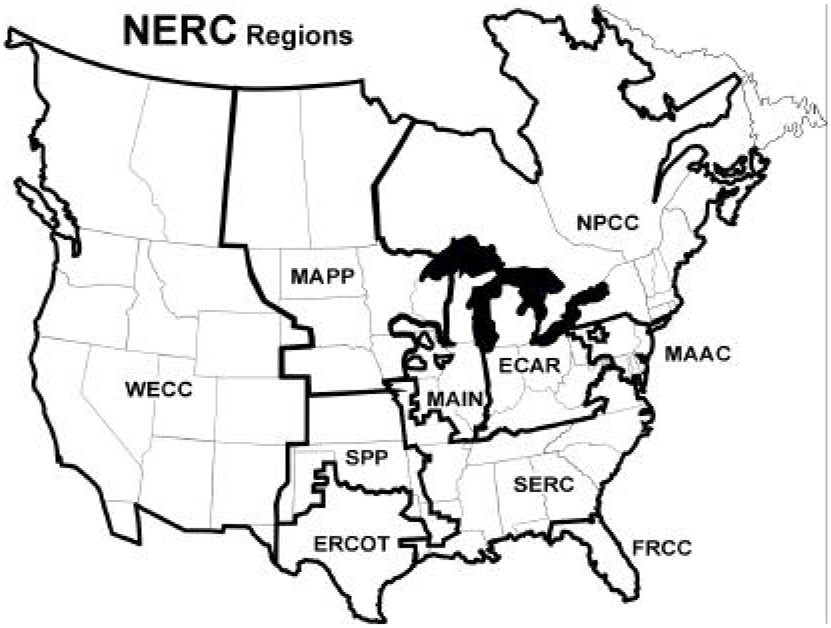
The Mid-Continent Area Power Pool (MAPP) is one of the nine regional reliability councils comprising the North American Electric Reliability Council (NERC). The MAPP region covers all of the states of Minnesota, Nebraska, North Dakota, most of South Dakota, and portions of the states of Iowa, Illinois, Michigan, Missouri, Montana and Wisconsin. The Canadian provinces of Manitoba and Saskatchewan are included in the MAPP region as well. The region is outlined on the map of the NERC regional councils on page I-4.

MAPP oversees the planning and operating activities in the region with respect to reliability. MAPP membership now totals 108 members and includes 14 transmission-owning members, 48 transmission-using members, 77 Power and Energy Market members, 18 associate members, and 8 regulatory participants. Two of the municipal utilities, IAMU and MMUA, are Joint Members and each contains 4 End-Use Load reporting members. Manitoba Hydro is a Member and Saskatchewan Power Corporation is an Associate Member of MAPP.

Information pertaining to the electrical utilities within the MAPP region that are Associate Members of MAPP or non-MAPP members and to the non-utility generators in the MAPP region is incorporated in the report as appropriate. Information about non-utility generators was supplied through inquiries to and responses by MAPP Members, MAPP Associate Members, and non-MAPP member electric utilities in the MAPP region.

This overview of regional planning is a compilation of each Member's load forecasts, planned new facilities and the resulting generating capacity and reserves. The overall projected system is tested periodically according to criteria contained in the MAPP System Design Standards. These standards include a set of contingencies referred to as probable disturbances. The overall system must be capable of withstanding these disturbances without interruption of load due to instability or cascading. Another set of contingencies is referred to as extreme disturbances. The system is designed to minimize the spread of any interruption that might result from such extreme disturbances. These procedures provide the basis for reporting on advance planning in this document. Similarly, the overview of operating activities based upon System Operating Standards provides the basis for the operating data contained in this document.

North American Electric Reliability Council

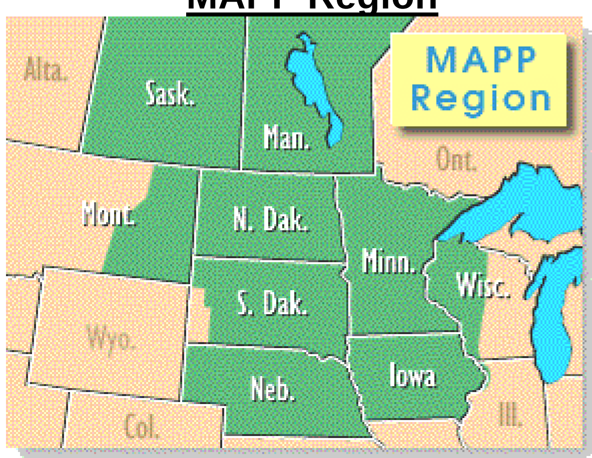


ECAR	East Central Area Reliability Coordination Agreement
ERCOT	Electric Reliability Council of Texas
FRCC	Florida Reliability Coordinating Council
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interconnected Network
MAPP	Mid-Continent Area Power Pool
NPCC	Northeast Power Coordinating Council
SERC	Southeastern Electric Reliability Council
SPP	Southwest Power Pool
WECC	Western Electricity Coordinating Council

Affiliate

ASCC Alaska Systems Coordinating Council

MAPP Region



MID-CONTINENT AREA POWER POOL

REPORTING SYSTEMS

SYSTEM NAME	INITIALS
Algona Municipal Utilities (1)	ALGN
Ames Municipal Electric System	AMES
Atlantic Municipal Utilities (1)	ATL
Basin Electric Power Cooperative	BEPC
Central Minnesota Municipal Power Agency (2)	CMMPA
GEN~SYS Energy (DPC)	GSE
Great River Energy (CP & UPA)	GRE
Harlan Municipal Utilities (1)	HMU
Hastings Utilities	HSTG
Heartland Consumers Power District	HCPD
Hutchinson Utilities Commission (2)	HUC
Lincoln Electric System	LES
Marshall Municipal Utilities	MMU
MidAmerican Energy Company/ Corn Belt Power Cooperative/ Cedar Falls Municipal Utilities/ City of Indianola/ Montezuma Municipal Electric Utilities/ Estherville Ia./ Waverly Ia./North Iowa Municipal Electric Cooperative Association	MEC
Minnesota Municipal Power Agency	MMPA
Minnesota Power	MP
Minnkota Power Cooperative Inc.	MPC
Missouri River Energy Services	MRES
Montana-Dakota Utilities Co.	MDU
Municipal Energy Agency of Nebraska	MEAN
Muscatine Power & Water	MPW
Nebraska Public Power District	NPPD
New Ulm Public Utilities (2)	NULM
Northwestern Public Service Company	NWPS
Omaha Public Power District	OPPD
Otter Tail Power Company	OTP
Pella Municipal Power and Light Department (1)	PELLA
Rochester Public Utilities	RPU
Southern Minnesota Municipal Power Agency	SMMPA
Western Area Power Administration – Upper Great Plains Region	WAPA
Willmar Municipal Utilities (2)	WLMR
Wisconsin Public Power Inc.	WPPI
Xcel Energy	XCEL
Manitoba Hydro	MHEB
SaskPower	SPC

(1) Joint Member through Iowa Association of Municipal Utilities (IAMU)
(2) Joint Member through Minnesota Municipal Utilities Association (MMUA)

EXPLANATION OF CODES – Section IV

I. UNIT TYPES

CA	Combined Cycle Steam Turbine Portion
CC	Combined Cycle Total Unit
CE	Compressed Air Energy Storage
CT	Combined Cycle Combustion Turbine Portion
CS	Combined Cycle Single Shaft
FC	Fuel Cell
GT	Combustion (Gas) Turbine (includes jet engine design)
HY	Hydraulic Turbine - Conventional
IC	Internal Combustion (piston)
NA	Unknown at this time
OT	Other (describe in "notes")
PS	Hydraulic Turbine - Pumped Storage
PV	Photovoltaic
ST	Steam Turbine, including nuclear, geothermal, and solar steam
WT	Wind Turbine

II. FUEL TYPES

BFG	Blast-Furnace Gas
BIT	Bituminous
DFO	Distillate Fuel Oil
GEO	Geothermal
JF	Jet Fuel
KER	Kerosene
LFG	Landfill Gas
LIG	Lignite
MSW	Municipal Solid Waste
NA	Not Available
NG	Natural Gas
NUC	Nuclear (Uranium, Plutonium, Thorium)
OBG	Other Biomass Gases
OBL	Other Biomass Liquids
OBS	Other Biomass Solids
OG	Other Gas
PC	Petroleum Coke
PG	Propane
RFO	Residual Fuel Oil
SUB	Sub bituminous
SUN	Solar
WAT	Water
WC	Waste/Other Coal
WDL	Wood Waste Liquids
WDS	Wood/Wood Waste Solids
WH	Waste Heat (reject heat)
WND	Wind
WO	Oil – Other than Waste Oil

EXPLANATION OF CODES – Section IV

III. STATUS CODES

Utility Units:

OP	Operating, available to operate, or on short-term scheduled or forced outage (less than three months).
OS	On long-term scheduled (maintenance) or forced outage; not available to operate (greater than three months).
SB	Cold standby (Reserve): deactivated (mothballed), in long-term storage and cannot be made available for service in a short period of time, usually requires three to six months to activate.
RE	Retired (no longer in service and not expected to be returned to service).
A	Generating unit capability increased (rerated or relicensed)
CO	Proposed Change of Ownership
D	Generating unit capability decreased (rerated or relicensed)
FC	Existing generator planned for conversion to another fuel or energy source
IP	Planned generator indefinitely postponed or canceled
L	Regulatory approval pending. Not under construction (started site preparation).
M	Generating unit put in deactivated shutdown status
OT	Other (describe under "notes")
P	Planned for installation but not utility-authorized. Not under construction.
RA	Previously deactivated or retired generator planned for reactivation
RP	Proposed for repowering or life extension
RT	Existing generator scheduled for retirement
T	Regulatory approval received but not under construction.
TS	Construction complete, but not yet in commercial operation (including low power testing of nuclear units).
U	Under construction, less than or equal to 50% complete (based on construction time to first electric date).
V	Under construction, more than 50% complete (based on construction time to first electric date).

MONTHLY
LOAD AND CAPABILITY DATA

MONTHLY LOAD AND CAPABILITY

May 2003 through December 2005

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FORECASTED MONTHLY LOAD & CAPABILITY
MEGAWATTS

MAPP - US

		MAY 2003	JUN 2003	JUL 2003	AUG 2003	SEP 2003	OCT 2003	NOV 2003	DEC 2003	JAN 2004	FEB 2004	MAR 2004	APR 2004
1	Internal Demand in MW (3-2)	23423	27528	29886	29212	25774	21124	22211	23557	23843	23011	21563	20758
2	Standby Demand	0	0	0	0	0	0	0	0	0	0	0	0
3	Total Internal Demand	23423	27528	29886	29212	25774	21124	22211	23557	23843	23011	21563	20758
4	Direct Control Load Management	24	71	71	74	27	80	181	336	348	346	188	58
5	Interruptable Demand	221	545	1257	1190	220	220	220	220	220	220	220	220
6	Net Internal Demand (3-4-5)	23178	26912	28557	27948	25527	20824	21810	23001	23275	22445	21155	20480
7	Schedule L Purchases	220	220	220	220	220	275	335	465	475	475	345	244
8	Committed Resources (9+10+11+12)	31478	31733	31655	31657	31865	31780	31877	31981	32095	32072	32037	31662
9	Distributed Generator Capacity (1 MW or greater)	3406	3454	3455	3440	3432	3391	3318	3311	3331	3341	3390	3400
10	Other Capacity (1 MW or greater)	27949	28156	28076	28094	28311	28265	28436	28546	28640	28607	28523	28139
11	Distributed Generator Capacity (less than 1 MW)	8	8	8	8	8	8	8	8	8	8	8	8
12	Other Capacity (less than 1 MW)	115	115	115	115	115	115	115	115	115	116	115	115
13	Uncommitted Resources	766	1066	1064	1063	1083	1083	1083	1083	1083	1083	1084	1085
14	Total Capacity (8+13)	32243	32799	32719	32720	32949	32864	32961	33064	33178	33155	33122	32747
15	Inoperable Capacity	39	0	0	0	7	7	7	7	7	0	0	161
16	Net Operable Capacity (14-15)	32204	32799	32719	32720	32942	32857	32954	33057	33171	33155	33122	32586
17	Total Capacity Purchases	5262	5777	6130	6056	5310	5014	3705	3854	3950	3732	3624	3536
18	Full Responsibility Purchases (Firm)	1189	1361	1731	1655	1272	1146	1049	1200	1358	1137	1039	949
19	Participation Purchases	4073	4416	4399	4401	4037	3869	2656	2654	2592	2595	2585	2587
20	Total Capacity Sales	2996	3683	3950	3947	3505	2935	3314	3470	3520	3369	3176	3024
21	Full Responsibility Sales	988	1243	1493	1489	1198	978	1143	1298	1367	1216	1123	1043
22	Participation Sales	2008	2440	2457	2458	2307	1957	2171	2172	2153	2153	2053	1981
23	Adjustment for Remotely Located (totally owned or shared) Generating Unit(s)	6	6	6	6	6	6	6	6	6	6	6	6
24	Planned Capacity Resources (16+17+23-20)	34476	34899	34904	34835	34752	34942	33351	33447	33607	33525	33576	33104
25	Adjusted Net Capability (14+19+23-22)	34314	34781	34666	34669	34685	34781	33451	33552	33623	33604	33660	33359
26	Annual System Demand	28634	28573	29917	29911	29852	29794	29805	29872	29856	29845	29836	29817
27	Monthly Adjusted Net Demand (6-7-18+21)	22976	26794	28319	27782	25453	20657	21904	23099	23284	22524	21239	20574
28	Annual Adjusted Net Demand (26-18+21)	28433	28455	29679	29745	29778	29627	29899	29970	29865	29924	29920	29911
29	Net Reserve Capacity Obligation (28 x 15%)	4137	4138	4353	4352	4330	4315	4392	4402	4387	4393	4395	4397
30	Total Firm Capacity Obligation (27+29)	27145	30932	32672	32135	29785	24999	26316	27518	27688	26934	25653	24998
31	Surplus or Deficit(-) Capacity (25-30)	7170	3849	1995	2535	4900	9782	7135	6034	5934	6670	8008	8361

SUMMER: MAY 1 - OCT 31; WINTER: NOV 1 - APR 30

FORECASTED MONTHLY LOAD & CAPABILITY
MEGAWATTS

MAPP - US

		MAY 2004	JUN 2004	JUL 2004	AUG 2004	SEP 2004	OCT 2004	NOV 2004	DEC 2004	JAN 2005	FEB 2005	MAR 2005	APR 2005
1	Internal Demand in MW (3-2)	23997	28132	30476	29823	26277	21567	22599	23984	24248	23327	21962	21001
2	Standby Demand	0	0	0	0	0	0	0	0	0	0	0	0
3	Total Internal Demand	23997	28132	30476	29823	26277	21567	22599	23984	24248	23327	21962	21001
4	Direct Control Load Management	24	72	73	75	27	85	187	346	359	357	199	63
5	Interruptable Demand	221	545	1272	1205	220	220	220	220	220	220	220	220
6	Net Internal Demand (3-4-5)	23752	27516	29131	28544	26030	21262	22192	23418	23669	22750	21543	20718
7	Schedule L Purchases	220	220	220	220	220	280	340	475	485	485	355	248
8	Committed Resources (9+10+11+12)	32030	31849	31728	31730	31939	31842	31934	32037	32084	32062	32027	31652
9	Distributed Generator Capacity (1 MW or greater)	3419	3464	3465	3450	3442	3394	3321	3314	3333	3343	3392	3402
10	Other Capacity (1 MW or greater)	28488	28262	28139	28157	28374	28324	28489	28599	28628	28595	28511	28127
11	Distributed Generator Capacity (less than 1 MW)	8	8	8	8	8	8	8	8	8	8	8	8
12	Other Capacity (less than 1 MW)	115	115	115	115	115	115	115	115	115	116	115	115
13	Uncommitted Resources	1175	1205	1203	1203	1218	1230	1229	1229	1446	1446	1638	1638
14	Total Capacity (8+13)	33205	33055	32931	32932	33156	33072	33163	33266	33530	33508	33664	33290
15	Inoperable Capacity	0	0	0	0	369	0	0	0	0	0	377	77
16	Net Operable Capacity (14-15)	33205	33055	32931	32932	32788	33072	33163	33266	33530	33508	33287	33213
17	Total Capacity Purchases	4529	4686	5043	4967	4312	4253	3413	3568	3331	3111	3006	2914
18	Full Responsibility Purchases (Firm)	1146	1283	1654	1577	1195	1123	1045	1202	1370	1147	1051	962
19	Participation Purchases	3382	3403	3389	3391	3117	3130	2368	2366	1961	1964	1954	1952
20	Total Capacity Sales	2443	3093	3491	3487	3044	2496	2528	2685	2377	2225	2132	2051
21	Full Responsibility Sales	895	1146	1396	1392	1101	886	1100	1256	1350	1198	1105	1026
22	Participation Sales	1548	1947	2095	2095	1943	1610	1428	1429	1027	1027	1027	1025
23	Adjustment for Remotely Located (totally owned or shared) Generating Unit(s)	6	6	6	6	6	6	6	6	6	6	6	6
24	Planned Capacity Resources (16+17+23-20)	35296	34655	34489	34418	34062	34834	34054	34156	34491	34400	34167	34082
25	Adjusted Net Capability (14+19+23-22)	35045	34517	34232	34234	34337	34597	34109	34210	34471	34452	34598	34223
26	Annual System Demand	29856	29938	30470	30493	30444	30376	30388	30454	30436	30417	30384	30363
27	Monthly Adjusted Net Demand (6-7-18+21)	23500	27379	28873	28360	25936	21025	22247	23472	23649	22802	21597	20781
28	Annual Adjusted Net Demand (26-18+21)	29605	29801	30213	30309	30351	30139	30443	30508	30416	30468	30437	30426
29	Net Reserve Capacity Obligation (28 x 15%)	4313	4340	4433	4437	4416	4392	4474	4483	4470	4475	4473	4475
30	Total Firm Capacity Obligation (27+29)	27841	31719	33306	32796	30353	25444	26738	27973	28135	27292	26087	25282
31	Surplus or Deficit(-) Capacity (25-30)	7204	2799	926	1437	3983	9154	7371	6237	6336	7160	8512	8941

SUMMER: MAY 1 - OCT 31; WINTER: NOV 1 - APR 30

FORECASTED MONTHLY LOAD & CAPABILITY
MEGAWATTS

MAPP - US

		MAY 2005	JUN 2005	JUL 2005	AUG 2005	SEP 2005	OCT 2005	NOV 2005	DEC 2005
1	Internal Demand in MW (3-2)	24494	28698	31088	30409	26917	22038	22929	24326
2	Standby Demand	0	0	0	0	0	0	0	0
3	Total Internal Demand	24494	28698	31088	30409	26917	22038	22929	24326
4	Direct Control Load Management	25	73	74	76	28	82	192	357
5	Interruptable Demand	221	564	1310	1243	220	220	220	220
6	Net Internal Demand (3-4-5)	24248	28061	29704	29090	26669	21736	22517	23749
7	Schedule L Purchases	220	220	220	220	220	277	345	485
8	Committed Resources (9+10+11+12)	31973	31857	31736	31737	31946	31843	31934	32037
9	Distributed Generator Capacity (1 MW or greater)	3420	3471	3473	3457	3449	3396	3323	3316
10	Other Capacity (1 MW or greater)	28429	28262	28139	28157	28374	28325	28489	28599
11	Distributed Generator Capacity (less than 1 MW)	8	8	8	8	8	8	8	8
12	Other Capacity (less than 1 MW)	115	115	115	115	115	114	114	114
13	Uncommitted Resources	1638	1633	1630	1630	1641	1641	1640	1640
14	Total Capacity (8+13)	33610	33489	33366	33367	33587	33484	33575	33678
15	Inoperable Capacity	0	0	0	0	0	0	0	0
16	Net Operable Capacity (14-15)	33610	33489	33366	33367	33587	33484	33575	33678
17	Total Capacity Purchases	3391	3549	3906	3829	3427	3373	2832	2989
18	Full Responsibility Purchases (Firm)	1113	1247	1617	1539	1159	1093	1014	1172
19	Participation Purchases	2277	2302	2288	2290	2268	2281	1818	1817
20	Total Capacity Sales	1885	2267	2515	2511	2224	1876	2015	2173
21	Full Responsibility Sales	830	1075	1325	1321	1030	819	1057	1214
22	Participation Sales	1055	1192	1190	1190	1194	1057	958	959
23	Adjustment for Remotely Located (totally owned or shared) Generating Unit(s)	6	6	6	6	6	6	6	6
24	Planned Capacity Resources (16+17+23-20)	35121	34778	34763	34691	34796	34986	34398	34500
25	Adjusted Net Capability (14+19+23-22)	34838	34606	34470	34472	34667	34713	34441	34542
26	Annual System Demand	30421	30509	31062	31077	31031	30960	30974	31039
27	Monthly Adjusted Net Demand (6-7-18+21)	23965	27889	29411	28872	26540	21463	22560	23791
28	Annual Adjusted Net Demand (26-18+21)	30137	30336	30770	30859	30903	30687	31017	31081
29	Net Reserve Capacity Obligation (28 x 15%)	4393	4420	4516	4519	4498	4474	4560	4569
30	Total Firm Capacity Obligation (27+29)	28387	32310	33927	33391	31039	25962	27137	28379
31	Surplus or Deficit(-) Capacity (25-30)	6452	2297	543	1082	3628	8750	7304	6163

SUMMER: MAY 1 - OCT 31; WINTER: NOV 1 - APR 30

FORECASTED MONTHLY LOAD & CAPABILITY
MEGAWATTS

MAPP-Canada

		MAY 2003	JUN 2003	JUL 2003	AUG 2003	SEP 2003	OCT 2003	NOV 2003	DEC 2003	JAN 2004	FEB 2004	MAR 2004	APR 2004
1	Internal Demand in MW (3-2)	5178	5313	5347	5519	5221	5441	6066	6661	6729	6489	5994	5384
2	Standby Demand	0	0	0	0	0	0	0	0	0	0	0	0
3	Total Internal Demand	5178	5313	5347	5519	5221	5441	6066	6661	6729	6489	5994	5384
4	Direct Control Load Management	0	0	0	0	0	0	0	0	0	0	0	0
5	Interruptable Demand	268	268	268	268	268	268	268	268	268	268	268	268
6	Net Internal Demand (3-4-5)	4910	5045	5079	5251	4953	5173	5798	6393	6461	6221	5726	5116
7	Schedule L Purchases	0	0	0	0	0	0	0	0	0	0	0	0
8	Committed Resources (9+10+11+12)	9044	8889	8871	8913	8947	9071	8670	8631	8587	8565	8573	8616
9	Distributed Generator Capacity (1 MW or greater)	0	0	0	0	0	0	0	0	0	0	0	0
10	Other Capacity (1 MW or greater)	9043	8889	8871	8913	8946	9070	8670	8631	8587	8565	8572	8616
11	Distributed Generator Capacity (less than 1 MW)	0	0	0	0	0	0	0	0	0	0	0	0
12	Other Capacity (less than 1 MW)	0	0	0	0	0	0	0	0	0	0	0	0
13	Uncommitted Resources	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Capacity (8+13)	9044	8889	8871	8913	8947	9071	8670	8631	8587	8565	8573	8616
15	Inoperable Capacity	373	358	85	241	364	408	85	0	0	286	286	434
16	Net Operable Capacity (14-15)	8671	8532	8786	8672	8583	8663	8585	8631	8587	8279	8287	8182
17	Total Capacity Purchases	0	0	0	0	0	50	550	550	550	550	550	500
18	Full Responsibility Purchases (Firm)	0	0	0	0	0	50	550	550	550	550	550	500
19	Participation Purchases	0	0	0	0	0	0	0	0	0	0	0	0
20	Total Capacity Sales	1760	1760	1760	1760	1760	1710	810	810	810	810	810	810
21	Full Responsibility Sales	750	750	750	750	750	700	0	0	0	0	0	0
22	Participation Sales	1010	1010	1010	1010	1010	1010	810	810	810	810	810	810
23	Adjustment for Remotely Located (totally owned or shared) Generating Unit(s)	0	0	0	0	0	0	0	0	0	0	0	0
24	Planned Capacity Resources (16+17+23-20)	6911	6772	7026	6912	6823	7003	8325	8371	8327	8019	8027	7872
25	Adjusted Net Capability (14+19+23-22)	8034	7879	7861	7903	7937	8061	7860	7821	7777	7755	7763	7806
26	Annual System Demand	6601	6601	6601	6601	6601	6601	6601	6823	6826	6826	6826	6826
27	Monthly Adjusted Net Demand (6-7-18+21)	5660	5795	5829	6001	5703	5823	5248	5843	5911	5671	5176	4616
28	Annual Adjusted Net Demand (26-18+21)	7351	7351	7351	7351	7351	7251	6051	6273	6276	6276	6276	6326
29	Net Reserve Capacity Obligation (28 x 15%)	878	878	878	878	878	863	743	776	776	776	776	784
30	Total Firm Capacity Obligation (27+29)	6537	6673	6707	6879	6580	6686	5991	6619	6687	6447	5953	5400
31	Surplus or Deficit(-) Capacity (25-30)	1496	1206	1154	1024	1356	1374	1870	1202	1089	1308	1810	2406

SUMMER: MAY 1 - OCT 31; WINTER: NOV 1 - APR 30

FORECASTED MONTHLY LOAD & CAPABILITY
MEGAWATTS

MAPP-Canada

		MAY 2004	JUN 2004	JUL 2004	AUG 2004	SEP 2004	OCT 2004	NOV 2004	DEC 2004	JAN 2005	FEB 2005	MAR 2005	APR 2005
1	Internal Demand in MW (3-2)	5250	5394	5432	5615	5298	5523	6171	6772	6812	6582	6088	5474
2	Standby Demand	0	0	0	0	0	0	0	0	0	0	0	0
3	Total Internal Demand	5250	5394	5432	5615	5298	5523	6171	6772	6812	6582	6088	5474
4	Direct Control Load Management	0	0	0	0	0	0	0	0	0	0	0	0
5	Interruptable Demand	268	268	268	268	268	268	268	268	268	268	268	268
6	Net Internal Demand (3-4-5)	4982	5126	5164	5347	5030	5255	5903	6504	6544	6314	5820	5206
7	Schedule L Purchases	0	0	0	0	0	0	0	0	0	0	0	0
8	Committed Resources (9+10+11+12)	9044	8889	8871	8913	8947	9071	8670	8631	8587	8565	8573	8616
9	Distributed Generator Capacity (1 MW or greater)	0	0	0	0	0	0	0	0	0	0	0	0
10	Other Capacity (1 MW or greater)	9043	8889	8871	8913	8946	9070	8670	8631	8587	8565	8572	8616
11	Distributed Generator Capacity (less than 1 MW)	0	0	0	0	0	0	0	0	0	0	0	0
12	Other Capacity (less than 1 MW)	0	0	0	0	0	0	0	0	0	0	0	0
13	Uncommitted Resources	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Capacity (8+13)	9044	8889	8871	8913	8947	9071	8670	8631	8587	8565	8573	8616
15	Inoperable Capacity	273	154	0	78	341	385	147	0	62	224	85	380
16	Net Operable Capacity (14-15)	8771	8735	8871	8835	8606	8686	8523	8631	8525	8341	8488	8236
17	Total Capacity Purchases	0	0	0	0	0	0	500	500	500	500	500	500
18	Full Responsibility Purchases (Firm)	0	0	0	0	0	0	500	500	500	500	500	500
19	Participation Purchases	0	0	0	0	0	0	0	0	0	0	0	0
20	Total Capacity Sales	1510	1510	1510	1510	1510	1510	810	810	810	810	810	810
21	Full Responsibility Sales	500	500	500	500	500	500	0	0	0	0	0	0
22	Participation Sales	1010	1010	1010	1010	1010	1010	810	810	810	810	810	810
23	Adjustment for Remotely Located (totally owned or shared) Generating Unit(s)	0	0	0	0	0	0	0	0	0	0	0	0
24	Planned Capacity Resources (16+17+23-20)	7261	7225	7361	7325	7096	7176	8213	8321	8215	8031	8178	7926
25	Adjusted Net Capability (14+19+23-22)	8034	7879	7861	7903	7937	8061	7860	7821	7777	7755	7763	7806
26	Annual System Demand	6826	6826	6826	6826	6826	6826	6826	6895	6895	6893	6893	6893
27	Monthly Adjusted Net Demand (6-7-18+21)	5482	5626	5664	5847	5530	5755	5403	6004	6044	5814	5320	4706
28	Annual Adjusted Net Demand (26-18+21)	7326	7326	7326	7326	7326	7326	6326	6395	6395	6393	6393	6393
29	Net Reserve Capacity Obligation (28 x 15%)	884	884	884	884	884	884	784	794	794	794	794	794
30	Total Firm Capacity Obligation (27+29)	6366	6510	6548	6731	6414	6639	6187	6798	6839	6608	6113	5500
31	Surplus or Deficit(-) Capacity (25-30)	1668	1369	1313	1172	1523	1422	1673	1023	938	1147	1649	2306

SUMMER: MAY 1 - OCT 31; WINTER: NOV 1 - APR 30

FORECASTED MONTHLY LOAD & CAPABILITY
MEGAWATTS

MAPP-Canada

		MAY 2005	JUN 2005	JUL 2005	AUG 2005	SEP 2005	OCT 2005	NOV 2005	DEC 2005
1	Internal Demand in MW (3-2)	5323	5476	5521	5707	5374	5594	6269	6879
2	Standby Demand	0	0	0	0	0	0	0	0
3	Total Internal Demand	5323	5476	5521	5707	5374	5594	6269	6879
4	Direct Control Load Management	0	0	0	0	0	0	0	0
5	Interruptable Demand	268	268	268	268	268	268	268	268
6	Net Internal Demand (3-4-5)	5055	5208	5253	5439	5106	5326	6001	6611
7	Schedule L Purchases	0	0	0	0	0	0	0	0
8	Committed Resources (9+10+11+12)	9044	8889	8871	8913	8947	9071	8670	8631
9	Distributed Generator Capacity (1 MW or greater)	0	0	0	0	0	0	0	0
10	Other Capacity (1 MW or greater)	9043	8889	8871	8913	8946	9070	8670	8631
11	Distributed Generator Capacity (less than 1 MW)	0	0	0	0	0	0	0	0
12	Other Capacity (less than 1 MW)	0	0	0	0	0	0	0	0
13	Uncommitted Resources	0	0	0	0	0	0	0	0
14	Total Capacity (8+13)	9044	8889	8871	8913	8947	9071	8670	8631
15	Inoperable Capacity	505	358	224	228	428	461	284	0
16	Net Operable Capacity (14-15)	8539	8532	8647	8686	8519	8610	8386	8631
17	Total Capacity Purchases	0	0	0	0	0	0	500	500
18	Full Responsibility Purchases (Firm)	0	0	0	0	0	0	500	500
19	Participation Purchases	0	0	0	0	0	0	0	0
20	Total Capacity Sales	1289	1289	1289	1289	1289	1289	789	789
21	Full Responsibility Sales	500	500	500	500	500	500	0	0
22	Participation Sales	789	789	789	789	789	789	789	789
23	Adjustment for Remotely Located (totally owned or shared) Generating Unit(s)	0	0	0	0	0	0	0	0
24	Planned Capacity Resources (16+17+23-20)	7250	7243	7358	7397	7230	7321	8097	8342
25	Adjusted Net Capability (14+19+23-22)	8255	8100	8082	8124	8158	8282	7881	7842
26	Annual System Demand	6893	6893	6893	6893	6893	6893	6893	6980
27	Monthly Adjusted Net Demand (6-7-18+21)	5555	5708	5753	5939	5606	5826	5501	6111
28	Annual Adjusted Net Demand (26-18+21)	7393	7393	7393	7393	7393	7393	6393	6480
29	Net Reserve Capacity Obligation (28 x 15%)	894	894	894	894	894	894	794	806
30	Total Firm Capacity Obligation (27+29)	6449	6602	6647	6833	6500	6720	6295	6917
31	Surplus or Deficit(-) Capacity (25-30)	1805	1498	1435	1292	1658	1562	1587	925

SUMMER: MAY 1 - OCT 31; WINTER: NOV 1 - APR 30

FORECASTED MONTHLY LOAD & CAPABILITY
MEGAWATTS

MAPP-Total

		MAY 2003	JUN 2003	JUL 2003	AUG 2003	SEP 2003	OCT 2003	NOV 2003	DEC 2003	JAN 2004	FEB 2004	MAR 2004	APR 2004
1	Internal Demand in MW (3-2)	28600	32841	35233	34732	30995	26566	28277	30218	30573	29500	27557	26142
2	Standby Demand	0	0	0	0	0	0	0	0	0	0	0	0
3	Total Internal Demand	28600	32841	35233	34732	30995	26566	28277	30218	30573	29500	27557	26142
4	Direct Control Load Management	24	71	71	74	27	80	181	336	348	346	188	58
5	Interruptable Demand	489	813	1525	1458	488	488	488	488	488	488	488	488
6	Net Internal Demand (3-4-5)	28087	31957	33636	33200	30480	25998	27608	29394	29737	28666	26881	25596
7	Schedule L Purchases	220	220	220	220	220	275	335	465	475	475	345	244
8	Committed Resources (9+10+11+12)	40521	40622	40526	40570	40812	40851	40547	40612	40681	40637	40610	40278
9	Distributed Generator Capacity (1 MW or greater)	3406	3454	3455	3440	3432	3391	3318	3311	3331	3341	3390	3400
10	Other Capacity (1 MW or greater)	36992	37045	36947	37007	37257	37336	37106	37177	37226	37172	37096	36755
11	Distributed Generator Capacity (less than 1 MW)	9	9	9	9	9	9	9	9	9	9	9	9
12	Other Capacity (less than 1 MW)	115	115	115	115	115	115	115	115	115	116	115	115
13	Uncommitted Resources	766	1066	1064	1063	1083	1083	1083	1083	1083	1083	1084	1085
14	Total Capacity (8+13)	41287	41689	41590	41633	41896	41934	41631	41695	41765	41720	41694	41363
15	Inoperable Capacity	412	358	85	241	371	415	92	7	7	286	286	595
16	Net Operable Capacity (14-15)	40875	41331	41505	41392	41525	41519	41539	41688	41758	41434	41408	40768
17	Total Capacity Purchases	5262	5777	6130	6056	5310	5064	4255	4404	4500	4282	4174	4036
18	Full Responsibility Purchases (Firm)	1189	1361	1731	1655	1272	1196	1599	1750	1908	1687	1589	1449
19	Participation Purchases	4073	4416	4399	4401	4037	3869	2656	2654	2592	2595	2585	2587
20	Total Capacity Sales	4756	5443	5710	5707	5265	4645	4124	4280	4330	4179	3986	3834
21	Full Responsibility Sales	1738	1993	2243	2239	1948	1678	1143	1298	1367	1216	1123	1043
22	Participation Sales	3018	3450	3467	3468	3317	2967	2981	2982	2963	2963	2863	2791
23	Adjustment for Remotely Located (totally owned or shared) Generating Unit(s)	6	6	6	6	6	6	6	6	6	6	6	6
24	Planned Capacity Resources (16+17+23-20)	41387	41670	41931	41748	41575	41944	41676	41819	41934	41544	41603	40976
25	Adjusted Net Capability (14+19+23-22)	42348	42660	42528	42573	42622	42842	41311	41373	41400	41359	41423	41165
26	Annual System Demand	35235	35174	36518	36512	36453	36395	36406	36695	36682	36671	36662	36643
27	Monthly Adjusted Net Demand (6-7-18+21)	28636	32589	34148	33784	31155	26480	27152	28941	29195	28195	26415	25190
28	Annual Adjusted Net Demand (26-18+21)	35784	35806	37030	37096	37129	36878	35950	36243	36141	36200	36197	36237
29	Net Reserve Capacity Obligation (28 x 15%)	5014	5016	5230	5230	5207	5178	5135	5178	5163	5169	5171	5181
30	Total Firm Capacity Obligation (27+29)	33682	37605	39379	39014	36365	31685	32306	34137	34376	33381	31605	30398
31	Surplus or Deficit(-) Capacity (25-30)	8666	5055	3149	3559	6256	11157	9005	7237	7024	7978	9818	10767

SUMMER: MAY 1 - OCT 31; WINTER: NOV 1 - APR 30

FORECASTED MONTHLY LOAD & CAPABILITY
MEGAWATTS

MAPP-Total

		MAY 2004	JUN 2004	JUL 2004	AUG 2004	SEP 2004	OCT 2004	NOV 2004	DEC 2004	JAN 2005	FEB 2005	MAR 2005	APR 2005
1	Internal Demand in MW (3-2)	29246	33526	35907	35439	31575	27090	28770	30756	31061	29909	28049	26474
2	Standby Demand	0	0	0	0	0	0	0	0	0	0	0	0
3	Total Internal Demand	29246	33526	35907	35439	31575	27090	28770	30756	31061	29909	28049	26474
4	Direct Control Load Management	24	72	73	75	27	85	187	346	359	357	199	63
5	Interruptable Demand	489	813	1540	1473	488	488	488	488	488	488	488	488
6	Net Internal Demand (3-4-5)	28733	32642	34295	33891	31060	26517	28095	29922	30214	29064	27362	25923
7	Schedule L Purchases	220	220	220	220	220	280	340	475	485	485	355	248
8	Committed Resources (9+10+11+12)	41074	40738	40599	40643	40885	40913	40604	40668	40671	40627	40600	40268
9	Distributed Generator Capacity (1 MW or greater)	3419	3464	3465	3450	3442	3394	3321	3314	3333	3343	3392	3402
10	Other Capacity (1 MW or greater)	37531	37151	37010	37070	37320	37395	37159	37230	37214	37160	37084	36743
11	Distributed Generator Capacity (less than 1 MW)	9	9	9	9	9	9	9	9	9	9	9	9
12	Other Capacity (less than 1 MW)	115	115	115	115	115	115	115	115	115	116	115	115
13	Uncommitted Resources	1175	1205	1203	1203	1218	1230	1229	1229	1446	1446	1638	1638
14	Total Capacity (8+13)	42248	41944	41802	41846	42103	42143	41833	41897	42117	42073	42237	41906
15	Inoperable Capacity	273	154	0	78	710	385	147	0	62	224	462	457
16	Net Operable Capacity (14-15)	41976	41790	41802	41768	41393	41758	41686	41897	42055	41849	41775	41449
17	Total Capacity Purchases	4529	4686	5043	4967	4312	4253	3913	4068	3831	3611	3506	3414
18	Full Responsibility Purchases (Firm)	1146	1283	1654	1577	1195	1123	1545	1702	1870	1647	1551	1462
19	Participation Purchases	3382	3403	3389	3391	3117	3130	2368	2366	1961	1964	1954	1952
20	Total Capacity Sales	3953	4603	5001	4997	4554	4006	3338	3495	3187	3035	2942	2861
21	Full Responsibility Sales	1395	1646	1896	1892	1601	1386	1100	1256	1350	1198	1105	1026
22	Participation Sales	2558	2957	3105	3105	2953	2620	2238	2239	1837	1837	1837	1835
23	Adjustment for Remotely Located (totally owned or shared) Generating Unit(s)	6	6	6	6	6	6	6	6	6	6	6	6
24	Planned Capacity Resources (16+17+23-20)	42557	41880	41850	41744	41157	42010	42267	42477	42705	42431	42345	42008
25	Adjusted Net Capability (14+19+23-22)	43078	42396	42093	42137	42273	42658	41969	42031	42247	42207	42361	42029
26	Annual System Demand	36682	36764	37297	37320	37271	37203	37215	37350	37331	37310	37277	37256
27	Monthly Adjusted Net Demand (6-7-18+21)	28982	33005	34537	34207	31466	26780	27650	29476	29694	28616	26916	25487
28	Annual Adjusted Net Demand (26-18+21)	36931	37127	37539	37635	37677	37466	36769	36904	36811	36861	36830	36819
29	Net Reserve Capacity Obligation (28 x 15%)	5196	5224	5316	5320	5299	5276	5257	5277	5264	5268	5266	5268
30	Total Firm Capacity Obligation (27+29)	34206	38229	39853	39527	36767	32082	32925	34771	34973	33900	32200	30781
31	Surplus or Deficit(-) Capacity (25-30)	8872	4168	2239	2610	5506	10575	9044	7260	7274	8307	10161	11247

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FORECASTED MONTHLY LOAD & CAPABILITY
MEGAWATTS

MAPP-Total

		MAY 2005	JUN 2005	JUL 2005	AUG 2005	SEP 2005	OCT 2005	NOV 2005	DEC 2005
1	Internal Demand in MW (3-2)	29817	34174	36609	36115	32291	27632	29198	31205
2	Standby Demand	0	0	0	0	0	0	0	0
3	Total Internal Demand	29817	34174	36609	36115	32291	27632	29198	31205
4	Direct Control Load Management	25	73	74	76	28	82	192	357
5	Interruptable Demand	489	832	1578	1511	488	488	488	488
6	Net Internal Demand (3-4-5)	29303	33269	34957	34529	31775	27062	28518	30360
7	Schedule L Purchases	220	220	220	220	220	277	345	485
8	Committed Resources (9+10+11+12)	41016	40746	40607	40651	40893	40914	40604	40669
9	Distributed Generator Capacity (1 MW or greater)	3420	3471	3473	3457	3449	3396	3323	3316
10	Other Capacity (1 MW or greater)	37472	37151	37010	37070	37320	37395	37159	37230
11	Distributed Generator Capacity (less than 1 MW)	9	9	9	9	9	9	9	9
12	Other Capacity (less than 1 MW)	115	115	115	115	115	114	114	114
13	Uncommitted Resources	1638	1633	1630	1630	1641	1641	1640	1640
14	Total Capacity (8+13)	42654	42379	42237	42280	42534	42554	42245	42309
15	Inoperable Capacity	505	358	224	228	428	461	284	0
16	Net Operable Capacity (14-15)	42149	42021	42013	42053	42106	42093	41961	42309
17	Total Capacity Purchases	3391	3549	3906	3829	3427	3373	3332	3489
18	Full Responsibility Purchases (Firm)	1113	1247	1617	1539	1159	1093	1514	1672
19	Participation Purchases	2277	2302	2288	2290	2268	2281	1818	1817
20	Total Capacity Sales	3174	3556	3804	3800	3513	3165	2804	2962
21	Full Responsibility Sales	1330	1575	1825	1821	1530	1319	1057	1214
22	Participation Sales	1844	1981	1979	1979	1983	1846	1747	1748
23	Adjustment for Remotely Located (totally owned or shared) Generating Unit(s)	6	6	6	6	6	6	6	6
24	Planned Capacity Resources (16+17+23-20)	42371	42021	42121	42088	42026	42307	42495	42842
25	Adjusted Net Capability (14+19+23-22)	43093	42706	42552	42597	42825	42994	42322	42384
26	Annual System Demand	37314	37402	37955	37970	37924	37853	37867	38020
27	Monthly Adjusted Net Demand (6-7-18+21)	29520	33597	35165	34810	32146	27289	28061	29902
28	Annual Adjusted Net Demand (26-18+21)	37530	37729	38163	38252	38296	38080	37410	37561
29	Net Reserve Capacity Obligation (28 x 15%)	5286	5314	5410	5413	5392	5368	5354	5375
30	Total Firm Capacity Obligation (27+29)	34836	38911	40574	40223	37539	32682	33431	35296
31	Surplus or Deficit(-) Capacity (25-30)	8257	3795	1978	2373	5286	10312	8890	7088

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FORECASTED MONTHLY SURPLUS & DEFICIT SUMMARY
MEGAWATTS

	MAY 2003	JUN 2003	JUL 2003	AUG 2003	SEP 2003	OCT 2003	NOV 2003	DEC 2003	JAN 2004	FEB 2004	MAR 2004	APR 2004
ALGN	13	8	4	5	5	13	13	13	13	13	14	15
AMES	34	21	10	22	34	45	55	51	57	55	56	44
ATL	14	11	10	13	12	15	18	18	17	17	17	17
BEPC	586	416	163	290	471	411	415	385	421	452	427	512
CMMPA	16	1	1	3	13	27	1	0	7	9	8	7
GRE	666	319	120	176	447	914	514	401	402	459	544	555
GSE	255	125	51	74	164	192	168	127	115	179	185	262
HCPD	29	20	11	13	23	27	20	13	11	17	20	22
HMU	7	4	4	5	5	8	5	5	5	5	5	5
HSTG	23	14	7	10	16	34	38	36	40	38	36	33
HUC	24	15	9	10	17	33	55	54	54	56	56	51
LES	117	102	142	155	149	153	193	188	260	251	259	248
MDU	111	56	12	25	109	172	108	68	86	102	125	136
MEAN	56	43	30	28	44	73	67	60	62	64	67	70
MEC	1229	613	231	347	751	2037	1742	1566	1622	1710	1849	1896
MMPA	17	-4	-16	-21	23	55	50	51	53	51	57	53
MP	277	223	186	185	243	229	178	138	134	138	220	278
MPC	20	28	27	27	41	24	54	70	70	71	70	61
MMU	4	4	4	4	4	7	6	8	20	19	19	19
MPW	71	56	47	51	57	76	67	65	63	63	65	66
MRES	188	107	66	74	163	236	164	110	103	119	168	200
NPPD	620	246	246	249	265	772	656	609	613	612	674	831
NULM	24	18	14	12	27	36	43	43	44	43	44	37
NWPS	94	33	8	-3	35	128	100	85	61	92	97	110
OPPD	217	119	77	50	137	766	588	537	475	565	607	332
OTP	77	87	51	31	72	152	269	219	192	187	271	264
PELLA	28	24	25	20	26	37	41	41	29	29	26	20
RPU	69	62	50	54	55	67	89	89	89	89	90	91
SMMPA	102	54	13	32	94	176	161	101	146	164	182	183
WAPA	948	599	259	325	670	951	598	358	399	628	766	976
WLMR	9	1	0	0	2	14	-4	-4	0	-1	1	1
WPPI	25	23	16	16	25	25	25	25	25	25	25	25
XCEL	1203	403	116	255	700	1876	638	505	246	349	957	940
MHEB	686	622	555	544	733	563	1320	826	758	896	1176	1681
SPC	811	584	599	480	623	811	550	377	331	412	634	725
MAPP-US	7170	3849	1995	2535	4900	9782	7135	6034	5934	6670	8008	8361
MAPP-Canada	1496	1206	1154	1024	1356	1374	1870	1202	1089	1308	1810	2406
MAPP-Total	8666	5055	3149	3559	6256	11157	9005	7237	7024	7978	9818	10767

FORECASTED MONTHLY SURPLUS & DEFICIT SUMMARY
MEGAWATTS

	MAY 2004	JUN 2004	JUL 2004	AUG 2004	SEP 2004	OCT 2004	NOV 2004	DEC 2004	JAN 2005	FEB 2005	MAR 2005	APR 2005
ALGN	13	9	4	6	6	14	14	14	14	14	15	16
AMES	35	21	10	23	34	46	56	52	59	56	58	45
ATL	14	11	10	12	12	15	18	18	17	17	17	17
BEPC	498	302	71	199	388	448	423	368	438	473	449	486
CMMPA	2	-13	-13	-11	-1	13	34	34	59	60	60	59
GRE	482	140	-51	-23	272	751	417	325	326	384	478	534
GSE	256	122	46	71	159	190	162	119	105	175	181	258
HCPD	31	23	14	14	24	28	19	13	-14	-8	-5	-3
HMU	7	4	4	5	4	8	5	5	5	4	4	5
HSTG	26	17	11	14	20	38	41	40	38	36	34	31
HUC	46	37	32	33	39	55	55	54	54	56	55	50
LES	182	89	90	102	99	198	239	233	246	239	248	235
MDU	150	56	11	23	108	172	105	65	83	99	122	133
MEAN	66	52	40	38	54	84	76	70	67	68	70	74
MEC	1508	449	-12	104	381	1804	1830	1648	1320	1410	1640	1662
MMPA	12	-10	-22	-27	19	52	46	47	47	45	51	48
MMU	16	16	15	16	16	18	18	20	20	19	18	19
MP	325	274	238	237	293	274	257	218	214	217	300	359
MPC	37	26	25	25	38	25	54	70	70	71	70	61
MPW	66	51	42	46	53	71	63	60	59	59	60	61
MRES	279	196	147	155	246	317	242	188	181	197	247	280
NPPD	680	305	273	275	297	721	605	557	1163	1162	1226	1386
NULM	22	16	13	11	26	35	42	42	43	42	43	36
NWPS	62	33	8	-3	3	98	98	83	59	90	94	107
OPPD	440	122	94	55	220	679	516	451	432	464	523	343
OTP	73	83	48	27	66	145	188	137	112	107	192	184
PELLA	17	12	13	9	14	26	29	29	29	29	25	18
RPU	91	75	64	68	69	89	89	89	89	89	90	91
SMMPA	131	53	10	31	80	162	146	84	131	146	192	196
WAPA	948	599	259	325	670	951	598	358	399	628	766	976
WLMR	9	-2	-5	-3	2	14	-1	-4	-12	-12	-10	-10
WPPI	25	22	14	15	25	25	25	24	26	25	25	25
XCEL	656	-388	-576	-432	245	1586	859	728	461	699	1171	1162
MHEB	911	843	772	754	957	783	1305	809	761	886	1160	1664
SPC	756	526	541	418	566	638	368	214	178	261	489	642
MAPP-US	7204	2799	926	1437	3983	9154	7371	6237	6336	7160	8512	8941
MAPP-Canada	1668	1369	1313	1172	1523	1422	1673	1023	938	1147	1649	2306
MAPP-Total	8872	4168	2239	2610	5506	10575	9044	7260	7274	8307	10161	11247

FORECASTED MONTHLY SURPLUS & DEFICIT SUMMARY
MEGAWATTS

	MAY 2005	JUN 2005	JUL 2005	AUG 2005	SEP 2005	OCT 2005	NOV 2005	DEC 2005
ALGN	17	12	8	9	9	17	18	16
AMES	13	12	0	14	31	43	53	49
ATL	13	10	10	12	11	15	18	17
BEPC	476	279	49	179	369	430	404	348
CMMPA	49	34	34	36	46	61	57	57
GRE	329	-26	-224	-195	111	607	284	187
GSE	251	116	37	63	150	182	154	112
HCPD	3	-6	-15	-15	-6	-1	-7	-13
HMU	6	3	4	4	4	8	5	5
HSTG	35	25	19	22	28	47	50	49
HUC	46	37	31	32	38	54	54	53
LES	167	73	67	79	83	179	224	218
MDU	108	52	6	19	105	169	102	61
MEAN	57	42	29	26	42	72	64	57
MEC	1008	197	-124	-5	276	1587	1562	1373
MMPA	4	-18	-31	-36	12	46	-10	-9
MMU	16	16	15	16	16	18	18	20
MP	349	298	261	260	317	298	283	243
MPC	34	24	23	23	33	18	54	70
MPW	86	70	62	65	72	91	83	80
MRES	268	183	133	141	234	307	229	174
NPPD	1230	863	825	828	855	1271	1154	1104
NULM	21	14	11	9	25	34	41	41
NWPS	59	34	8	-4	0	96	95	80
OPPD	384	122	78	50	115	558	476	456
OTP	86	94	57	39	81	157	127	72
PELLA	14	11	12	6	13	25	29	29
RPU	91	68	59	62	64	89	139	139
SMMPA	121	57	13	35	80	154	137	74
WAPA	948	599	259	325	670	951	598	358
WLMR	-3	-14	-17	-16	-10	3	-12	-15
WPPI	25	20	13	13	25	25	25	23
XCEL	142	-1003	-1166	-1015	-270	1140	795	635
MHEB	1131	1058	979	962	1176	1009	1312	808
SPC	674	440	456	329	482	553	275	116
MAPP-US	6452	2297	543	1082	3628	8750	7304	6163
MAPP-Canada	1805	1498	1435	1292	1658	1562	1587	925
MAPP-Total	8257	3795	1978	2373	5286	10312	8890	7088

SEASONAL
LOAD AND CAPABILITY DATA

Section III

SEASONAL LOAD AND CAPABILITY

Summer 2003 through Summer 2012

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FORECASTED SEASONAL LOAD & CAPABILITY
MEGAWATTS

MAPP-US

		SUM 2003	WIN 2003	SUM 2004	WIN 2004	SUM 2005	WIN 2005	SUM 2006	WIN 2006	SUM 2007	WIN 2007
1	Internal Demand in MW (3-2)	29957	24148	30555	24541	31156	24947	31763	25367	32413	25779
2	Standby Demand	0	0	0	0	0	0	0	0	0	0
3	Total Internal Demand	29957	24148	30555	24541	31156	24947	31763	25367	32413	25779
4	Direct Control Load Management	74	346	75	357	76	348	78	338	79	329
5	Interruptable Demand	1259	220	1273	220	1311	220	1338	220	1368	220
6	Net Internal Demand (3-4-5)	28624	23582	29207	23964	29769	24379	30347	24809	30966	25230
7	Schedule L Purchases	220	475	220	485	220	475	220	465	220	455
8	Committed Resources (9+10+11+12)	32194	32646	32267	32636	32275	32642	32269	32643	32319	32693
9	Distributed Generator Capacity (1 MW or greater)	3566	3309	3576	3311	3584	3311	3584	3312	3584	3312
10	Other Capacity (1 MW or greater)	28434	29264	28497	29252	28477	29262	28475	29261	28525	29311
11	Distributed Generator Capacity (less than 1 MW)	10	8	10	8	10	8	10	8	10	8
12	Other Capacity (less than 1 MW)	184	64	184	64	204	61	201	61	201	61
13	Uncommitted Resources	500	608	640	971	1067	1182	1079	1224	2208	2375
14	Total Capacity (8+13)	32694	33254	32907	33607	33341	33824	33348	33867	34527	35068
15	Inoperable Capacity	0	7	0	0	0	0	0	0	0	0
16	Net Operable Capacity (14-15)	32694	33247	32907	33607	33341	33824	33348	33867	34527	35068
17	Total Capacity Purchases	6132	3935	5043	3310	3969	3127	3777	3034	3745	2990
18	Full Responsibility Purchases (Firm)	1731	2366	1654	2223	1618	2186	1623	2192	1569	2145
19	Participation Purchases	4401	1568	3389	1086	2351	941	2154	842	2176	845
20	Total Capacity Sales	3946	3521	3491	2755	2515	2671	2381	2531	2223	2504
21	Full Responsibility Sales	1513	1345	1418	1330	1319	1312	1329	1261	1274	1195
22	Participation Sales	2433	2176	2073	1425	1196	1359	1052	1270	949	1310
23	Adjustment for Remotely Located (totally owned or shared) Generating Unit(s)	6	6	6	6	6	6	6	6	6	6
24	Planned Capacity Resources (16+17+23-20)	34886	33667	34465	34168	34802	34286	34750	34377	36055	35560
25	Adjusted Net Capability (14+19+23-22)	34668	32653	34229	33274	34503	33412	34456	33446	35760	34610
26	Annual System Demand	29933	29693	30514	30238	31097	30791	31668	31399	32336	32046
27	Monthly Adjusted Net Demand (6-7-18+21)	28406	22561	28971	23070	29471	23505	30053	23878	30670	24280
28	Annual Adjusted Net Demand (26-18+21)	29715	28672	30278	29344	30798	29917	31374	30468	32041	31096
29	Net Reserve Capacity Obligation (28 x 15%)	4358	4208	4442	4309	4520	4395	4607	4478	4707	4572
30	Total Firm Capacity Obligation (27+29)	32764	26785	33414	27396	33991	27921	34659	28378	35377	28876
31	Surplus or Deficit(-) Capacity (25-30)	1904	5867	816	5878	512	5490	-204	5068	382	5734

SUMMER: MAY 1 - OCT 31; WINTER: NOV 1 - APR 30

FORECASTED SEASONAL LOAD & CAPABILITY
MEGAWATTS

MAPP-US

		SUM 2008	WIN 2008	SUM 2009	WIN 2009	SUM 2010	WIN 2010	SUM 2011	WIN 2011	SUM 2012
1	Internal Demand in MW (3-2)	33022	26167	33640	26561	34228	26946	34811	27323	35383
2	Standby Demand	0	0	0	0	0	0	0	0	0
3	Total Internal Demand	33022	26167	33640	26561	34228	26946	34811	27323	35383
4	Direct Control Load Management	80	320	81	331	82	342	84	353	85
5	Interruptable Demand	1388	220	1407	220	1426	220	1445	220	1462
6	Net Internal Demand (3-4-5)	31554	25627	32151	26010	32720	26384	33282	26750	33835
7	Schedule L Purchases	220	445	220	455	220	465	220	475	220
8	Committed Resources (9+10+11+12)	32320	32693	32920	33293	32920	33274	32901	33274	32893
9	Distributed Generator Capacity (1 MW or greater)	3585	3312	3585	3312	3585	3293	3566	3293	3566
10	Other Capacity (1 MW or greater)	28525	29311	29125	29911	29125	29912	29125	29911	29117
11	Distributed Generator Capacity (less than 1 MW)	10	8	10	8	10	8	10	8	10
12	Other Capacity (less than 1 MW)	201	61	201	61	201	61	201	61	200
13	Uncommitted Resources	2208	2375	2508	2675	2508	2675	2508	2675	2508
14	Total Capacity (8+13)	34528	35068	35428	35968	35428	35949	35409	35949	35401
15	Inoperable Capacity	0	0	0	0	0	0	0	0	0
16	Net Operable Capacity (14-15)	34528	35068	35428	35968	35428	35949	35409	35949	35401
17	Total Capacity Purchases	3726	2998	3726	3105	3682	3007	3629	3022	3654
18	Full Responsibility Purchases (Firm)	1526	2152	1528	2160	1530	2167	1518	2181	1520
19	Participation Purchases	2200	845	2198	945	2152	840	2111	840	2134
20	Total Capacity Sales	1993	2405	2373	2709	2333	2592	2063	2388	2063
21	Full Responsibility Sales	1154	1155	1154	1159	1154	1165	1079	1091	1079
22	Participation Sales	839	1250	1219	1550	1179	1427	984	1297	984
23	Adjustment for Remotely Located (totally owned or shared) Generating Unit(s)	6	6	6	6	6	6	6	6	6
24	Planned Capacity Resources (16+17+23-20)	36267	35667	36787	36371	36783	36371	36982	36589	36999
25	Adjusted Net Capability (14+19+23-22)	35895	34670	36413	35370	36407	35369	36542	35499	36557
26	Annual System Demand	32952	32658	33579	33246	34160	33817	34741	34379	35308
27	Monthly Adjusted Net Demand (6-7-18+21)	31181	24630	31777	25009	32343	25383	32842	25660	33394
28	Annual Adjusted Net Demand (26-18+21)	32579	31661	33204	32245	33784	32815	34301	33289	34867
29	Net Reserve Capacity Obligation (28 x 15%)	4788	4657	4881	4744	4968	4830	5046	4901	5131
30	Total Firm Capacity Obligation (27+29)	35969	29310	36658	29778	37312	30238	37888	30582	38524
31	Surplus or Deficit(-) Capacity (25-30)	-74	5360	-245	5592	-905	5131	-1346	4917	-1967

SUMMER: MAY 1 - OCT 31; WINTER: NOV 1 - APR 30

FORECASTED SEASONAL LOAD & CAPABILITY
MEGAWATTS

MAPP-Canada

		SUM 2003	WIN 2003	SUM 2004	WIN 2004	SUM 2005	WIN 2005	SUM 2006	WIN 2006	SUM 2007	WIN 2007
1	Internal Demand in MW (3-2)	5519	6729	5615	6812	5707	6925	5785	6995	5845	7080
2	Standby Demand	0	0	0	0	0	0	0	0	0	0
3	Total Internal Demand	5519	6729	5615	6812	5707	6925	5785	6995	5845	7080
4	Direct Control Load Management	0	0	0	0	0	0	0	0	0	0
5	Interruptable Demand	268	268	268	268	268	268	268	268	268	268
6	Net Internal Demand (3-4-5)	5251	6461	5347	6544	5439	6657	5517	6727	5577	6812
7	Schedule L Purchases	0	0	0	0	0	0	0	0	0	0
8	Committed Resources (9+10+11+12)	8871	8565	8871	8565	8871	8565	8871	8565	8871	8565
9	Distributed Generator Capacity (1 MW or greater)	0	0	0	0	0	0	0	0	0	0
10	Other Capacity (1 MW or greater)	8871	8565	8871	8565	8871	8565	8871	8565	8871	8565
11	Distributed Generator Capacity (less than 1 MW)	0	0	0	0	0	0	0	0	0	0
12	Other Capacity (less than 1 MW)	0	0	0	0	0	0	0	0	0	0
13	Uncommitted Resources	0	0	0	0	0	0	0	0	0	0
14	Total Capacity (8+13)	8871	8565	8871	8565	8871	8565	8871	8565	8871	8565
15	Inoperable Capacity	241	0	78	0	228	0	163	0	92	0
16	Net Operable Capacity (14-15)	8630	8565	8793	8565	8643	8565	8708	8565	8779	8565
17	Total Capacity Purchases	0	550	0	500	0	500	0	500	0	500
18	Full Responsibility Purchases (Firm)	0	550	0	500	0	500	0	500	0	500
19	Participation Purchases	0	0	0	0	0	0	0	0	0	0
20	Total Capacity Sales	1760	810	1510	810	1289	789	1289	789	1139	639
21	Full Responsibility Sales	750	0	500	0	500	0	500	0	500	0
22	Participation Sales	1010	810	1010	810	789	789	789	789	639	639
23	Adjustment for Remotely Located (totally owned or shared) Generating Unit(s)	0	0	0	0	0	0	0	0	0	0
24	Planned Capacity Resources (16+17+23-20)	6870	8305	7283	8255	7354	8276	7419	8276	7640	8426
25	Adjusted Net Capability (14+19+23-22)	7861	7755	7861	7755	8082	7776	8082	7776	8232	7926
26	Annual System Demand	6733	6736	6831	6829	6916	6932	6978	7005	7048	7059
27	Monthly Adjusted Net Demand (6-7-18+21)	6001	5911	5847	6044	5939	6157	6017	6227	6077	6312
28	Annual Adjusted Net Demand (26-18+21)	7483	6186	7331	6329	7416	6432	7478	6505	7548	6559
29	Net Reserve Capacity Obligation (28 x 15%)	897	763	884	784	897	799	906	809	915	816
30	Total Firm Capacity Obligation (27+29)	6899	6674	6732	6829	6836	6956	6923	7036	6992	7128
31	Surplus or Deficit(-) Capacity (25-30)	962	1081	1130	926	1246	820	1159	740	1240	798

SUMMER: MAY 1 - OCT 31; WINTER: NOV 1 - APR 30

FORECASTED SEASONAL LOAD & CAPABILITY
MEGAWATTS

MAPP-Canada

		SUM 2008	WIN 2008	SUM 2009	WIN 2009	SUM 2010	WIN 2010	SUM 2011	WIN 2011	SUM 2012
1	Internal Demand in MW (3-2)	5947	7158	6029	7229	6109	7290	6185	7341	6229
2	Standby Demand	0	0	0	0	0	0	0	0	0
3	Total Internal Demand	5947	7158	6029	7229	6109	7290	6185	7341	6229
4	Direct Control Load Management	0	0	0	0	0	0	0	0	0
5	Interruptable Demand	268	268	268	268	268	268	268	268	268
6	Net Internal Demand (3-4-5)	5679	6890	5761	6961	5841	7022	5917	7073	5961
7	Schedule L Purchases	0	0	0	0	0	0	0	0	0
8	Committed Resources (9+10+11+12)	8871	8565	8871	8565	8871	8565	8871	8565	8871
9	Distributed Generator Capacity (1 MW or greater)	0	0	0	0	0	0	0	0	0
10	Other Capacity (1 MW or greater)	8871	8565	8871	8565	8871	8565	8871	8565	8871
11	Distributed Generator Capacity (less than 1 MW)	0	0	0	0	0	0	0	0	0
12	Other Capacity (less than 1 MW)	0	0	0	0	0	0	0	0	0
13	Uncommitted Resources	0	0	0	0	0	0	0	0	0
14	Total Capacity (8+13)	8871	8565	8871	8565	8871	8565	8871	8565	8871
15	Inoperable Capacity	231	0	156	0	156	0	231	0	156
16	Net Operable Capacity (14-15)	8640	8565	8715	8565	8715	8565	8640	8565	8715
17	Total Capacity Purchases	0	500	0	500	0	500	0	500	0
18	Full Responsibility Purchases (Firm)	0	500	0	500	0	500	0	500	0
19	Participation Purchases	0	0	0	0	0	0	0	0	0
20	Total Capacity Sales	1139	639	1109	609	1059	559	1059	559	1029
21	Full Responsibility Sales	500	0	500	0	500	0	500	0	500
22	Participation Sales	639	639	609	609	559	559	559	559	529
23	Adjustment for Remotely Located (totally owned or shared) Generating Unit(s)	0	0	0	0	0	0	0	0	0
24	Planned Capacity Resources (16+17+23-20)	7501	8426	7606	8456	7656	8506	7581	8506	7686
25	Adjusted Net Capability (14+19+23-22)	8232	7926	8262	7956	8312	8006	8312	8006	8342
26	Annual System Demand	7133	7158	7211	7234	7282	7309	7343	7379	7394
27	Monthly Adjusted Net Demand (6-7-18+21)	6179	6390	6261	6461	6341	6522	6417	6573	6461
28	Annual Adjusted Net Demand (26-18+21)	7633	6658	7711	6734	7782	6809	7843	6879	7894
29	Net Reserve Capacity Obligation (28 x 15%)	927	830	938	840	947	850	955	858	961
30	Total Firm Capacity Obligation (27+29)	7107	7220	7199	7301	7288	7372	7372	7431	7422
31	Surplus or Deficit(-) Capacity (25-30)	1125	706	1063	655	1024	634	940	574	920

SUMMER: MAY 1 - OCT 31; WINTER: NOV 1 - APR 30

FORECASTED SEASONAL LOAD & CAPABILITY
MEGAWATTS

MAPP-Total

		SUM 2003	WIN 2003	SUM 2004	WIN 2004	SUM 2005	WIN 2005	SUM 2006	WIN 2006	SUM 2007	WIN 2007
1	Internal Demand in MW (3-2)	35476	30877	36170	31353	36863	31872	37548	32362	38258	32859
2	Standby Demand	0	0	0	0	0	0	0	0	0	0
3	Total Internal Demand	35476	30877	36170	31353	36863	31872	37548	32362	38258	32859
4	Direct Control Load Management	74	346	75	357	76	348	78	338	79	329
5	Interruptable Demand	1527	488	1541	488	1579	488	1606	488	1636	488
6	Net Internal Demand (3-4-5)	33876	30043	34554	30508	35208	31036	35864	31536	36542	32042
7	Schedule L Purchases	220	475	220	485	220	475	220	465	220	455
8	Committed Resources (9+10+11+12)	41065	41211	41138	41200	41146	41206	41140	41208	41190	41258
9	Distributed Generator Capacity (1 MW or greater)	3566	3309	3576	3311	3584	3311	3584	3312	3584	3312
10	Other Capacity (1 MW or greater)	37305	37829	37368	37817	37348	37826	37346	37826	37395	37876
11	Distributed Generator Capacity (less than 1 MW)	10	9	10	9	10	8	10	8	10	8
12	Other Capacity (less than 1 MW)	184	64	184	64	204	61	201	61	201	61
13	Uncommitted Resources	500	608	640	971	1067	1182	1079	1224	2208	2375
14	Total Capacity (8+13)	41566	41819	41778	42172	42212	42389	42218	42432	43397	43633
15	Inoperable Capacity	241	7	78	0	228	0	163	0	92	0
16	Net Operable Capacity (14-15)	41325	41812	41700	42172	41984	42389	42055	42432	43305	43633
17	Total Capacity Purchases	6132	4485	5043	3810	3969	3627	3777	3534	3745	3490
18	Full Responsibility Purchases (Firm)	1731	2916	1654	2723	1618	2686	1623	2692	1569	2645
19	Participation Purchases	4401	1568	3389	1086	2351	941	2154	842	2176	845
20	Total Capacity Sales	5706	4331	5001	3565	3804	3460	3670	3320	3362	3143
21	Full Responsibility Sales	2263	1345	1918	1330	1819	1312	1829	1261	1774	1195
22	Participation Sales	3443	2986	3083	2235	1985	2148	1841	2059	1588	1949
23	Adjustment for Remotely Located (totally owned or shared) Generating Unit(s)	6	6	6	6	6	6	6	6	6	6
24	Planned Capacity Resources (16+17+23-20)	41677	41972	41748	42423	42156	42561	42168	42653	43695	43986
25	Adjusted Net Capability (14+19+23-22)	42449	40408	42091	41029	42585	41187	42537	41222	43991	42536
26	Annual System Demand	36666	36429	37345	37067	38013	37723	38646	38405	39384	39105
27	Monthly Adjusted Net Demand (6-7-18+21)	34408	28472	34819	29114	35409	29662	36070	30106	36747	30592
28	Annual Adjusted Net Demand (26-18+21)	37198	34859	37609	35673	38214	36349	38852	36974	39589	37655
29	Net Reserve Capacity Obligation (28 x 15%)	5255	4971	5327	5093	5418	5194	5513	5286	5622	5388
30	Total Firm Capacity Obligation (27+29)	39663	33459	40145	34225	40827	34878	41582	35414	42369	36003
31	Surplus or Deficit(-) Capacity (25-30)	2787	6948	1945	6804	1758	6310	955	5808	1623	6532

SUMMER: MAY 1 - OCT 31; WINTER: NOV 1 - APR 30

FORECASTED SEASONAL LOAD & CAPABILITY
MEGAWATTS

MAPP-Total

		SUM 2008	WIN 2008	SUM 2009	WIN 2009	SUM 2010	WIN 2010	SUM 2011	WIN 2011	SUM 2012
1	Internal Demand in MW (3-2)	38969	33325	39669	33790	40337	34236	40996	34664	41612
2	Standby Demand	0	0	0	0	0	0	0	0	0
3	Total Internal Demand	38969	33325	39669	33790	40337	34236	40996	34664	41612
4	Direct Control Load Management	80	320	81	331	82	342	84	353	85
5	Interruptable Demand	1656	488	1675	488	1694	488	1713	488	1730
6	Net Internal Demand (3-4-5)	37233	32517	37912	32971	38561	33406	39198	33823	39796
7	Schedule L Purchases	220	445	220	455	220	465	220	475	220
8	Committed Resources (9+10+11+12)	41191	41258	41791	41858	41791	41839	41772	41839	41764
9	Distributed Generator Capacity (1 MW or greater)	3585	3312	3585	3312	3585	3293	3566	3293	3566
10	Other Capacity (1 MW or greater)	37395	37876	37995	38476	37995	38476	37995	38476	37988
11	Distributed Generator Capacity (less than 1 MW)	10	8	10	8	10	8	10	8	10
12	Other Capacity (less than 1 MW)	201	61	201	61	201	61	201	61	200
13	Uncommitted Resources	2208	2375	2508	2675	2508	2675	2508	2675	2508
14	Total Capacity (8+13)	43399	43633	44299	44533	44299	44514	44280	44514	44272
15	Inoperable Capacity	231	0	156	0	156	0	231	0	156
16	Net Operable Capacity (14-15)	43168	43633	44143	44533	44143	44514	44049	44514	44116
17	Total Capacity Purchases	3726	3498	3726	3605	3682	3507	3629	3522	3654
18	Full Responsibility Purchases (Firm)	1526	2652	1528	2660	1530	2667	1518	2681	1520
19	Participation Purchases	2200	845	2198	945	2152	840	2111	840	2134
20	Total Capacity Sales	3132	3044	3482	3318	3392	3151	3122	2947	3092
21	Full Responsibility Sales	1654	1155	1654	1159	1654	1165	1579	1091	1579
22	Participation Sales	1478	1889	1828	2159	1738	1986	1543	1856	1513
23	Adjustment for Remotely Located (totally owned or shared) Generating Unit(s)	6	6	6	6	6	6	6	6	6
24	Planned Capacity Resources (16+17+23-20)	43768	44093	44393	44826	44439	44877	44563	45095	44685
25	Adjusted Net Capability (14+19+23-22)	44127	42596	44675	43326	44719	43375	44854	43505	44899
26	Annual System Demand	40085	39816	40789	40480	41442	41126	42084	41758	42702
27	Monthly Adjusted Net Demand (6-7-18+21)	37361	31020	38038	31470	38685	31905	39259	32233	39855
28	Annual Adjusted Net Demand (26-18+21)	40212	38319	40915	38979	41565	39624	42144	40168	42761
29	Net Reserve Capacity Obligation (28 x 15%)	5715	5486	5819	5584	5915	5679	6001	5759	6091
30	Total Firm Capacity Obligation (27+29)	43076	36530	43857	37078	44600	37610	45260	38013	45946
31	Surplus or Deficit(-) Capacity (25-30)	1051	6066	818	6247	119	5765	-406	5491	-1047

SUMMER: MAY 1 - OCT 31; WINTER: NOV 1 - APR 30

FORECASTED SEASONAL SURPLUS & DEFICIT SUMMARY
MEGAWATTS

	SUM 2003	WIN 2003	SUM 2004	WIN 2004	SUM 2005	WIN 2005	SUM 2006	WIN 2006	SUM 2007	WIN 2007
ALGN	5	12	4	13	8	15	7	15	7	14
AMES	10	51	10	52	0	48	-2	47	-4	46
ATL	10	17	10	17	10	17	9	17	9	17
BEPC	166	440	74	460	52	435	43	557	153	550
CMMPA	-2	7	-17	58	43	56	33	72	47	70
GRE	120	401	-51	325	-224	187	-364	101	-140	488
GSE	56	115	46	105	37	89	18	67	-12	47
HCPD	11	11	14	-14	-15	-15	-37	-36	-47	-46
HMU	4	5	4	5	4	5	3	4	3	4
HSTG	7	31	11	34	19	43	15	41	36	63
HUC	9	54	32	54	31	53	31	53	30	52
LES	142	251	90	243	67	227	47	217	76	253
MDU	12	68	11	65	6	61	2	34	9	30
MEAN	30	66	40	71	29	66	28	65	8	45
MEC	231	1671	-13	1377	-120	1480	-237	1397	254	1869
MMPA	-21	59	-27	56	-36	-4	-103	-19	-113	-26
MMU	6	9	18	20	18	20	18	20	18	20
MP	186	134	238	214	261	215	220	174	179	220
MPC	27	70	25	70	23	71	41	72	59	72
MPW	47	63	42	59	62	78	58	76	56	74
MRES	66	105	147	183	133	170	116	157	103	145
NPPD	166	613	273	1163	825	1116	780	1077	749	1053
NULM	12	37	11	36	9	35	7	34	6	33
NWPS	-3	61	-3	59	-4	56	-3	54	0	51
OPPD	50	475	55	432	51	383	52	307	52	246
OTP	31	187	27	107	39	47	41	44	35	37
PELLA	20	25	9	24	6	24	6	34	17	34
RPU	50	89	64	89	59	139	101	139	93	139
SMMPA	13	66	10	50	13	15	14	4	6	-4
WAPA	230	251	230	251	230	251	230	251	230	251
WLMR	0	-3	-5	-14	-17	-13	-17	-15	-19	-16
WPPI	16	25	14	24	13	23	12	21	16	26
XCEL	116	400	-576	192	-1116	97	-1375	-11	-1536	-123
MHEB	502	737	712	739	920	742	882	713	1008	851
SPC	460	345	418	187	326	77	277	27	232	-53
MAPP-US	1824	5867	816	5878	512	5490	-204	5068	382	5734
MAPP-Canada	962	1081	1130	926	1246	820	1159	740	1240	798
MAPP-Total	2787	6948	1945	6804	1758	6310	955	5808	1623	6532

FORECASTED SEASONAL SURPLUS & DEFICIT SUMMARY
MEGAWATTS

	SUM 2008	WIN 2008	SUM 2009	WIN 2009	SUM 2010	WIN 2010	SUM 2011	WIN 2011	SUM 2012
ALGN	6	14	6	14	5	13	5	13	4
AMES	-6	44	-9	43	-11	43	-11	43	-11
ATL	9	17	8	17	8	16	8	16	7
BEPC	136	531	111	514	95	591	71	574	52
CMMPA	46	69	44	68	43	66	40	64	38
GRE	-154	524	-224	401	-351	334	-355	382	-478
GSE	-80	-16	201	270	182	257	163	243	143
HCPD	-47	-47	-48	-47	-48	-48	-49	-48	-49
HMU	3	4	2	4	2	4	2	4	2
HSTG	33	61	30	58	27	56	23	53	20
HUC	30	52	28	50	28	50	27	50	27
LES	57	291	90	283	71	270	50	256	33
MDU	5	27	1	23	-4	20	-8	16	-12
MEAN	5	43	4	43	2	40	0	39	-3
MEC	128	1730	-37	1642	-151	1555	-259	1474	-362
MMPA	-123	-33	-163	-70	-174	-102	-210	-110	-252
MMU	18	20	18	20	18	20	18	20	18
MP	226	181	173	153	156	137	132	116	115
MPC	78	73	96	73	94	73	92	73	90
MPW	54	72	52	70	48	49	27	47	25
MRES	90	133	77	122	63	108	46	95	33
NPPD	762	1074	895	1213	848	1171	894	1229	838
NULM	4	32	3	31	1	30	-1	29	-3
NWPS	0	49	0	46	0	44	0	41	0
OPPD	54	201	52	468	52	439	54	413	53
OTP	28	34	22	28	-36	-24	-37	-24	-37
PELLA	17	33	16	32	16	31	14	41	14
RPU	85	139	75	139	66	164	83	164	74
SMMPA	-55	-12	-64	-19	-73	-27	-83	-35	-93
WAPA	230	251	230	251	230	251	230	251	230
WLMR	-22	-17	-24	-18	-25	-50	-63	-51	-66
WPPI	15	24	13	23	12	22	11	20	9
XCEL	-1706	-238	-1924	-353	-2098	-472	-2261	-584	-2427
MHEB	971	823	965	828	976	848	929	809	924
SPC	154	-117	98	-173	48	-214	12	-234	-4
MAPP-US	-74	5360	-245	5592	-905	5131	-1346	4917	-1967
MAPP-Canada	1125	706	1063	655	1024	634	940	574	920
MAPP-Total	1051	6066	818	6247	119	5765	-406	5491	-1047

GENERATOR CAPABILITY DATA

GENERATOR CAPABILITY DATA

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FORECASTED MONTHLY GENERATION CAPABILITY SUMMARY
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	MAY 2003	JUN 2003	JUL 2003	AUG 2003	SEP 2003	OCT 2003	NOV 2003	DEC 2003	JAN 2004	FEB 2004	MAR 2004	APR 2004
ALGN	37	37	37	37	37	37	37	37	37	37	37	37
AMES	122	122	121	121	122	123	125	126	126	126	126	123
ATL	32	32	32	32	32	32	32	32	32	32	32	32
BEPC	1768	1765	1761	1755	1753	1751	1753	1764	1767	1768	1768	1768
CMMPA	138	138	138	138	138	138	138	138	141	141	141	141
GRE	2403	2355	2340	2342	2369	2434	2438	2472	2474	2474	2431	2380
GSE	1120	1096	1089	1092	1116	1144	1157	1163	1165	1162	1159	1152
HCPD	51	51	51	51	51	51	51	51	51	51	51	51
HMU	3	3	3	3	3	3	3	3	3	3	3	3
HSTG	132	132	132	132	132	132	132	132	132	132	132	132
HUC	104	102	102	102	104	106	106	106	106	106	106	106
LES	476	551	588	588	588	530	565	573	636	632	625	603
MDU	439	475	472	472	475	481	442	445	446	446	444	439
MEAN	91	91	91	91	91	91	91	91	91	91	91	91
MEC	4753	5045	5038	5037	5054	5104	5145	5192	5197	5195	5144	5063
MMPA	43	43	43	43	43	43	47	49	49	49	48	45
MMU	16	15	15	15	15	18	18	20	20	20	19	19
MP	1985	1985	1982	1979	1987	1985	1987	1982	1980	1979	1982	1985
MPC	575	565	563	563	575	575	575	575	575	575	575	575
MPW	234	233	233	233	234	234	226	226	226	226	226	226
MRES	416	413	418	419	421	436	440	441	441	441	440	439
NPPD	3184	3179	3166	3167	3178	3185	3186	3188	3193	3189	3186	3186
NULM	73	71	71	71	73	75	81	80	80	80	81	75
NWPS	327	315	312	312	316	329	332	332	332	332	332	332
OPPD	2262	2557	2545	2545	2567	2278	2177	2177	2177	2177	2176	2130
OTP	690	683	678	678	684	697	707	711	711	711	708	703
PELLA	65	65	65	65	65	65	65	65	65	65	65	65
RPU	191	191	190	190	189	189	189	189	189	189	190	191
SMMPA	581	596	596	596	596	591	591	591	591	591	591	591
WAPA	2408	2444	2446	2430	2417	2380	2307	2299	2316	2326	2376	2393
WLMR	35	35	35	35	35	35	21	21	21	21	21	21
WPPI	129	129	129	129	129	129	129	129	129	129	129	129
XCEL	7359	7286	7237	7257	7359	7463	7668	7663	7678	7659	7686	7519
MHEB	5490	5434	5416	5458	5491	5517	5116	5077	5033	5011	5019	5062
SPC	3554	3455	3455	3455	3455	3554	3554	3554	3554	3554	3554	3554
MAPP-US	32243	32799	32719	32720	32949	32864	32961	33064	33178	33155	33122	32747
MAPP-Canada	9044	8889	8871	8913	8947	9071	8670	8631	8587	8565	8573	8616
MAPP-Total	41287	41689	41590	41633	41896	41934	41631	41695	41765	41720	41694	41363

FORECASTED MONTHLY GENERATION CAPABILITY SUMMARY
MEGAWATTS

	MAY 2004	JUN 2004	JUL 2004	AUG 2004	SEP 2004	OCT 2004	NOV 2004	DEC 2004	JAN 2005	FEB 2005	MAR 2005	APR 2005
ALGN	37	37	37	37	37	37	37	37	37	37	37	37
AMES	122	122	121	121	122	123	125	126	126	126	126	123
ATL	32	32	32	32	32	32	32	32	32	32	32	32
BEPC	1768	1765	1761	1755	1753	1751	1753	1764	1767	1768	1768	1768
CMMPA	141	141	141	141	141	141	141	141	141	141	141	141
GRE	2403	2355	2340	2342	2369	2434	2438	2472	2474	2474	2431	2380
GSE	1129	1105	1098	1101	1121	1150	1163	1169	1171	1168	1165	1158
HCPD	51	51	51	51	51	51	51	51	51	51	51	51
HMU	3	3	3	3	3	3	3	3	3	3	3	3
HSTG	132	132	132	132	132	132	132	132	132	132	132	132
HUC	104	102	102	102	104	106	106	106	106	106	106	106
LES	642	641	641	641	641	583	618	626	636	632	625	603
MDU	478	475	472	472	475	481	442	445	446	446	444	439
MEAN	91	91	91	91	91	91	91	91	91	91	91	91
MEC	5063	5085	5078	5077	5094	5144	5185	5232	5237	5235	5374	5293
MMPA	43	43	43	43	43	43	47	49	49	49	48	45
MMU	16	15	15	15	15	18	18	20	20	20	19	19
MP	1985	1985	1982	1979	1987	1985	1987	1982	1980	1979	1982	1985
MPC	575	565	563	563	575	575	575	575	575	575	575	575
MPW	234	233	233	233	234	234	226	226	226	226	226	226
MRES	516	513	512	513	515	526	530	531	531	531	530	529
NPPD	3184	3179	3166	3167	3178	3195	3196	3198	3420	3416	3413	3413
NULM	73	71	71	71	73	75	81	80	80	80	81	75
NWPS	327	315	312	312	316	329	332	332	332	332	332	332
OPPD	2586	2563	2551	2551	2573	2284	2177	2177	2178	2178	2178	2132
OTP	690	683	678	678	684	697	707	711	711	711	708	703
PELLA	65	65	65	65	65	65	65	65	65	65	65	65
RPU	191	191	190	190	189	189	189	189	189	189	190	191
SMMPA	591	603	603	603	603	591	591	591	591	591	591	591
WAPA	2408	2444	2446	2430	2417	2380	2307	2299	2316	2326	2376	2393
WLMR	35	35	35	35	35	35	21	21	9	9	9	9
WPPI	129	129	129	129	129	129	129	129	129	129	129	129
XCEL	7359	7286	7237	7257	7359	7463	7668	7663	7678	7659	7686	7519
MHEB	5490	5434	5416	5458	5491	5517	5116	5077	5033	5011	5019	5062
SPC	3554	3455	3455	3455	3455	3554	3554	3554	3554	3554	3554	3554
MAPP-US	33205	33055	32931	32932	33156	33072	33163	33266	33530	33508	33664	33290
MAPP-Canada	9044	8889	8871	8913	8947	9071	8670	8631	8587	8565	8573	8616
MAPP-Total	42248	41944	41802	41846	42103	42143	41833	41897	42117	42073	42237	41906

FORECASTED MONTHLY GENERATION CAPABILITY SUMMARY
MEGAWATTS

	MAY 2005	JUN 2005	JUL 2005	AUG 2005	SEP 2005	OCT 2005	NOV 2005	DEC 2005
ALGN	37	37	37	37	37	37	37	37
AMES	122	142	141	141	142	143	145	146
ATL	32	32	32	32	32	32	32	32
BEPC	1768	1765	1761	1755	1753	1751	1753	1764
CMMPA	141	141	141	141	141	141	141	141
GRE	2403	2355	2340	2342	2369	2434	2438	2472
GSE	1135	1115	1108	1111	1127	1154	1167	1173
HCPD	51	51	51	51	51	51	51	51
HMU	3	3	3	3	3	3	3	3
HSTG	132	132	132	132	132	132	132	132
HUC	104	102	102	102	104	106	106	106
LES	642	641	641	641	641	583	618	626
MDU	439	475	472	472	475	481	442	445
MEAN	91	91	91	91	91	91	91	91
MEC	5293	5275	5268	5267	5284	5334	5375	5422
MMPA	43	43	43	43	43	43	47	49
MMU	16	15	15	15	15	18	18	20
MP	1985	1985	1982	1979	1987	1985	1987	1982
MPC	575	565	563	563	575	575	575	575
MPW	234	233	233	233	234	234	226	226
MRES	516	513	512	513	515	526	530	531
NPPD	3411	3406	3393	3394	3405	3411	3412	3414
NULM	73	71	71	71	73	75	81	80
NWPS	327	315	312	312	316	329	332	332
OPPD	2588	2565	2553	2552	2575	2286	2178	2178
OTP	682	675	670	670	676	689	699	703
PELLA	65	65	65	65	65	65	65	65
RPU	191	191	190	190	189	189	189	189
SMMPA	591	609	609	609	609	591	591	591
WAPA	2408	2444	2446	2430	2417	2380	2307	2299
WLMR	23	23	23	23	23	23	9	9
WPPI	129	129	129	129	129	129	129	129
XCEL	7359	7286	7237	7257	7359	7463	7668	7663
MHEB	5490	5434	5416	5458	5491	5517	5116	5077
SPC	3554	3455	3455	3455	3455	3554	3554	3554
MAPP-US	33610	33489	33366	33367	33587	33484	33575	33678
MAPP-Canada	9044	8889	8871	8913	8947	9071	8670	8631
MAPP-Total	42654	42379	42237	42280	42534	42554	42245	42309

FORECASTED SEASONAL GENERATION CAPABILITY SUMMARY
MEGAWATTS

	SUM 2003	WIN 2003	SUM 2004	WIN 2004	SUM 2005	WIN 2005	SUM 2006	WIN 2006	SUM 2007	WIN 2007
ALGN	37	37	37	37	37	37	37	37	37	37
AMES	121	126	121	126	141	146	141	146	141	146
ATL	32	32	32	32	32	32	32	32	32	32
BEPC	1764	1768	1764	1768	1764	1768	1764	1768	1764	1768
CMMPA	138	141	141	141	141	141	141	141	141	141
GRE	2340	2472	2340	2472	2340	2472	2340	2472	2740	2972
GSE	1089	1165	1098	1171	1108	1175	1108	1175	1108	1175
HCPD	51	51	51	51	51	51	51	51	51	51
HMU	3	3	3	3	3	3	3	3	3	3
HSTG	132	132	132	132	132	132	132	132	157	157
HUC	102	106	102	106	102	106	102	106	102	106
LES	588	636	641	636	641	636	641	636	741	736
MDU	472	445	472	445	472	445	472	487	550	487
MEAN	91	91	91	91	91	91	91	91	141	141
MEC	5036	5297	5076	5337	5266	5532	5266	5532	5792	6058
MMPA	43	49	43	49	43	49	43	49	43	49
MMU	18	20	18	20	18	20	18	20	18	20
MP	1982	1980	1982	1980	1982	1956	1959	1932	1935	1909
MPC	563	575	563	575	563	599	587	622	610	646
MPW	233	226	233	226	233	226	233	226	233	226
MRES	418	441	512	531	512	531	512	531	512	531
NPPD	3166	3193	3166	3420	3393	3426	3399	3426	3399	3426
NULM	71	75	71	75	71	75	71	75	71	75
NWPS	312	332	312	332	312	332	312	332	312	332
OPPD	2545	2177	2551	2178	2553	2178	2553	2180	2553	2180
OTP	678	711	678	711	670	703	670	703	670	703
PELLA	65	65	65	65	65	65	65	65	65	65
RPU	190	189	190	189	190	189	190	189	190	189
SMMPA	596	591	603	591	609	591	609	591	609	591
WAPA	2417	2299	2417	2299	2417	2299	2417	2299	2417	2299
WLMR	35	21	35	9	23	9	23	9	23	9
WPPI	129	129	129	129	129	129	129	129	129	129
XCEL	7237	7678	7237	7678	7237	7678	7237	7678	7237	7678
MHEB	5416	5011	5416	5011	5416	5011	5416	5011	5416	5011
SPC	3455	3554	3455	3554	3455	3553	3455	3553	3455	3553
MAPP-US	32694	33254	32907	33607	33341	33824	33348	33867	34527	35068
MAPP-Canada	8871	8565	8871	8565	8871	8565	8871	8565	8871	8565
MAPP-Total	41566	41819	41778	42172	42212	42389	42218	42432	43397	43633

FORECASTED SEASONAL GENERATION CAPABILITY SUMMARY
MEGAWATTS

	SUM 2008	WIN 2008	SUM 2009	WIN 2009	SUM 2010	WIN 2010	SUM 2011	WIN 2011	SUM 2012
ALGN	37	37	37	37	37	37	37	37	37
AMES	141	146	141	146	141	146	141	146	141
ATL	32	32	32	32	32	32	32	32	32
BEPC	1764	1768	1764	1768	1764	1768	1764	1768	1764
CMMPA	141	141	141	141	141	141	141	141	141
GRE	2740	2972	2740	2972	2740	2972	2740	2972	2740
GSE	1108	1175	1408	1475	1408	1475	1408	1475	1408
HCPD	51	51	51	51	51	51	51	51	51
HMU	3	3	3	3	3	3	3	3	3
HSTG	157	157	157	157	157	157	157	157	157
HUC	102	106	102	106	102	106	102	106	102
LES	741	736	741	736	741	736	741	736	741
MDU	550	487	550	487	550	487	550	487	550
MEAN	141	141	141	141	141	141	141	141	141
MEC	5792	6058	5792	6058	5792	6058	5792	6058	5792
MMPA	43	49	43	49	43	49	43	49	43
MMU	18	20	18	20	18	20	18	20	18
MP	1912	1885	1889	1885	1889	1885	1889	1885	1889
MPC	633	670	657	670	657	670	657	670	657
MPW	233	226	233	226	233	207	214	207	214
MRES	512	531	512	531	512	531	512	531	512
NPPD	3399	3426	3399	3426	3399	3426	3399	3426	3391
NULM	71	75	71	75	71	75	71	75	71
NWPS	312	332	312	332	312	332	312	332	312
OPPD	2554	2180	3154	2780	3154	2780	3154	2780	3154
OTP	670	703	670	703	670	703	670	703	670
PELLA	65	65	65	65	65	65	65	65	65
RPU	190	189	190	189	190	189	190	189	190
SMMPA	609	591	609	591	609	591	609	591	609
WAPA	2417	2299	2417	2299	2417	2299	2417	2299	2417
WLMR	23	9	23	9	23	9	23	9	23
WPPI	129	129	129	129	129	129	129	129	129
XCEL	7237	7678	7237	7678	7237	7678	7237	7678	7237
MHEB	5416	5011	5416	5011	5416	5011	5416	5011	5416
SPC	3455	3553	3455	3553	3455	3553	3455	3553	3455
MAPP-US	34528	35068	35428	35968	35428	35949	35409	35949	35401
MAPP-Canada	8871	8565	8871	8565	8871	8565	8871	8565	8871
MAPP-Total	43399	43633	44299	44533	44299	44514	44280	44514	44272

Generator Information - Planned Generators
MEGAWATTS

Company Name	Plant Name	Generator ID	Prime Mover	Energy Source Primary	Net Capacity Sum	Net Capacity Win	Current Eff. Date	Status Code
Ames Municipal Electric System	Ames GT	GT2		DFO	20	20	2005-05	P
Blooming Prairie Public Util Comm	Blooming Prairie	5		DFO	2	2	2003-06	P
Central Minnesota Municipal Power Agency	Glencoe Landfill Gas	LF1	GT	LFG	3.2	3.2	2004-01	P
Corn Belt Power	Wisdom GT	NA1		NG	74.6	86	2004-06	P
Dairyland Power Cooperative	Lake Mills LFG	1	IC	LFG	6	6	2003-09	P
Dairyland Power Cooperative	Seven Mile Creek LFG	1	IC	LFG	3	3	2003-09	P
Dairyland Power Cooperative	NA 1	7	ST	SUB	300	300	2009-06	P
Dairyland Power Cooperative	Argyle	4	IC	DFO	2.25	2.25	2004-07	L
Dairyland Power Cooperative	Elroy	6	IC	DFO	2	2	2004-09	L
Dairyland Power Cooperative	Elroy	7	IC	DFO	2	2	2004-09	L
Dairyland Power Cooperative	Lanesboro	4	IC	DFO	2	2	2004-10	P
Dairyland Power Cooperative	New Lisbon	6	IC	DFO	2	2	2005-06	P
Dairyland Power Cooperative	New Lisbon	7	IC	DFO	2	2	2005-06	P
Dairyland Power Cooperative	Argyle	2	IC	DFO	1.014	1.014	2004-07	RT
Dairyland Power Cooperative	Argyle	3	IC	DFO	1.079	1.079	2004-07	RT
Grand Island, City of	Burdick	GT-2	GT	NG	40	40	2003-04	TS
Grand Island, City of	Burdick	GT-3	GT	NG	40	40	2003-04	TS
Grand Marais City of	Grand Marais	2		DFO	0.6	0.6	2003-12	RT
Grand Marais City of	Grand Marais	5		DFO	1.1	1.1	2003-12	RT
Grand Marais City of	Grand Marais	6		DFO	1	1	2003-12	RT
Grand Marais City of	Grand Marais	7		DFO	2	2	2004-06	P
Grand Marais City of	Grand Marais	8		DFO	2	2	2004-06	P
Grand Marais City of	Grand Marais	9		DFO	2	2	2004-06	P
Great River Energy	NA	NA	CC	NG	400	500	2007-05	P
Harlan Municipal Utilities	Harlan	3		DFO	2	2	2005-06	P
Hastings Utilities (NE)	Whelen Energy Center	2	ST	SUB	25	25		P
Lincoln Electric System	Salt Valley	1	CA	WH	27	27	2004-01	U
Lincoln Electric System	Salt Valley	2	GT	NG	37	37	2003-06	V
Lincoln Electric System	Salt Valley	3	GT	NG	37	37	2003-06	V
Lincoln Electric System	Salt Valley	4	GT	NG	37	37	2003-07	V
Lincoln Electric System	Salt Valley	BSU	IC	DFO	2	2	2003-06	V
Lincoln Electric System	Salt Valley	2	CT	NG	9	9	2004-01	A
Lincoln Electric System	Salt Valley	3	CT	NG	9	9	2004-01	A
Lincoln Electric System	Salt Valley	4	GT	NG	9	9	2004-01	A

Generator Information - Planned Generators
MEGAWATTS

Company Name	Plant Name	Generator ID	Prime Mover	Energy Source Primary	Net Capacity Sum	Net Capacity Win	Current Eff. Date	Status Code
MidAmerican Energy Company	Greater Des Moines Energy Cent	GT1		NG	155	205	2003-06	V
MidAmerican Energy Company	Greater Des Moines Energy Cent	GT2		NG	155	205	2003-06	V
MidAmerican Energy Company	Greater Des Moines Energy Cent	ST1		NG	190	195	2005-03	U
MidAmerican Energy Company	Council Bluffs Energy Center	4		SUB	750	750	2007-06	P
Minnkota Power Cooperative, Inc.	Reed	1	IC	DFO	2	2	2003-05	V
Minnkota Power Cooperative, Inc.	Reed	2	IC	DFO	2	2	2003-05	V
Minnkota Power Cooperative, Inc.	Reed	3	IC	DFO	2	2	2003-05	V
Minnkota Power Cooperative, Inc.	Reed	4	IC	DFO	2	2	2003-05	V
Minnkota Power Cooperative, Inc.	Reed	5	IC	DFO	2	2	2003-05	V
Minnkota Power Cooperative, Inc.	Reed	6	IC	DFO	2	2	2003-05	V
Minnkota Power Cooperative, Inc.	Oxbow	1	IC	DFO	2	2	2003-05	V
Minnkota Power Cooperative, Inc.	Oxbow	2	IC	DFO	2	2	2003-05	V
Minnkota Power Cooperative, Inc.	Arthur	1	IC	DFO	2	2	2003-05	V
Minnkota Power Cooperative, Inc.	Arthur	2	IC	DFO	2	2	2003-05	V
Missouri River Energy Services	Exira Station	1	GT	NG	47.5	47.5	2004-05	P
Missouri River Energy Services	Exira Station	2	GT	NG	47.5	47.5	2004-05	P
Montana-Dakota Utilities Co.	Glendive CT	2	GT	NG	39	42	2003-06	U
Nebraska Public Power District	Proposed New Plant 1	1	WT	WND	10	10	2004-10	P
Nebraska Public Power District	Proposed New Plant 2	1	CC	NG	217	217	2005-01	L
Nebraska Public Power District	Mullen	1		DFO	0.35	0.35	2005-10	OT
Nebraska Public Power District	Mullen	2		DFO	0.65	0.65	2005-10	OT
Nebraska Public Power District	Spalding	1		DFO	0	0	2006-01	OT
Nebraska Public Power District	Spalding	2		DFO	0.4	0.4	2006-01	OT
Nebraska Public Power District	Spalding	3		DFO	1.4	1.4	2006-01	OT
Nebraska Public Power District	Spalding	4		DFO	0.2	0.2	2006-01	OT
Nebraska Public Power District	Spalding	5		DFO	0.25	0.25	2006-01	OT
Nebraska Public Power District	Wilber	4		DFO	0.78	0.78	2006-01	OT
Nebraska Public Power District	Wilber	5		DFO	0.59	0.59	2006-01	OT
Nebraska Public Power District	Wilber	6		DFO	1.57	1.57	2006-01	OT
Nebraska Public Power District	Belleville, KS	4		NG	0.8	0.8	2012-05	OT
Nebraska Public Power District	Belleville, KS	6		NG	3.1	3.1	2012-05	OT
Nebraska Public Power District	Belleville, KS	7		NG	4.1	4.1	2012-05	OT
Nebraska Public Power District	Proposed New Plant 2	1		NG	229	229	2006-01	A
North Branch Public Utilities	North Branch	3		DFO	2	2	2003-06	P
North Branch Public Utilities	North Branch	4		DFO	2	2	2003-06	P

Generator Information - Planned Generators
MEGAWATTS

Company Name	Plant Name	Generator ID	Prime Mover	Energy Source Primary	Net Capacity Sum	Net Capacity Win	Current Eff. Date	Status Code
Northwestern Public Service Company	Webster	1		DFO	0.8	0.8	2002-03	RA
Omaha Public Power District	Cass County	1	GT	NG	159.5	190	2003-06	V
Omaha Public Power District	Cass County	2	GT	NG	159.5	190	2003-06	V
Omaha Public Power District	Elk City	5	IC	LFG	0.75	0.75	2005-01	P
Omaha Public Power District	Elk City	6	IC	LFG	0.75	0.75	2005-01	P
Omaha Public Power District	Elk City	7	IC	LFG	0.75	0.75	2007-01	P
Omaha Public Power District	Elk City	8	IC	LFG	0.75	0.75	2007-01	P
Omaha Public Power District	Nebraska City	2	ST	SUB	600	600	2009-05	P
Omaha Public Power District	Fort Calhoun	1		NUC	600	600	2003-11	A
Otter Tail Power Company	New CT (Solway)	1		NG	43	47	2003-05	V
Otter Tail Power Company	New CT Diesel (Solway)	D1		DFO	1.25	1.25	2003-05	V
Otter Tail Power Company	Perham Incinerator	1		MSW	2.5	2.5	2003-05	TS
Pella Municipal Power And Light Department	City of Pella - IC	10		DFO	2	2	2003-05	L
Pella Municipal Power And Light Department	City of Pella - IC	11		DFO	2	2	2003-05	L
Pella Municipal Power And Light Department	City of Pella - IC	12		DFO	2	2	2003-05	L
Pella Municipal Power And Light Department	City of Pella - IC	13		DFO	2	2	2003-05	L
Pella Municipal Power And Light Department	City of Pella - IC	14		DFO	2	2	2003-05	L
Pella Municipal Power And Light Department	City of Pella - IC	15		DFO	2	2	2003-05	L
Pella Municipal Power And Light Department	City of Pella - IC	16		DFO	2	2	2003-05	L
Pella Municipal Power And Light Department	City of Pella - IC	3		DFO	2	2	2003-05	L
Pella Municipal Power And Light Department	City of Pella - IC	4		DFO	2	2	2003-05	L
Pella Municipal Power And Light Department	City of Pella - IC	5		DFO	2	2	2003-05	L
Pella Municipal Power And Light Department	City of Pella - IC	6		DFO	2	2	2003-05	L
Pella Municipal Power And Light Department	City of Pella - IC	7		DFO	2	2	2003-05	L
Pella Municipal Power And Light Department	City of Pella - IC	8		DFO	2	2	2003-05	L
Pella Municipal Power And Light Department	City of Pella - IC	9		DFO	2	2	2003-05	L
Princeton Public Utils Comm	Princeton	7		DFO	5	5	2003-06	P
Redwood Falls Public Util Comm	Redwood Falls	2		DFO	2	2	2003-05	P
Redwood Falls Public Util Comm	Redwood Falls	3		DFO	2	2	2003-05	P
Redwood Falls Public Util Comm	Redwood Falls	4		DFO	2	2	2003-05	P
Saint Peter Public Util Comm	Saint Peter	1		DFO	2	2	2003-06	P
Saint Peter Public Util Comm	Saint Peter	2		DFO	2	2	2003-06	P
Saint Peter Public Util Comm	Saint Peter	3		DFO	2	2	2003-06	P
Saint Peter Public Util Comm	Saint Peter	4		DFO	2	2	2003-06	P
Saint Peter Public Util Comm	Saint Peter	5		DFO	2	2	2003-06	P
Saint Peter Public Util Comm	Saint Peter	6		DFO	2	2	2003-06	P

Generator Information - Planned Generators

MEGAWATTS

Company Name	Plant Name	Generator ID	Prime Mover	Energy Source Primary	Net Capacity Sum	Net Capacity Win	Current Eff. Date	Status Code
Saskatchewan Power Corporation	Cory	1		NG	81.7	95.1	2003-01	TS
Saskatchewan Power Corporation	Cory	2		NG	81.7	95.1	2003-01	TS
Saskatchewan Power Corporation	Cory	3		NG	68.2	72.6	2003-01	TS

Generator Information - Joint Owned Units
MEGAWATTS

Plant Name	Generator ID	Energy Source Primary	Net Capacity Sum	Net Capacity Win	Owning Company	Percent Owned
Laramie River	1	SUB	550.0	550.0	MRES	49.55
					LES	31.54
					HCPD	9.03
					BEPC	8.14
					MEAN	1.74
Duane Arnold	1	NUC	520.0	535.0	IESC	90
					CBPC	10
Council Bluffs	3	SUB	690	690	MEC	79.1
					CIPCO	11.5
					CBPC	3.8
					CFU	3.1
					ATL	2.5
Neal North	3	SUB	515	515	MEC	72
					IESC	28
Ottumwa	1	SUB	738.1	738.1	MEC	52
					IESC	48
Louisa	1	SUB	700.0	700.0	MEC	88
					CIPCO	4.6
					IPW	4
					Waverly	1.1
					HRLN	0.8
					Eldridge	0.5
					Tipton	0.5
					Geneseo	0.5

Generator Information - Joint Owned Units
MEGAWATTS

Plant Name	Generator ID	Energy Source Primary	Net Capacity Sum	Net Capacity Win	Owning Company	Percent Owned
Neal South	4	SUB	624.0	624.0	MEC	40.57
					IPW	21.53
					CBPC	9.03
					NIPCO	9.03
					NWPS	8.68
					ALGN	2.94
					Webster	2.6
					CFU	2.5
					Spencer	1.22
					Coon Rapids	0.52
					Laurens	0.52
					Bancroft	0.35
					Milford	0.35
					Graettinger	0.17
Clay Boswell	4	SUB	424.4	424.4	MP	79.9
					WPPI	20.1
Clay Boswell	D4	DFO	0.7	0.7	MP	80
					WPPI	20
Milton R Young	2	LIG	455.0	447.0	MP	70.85
					MPC	29.15
Big Stone	1	SUB	455.5	470.3	OTP	53.88
					NWPS	23.43
					MDU	22.69
Big Stone	D1	DFO	0.6	0.6	OTP	57.2
					MDU	21.53
					NWPS	21.27
Potlatch Cogen	1	WDS	11.9	11.9	OTP	50
					MPC	50

Generator Information - Joint Owned Units

MEGAWATTS

Plant Name	Generator ID	Energy Source Primary	Net Capacity Sum	Net Capacity Win	Owning Company	Percent Owned
Coyote	1	LIG	427.0	427.0	OTP	35
					MPC	30
					MDU	25
					NWPS	10
Sherburne County	3	SUB	871.0	871.0	NSP	59
					SMMPA	41

FORECAST OF SYSTEM DEMAND

Section V

Forecast of System Demand for MAPP

Monthly Summary by Reporting System May 2003 through December 2005..............................V-3
Seasonal Summary by Reporting System Summer 2003 through Summer 2012 ....V-6

FORECASTED MONTHLY SYSTEM DEMAND SUMMARY
MEGAWATTS

	MAY 2003	JUN 2003	JUL 2003	AUG 2003	SEP 2003	OCT 2003	NOV 2003	DEC 2003	JAN 2004	FEB 2004	MAR 2004	APR 2004
ALGN	16	20	24	23	23	15	16	17	17	17	15	15
AMES	91	110	119	107	90	80	72	77	71	73	72	81
ATL	20	25	26	24	25	19	16	17	17	17	17	17
BEPC	935	1124	1340	1207	1024	975	1004	1104	1220	1042	1000	878
CMMPA	65	80	80	78	68	54	57	58	57	56	56	57
GRE	1768	2080	2264	2212	1952	1562	1709	1863	1858	1802	1654	1579
GSE	621	731	799	778	709	704	741	788	799	732	724	642
HCPD	65	74	83	82	72	68	73	80	82	76	73	71
HMU	12	14	14	13	14	10	9	10	10	10	10	10
HSTG	86	95	101	98	91	73	64	66	67	69	71	74
HUC	48	55	61	60	55	41	42	43	43	41	41	46
LES	574	679	761	747	653	487	477	515	506	494	471	460
MDU	328	420	462	449	367	309	337	381	364	348	324	307
MEAN	106	127	141	140	122	90	95	103	101	97	93	91
MEC	3490	4408	4683	4567	4138	2980	3044	3267	3213	3129	3030	2919
MMPA	162	183	195	200	156	124	133	134	133	135	128	129
MMU	75	81	83	81	80	74	73	73	79	74	75	72
MP	1567	1616	1649	1647	1600	1616	1642	1673	1675	1671	1591	1536
MPC	425	430	430	430	420	500	640	770	780	780	650	549
MPW	122	137	144	141	134	116	117	120	121	121	120	119
MRES	182	261	306	299	212	154	230	284	292	276	226	193
NPPD	1599	2024	2324	2254	1969	1555	1631	1725	1760	1688	1610	1445
NULM	42	46	49	51	38	31	30	30	29	30	29	31
NWPS	218	267	289	298	265	184	187	202	226	195	191	177
OPPD	1844	1988	2021	2048	1984	1293	1350	1403	1437	1346	1303	1531
OTP	565	550	580	604	568	498	583	662	691	694	579	551
PELLA	42	46	45	49	44	34	31	31	31	31	34	39
RPU	203	255	264	260	258	183	173	181	175	169	166	186
SMMPA	215	285	321	304	251	209	231	276	243	234	221	200
WAPA	942	1062	1129	1052	1014	900	1071	1141	1010	950	961	878
WLMR	48	59	61	60	55	42	46	46	44	45	43	43
WPPI	48	56	63	63	51	45	50	54	52	50	47	46
XCEL	6898	8142	8973	8787	7274	6102	6235	6363	6640	6518	5937	5787
MHEB	2814	2822	2870	2924	2768	2964	3326	3782	3804	3645	3372	2911
SPC	2364	2491	2477	2596	2452	2478	2740	2879	2925	2844	2622	2473
MAPP-US	23423	27528	29886	29212	25774	21124	22211	23557	23843	23011	21563	20758
MAPP-Canada	5178	5313	5347	5519	5221	5441	6066	6661	6729	6489	5994	5384
MAPP-Total	28600	32841	35233	34732	30995	26566	28277	30218	30573	29500	27557	26142

FORECASTED MONTHLY SYSTEM DEMAND SUMMARY
MEGAWATTS

	MAY 2004	JUN 2004	JUL 2004	AUG 2004	SEP 2004	OCT 2004	NOV 2004	DEC 2004	JAN 2005	FEB 2005	MAR 2005	APR 2005
ALGN	16	20	25	23	23	15	16	17	17	17	15	15
AMES	91	111	121	108	92	81	73	78	71	74	72	82
ATL	20	25	27	24	25	19	17	17	17	17	17	17
BEPC	983	1176	1395	1260	1069	1008	1038	1162	1246	1064	1021	897
CMMPA	67	82	82	80	69	55	58	59	58	57	57	58
GRE	1893	2200	2366	2342	2058	1656	1773	1906	1906	1849	1696	1572
GSE	630	745	814	792	720	714	750	798	814	741	733	650
HCPD	66	74	83	83	73	69	74	80	83	77	74	72
HMU	12	14	14	13	14	10	10	10	10	10	10	10
HSTG	88	97	103	100	93	75	66	67	69	71	73	76
HUC	49	56	61	60	56	42	42	43	43	41	42	47
LES	577	684	770	756	660	494	483	521	518	505	481	472
MDU	331	423	465	452	370	311	340	384	367	351	326	310
MEAN	107	128	142	141	124	90	96	104	108	105	101	99
MEC	3556	4473	4753	4636	4216	3034	3099	3329	3279	3193	3093	2986
MMPA	168	190	202	207	161	128	138	139	138	140	133	133
MMU	76	82	84	82	81	75	74	78	80	75	75	72
MP	1590	1640	1674	1672	1623	1640	1659	1691	1693	1689	1609	1553
MPC	428	432	432	432	423	504	645	780	790	790	660	553
MPW	124	139	147	144	137	118	119	122	123	123	122	121
MRES	191	271	318	311	221	161	240	295	302	286	235	201
NPPD	1634	2059	2362	2290	2001	1585	1661	1758	1792	1719	1639	1471
NULM	43	47	50	52	39	32	31	31	29	30	29	32
NWPS	220	269	292	302	267	186	189	204	228	197	193	179
OPPD	1917	2057	2074	2108	1966	1349	1386	1453	1473	1440	1381	1514
OTP	568	554	584	608	573	504	589	669	697	701	585	559
PELLA	42	46	45	49	44	34	31	31	31	31	35	41
RPU	209	262	271	267	265	188	178	186	179	172	169	190
SMMPA	224	292	329	311	268	216	240	286	252	246	209	185
WAPA	942	1062	1129	1052	1014	900	1071	1141	1010	950	961	878
WLMR	49	60	63	60	56	43	44	47	45	45	43	43
WPPI	49	57	64	64	53	46	51	55	53	51	49	47
XCEL	7036	8304	9134	8943	7423	6186	6318	6444	6726	6469	6023	5866
MHEB	2808	2820	2873	2933	2764	2963	3341	3798	3802	3655	3389	2928
SPC	2442	2574	2559	2682	2534	2560	2830	2974	3010	2927	2699	2546
MAPP-US	23997	28132	30476	29823	26277	21567	22599	23984	24248	23327	21962	21001
MAPP-Canada	5250	5394	5432	5615	5298	5523	6171	6772	6812	6582	6088	5474
MAPP-Total	29246	33526	35907	35439	31575	27090	28770	30756	31061	29909	28049	26474

FORECASTED MONTHLY SYSTEM DEMAND SUMMARY
MEGAWATTS

	MAY 2005	JUN 2005	JUL 2005	AUG 2005	SEP 2005	OCT 2005	NOV 2005	DEC 2005
ALGN	16	21	25	24	24	16	16	18
AMES	91	112	123	109	93	82	74	79
ATL	20	26	27	25	25	19	17	17
BEPC	998	1192	1415	1279	1086	1024	1055	1181
CMMPA	68	83	83	81	71	56	60	60
GRE	1972	2292	2465	2440	2145	1726	1815	1952
GSE	640	759	831	808	733	724	760	807
HCPD	66	75	84	83	74	69	75	81
HMU	12	15	15	14	14	10	10	10
HSTG	90	100	106	103	96	77	68	69
HUC	49	56	62	61	57	43	43	44
LES	591	699	790	776	673	510	495	533
MDU	334	427	469	456	373	314	343	387
MEAN	116	137	151	150	133	100	107	115
MEC	3637	4569	4854	4734	4310	3093	3160	3397
MMPA	175	197	210	215	167	133	143	144
MMU	77	83	85	83	82	76	75	79
MP	1609	1660	1694	1692	1643	1660	1677	1709
MPC	431	434	434	434	428	508	650	790
MPW	126	141	149	146	139	120	121	124
MRES	200	282	330	322	231	169	251	307
NPPD	1665	2093	2401	2328	2034	1615	1692	1791
NULM	44	48	51	54	40	33	32	32
NWPS	223	272	295	306	270	188	191	206
OPPD	1967	2107	2138	2162	2114	1464	1419	1441
OTP	575	561	593	614	578	510	594	678
PELLA	44	47	46	51	45	35	31	31
RPU	213	267	276	272	270	192	181	190
SMMPA	227	299	337	318	279	224	250	296
WAPA	942	1062	1129	1052	1014	900	1071	1141
WLMR	50	61	65	63	58	44	45	48
WPPI	51	58	66	65	54	47	52	56
XCEL	7176	8464	9289	9091	7565	6259	6359	6514
MHEB	2810	2827	2887	2946	2766	2959	3356	3818
SPC	2514	2649	2634	2760	2608	2635	2913	3061
MAPP-US	24494	28698	31088	30409	26917	22038	22929	24326
MAPP-Canada	5323	5476	5521	5707	5374	5594	6269	6879
MAPP-Total	29817	34174	36609	36115	32291	27632	29198	31205

FORECASTED SEASONAL SYSTEM DEMAND SUMMARY
MEGAWATTS

	SUM 2003	WIN 2003	SUM 2004	WIN 2004	SUM 2005	WIN 2005	SUM 2006	WIN 2006	SUM 2007	WIN 2007
ALGN	24	17	25	17	25	18	26	18	26	19
AMES	119	77	121	78	123	79	124	80	126	81
ATL	26	17	27	17	27	17	27	17	27	17
BEPC	1340	1220	1395	1246	1415	1269	1440	1288	1461	1303
CMMPA	80	58	82	59	83	61	84	62	86	63
GRE	2264	1863	2366	1906	2465	1952	2560	1998	2658	2046
GSE	799	799	814	814	831	831	847	847	865	860
HCPD	83	82	83	83	84	83	85	84	85	84
HMU	14	10	14	10	15	10	15	11	15	11
HSTG	101	71	103	73	106	75	109	77	112	79
HUC	61	43	61	43	62	44	62	44	63	45
LES	761	515	770	521	790	533	806	541	824	552
MDU	462	381	465	384	469	387	473	390	477	393
MEAN	141	103	142	108	151	112	152	113	153	114
MEC	4683	3267	4753	3329	4854	3404	4954	3472	5061	3558
MMPA	200	135	207	140	215	149	223	155	231	161
MMU	83	79	84	80	85	82	87	84	89	86
MP	1649	1675	1674	1693	1694	1711	1709	1726	1724	1741
MPC	430	780	432	790	434	800	436	810	438	820
MPW	144	121	147	123	149	126	152	127	154	129
MRES	306	292	318	302	330	314	345	325	356	335
NPPD	2324	1760	2362	1792	2401	1826	2441	1859	2481	1892
NULM	51	30	52	31	54	32	55	32	56	33
NWPS	298	226	302	228	306	230	309	232	312	234
OPPD	2048	1437	2108	1473	2162	1514	2229	1587	2329	1633
OTP	604	694	608	701	614	712	620	715	626	723
PELLA	49	34	49	35	51	35	51	36	52	36
RPU	264	181	271	186	276	186	283	190	290	194
SMMPA	321	299	329	309	337	311	346	317	353	318
WAPA	1129	1141	1129	1141	1129	1141	1129	1141	1129	1141
WLMR	61	46	63	47	65	48	67	49	69	50
WPPI	63	54	64	55	66	56	67	57	68	58
XCEL	8973	6640	9134	6726	9289	6798	9451	6882	9617	6969
MHEB	2924	3804	2933	3802	2946	3818	2983	3845	3004	3856
SPC	2596	2925	2682	3010	2760	3107	2802	3150	2841	3224
MAPP-US	29957	24148	30555	24541	31156	24947	31763	25367	32413	25779
MAPP-Canada	5519	6729	5615	6812	5707	6925	5785	6995	5845	7080
MAPP-Total	35476	30877	36170	31353	36863	31872	37548	32362	38258	32859

FORECASTED SEASONAL SYSTEM DEMAND SUMMARY
MEGAWATTS

	SUM 2008	WIN 2008	SUM 2009	WIN 2009	SUM 2010	WIN 2010	SUM 2011	WIN 2011	SUM 2012
ALGN	27	19	27	19	28	20	28	20	29
AMES	128	82	130	83	132	83	132	83	132
ATL	28	17	28	18	28	18	29	18	29
BEPC	1476	1319	1497	1334	1511	1352	1532	1367	1549
CMMPA	87	64	89	65	90	67	92	68	94
GRE	2759	2097	2863	2154	2974	2205	3078	2257	3185
GSE	880	871	897	882	913	893	930	904	947
HCPD	85	85	86	85	86	86	87	86	87
HMU	15	11	16	11	16	11	16	11	16
HSTG	115	81	118	83	121	85	124	87	127
HUC	63	45	64	46	64	46	65	46	65
LES	841	561	856	567	872	578	888	589	903
MDU	481	396	484	399	488	401	492	404	496
MEAN	155	116	156	116	158	118	160	119	162
MEC	5171	3630	5272	3703	5373	3775	5467	3841	5558
MMPA	240	167	249	173	258	179	268	186	278
MMU	91	88	93	90	95	92	97	94	99
MP	1738	1754	1764	1778	1779	1792	1800	1811	1815
MPC	440	830	442	840	444	850	446	860	448
MPW	156	131	158	133	161	134	163	136	165
MRES	368	345	379	355	391	367	405	379	417
NPPD	2521	1926	2562	1960	2603	1994	2645	2030	2687
NULM	58	34	59	35	61	36	62	37	64
NWPS	315	236	318	238	322	240	325	242	328
OPPD	2390	1669	2448	1693	2483	1717	2524	1737	2568
OTP	633	727	639	733	647	736	649	737	649
PELLA	52	37	53	38	53	39	54	40	54
RPU	297	199	305	204	313	209	320	215	328
SMMPA	361	320	369	322	377	323	385	329	394
WAPA	1129	1141	1129	1141	1129	1141	1129	1141	1129
WLMR	71	51	73	52	74	53	75	54	77
WPPI	69	60	70	61	72	62	73	63	74
XCEL	9782	7059	9945	7150	10113	7244	10271	7332	10430
MHEB	3040	3881	3074	3904	3110	3931	3155	3967	3186
SPC	2908	3277	2955	3325	2999	3359	3029	3374	3043
MAPP-US	33022	26167	33640	26561	34228	26946	34811	27323	35383
MAPP-Canada	5947	7158	6029	7229	6109	7290	6185	7341	6229
MAPP-Total	38969	33325	39669	33790	40337	34236	40996	34664	41612

NET ENERGY REQUIREMENTS

ANNUAL NET ENERGY REQUIREMENTS 2003 through 2012

Annual Summary by Reporting System VI-3

FORECAST ANNUAL NET ENERGY
GIGAWATT HOURS

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
ALGN	116	116	117	120	123	125	128	130	133	135
AMES	547	554	566	576	586	596	606	616	616	616
ATL	109	110	112	113	114	115	117	118	119	120
BEPC	7127	7523	7659	7776	7889	8012	8098	8183	8281	8371
CMMPA	399	407	415	423	432	440	449	458	467	477
GRE	11726	12535	12911	13285	13671	14067	14489	14938	15357	15787
GSE	4514	4585	4671	4758	4844	4935	5029	5128	5223	5317
HCPD	537	541	548	556	561	565	570	575	580	584
HMU	65	65	66	67	68	69	70	72	73	74
HSTG	483	494	507	519	533	547	561	576	591	606
HUC	317	325	331	335	341	346	351	357	362	367
LES	3448	3518	3615	3695	3789	3875	3940	4034	4127	4209
MDU	2209	2226	2248	2267	2287	2305	2322	2336	2351	2365
MEAN	617	631	684	694	704	715	726	737	748	759
MEC	21138	21635	22100	22505	22899	23352	23745	24142	24540	24963
MMPA	945	980	1017	1055	1094	1135	1178	1222	1267	1315
MMU	580	591	602	615	628	641	654	668	682	696
MP	12367	12461	12467	12490	12520	12567	12610	12742	12834	12954
MPC	3750	3844	3940	4039	4139	4243	4349	4458	4569	4683
MPW	918	936	954	977	992	1007	1023	1039	1055	1072
MRES	1560	1618	1683	1758	1816	1875	1934	1992	2067	2126
NPPD	11886	12122	12356	12595	12838	13089	13338	13589	13846	14104
NULM	200	204	208	212	216	221	225	230	234	239
NWPS	1349	1376	1403	1431	1459	1488	1518	1548	1580	1611
OPPD	9721	10063	10415	10774	11141	11365	11562	11798	11949	12154
OTP	3842	3881	3939	3980	4011	4051	4082	4124	4135	4135
PELLA	198	198	209	209	209	209	210	210	210	211
RPU	1312	1344	1374	1412	1447	1483	1520	1558	1597	1637
SMMPA	2836	2926	3014	3105	3180	3254	3329	3407	3486	3561
WAPA	7204	7904	8438	9190	9005	9479	9479	9479	9479	9479
WLMR	279	286	293	299	305	311	318	324	330	336
WPPI	312	318	325	332	338	345	352	359	365	372
XCEL	44907	45771	46418	47154	47984	48950	49689	50590	51449	52443
MHEB	21305	21550	21689	21904	22122	22336	22552	22796	23066	23331
SPC	18714	19430	19978	20269	20570	21115	21441	21794	22014	22157
MAPP-US	157518	162091	165604	169315	172163	175777	178570	181736	184702	187878
MAPP-Canada	40019	40980	41667	42173	42692	43451	43993	44590	45080	45488
MAPP-Total	197537	203071	207271	211488	214855	219228	222563	226326	229783	233366

BULK ELECTRICAL TRANSMISSION MAP

Section VII

BULK ELECTRICAL TRANSMISSION MAP

The Mid-Continent Area Power Pool prepares a Bulk Electrical Transmission Map, which details existing and proposed facilities each year for a ten-year period.

For ordering information, contact:

MAPPCOR
1125 Energy Park Drive
Saint Paul, MN 55108-5001
(651) 632-8400

PROPOSED BULK ELECTRIC TRANSMISSION LINE ADDITIONS

Section VIII

PROPOSED BULK ELECTRIC TRANSMISSION LINE ADDITIONS

This item contains a list of the bulk electric transmission lines significant for interconnected operation proposed for installation during the ten years of the reporting period. The list covers transmission lines rated 230 kV and above.

Column 01: Identifies the line owners by name abbreviation and EIA utility code.

Column 02: Identifies each terminal of the facility.

Column 03: Shows the line length in circuit miles.

Column 04: The date that the facility is expected to be in service.

Column 05: The nominal operating voltage in kilovolts (kV).

Column 06: The nominal design voltage in kilovolts (kV).

List of Proposed Bulk Transmission Lines

Entity Name	Entity EIA Code	From Location	To Location	Line Length in Circuit Miles	Expected Service Date	Operating Voltage kV	Design Voltage kV
1		2		3	4	5	6
Dairyland Power Cooperative	4716	Apple River	Chisago	36	2006-07	161	161
Dairyland Power Cooperative	4716	Apple River	Chisago	2	2006-07	115	115
LES	11018	14th & Fletcher	84th & Buff	3	2003-04	115	115
LES	11018	19th & Alvo	NW 12th & Arbor	4	2003-11	115	115
LES	11018	NW 68th & Holdrege	NW 12th & Arbor	11	2005-05	115	115
LES	11018	Rokeby	40th & Rokeby	5	2006-05	115	115
LES	11018	NW 68th & Holdrege	128th & Adams	28	2007-05	345	345
Manitoba Hydro Electric Board	-200	Herblet Lake	Sherridon	45	2005-10	115	115
Manitoba Hydro Electric Board	-200	Herblet Lake	Chisel Lake	4	2005-10	115	115
Manitoba Hydro Electric Board	-200	Silver	Rosser	57	2005-10	230	230
Manitoba Hydro Electric Board	-200	Dorsey	Portage South	44	2008-10	230	230
Minnesota Power	12647	ARROWHEAD	WESTON, WI	220	2005-06	345	345
Minnesota Power	12647	Arrowhead	MN-WI State line	12	2005-06	345	345
American Transmission Company	659	MN-WI State Line	Weston	207	2005-06	345	345
NPPD	13337	Broken Bow	Crooked Creek	40	2003-04	115	115
OPPD	14127	Sub 3458	Under Plan	68	2009-04	345	345
Otter Tail Power Co.	14232	Frazee	Audubon	20	2004-12	115	115
Otter Tail Power Co.	14232	Canby	Dawson	22	2004-12	115	115
Otter Tail Power Co.	14232	Dawson	Appleton	22	2008-12	115	115
NSP	1904	Chisago		36	2004-06	161	161
NSP	1904	Ironwood	Gogebic	34	2005-11	115	115
NSP	1904	Wilmarth	West Faribault	53	2003-05	161	161
NSP	1904	Air Lake	Empire	18	2003-05	115	115
NSP	1904	Red Rock	Rogers Lake	6	2003-05	115	115
NSP	1904	Rugby Substation	Canada Border	53	2002-10	230	230

CCC/NFAAT/S/2

Request: The Crown Corporations Council requested a summary of the new information from the updated 2003 Power Resource Plan and sensitivity analysis regarding its implications on Wuskwatim evaluations.

Response: Since the economic evaluations of Wuskwatim advancement reported in the main submission are based on the 2002/2003 Power Resource Plan, the impact on the IRR of incorporating the 2003/2004 Resource Plan is examined to ensure that prior studies and sensitivities continue to be valid for the purposes of evaluating the economics of the Wuskwatim Project.

Compared to the 2002/03 Power Resource Plan, the 2003/2004 Power Resource Plan includes 250 MW of wind development, additional upgrades to existing facilities, higher load forecast and current demand-side management projections, adjusted to account for most recent savings to date estimates. Under these assumptions, new generation would be needed in 2019 to meet domestic load and Wuskwatim would be the recommended next plant (as opposed to the 2002/2003 Power Resource Plan sequence in which Wuskwatim development occurred in 2020). The sensitivity therefore not only includes the impact of the 2003/04 assumptions, it also includes the effect of advancing Wuskwatim not from 2020, but from 2019 instead. (Further details of the 2003/04 Power Resource Plan are included in the attached CCC/NFAAT/S/2a.

The economic evaluation of Wuskwatim advancement has been recalculated with the changes from the 2003/2004 PRP. The overall impact on the IRR is a reduction of 0.1%, i.e. the IRR drops from 10.3% to 10.2%. This calculation also includes the impact of the updated Economic Outlook resulting in slightly lower future escalation in U.S. export prices

The generation sequence recommended for the 2003/04 IFF is Wuskwatim 2009/10 followed by Gull 2022/23. The evaluations submitted April 30, 2003 in the "Need For and Alternatives to the

Wuskwatim Project" are judged to still be appropriate for use with the current resource plan recommendation. The sensitivities included in that submission are extensive. The current results continue to indicate that the development sequence of Wuskwatim followed by Gull is the best generation sequence to meet Manitoba load under a wide range of sensitivity factors. The updated set of factors in the 2003/04 Resource Plan fall well within the range of sensitivities that were assessed in the submission.

Financial sensitivities are not completed at this time, but will be provided when available.

CCC/NFAAT/S/2a

2003/04 Power Resource Plan Report

Power Planning and Development Division

July 2003

TABLE OF CONTENT

2003/04 Power Resource Plan 1
Base Case Power Resource Plan for the 2003/04 IFF 1
Changes from Last Year 3
Uncertainty with Regards to Plan 4

Attachments:
Table A: Dependable Energy (GWh) Base Manitoba Load Forecast - Supply/Demand Balance 2003 IFF Sequence
Table B: Annual Peak Capacity (MW): Base Manitoba Load Forecast - Supply/Demand Balance 2003 IFF Sequence
Figure 1a and Figure 1b: 2003 Manitoba Base Load Forecast

2003/04 Power Resource Plan

The "Need For and Alternatives To the Wuskwatim Project" report recently submitted to the Manitoba Clean Environment Commission (CEC) contains comprehensive evaluations on the Wuskwatim project, including sensitivities and analyses of alternatives to Wuskwatim development. That document includes consideration of most of the long-term issues normally considered in the Power Resource Plan report and in many ways is more detailed than traditional Power Resource Plans. Although the 2003/04 Power Resource Plan incorporates updates to key variables, including the addition of 250 MW of wind, the 2003 Manitoba Load Forecast and current supply and DSM assumptions, this information is used only to adjust the in-service dates required for future plants. No new economic analysis has been conducted and economic conclusions rely on work conducted for the "Need For and Alternatives To the Wuskwatim Project" report, which continues to indicate that Wuskwatim is least cost option for next plant.

Base Case Power Resource Plan for the 2003/04 IFF

The 2003/04 Power Resource Plan, utilizing evaluations conducted in the "Need for and Alternatives To The Wuskwatim Project" has been updated to include 250 MW of wind generation, additional upgrades to existing facilities, a higher base domestic load forecast, and current demand-side management projections, adjusted to account for most recent savings to date estimates. The following Power Resource Plan has been adopted for use in the 2003/04 IFF and the 20 year capital plan.

<u>Supply-Side Enhancement Projects (SSE)</u>

Total: 670 MW/3339 GWh by Mar 2012 including:

Achieved to Date:	140 MW/732 GWh by Mar 2003
Planned Additional:	216 MW/ 457 GWh by Mar 2012
Kelsey Rerunnering	(75 MW/0 GWh) by 2011/12
HVDC Bipole III Line	(86 MW/437 GWh) by 2010/11
Winnipeg River Plants	(10 MW/20 GWh)
Northern AC Enhancements	(45 MW/undetermined)

License Review and Continuation of Operation: 314 MW/2150 GWh

Pointe du Bois	(77 MW/320 GWh)	License Review Dec. 2011
Selkirk #1-2	(132 MW/1030 GWh)	License Review 2005/06-2019/20
Brandon #5	(105 MW/800 GWh)	License Review 2006/07-2018/19

<u>Demand Side Management Program (DSM)</u>

Completed and Planned: 299 MW/ 983 GWh by Mar 2012

<u>New Generation</u>

Wind:

Phase I	(100 MW)	2005/06
Phase II	(50 MW)	2006/07
Phase III	(50 MW)	2007/08
Phase IV	(50 MW)	2008/09

Hydro:

Wuskwatim	(200 MW)	2009/10
Gull	(620 MW)	2022/23

Figure 1(a) provides current energy projections for total firm load and supply (resources). The total load includes the 2003 base domestic forecast and current committed firm exports. The resources include the ongoing operation of existing generation that has already been committed such as Brandon #5 (2006/07) and Selkirk #1 & 2 (2005/06), although these still must pass through the regulatory process. Successful license review for Brandon #5 and Selkirk #1 & 2 will allow the lives of these facilities to extend to the years 2018/19 and 2019/20 respectively. The energy and capacity available from reduction in transmission losses resulting from construction and system operation of Bipole III line (2010/11) has been included.

Changes from Last Year

The projection of resources now includes capacity and energy that is expected to be available to the Manitoba Hydro System from a total of 250MW of proposed wind developments. The Corporation has committed to 250MW of wind generation provided that it is technically and economically and financially viable. Manitoba Hydro is currently undertaking wind monitoring at seven sites in the province. It is expected that wind power will be developed at one or more of these sites with an in-service-date as early as 2005/06.

In 2002, approval was obtained to undertake a Kelsey rerunnering project that is expected to result in an increase of 25 MW. This approved project could be upgraded further to obtain up to an additional 50 MW at Kelsey for a total enhancement of 75 MW. This total enhancement of 75 MW has been included in the resource plan, although approval for the additional 50 MW has not been obtained at this time.

The increase in dependable energy compared to last year, resulting from other Supply-Side Enhancements (completed by end of March 2003) now include estimates for energy gains resulting from programs such as ice management, reservoir optimization, improved thermal operating limits and life assurance.

The projection includes Option 4 DSM derived from the 2001/02 plan adjusted to be incremental to the savings achieved to date. Long range DSM plans remain unchanged from last year. Future DSM options are currently in the process of being updated, including an assessment of maximum market attainable DSM potential and potential reductions associated with the Winnipeg Hydro acquisition. It is expected that a revised DSM plan will be included in the 2004/05 Power Resource Plan.

In summary, whereas the 2002/2003 Power Resource Plan included Wuskwatim-2020 and Gull-2023, the approved sequence for the 2003/2004 Power Resource Plan now includes Wuskwatim-2009 and Gull-2022. A higher load forecast of about 960 GWh in 2020/21 is largely offset by additional firm energy available from wind power estimated to be around 720 GWh. This results in a net change of about 240 GWh (more load) in 2020/21, but would have meant advancing Wuskwatim to 2019/20 to meet domestic load. Instead, the "Need For and Alternatives To the Wuskwatim Project" process has been initiated to protect an in-service date of 2009 for Wuskwatim, which is reflected in the Plan. The in-service date of Gull is advanced to 2022 (compared to 2023 in the 2002/2003 IFF) to support a deficit of approximately 300 GWh in that year. Figure 1(b) and Table A depict the energy balances, and Table B depicts capacity balances for the recommended IFF sequence.

Uncertainty with Regards to Plan

Some uncertainty with regards to factors such as load growth, inability to develop planned additions and inability to extend existing operations, could affect the timing, the sequence and the extent of development of the resources indicated in this plan.

Although only a 25 MW capacity increase for Kelsey rerunnering has been approved, the proposed project providing 75 MW of incremental capacity assumed for the 2003/04 Power Resource Plan has no associated dependable energy and does not affect the timing of new generation.

No final commitment decisions have been made on specific facilities. Wind would only be developed when proven to be technical, economic and financially viable. Studies and negotiations related to wind development are still ongoing.

There is a risk that planned transmission improvements and developments will be delayed from their current schedules. Specifically, the 2010/2011 in-service date of the Bipole III HVDC line is subject to an extensive community consultation and environmental process. Delays to in-service of the line do not have the potential to affect resource requirements unless delays extend into the 2020 timeframe, which is unlikely.

Brandon Unit#5 License Review (LR) for continuing operation is assumed to occur before 2006/07. However, there is some uncertainty that continued operation to 2018/19 might not be technically or economically feasible. Uncertainty with respect to Brandon Unit #5 LR does not affect the timing of next plant for domestic load requirements as the current plan assumes unit #5 retirement has already occurred before the domestic requirement for new plant.

There are a range of options for the rehabilitation/redevelopment of Pointe du Bois and Slave Falls Generating Stations. Engineering studies are currently underway and a recommendation will be forthcoming once an evaluation has been completed.

The Clean Environment Commission review process has been initiated to protect an in-service date of 2009 for Wuskwatim. Although, no decision has been made at this time to proceed with Wuskwatim development, development of Wuskwatim for 2009 mitigates against the risks that load growth could be higher than forecast, or planned-for supply options, such as wind or Supply-Side Enhancements, may not be fully realized. Despite the assumption that Wuskwatim will proceed in 2009, next plant (Gull) might still be required to be advanced under these conditions.

TABLE A
DEPENDABLE ENERGY (GWh): BASE MANITOBA LOAD FORECAST
Supply/Demand Balance - 2003 IFF Sequence
Wind (250 MW) - 2005, Wuskwatim - 2009, Gull - 2022, SCCT - 2031, SCCT - 2035
Resource and Demand at the Generation Level

Fiscal Year Beginning April	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Power Resources																	
Manitoba Hydroelectric Plants																	
Existing Meeting MB Load	21170	21150	21140	21120	21110	21090	21080	21060	21040	21030	20690	20660	20640	20630	20610	20600	20590
WUSKWATIM	0	0	0	0	878	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250
GULL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
500 MW HVDC Bipole III	0	0	0	0	0	437	437	437	437	437	437	437	437	437	437	437	437
Manitoba Thermal Plants																	
Brandon Unit 5 License Review	800	800	800	800	800	800	800	800	800	800	800	800	800	800	0	0	0
Selkirk License Review	1030	1030	1030	1030	1030	1030	1030	1030	1030	1030	1030	1030	1030	1030	1030	0	0
Brandon Units 6-7 SCCT	2300	2300	2300	2300	2300	2300	2300	2300	2300	2300	2300	2300	2300	2300	2300	2300	2300
SCCT's	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	215	359	502	645	717	717	717	717	717	717	717	717	717	717	717	717	717
Demand Side Management	190	242	291	337	377	413	445	469	492	518	543	568	597	618	637	657	649
Major Rerunnering																	
Kelsey Rerunnering	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Imports	2938	2790	2579	2560	2560	2560	2560	2560	2560	2560	2655	2114	1624	1430	1430	1430	1430
TOTAL POWER RESOURCES	28643	28671	28642	28792	29772	30597	30619	30623	30626	30642	30422	29876	29395	29212	28411	27391	27373
Demand																	
2003 Base Load	23154	23444	23738	23969	24195	24390	24622	24871	25123	25387	25657	25929	26204	26479	26783	27057	27356
Exports																	
Total Contract Sales	4120	3993	3400	3304	3174	2944	2924	2794	2782	2782	385	194	0	0	0	0	0
TOTAL LOAD	27274	27437	27138	27273	27369	27334	27546	27665	27905	28169	26042	26123	26204	26479	26783	27057	27356
SURPLUS	1369	1234	1504	1519	2403	3263	3073	2958	2721	2473	4380	3753	3191	2733	1628	334	17

TABLE A
DEPENDABLE ENERGY (GWh): BASE MANITOBA LOAD FORECAST
Supply/Demand Balance - 2003 IFF Sequence
Wind (250 MW) - 2005, Wuskwatim - 2009, Gull - 2022, SCCT - 2031, SCCT - 2035
Resource and Demand at the Generation Level

Fiscal Year Beginning April	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38
Power Resources																
Manitoba Hydroelectric Plants																
Existing Meeting MB Load	20580	20580	20570	20560	20560	20550	20540	20540	20530	20530	20520	20510	20510	20500	20490	20490
WUSKWATIM	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250
GULL	1371	2900	2900	2900	2900	2900	2900	2900	2900	2900	2900	2900	2900	2900	2900	2900
500 MW HVDC Bipole III	437	386	334	334	334	334	334	334	334	334	334	334	334	334	334	334
Manitoba Thermal Plants																
Brandon Unit 5 License Review	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Selkirk License Review	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Brandon Units 6-7 SCCT	2300	2300	2300	2300	2300	2300	2300	2300	2300	2300	2300	2300	2300	2300	2300	2300
SCCT's	0	0	0	0	0	0	0	0	0	1100	1100	1100	1100	2200	2200	2200
Wind	717	717	717	717	717	717	717	717	717	717	717	717	717	717	717	717
Demand Side Management	633	610	585	560	545	533	525	527	531	531	531	531	531	531	531	531
Major Rerunnering																
Kelsey Rerunnering	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Imports	1430	1430	1430	1430	1430	1430	1430	1430	1430	1430	1430	1430	1430	1430	1430	1430
TOTAL POWER RESOURCES	28718	30173	30086	30051	30036	30014	29997	29998	29992	31092	31082	31072	31072	32162	32152	32152
Demand																
2003 Base Load	27651	27892	28173	28453	28732	29012	29291	29570	29847	30127	30406	30686	30965	31245	31524	31803
Exports																
Total Contract Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD	27651	27892	28173	28453	28732	29012	29291	29570	29847	30127	30406	30686	30965	31245	31524	31803
SURPLUS	1067	2281	1913	1598	1304	1002	706	428	145	965	676	386	107	917	628	349

TABLE B

ANNUAL PEAK CAPACITY (MW): BASE MANITOBA LOAD FORECAST

Supply/Demand Balance - 2003 IFF Sequence

Wind (250 MW) - 2005, Wuskwatim - 2009, Gull - 2022, SCCT - 2031, SCCT - 2035

Resource and Demand at the Generation Level

Fiscal Year Beginning April	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Power Resources																	
Manitoba Hydroelectric Plants																	
Existing	4828	4828	4828	4828	4828	4828	4828	4828	4828	4828	4828	4828	4828	4828	4828	4828	4828
WUSKWATIM	0	0	0	0	200	200	200	200	200	200	200	200	200	200	200	200	200
GULL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
500 MW HVDC Bipole III	0	0	0	0	0	86	86	86	86	86	86	86	86	86	86	86	86
Manitoba Thermal Plants																	
Brandon Unit 5 License Review	105	105	105	105	105	105	105	105	105	105	105	105	105	105	0	0	0
Selkirk License Review	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	0	0
Brandon Units 6-7 SCCT	298	298	298	298	298	298	298	298	298	298	298	298	298	298	298	298	298
SCCT's	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	11	17	22	28	28	28	28	28	28	28	28	28	28	28	28	28	28
Demand Side Management	56	68	79	90	99	108	117	123	130	138	143	149	156	161	167	172	171
Major Rerunnering																	
Kelsey Rerunnering	11	21	32	43	54	64	75	75	75	75	75	75	75	75	75	75	75
Imports																	
Total Diversities	550	550	550	550	550	550	550	550	550	550	660	440	440	220	0	0	0
TOTAL POWER RESOURCES	5991	6019	6046	6073	6293	6399	6418	6425	6432	6439	6555	6340	6347	6133	5813	5687	5685
Peak Demand																	
2003 Base Load	4090	4125	4163	4190	4217	4239	4266	4296	4335	4377	4419	4462	4505	4549	4597	4640	4688
Exports																	
Total Contract Sales	842	842	675	675	641	584	584	550	550	550	0	0	0	0	0	0	0
Total Load	4932	4967	4838	4865	4858	4823	4850	4846	4885	4927	4419	4462	4505	4549	4597	4640	4688
Reserve	425	429	434	437	440	443	446	450	454	459	451	483	488	519	552	557	563
TOTAL DEMAND	5357	5396	5272	5302	5298	5266	5296	5296	5339	5386	4870	4945	4993	5068	5149	5197	5251
SURPLUS	633	622	774	771	995	1133	1122	1129	1093	1053	1684	1396	1354	1064	665	490	435

TABLE B

ANNUAL PEAK CAPACITY (MW): BASE MANITOBA LOAD FORECAST

Supply/Demand Balance - 2003 IFF Sequence

Wind (250 MW) - 2005, Wuskwatim - 2009, Gull - 2022, SCCT - 2031, SCCT - 2035

Resource and Demand at the Generation Level

Fiscal Year Beginning April	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38
Power Resources																
Manitoba Hydroelectric Plants																
Existing	4828	4828	4828	4828	4828	4828	4828	4828	4828	4828	4828	4828	4828	4828	4828	4828
WUSKWATIM	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
GULL	299	616	616	616	616	616	616	616	616	616	616	616	616	616	616	616
500 MW HVDC Bipole III	86	86	76	66	66	66	66	66	66	66	66	66	66	66	66	66
Manitoba Thermal Plants																
Brandon Unit 5 License Review	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Selkirk License Review	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Brandon Units 6-7 SCCT	298	298	298	298	298	298	298	298	298	298	298	298	298	298	298	298
SCCT's	0	0	0	0	0	0	0	0	0	142	142	142	142	284	284	284
Wind	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28
Demand Side Management	168	164	159	154	152	150	149	149	150	150	150	150	150	150	150	150
Major Rerunnering																
Kelsey Rerunnering	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Imports																
Total Diversities	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL POWER RESOURCES	5981	6294	6279	6264	6262	6260	6259	6259	6260	6402	6402	6402	6402	6544	6544	6544
Peak Demand																
2003 Base Load	4734	4772	4816	4860	4904	4948	4992	5036	5080	5124	5168	5212	5256	5300	5344	5388
Exports																
Total Contract Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	4734	4772	4816	4860	4904	4948	4992	5036	5080	5124	5168	5212	5256	5300	5344	5388
Reserve	568	573	578	583	588	594	599	604	610	615	620	625	631	636	641	647
TOTAL DEMAND	5302	5345	5394	5443	5492	5542	5591	5640	5690	5739	5788	5837	5887	5936	5985	6035
SURPLUS	679	949	885	821	769	718	668	619	570	663	614	564	515	608	559	509

2003 Manitoba Base Load Forecast

Figure 1a

System Firm Energy Demand and Resources - No New Hydro Genereation

SelkirkLR-05/06, Wind (250MW)-05/06, Brandon#5LR-06/07, 500kV HVDC Line -2010/11

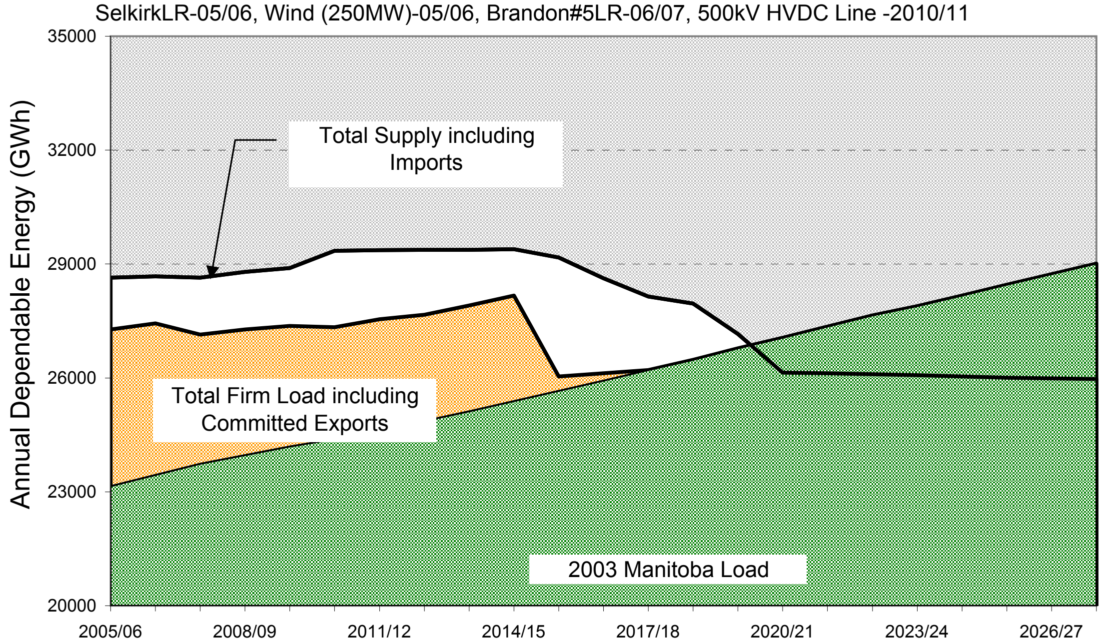
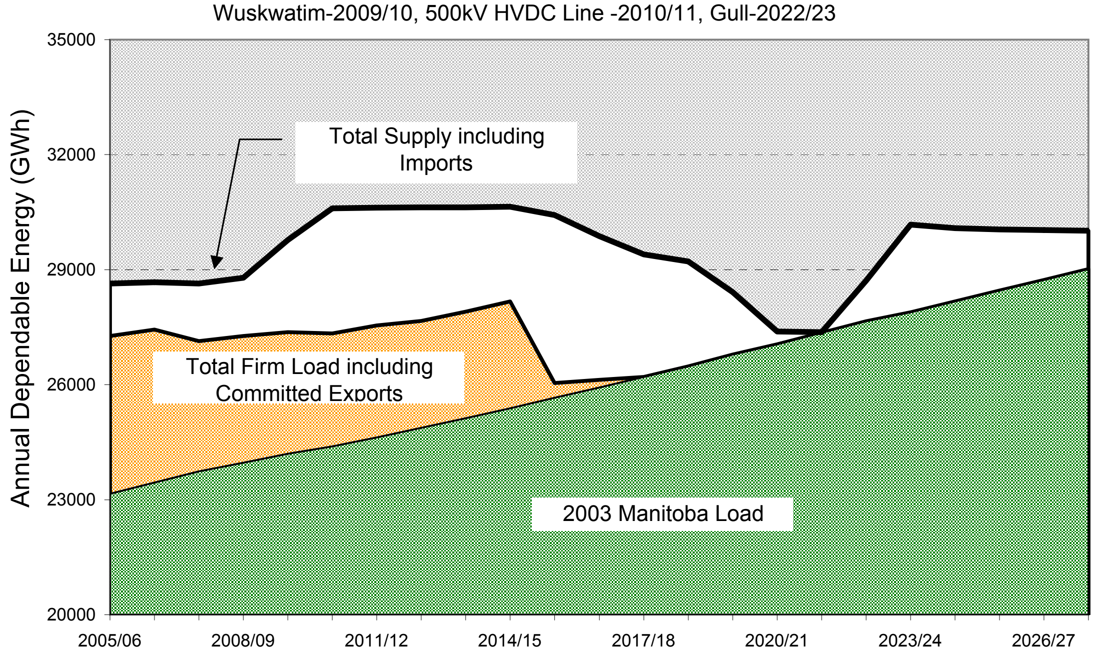


Figure 1b

System Firm Energy Demand and Resources - With New Hydro Generation

SelkirkLR-05/06, Wind (250MW)-05/06, Brandon#5LR-06/07, Wuskwatim-2009/10, 500kV HVDC Line -2010/11, Gull-2022/23



CCC/NFAAT/S/3

Request: CCC requested an assessment of the decrease to Low Export Prices that would be need to have the project breakeven with WACC (6.08%) and Cost of Debt (5.34%)

Response: A sensitivity was conducted to determine the extent by which the Low export price forecast would be required to be reduced in order for the internal rate of return (IRR) of the Wuskwatim Project to become equal to:

- the Corporation's Weighted Average Cost of Capital (6.08%)[1] and
- the Corporation's Cost of Debt (5.34%).

This sensitivity was undertaken by reducing the Low export price forecast uniformly over the study period in the scenario where Wuskwatim is advanced from 2020 to 2009 with the objective of achieving the IRR values specified above. The following table summarizes the reductions required to achieve the specific IRR values.

The table also includes an approximation of the natural gas price that would have to occur in the marketplace in order to produce an electricity price that is equivalent to the low export price and the corresponding prices in each of associated breakeven scenarios. CAC/MSOS/NFAAT/S/3 provides additional details on the methodology utilized in determining these equivalent natural gas prices and discusses the likelihood of such prices materializing in the future.

[1] Manitoba Hydro's real weighted average cost of capital and cost of debt have been revised to 5.98% and 5.25% respectively, slightly less than the 6.08% and 5.34% rates applicable at the time the Wuskwatim evaluation was prepared. An even greater reduction to the low export price forecast, therefore, would be required before the Wuskwatim project would breakeven using the current WACC and cost of debt assumptions.

Scenario: Low Export Prices	**Reduction in Export Price from Low**	**IRR**	**Equivalent natural gas price** ($2002 US/mmBtu)
IRR of Advancement Comparison, W-2009 vs W-2020	0%	8.5% (Low export price)	~$3.10
IRR = WACC:	30%	6.08%	~$1.25
IRR = Cost of Debt:	35%	5.34%	~$0.75

To put the equivalent natural gas prices in the above table into perspective, publicly available "low" price forecasts for the post-2010 period are significantly higher. The National Energy Board's recent report entitled "Scenarios for Supply and Demand to 2025" published in July 2003, predicts natural gas prices of US $3.45 in 2010 with real escalation thereafter in the Supply Push Scenario (which is the scenario that results in low natural gas prices). The US Energy Information Administration in its Annual Energy Outlook 2003 predicts in its low economic growth case (which results in lower natural gas prices), a price of US $3.18 in 2010, reaching US $4.09 (in $2002) by 2025. Current natural gas prices are approximately US $4.85 per mmbtu[2] which reflect the current tight supply situation due, in part, to low natural gas storage levels.

[2] US $4.85 per mmbtu is the price of Henry Hub natural gas trading on the New York Mercantile Exchange as at July 30, 2003. The 12 month strip (i.e., September 2003 – August 2004 average) on the same date was US $4.67/mmbtu.

CCC/NFAAT/S/4

CAC/MSOS/NFAAT/S/5

Request: CCC and CAC/MSOS requested that an IRR sensitivity be conducted on the impact of a drought of record occurring coincident with the advanced in-service date of the project.

Response: A sensitivity has been studied to determine the impact on the economics of Wuskwatim advancement under a scenario corresponding to a severe drought of record (1987 to 1992) occurring simultaneously with the 2009 in-service date of Wuskwatim generation. This sensitivity tests the robustness of the decision to advance Wuskwatim under an adverse set of streamflow conditions.

In this analysis, the average of 86 historic flow sequences (1912-1997) is replaced by a system drought of record (1987-1992) occurring coincident with the advanced 2009 in-service date of the project, as shown in the table below. Water flows after the drought period continue in sequence to 1997, which is the end of the flow record. The flow sequence then wraps back around to the first year of record (1912) and continues sequentially to the end of the study period. A system operation simulation model was used to determine the resulting export revenues and production costs while capital costs remain unchanged from those in the average of all flow conditions.

Wuskwatim ISD	Forecast Year	Historic Flow Year
Advanced ISD	2009	1987
	2010	1988
	2011	1989
	2012	1990
	2013	1991
	2014	1992
	2015	1993
	2016	1994
	2017	1995
	2018	1996
	2019	1997
Base ISD	2020	1912
	2021 to period end	1913, etc.

The economic analysis for this drought sensitivity compares Wuskwatim 2020 to Wuskwatim 2009. The drought sequence of water flows causes the net export revenues associated with Wuskwatim advancement to decrease by an average of about 9% per year during the period of advancement from 2009 to 2020. This reduction in benefits results in the IRR of Wuskwatim being reduced from 10.3% to 9.7%. Such a reduction in IRR is well within the range of other sensitivity analyses, and it is concluded that the project economics are robust under a scenario of lowest water flows.

MH/NCN/NFAAT/S/1

Social Benefit Cost Analysis – Low and High Export Prices

See attached report prepared by Marvin Shaffer and Associates Ltd. MH/NCN/NFAAT/S/1a

MH/NCN/NFAAT/S/1a

SOCIAL NET BENEFITS
OF
ADVANCING
THE WUSKWATIM PROJECT

Prepared for Manitoba Hydro

by

Marvin Shaffer & Associates Ltd.

August, 2003

1.0 Introduction

In its submission to the Manitoba Clean Environment Commission (***Need for and Alternatives to the Wuskwatim Project***, April 2003), Manitoba Hydro provided an economic analysis that concludes advancing the in-service date for Wuskwatim from 2020 to 2009 for export purposes would yield an attractive rate of return consistent with the low risk it entails.[1] This analysis and estimated return is based on the incremental revenues and expenditures that advancing Wuskwatim would have on Manitoba Hydro. The return is the amount that would be shared by Manitoba Hydro (and its customers) and Nisichawayasihk Cree Nation (NCN) in accordance with their Agreement in Principle for Wuskwatim.

In economic terminology, the economic analysis in Manitoba Hydro's April submission is from a private project perspective. The purpose of this report is to present an evaluation of advancing Wuskwatim from a broader social perspective—to estimate the net benefits taking into account not just the financial return to be shared by Manitoba Hydro, its customers and NCN, but all of the benefits and costs Manitobans would realize or incur as a result of the project.

The project scope, characteristics, advancement period and financial implications assumed in this social benefit-cost evaluation are the same as set out by Manitoba Hydro in its April submission. The evaluation covers both the generation component that would be undertaken by Manitoba Hydro and NCN, and the associated transmission that would be undertaken by Manitoba Hydro.

The starting point for the evaluation is the impact of the project on revenues and expenditures, as in the private analysis. A series of adjustments are then made to move from a private project to social perspective:

- Government transfers- Some of the project's expenditures are simply transfers to government. Most significantly, there are water rentals and capital taxes paid to government, neither of which reflect nor are intended to offset real resource or other costs caused by the project. These transfers to government are recognized as a benefit to taxpayers.
- Other transfers- Included in Wuskwatim-related transmission costs are the expenditures that Manitoba Hydro would incur to create a fund for the benefit of aboriginal communities whose traditional lands would be traversed by the transmission line required for the project. Since the impacts of the line are expected to be minimized in routing and other mitigative measures, the real resource costs are likely to be small.[2] The fund is therefore recognized as a benefit to the recipient communities.
- Employment and other income impacts- In the private project evaluation, all wages and payments to contractors are treated as costs. However, to the extent

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[1] The internal real (inflation-adjusted) rate of return under the expected export price forecast is estimated at 10.3%, and 8.0% and 12.1% under low and high price forecasts respectively.

[2] April 2003 submission, ***Integrated Executive Summary of Environmental Impact Statements***, p.27.

these wages and other payments exceed what the recipient Manitobans would otherwise have earned (for example, any wages paid to workers who would otherwise be unemployed or underemployed), they constitute a benefit and are recognized as such in the social evaluation. On the other hand, there are expenditures that the project and the government would incur to upgrade education and provide training in order to increase the employment of nearby and other northern aboriginal residents. These expenditures, less whatever long term (post-Wuskwatim) benefit the education and training provides, are recognized as social costs, serving to reduce the net income benefit.

- Environmental and social impacts- Adverse environmental impacts from the construction and operation of Wuskwatim are expected to be minimal due to the low head design and relatively small amount of flooding it would entail. Also, because of the environmentally sensitive project design and the partnership agreement Manitoba Hydro has entered into with NCN, adverse social impacts are expected to be small. If there were any uncompensated residual impacts they would have had to be recognized as costs of the project. On the positive side, generation of power from Wuskwatim would displace thermal power production in the export market and consequently reduce greenhouse gas (GHG) as well as local air emissions. The GHG reductions benefit Manitobans wherever they occur. In the expected and high export price scenarios, the benefit of GHG reductions is reflected in the forecast prices. No further adjustment is required. However, no environmental premium is captured in the low export price scenario and in this case, the value of the GHG reductions are included as a social benefit.

The private project impacts and social adjustments are expressed in annual dollar terms. The overall net benefit is calculated by discounting future values to an equivalent present value. The discount rate generally used in social benefit-cost analysis is a weighted average social opportunity cost of capital—reflecting what investment, if any, is foregone and additional foreign borrowing or saving induced as a result of the project. A range of 6% to 8% real is used in this evaluation, with the lower end more appropriate the more that the project simply results in more borrowing or saving—the higher end more appropriate the more that investment in Wuskwatim displaces other investment in Manitoba.[3]

[3] Seminal research on the social opportunity cost of capital (SOCC) in Canada was undertaken by Professors Glenn Jenkins and David Burgess in the 1970s and early 1980s. At that time Jenkins' research suggested the SOCC was approximately 10% real. Burgess, who argued that capital requirements are met more by foreign borrowing and less by displacing other investment, suggested the SOCC was approximately 7% real. In their recent text (***Cost-Benefit Analysis, Concepts and Practice***, *2001*), Boardman et.al. note that prescribed discount rates in North American jurisdictions have tended lower in recent years. British Columbia Crown Corporations, including BC Hydro, use a rate of 8% real. The U.S. Office of Management and Budget revised the rate it requires for all executive agency benefit-cost analyses from 10% to 7% real. Boardman et. al. also note that the sources of capital as estimated by Jenkins and Burgess would currently imply SOCCs of 7% and 5% respectively, based on estimated social costs of each source.

2.0 Private Project Net Benefits

There are three broad financial impacts that would result from advancing the in-service date of Wuskwatim from 2020 to 2009. Capital expenditures for the project would be advanced, with the bulk of expenditures being made over the 2004-2008 period as compared to 2015-2019. There would be additional O&M expenditures, including water rental and capital taxes, incurred over the 2009-2020 period. And there would be additional export revenues over the 2009-2020 period because of the additional generating capacity Wuskwatim provides.

In Table 1, the 2002 present values of these impacts and overall net effect are shown for three export price scenarios: low and high price scenarios which are likely to bracket the range of possible outcomes, and an expected price scenario which, as explained in Manitoba Hydro's April submission, incorporates on a probabilistic basis some environmental premium for hydro power on top of a reference export price forecast. The present values are expressed in millions of 2002 Cdn $ and calculated at 6% and 8% real discount rates.

Table 1 – Financial Impacts of the Project

(2002 NPV, $million Cdn)

Discount Rate	*Incremental Capital Expenditures*[4]	*Incremental O&M (Including taxes)*	*Incremental Export Revenue*			*Private Net Benefits*		
			Low	*Expected*	*High*	*Low*	*Expected*	*High*
6%	217.31	58.51	385.17	479.98	593.01	109.34	204.15	317.18
8%	242.97	48.49	309.59	384.19	475.05	18.11	92.71	183.57

As shown in the table, advancing Wuskwatim would have significant financial private net benefits, ranging from $109 to $317 million at a 6% discount rate and $18 to $184 million at an 8% discount rate. As with most capital intensive projects, the lower the discount rate, in other words, the lower the assumed opportunity cost of capital, the markedly greater are the net benefits.

[4] Incremental capital expenditures reflect the difference in the present value of the generation and transmission capital expenditures for the 2009 and 2020 in-service dates, net of the present values of the residual value of the assets at the end of the planning period in each case.

3.0 Social Adjustments

3.1 Government Transfers

Over three quarters of the incremental O&M expenditures the project would incur as a result of advancing Wuskwatim are transfers to government. As shown in Table 2 below, the present value of the incremental water rentals and capital taxes total $46 million at a 6% discount rate, $38 million at an 8% discount rate. These are benefits to Manitoba taxpayers.

Table 2 - Government Transfers

(2002 NPV, $million Cdn)

Discount Rate	*Incremental Water Rentals*	*Incremental Capital Taxes*	*Total Incremental Government Transfers*
6%	27.70	17.92	45.62
8%	22.28	15.80	38.08

There are as well other tax revenues that would be directly and indirectly generated by the expenditures for the construction and operation of Wuskwatim. For example, all of the materials used to construct the project, except for power generation equipment, are subject to provincial sales tax. There are fuel, income and other taxes that would be paid. The economic impact assessment provided in the April submission indicates that the provincial tax impact from construction could total over $55 million. The present value benefit from advancing those tax payments would be significant. However, much of this tax impact is from income taxes and incremental income benefits (including the portion taxed by government) are estimated in section 3.3 below. They are therefore not included here. Also, the extent to which the sales, fuel and other such tax impacts increase transfers to the government depends on the extent to which the project-related purchases give rise to more production and sales of those goods as opposed to diverting the taxed goods from other users. The actual increase in tax revenues would be less than the gross impact estimates. What the net impact would be is highly uncertain and not included in the estimated benefits from the project.

3.2 Other Transfers

Manitoba Hydro is planning to contribute over $5 million to a fund for the benefit of aboriginal communities whose traditional lands would be traversed by the transmission line required for Wuskwatim. The earlier contribution due to the advancement of Wuskwatim would benefit the recipient communities. The increase in the 2002 present value of the contribution is $1.8 million at a 6% discount rate and $1.9 million at an 8% discount rate.

3.3 Employment and Other Income Impacts

The construction of Wuskwatim would directly generate an estimated 2200 person years (PYs) of employment. It is estimated that over 1800 of the PYs would go to Manitobans and of those over 700 would go to Northern Manitobans. The earnings and benefits per PY would average \$110,000. The total income from this employment would be approximately \$200 million (in 2002\$), representing 38% of the total capital cost.

The extent to which this income constitutes a social benefit depends on two factors: 1) the percentage of the workers who would otherwise be unemployed and 2) for those who would otherwise be employed, the difference between the average income that would earned at Wuskwatim and the average income that would be earned elsewhere.

Unemployment rates in Manitoba are at low levels, averaging 5.0% over the past three years.[5] However, the provincial rate masks important regional and occupational differences. Unemployment is significantly higher in northern Manitoba, especially in aboriginal communities. It is also high for a number of non-designated trades.[6] It is likely that many of the persons hired from these northern communities and for non-designated trades would otherwise be un- or underemployed.

On the other hand, based on current relatively low unemployment rates, it is likely that a large percentage of the designated trade workers, particularly from southern Manitoba, would otherwise be employed. They would still benefit (though to a lesser extent than those who would otherwise be unemployed) because their incomes at Wuskwatim would exceed what they could otherwise have earned. It is the higher income that would attract them to the jobs.

It is impossible to determine precisely what percentage of northern (or other) Manitoban workers would otherwise be unemployed and to what extent the average incomes at Wuskwatim exceed the incomes that would have been earned by workers attracted from other jobs. However, to illustrate the order of magnitude of the social benefit from the construction employment it is assumed that 20% of the income earned at Wuskwatim would be by workers who would otherwise be unemployed, based on the approximate proportion of the construction workforce accounted for by high unemployment non-designated trades. It is also assumed that the incomes earned by workers attracted from other jobs would be at least 10% higher than what they would have earned elsewhere. Under these assumptions, 28% of the labour income earned at Wuskwatim would be a social benefit. That would be the incremental earnings due to the project. The present value increase in this social benefit resulting from the advancement of Wuskwatim would be \$20.5 million at a 6% discount rate and \$24.4 million at an 8% discount rate.

[5] Source: Statistics Canada 71-001

[6] For example, the estimated unemployment rates for labourers and heavy equipment operators, which together account for some 20% of the peak workforce, were 25.8% and 10.9% respectively in June, 2003 (based on EI claimant data).

Operations and maintenance at Wuskwatim would require approximately 6 full time equivalent jobs, generating employment income of some $460,000 per year. On the assumption that the persons filling these positions would be attracted or promoted from other jobs, with average incomes at least 10% greater than what the persons hired would otherwise have earned, there would be a social benefit of at least 10% of the total O&M earnings. At 10%, the net present value benefit from advancing Wuskwatim would be $.26 million at a 6% discount rate $.21 million at an 8% discount rate.

Educational upgrade and training costs that the project and the federal and provincial governments would incur are estimated to total $15 million. The increase in the present value cost of advancing these expenditures would be $5.4 million at a 6% discount rate and $6.2 million at an 8% discount rate. Education and training are expected to provide benefits well beyond the work at Wuskwatim. The enhanced employability should increase the life-time earnings for the persons trained. However, even if one assigns all of these educational and training costs to the Wuskwatim project, it would still leave a net employment benefit of $15.4 million at a 6% rate and $18.4 million at an 8% discount rate, as shown in Table 3 below.[7]

These net employment benefit estimates should not be considered precise. As noted earlier they are meant only to be illustrative of the order of magnitude of the social benefits from the advancement of employment and training for Wuskwatim. The key point is that they are significant even if understated in the table due to the conservative assumptions employed.

Table 3 – Employment Benefits

(2002 NPV, $million Cdn)

Discount Rate	*Incremental Construction Income*	*Incremental O&M Income*	*Training and Educational Upgrade Costs*	*Net Employment Benefits*
6%	20.54	.26	(5.41)	15.39
8%	24.38	.21	(6.17)	18.41

3.4 Environmental and Social Impacts

Wuskwatim has been designed to be a low impact project. The low head design would result in limited flooding, the operating plan would serve to stabilize water levels on Wuskwatim Lake and limit downstream water level and flow changes, and Manitoba Hydro and NCN are committed to an environmental protection plan to avoid adverse effects.[8] The environmental review concluded that no significant residual adverse effects

[7] A significant proportion of the education and training funds are expected to be provided by the federal government. This is still included as a cost to Manitobans on the assumption that these expenditures would reduce federal spending on other initiatives in the province.

[8] April 2003 submission, ***Integrated Executive Summary of Environmental Impact Statements***, p.18.

are expected and there may even be improvement in harvesting and other resource use because of the improved access the project provides.

Wuskwatim is expected to have a positive impact on GHG emissions. The advancement of Wuskwatim for export purposes would mean that the purchasing utilities would not have to acquire the equivalent amount of power from other sources. The most likely alternative sources are thermal, and even if Wuskwatim were to displace efficient natural gas-fired combined cycle power, it would reduce GHG emissions by some 500 tons of CO_{2e}/GWh.[9] If Wuskwatim were to displace power production from coal plants, the GHG reductions would be greater.

In the expected and high price forecasts, the value of the GHG emission impact is captured in the export price. It is assumed in those forecasts that the purchasers would pay a premium for hydro power because of the offset or other obligations they would have with higher emitting alternative sources of power. Consequently, no social adjustment is required. The low forecast, on the other hand, assumes that the export price does not capture any environmental benefit. However, even if Manitoba Hydro and NCN do not capture the value in their export revenues, there still would be a benefit to Manitobans from the GHG impact. GHG-related damages or offset costs would be avoided. There is a wide range of damage or offset cost estimates for GHGs. A low end of the range suggested in Canadian Kyoto implementation studies is $10 Cdn/ton.[10] This would suggest a benefit for Wuskwatim of at least $5Cdn/MWh, or roughly 10% of the assumed low export price[11]. On that basis, the present value GHG benefit of advancing Wuskwatim would be $38.5 million at a 6% discount rate; $31.0 million at an 8% discount rate. These are included as social benefits in the low export price scenario.

4.0 Overall Social Net Benefits

Table 4 below summarizes all of the estimated adjustments required to move from a private project to social perspective. The total is in the order of $89 to $101 million in the low price scenario and $58-63 million in the expected and high price scenarios. The expected and high scenarios still offer greater overall benefits; it is just that the social *adjustments* are less in the expected and high price scenarios because the benefit of GHG reductions is assumed to be already captured in Manitoba Hydro's export price. The single most significant adjustment is for the water rental and capital tax transfers to government—costs from the perspective of the project, but benefits from the point of

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[9] Pembina Institute, ***Life Cycle Evaluation of GHG Emissions and Land Change Related to Selected Power Generation Options in Manitoba***, Feb.25, 2003.

[10]The low carbon price suggested in Manitoba Hydro's April submission is $10US/ton.

[11] The $5/MWh assumes that Wuskwatim displaces new combined cycle gas generation and thereby reduces GHG emissions by 500 tons of CO_{2e}/GWh. If the low export prices were the result of widespread continuing use of coal plants in the U.S., the GHG benefit from Wuskwatim would be even greater. Instead of displacing combined cycle gas plants, the export from Wuskwatim might displace coal generation, a source with some two times the GHG emissions per GWH than combined cycle gas.

view of Manitoba taxpayers. The adjustment for employment benefits is also significant even with the conservative assumptions employed to develop these illustrative estimates.

Table 4 – Social Adjustments

Social Adjustment	*Basis for Estimate*	*Major Factors/Assumptions*	*Beneficiaries*	*NPV@ 6% ($million Cdn)*	*NPV@8% ($million Cdn)*
Government Transfers	Incremental taxes to provincial government	Includes water rentals and capital taxes Provincial sales tax impact not included	Manitoba taxpayers	45.62	38.09
Other Transfers	Transmission development fund	Fund is to provide net benefit; adverse impacts mitigated or otherwise addressed	Aboriginal communities whose traditional lands traversed by line	1.8	1.9
Net Employment	Incremental income less training and upgrade costs	Illustrative conservative assumptions re: percentage of workers otherwise unemployed; wage premium and on-going benefits from training	Workers hired in construction and O&M	15.39	18.41
GHG Emission Reduction	Value of GHG emission reductions	Wuskwatim displaces combined cycle power; benefit $10/tonne of CO_{2e}; benefit not captured in low export price scenario	Global	38.52	30.96
Total-Low Export Price Scenario				***101.33***	***89.34***
Total-Expected/High Export Price Scenario				***62.81***	***58.38***

In Table 5 the social adjustments are added to the private net benefits to show the estimated overall social net benefits from advancing Wuskwatim. The estimated total social net benefits range from $210 to $380 million at a 6% discount rate and $107 to $242 million at an 8% discount rate. The impact of the social adjustments is most noticeable in the low price scenario, but in all cases the estimated social net benefits significantly exceed the private project net benefits In addition to the project benefits that

Manitoba Hydro, its customers and its partner NCN would share, there are benefits that would accrue to taxpayers, aboriginal communities, workers and the global environment.

Table 5 - Overall Social Net Benefits

(2002 NPV, $million Cdn)

Discount Rate	*Private Net Benefits*			*Social Adjustments*		*Overall Social Net Benefits*		
	Low	*Exp.*	*High*	*Low*	*Exp/ High*	*Low*	*Expected*	*High*
6%	109.34	204.15	317.18	101.3	62.81	210.67	266.96	379.99
8%	18.11	92.71	183.57	89.34	58.38	107.46	151.11	241.96

CAC/MSOS/NFAAT/S/6

Request: CAC requested that a sensitivity be performed on Wuskwatim Project Economics to: Development of Twice the Current Forecast for DSM; 250 MW Wind; a combination of these two sensitivities.

Response: A set of sensitivities were conducted to determine the impact on the internal rate of return (IRR) of the Wuskwatim Project if additional surplus energy and capacity was available to the system for export through:

- Double the size of Demand Side Management (DSM)
- 250 MW of wind generation
- Combining these two sensitivities

These sensitivities examine the individual and combined extent to which the IRR would decline for the Wuskwatim Project through the advancement period of 2009 to 2020, if the output of Wuskwatim would be required to compete for interconnection space and export market share with additional system surplus energy and capacity from wind and/or additional DSM.

For the DSM sensitivity, the DSM was doubled from current projected forecast throughout the study period. This increase in incremental DSM for the year 2015/16 for example, would be 322 MW/ 1230 GWH in this sensitivity versus 161 MW/ 615 GWH which was included in the base evaluation. For the wind sensitivity wind generation was assumed to be 250 MW with a 35% capacity factor, in-service date of 2009 and assumed to continue to be in place through to the end of the study period. Both sensitivities have the effect of increasing Manitoba Hydro’s surplus capacity & energy available for export and are assumed to be developed or committed before Wuskwatim.

The following table shows the results of the impact these individual sensitivities have on the IRR of the Wuskwatim project as well as the combined effect. It is important to note that even the combined effect of these sensitivities still only results in a 0.1% drop in IRR.

Scenario	**IRR**
IRR of Base Advancement Comparison, W-2009 vs W-2020	10.3%
Impact on IRR of Doubling DSM Sensitivity:	-0.05%
Impact on IRR of 250 MW of Wind Sensitivity:	-0.05%
DSM and addition of 250 MW of wind generation:	-0.1%
IRR of resulting combined sensitivity:	10.2%

MH/NCN/NFAAT/S/2

Summary of Economic Evaluations and Sensitivities

Sensitivity analysis provides a means to examine the vulnerability of a project to deviations to key specific assumptions. This section summarizes and integrates the economic sensitivities for the Wuskwatim project, including those already reported in Table 6.5 of the main submission (labeled A through P), as well as additional economic sensitivities now filed in this supplemental submission (labeled Q through Z). This information is intended to demonstrate the broad range of conditions under which the Wuskwatim Project economics have been tested and proven to be robust. This integration is not a response to a specific request.

See attached (MH/NCN/NFAAT/S/2a)

TABLE S6.5
WUSKWATIM PROJECT SENSITIVITY ANALYSIS

	Sequence Assumption	IRR (Real)	Difference from "A"
A.	**Wuskwatim Long-Term Economics – Expected Export Prices**	**10.3%**	
B.	**Wuskwatim Advancement (2009 vs. 2020) – Expected Export Prices**	**10.3%**	
Low and High Export Price Forecasts			
C.	LOW Export Price Forecast	8.0%	-2.4%
D.	HIGH Export Price Forecast	12.1%	1.8%
Reference and Environmental Export Price Forecasts			
E.	Reference Forecast (No Environmental Export Premium)	9.2%	-1.1%
F.	LOW Environmental Export Premium Forecast	10.2%	-0.1%
G.	MEDIUM Environmental Export Premium Forecast	10.9%	0.5%
H.	HIGH Environmental Export Premium Forecast	11.4%	1.1%
Sensitivities to Wuskwatim Long-Term Economics – Expected Export Prices			
I.	Capital Cost INCREASE of 15% ($95 million)	9.2%	-1.1%
J.	Capital Cost DECREASE of 15% ($95 million)	11.7%	1.4%
K.	10% Flow Reduction on the Burntwood River at Wuskwatim	9.8%	-0.5%
L.	+300 MW Interconnection Capability Adjustment	10.5%	0.2%
M.	-300 MW Interconnection Capability Adjustment	10.0%	-0.3%
N.	Wuskwatim 2010 ISD with added Costs during delay (NPV cost of $28.4 million, 2002 present value dollars)	10.2%	-0.1%

	Sequence Assumption	IRR (Real)	Difference from "B"
B.	**Wuskwatim Advancement (2009 vs. 2020) – Expected Export Prices**	**10.3%**	
Low and High Export Price Forecasts			
O.	LOW Export Price Forecast	8.5%	-1.8%
P.	HIGH Export Price Forecast	12.3%	2.0%
Reference and Environmental Export Price Forecasts			
Q.	Reference Forecast (No Environmental Export Premium)	9.6%	-0.7%
R.	LOW Environmental Export Premium Forecast	10.4%	0.1%
S.	MEDIUM Environmental Export Premium Forecast	11.0%	0.7%
T.	HIGH Environmental Export Premium Forecast	11.5%	1.2%
Sensitivities to Wuskwatim Advancement – Expected Export Prices			
U.	Impact of 250 MW of Wind (ISD – 2009)	10.25%	-0.05%
V.	Impact of increasing (2x) DSM	10.25%	-0.05%
W.	Combined impact of Wind in 2009 and Increased DSM (ie 250 MW of wind and doubling DSM)	10.2%	-0.1%
X.	Impact of System Drought (ie '87 to 91 drought repeating in 2009)	9.7%	-0.6%
Y.	Impact of 2003 Power Resource Plan Update (Wuskwatim Advancement 2009 vs. 2019)	10.2%	-0.1%
Z.	Wuskwatim 2010 ISD with added Costs during delay (NPV cost of $30.8 million, 2002 present value dollars)	10.0%	-0.3%

Note: Inconsistencies in differences are due to rounding.

CCC/NFAAT/S/5

CAC/MSOS/NFAAT/S/7

FINANCIAL SENSITIVITY – 5-YEAR LOW WATER FLOW CONDITIONS COINCIDING WITH ADVANCED IN-SERVICE

Request: The Crown Corporations Council and CAC/MSOS requested a financial sensitivity to drought.

Response: With export sales contributing a third of total electricity sales, Manitoba Hydro's largest predictable financial risk remains that of drought. While the timing of droughts is unknown, history suggests that they will occur on average every 8-10 years. This sensitivity has been formulated, using data and assumptions consistent with **Section CCC/NFAAT/S/4; CAC/MSOS/NFAAT/S/5** of this supplemental filing, to simulate the worst drought on record (1987 to 1992) occurring simultaneously with the in-service of Wuskwatim advanced to 2009. The sensitivity tests the robustness of the decision to advance Wuskwatim under drought conditions rather than the impacts of drought per se on Manitoba Hydro's financial stability.

As in the main submission, the analysis evaluates the year-by-year impacts of advancing Wuskwatim on Manitoba Hydro's profitability, performance on financial targets and cumulative rates charged to customers. In this analysis, the average of 86 historic flow sequences (1912-1997) is replaced by actual flow conditions, with the 1987-1992 drought flows being assumed to occur over the five years 2009/10 to 2013/14 under both the base case (Wuskwatim 2020) and the advanced case (Wuskwatim 2009). Water flows after the drought period are assumed to be identical to those which actually occurred from 1993 to 1997 (1997 marks the end of the historical data currently available in the flow simulation model). Thereafter, flows revert to those experienced in 1912 and subsequent years, continuing sequentially to the end of the financial projections. Export revenues and production costs have been modified accordingly while capital costs remain unchanged. The financial analysis of the drought sensitivity compares Wuskwatim 2020 to Wuskwatim 2009 at expected export prices.

Figure 1 shows the incremental impact on Manitoba Hydro's net income from the advancement of Wuskwatim if the Corporation experiences a repeat of the worst drought on record in the early years of the Project. In all years, net income is higher ($3 to $136 million) under drought conditions if Wuskwatim is advanced from 2020 to 2009. Interest coverage (**Figure 2**) follows a similar pattern to net income, with the advancement of the Wuskwatim Project resulting in improvements to the ratios in all but the year prior to in-service.

Figure 1

Sensitivity to 5-Year Low Water Flow Conditions
Coinciding with Advanced In-service
Impacts of Wuskwatim Advancement on Manitoba Hydro's Net Income

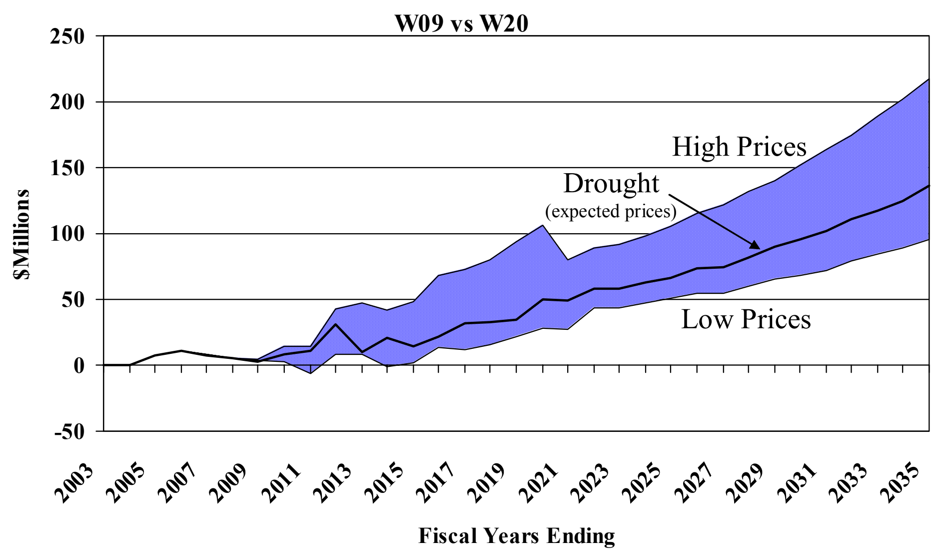
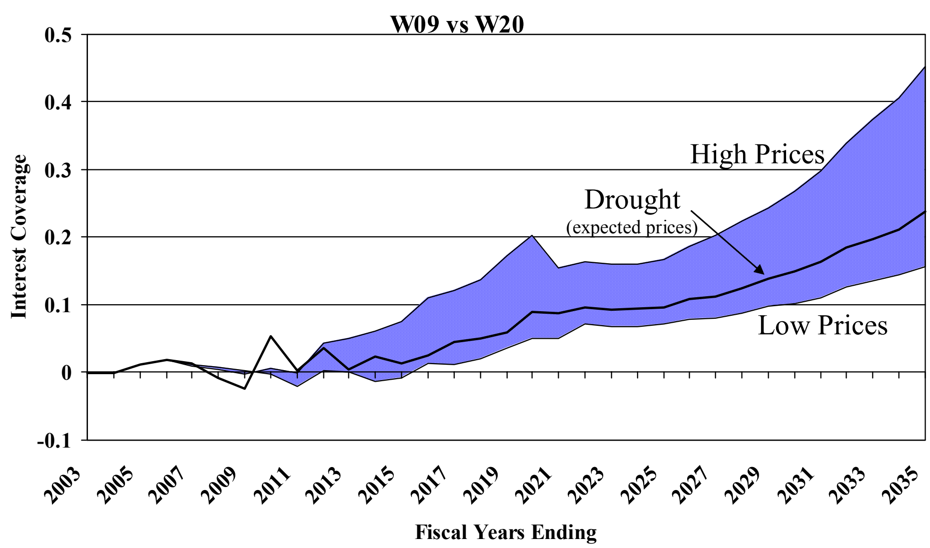


Figure 2

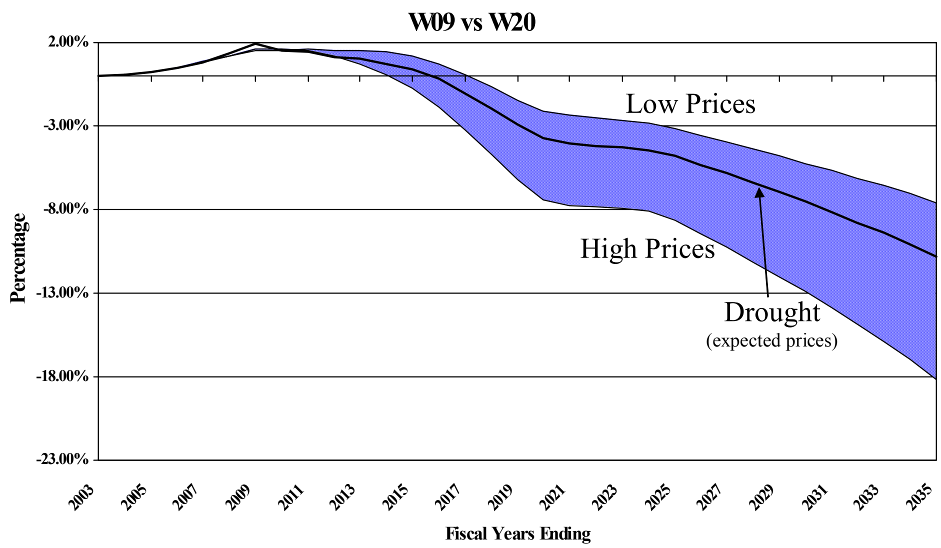
Sensitivity to 5-Year Low Water Flow Conditions
Coinciding with Advanced In-service
Impacts of Wuskwatim Advancement on
Manitoba Hydro's Interest Coverage



Although the advancement of Wuskwatim would increase Manitoba Hydro's 2009/10 debt levels, this does not, even with low water flow conditions, affect the Corporation's financial stability. **Figure 3** shows that Manitoba Hydro's debt ratio under the Wuskwatim 2009 drought scenario would increase by no more than 1.9% over the comparable Wuskwatim 2020 case and would recover to the same level as the latter case by 2016.

Figure 3

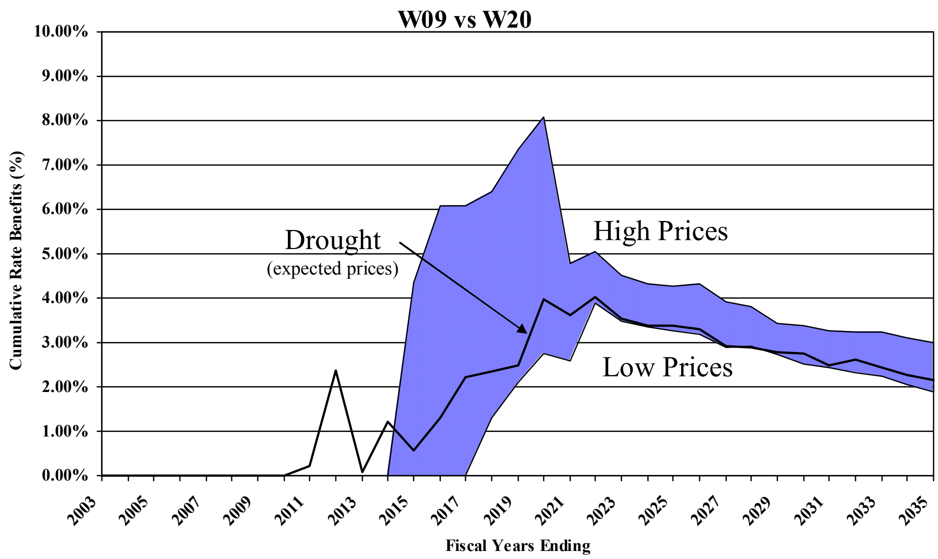
Sensitivity to 5-Year Low Water Flow Conditions
Coinciding with Advanced In-service
Impacts of Wuskwatim Advancement on Manitoba Hydro's Debt Ratio



The potential cumulative percent customer rate benefits and present value of customer bill benefits are shown in **Figures 4 and 5**. The potential long-term rate savings are derived by assuming the same rate increases in the Wuskwatim 2009 case as in the 2020 base case, until rate adjustments are assumed to be made in the 2020 base case in the year following the start of the drought to recover the losses incurred and maintain the Corporation's financial position. The long-term rate benefits of advancing Wuskwatim are determined by comparing the 2009 and 2020 cases after this point. In the Wuskwatim 2009 case, rates could be as much as 4% lower than with a 2020 in-service (2% lower over the long term) even with extended low flow conditions at the start-up. As stated in the main submission for the high and low price scenarios, the decline in rate benefits after 2020 reflects that the two sequences are identical beyond that point. In the advanced case the lower book value and associated carrying costs and the higher net income during the advancement period result in lower debt levels in the future years.

Figure 4

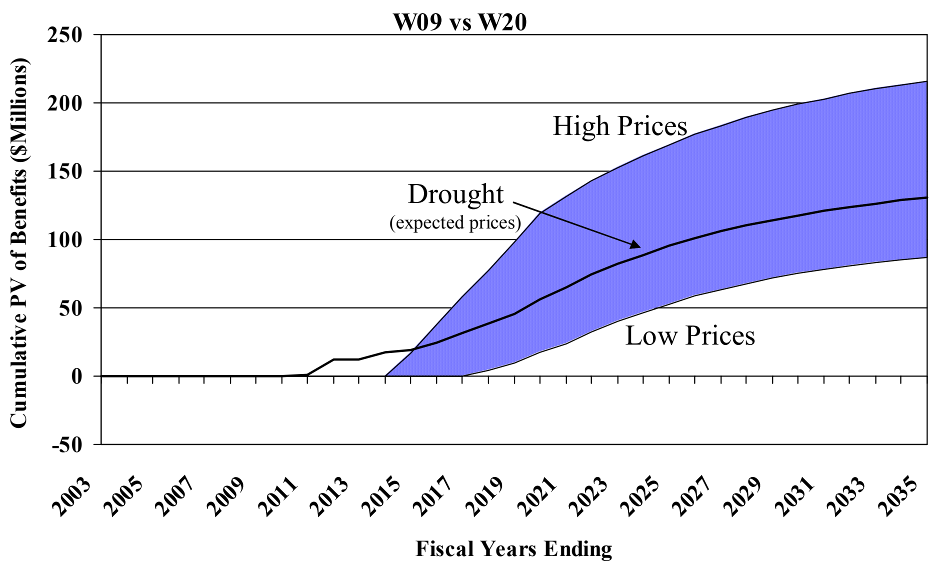
Sensitivity to 5-Year Low Water Flow Conditions
Coinciding with Advanced In-service
Impacts of Wuskwatim Advancement on Customer Rates



1 On a present value basis discounted back to 2002, the advancement of the Wuskwatim Project,
2 even with drought conditions occurring at start-up, could yield a cumulative reduction of up to
3 $131 million (PV) in the rates that would otherwise be payable by the end of the study period.

Figure 5

Sensitivity to 5-Year Low Water Flow Conditions
Coinciding with Advanced In-service
Impacts of Wuskwatim Advancement on Customer Bills



In summary, the advancement of Wuskwatim to 2009 continues to have a positive impact on Manitoba Hydro's consolidated financial position even under severe extended low water flow conditions. Wuskwatim's small initial incremental increase to the Corporation's debt ratio is projected to have no impact to Manitoba Hydro's financial stability and will not cause rate increases over and above those required to offset the impacts of drought without Wuskwatim advanced. The analysis demonstrates that the worst drought on record coinciding with the start-up of the advanced Wuskwatim falls well within the bounds of the low and high export drought conditions. The advancement of Wuskwatim helps to shield Manitoba Hydro customers from some of the rate impacts associated with drought by reducing the amount of costly imports and thermal generation that would otherwise be required under extended low water flows.

CCC/NFAAT/S/6

FINANCIAL STABILITY

Request: The Crown Corporations Council requested a further description of the concept of financial stability.

Response: The scope of the CEC review is to include assurance that Manitoba Hydro's financial stability will not be negatively affected. Manitoba Hydro interprets "financial stability" as the ability to be financially self-supporting on an ongoing basis while maintaining predictable and reasonable rate increases. For example, credit rating agencies assess the dependence of Crown corporations such as Manitoba Hydro on the Province by determining whether the Crown's financial position and outlook indicate self-supporting status. If so, this debt does not have to be added to that of the Province for credit rating purposes. Financial stability also means the capacity to sustain losses as a normal part of doing business without requiring inordinate rate increases or bailouts from the Corporation's owner. Manitoba Hydro has debt/equity and interest coverage targets which assist the Corporation to absorb financial losses caused by such contingencies as drought, market downturns and facility malfunctioning or accidents. An objective of the CEC review is to gain comfort that the advancement of Wuskwatim and associated increase in debt will not materially enlarge the Corporation's risk of depleting its equity and thereby it's financial stability.

CCC/NFAAT/S/7

PROJECTED BALANCE SHEETS & FINANCING REQUIREMENTS STATEMENTS

Request: The Crown Corporations Council requested projected balance sheets and financing requirements statements.

Response: See **Attachment CCC/NFAAT/S/7a Tables A.21 through A.24**.

ATTACHMENT CCC/NFAAT/S/7a Table: A.21 (cont'd)

Wuskwatim 2009 Low Price Scenario

PROJECTED BALANCE SHEET
Electric Operations
(In Millions of Dollars)

For year ending March 31:	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
ASSETS:																	
Plant in Service	9,462	9,894	10,308	10,633	11,067	11,342	11,710	12,972	13,571	13,862	14,121	14,778	15,273	15,776	16,290	16,796	17,279
Accum Depreciation	(3,037)	(3,300)	(3,573)	(3,858)	(4,151)	(4,459)	(4,773)	(5,106)	(5,451)	(5,805)	(6,168)	(6,540)	(6,916)	(7,299)	(7,690)	(8,091)	(8,501)
Net Plant in Service	6,425	6,594	6,735	6,775	6,915	6,883	6,937	7,866	8,120	8,057	7,953	8,239	8,357	8,477	8,600	8,705	8,778
Construct in Progress	428	509	633	741	880	1,284	1,522	721	459	466	491	319	321	471	536	637	842
Current & Other Assets	3,560	3,289	3,375	3,605	3,773	3,939	3,766	3,453	3,707	3,982	4,262	4,098	4,435	4,540	4,773	4,949	4,661
	10,412	10,392	10,743	11,121	11,568	12,107	12,225	12,040	12,286	12,504	12,705	12,656	13,113	13,489	13,908	14,292	14,281
LIABILITIES:																	
Long Term Debt (Net)	7,187	7,167	7,478	7,429	8,307	8,719	8,586	8,666	9,050	9,026	8,722	8,894	9,269	9,007	9,465	8,923	9,507
Current & Other Liab.	1,783	1,770	1,755	2,140	1,662	1,760	1,969	1,655	1,458	1,626	2,041	1,737	1,735	2,273	2,133	2,964	2,276
NCN Investment in Wuskwatim Project	0	0	15	25	36	49	59	62	60	60	59	58	57	56	55	54	53
Contrib for Construct.	266	262	259	255	251	246	242	238	234	231	227	223	219	216	212	209	206
Retained Earnings	1,176	1,193	1,237	1,272	1,313	1,332	1,369	1,420	1,484	1,562	1,657	1,744	1,833	1,937	2,043	2,142	2,238
	10,412	10,392	10,743	11,121	11,568	12,107	12,225	12,040	12,286	12,504	12,705	12,656	13,113	13,489	13,908	14,292	14,281
Debt:Equity Ratio	79:21	79:21	80:20	80:20	81:19	81:19	82:18	81:19	81:19	80:20	78:22	78:22	77:23	77:23	76:24	76:24	76:24

Wuskwatim 2009 Low Price Scenario

PROJECTED BALANCE SHEET
Electric Operations
(In Millions of Dollars)

For year ending March 31:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
ASSETS:																
Plant in Service	17,774	18,276	18,787	19,308	22,118	24,443	24,995	25,558	26,132	26,717	27,317	27,926	28,546	29,178	30,025	30,684
Accum Depreciation	(8,920)	(9,350)	(9,788)	10,238)	(10,725)	(11,260)	(11,796)	(12,340)	(12,890)	(13,448)	(14,013)	(14,587)	(15,169)	(15,758)	(16,356)	(16,971)
Net Plant in Service	8,854	8,926	8,999	9,071	11,393	13,183	13,199	13,218	13,242	13,269	13,304	13,339	13,377	13,420	13,669	13,713
Construct in Progress	1,264	1,905	2,677	3,516	1,963	344	347	349	352	354	357	377	456	547	369	372
Current & Other Assets	4,719	4,658	4,067	4,149	4,454	4,786	4,840	5,205	5,606	5,972	6,174	6,046	6,517	7,030	7,282	7,559
	14,838	15,489	15,742	16,736	17,810	18,313	18,386	18,773	19,199	19,596	19,836	19,762	20,350	20,997	21,320	21,644
LIABILITIES:																
Long Term Debt (Net)	9,761	9,672	10,465	11,464	12,264	12,164	12,364	12,564	12,504	12,454	12,054	12,446	12,646	12,746	12,646	13,046
Current & Other Liab.	2,485	3,128	2,484	2,368	2,524	3,004	2,755	2,821	3,187	3,513	4,031	3,446	3,718	4,148	4,452	4,258
NCN Investment in Wuskwatim Project	53	52	51	50	49	48	47	46	45	44	44	43	42	41	40	39
Contrib for Construct.	204	201	199	197	195	193	191	190	189	188	188	188	189	190	191	194
Retained Earnings	2,335	2,437	2,544	2,657	2,779	2,904	3,029	3,152	3,275	3,397	3,519	3,639	3,756	3,873	3,990	4,108
	14,838	15,489	15,742	16,736	17,810	18,313	18,386	18,773	19,199	19,596	19,836	19,762	20,350	20,997	21,320	21,644
Debt:Equity Ratio	76:24	77:23	77:23	78:22	79:21	78:22	77:23	77:23	76:24	75:25	75:25	74:26	74:26	73:27	73:27	72:28

Wuskwatim 2009 Low Price Scenario

FINANCING REQUIREMENTS STATEMENTS
Electric Operations
(In Millions of Dollars)

For year ending March 31:	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
FUNDS FROM OPERATIONS																	
Net Income	71	68	45	35	40	19	37	51	64	78	95	87	89	104	105	99	96
Provision for Deprec	256	270	282	301	310	324	331	350	363	372	381	390	396	394	402	410	420
Other (Net)	(40)	(40)	149	96	93	98	64	13	(29)	(40)	(50)	(54)	(55)	(75)	(87)	(78)	(72)
	286	298	475	433	444	441	432	413	398	411	426	423	431	423	420	432	444
APPLICATION OF FUNDS																	
Capital Expenditures	377	424	518	536	570	675	602	447	331	289	273	477	488	497	511	599	678
Repayment of LTD	316	0	211	103	94	292	0	0	103	0	0	0	0	0	451	255	377
Sinking Fund Deposit	81	68	84	84	90	83	89	128	178	181	180	185	187	61	63	68	79
Other	380	174	257	227	181	191	159	92	48	49	53	77	93	102	106	66	69
	1,154	667	1,070	949	936	1,241	851	667	660	518	506	738	768	659	1,131	987	1,203
FINANCING REQUIREMENTS	868	369	595	517	492	799	418	254	262	108	80	316	337	236	710	556	759

Wuskwatim 2009 Low Price Scenario

FINANCING REQUIREMENTS STATEMENTS
Electric Operations
(In Millions of Dollars)

For year ending March 31:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
FUNDS FROM OPERATIONS																
Net Income	97	102	107	113	122	125	125	123	123	122	122	120	116	117	118	117
Provision for Deprec	427	437	446	456	491	538	540	547	555	562	570	579	587	596	605	623
Other (Net)	(60)	(46)	(26)	12	15	13	10	5	(9)	(15)	(22)	(28)	(40)	(49)	(59)	(72)
	465	494	527	581	628	676	675	675	668	670	670	671	664	664	664	668
APPLICATION OF FUNDS																
Capital Expenditures	907	1,131	1,271	1,349	1,246	694	543	554	565	577	592	617	688	713	658	652
Repayment of LTD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sinking Fund Deposit	77	96	118	133	145	159	168	162	171	178	185	182	166	175	187	183
Other	71	75	78	81	83	86	89	92	95	98	101	105	105	108	112	114
	1,056	1,302	1,467	1,564	1,473	939	800	808	831	853	877	904	959	997	957	949
FINANCING REQUIREMENTS	591	808	940	983	846	263	125	133	163	183	207	233	295	332	293	280

ATTACHMENT CCC/NFAAT/S/7a Table: A.22 (cont'd)

Wuskwatim 2020 Low Price Scenario

PROJECTED BALANCE SHEET
Electric Operations
(In Millions of Dollars)

For year ending March 31:	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
ASSETS:																	
Plant in Service	9,462	9,894	10,308	10,633	11,067	11,342	11,710	11,995	12,649	12,940	13,199	13,856	14,351	14,854	15,368	15,874	16,357
Accum Depreciation	(3,037)	(3,300)	(3,573)	(3,858)	(4,151)	(4,459)	(4,773)	(5,095)	(5,425)	(5,764)	(6,112)	(6,469)	(6,831)	(7,199)	(7,576)	(7,962)	(8,357)
Net Plant in Service	6,425	6,594	6,735	6,775	6,915	6,883	6,937	6,901	7,224	7,176	7,087	7,387	7,520	7,655	7,792	7,913	8,000
Construct in Progress	444	503	454	419	380	592	662	789	479	486	511	459	513	771	1,015	1,331	1,778
Current & Other Assets	3,540	3,269	3,422	3,635	3,785	3,930	3,738	3,434	3,684	3,960	4,248	3,989	4,318	4,435	4,671	4,854	4,577
	10,409	10,366	10,611	10,829	11,080	11,405	11,336	11,123	11,387	11,622	11,845	11,836	12,351	12,861	13,479	14,097	14,355
LIABILITIES:																	
Long Term Debt (Net)	7,187	7,167	7,478	7,429	7,907	8,119	7,786	7,866	8,250	8,226	7,922	8,294	8,669	8,407	9,065	8,923	9,707
Current & Other Liab.	1,780	1,744	1,644	1,891	1,636	1,740	1,975	1,638	1,451	1,643	2,088	1,622	1,679	2,342	2,199	2,850	2,214
NCN Investment in Wuskwatim Project	0	0	0	0	0	0	0	0	0	0	0	0	0	21	34	49	64
Contrib for Construct.	266	262	259	255	251	246	242	238	234	231	227	223	219	216	212	209	206
Retained Earnings	1,176	1,193	1,230	1,255	1,286	1,300	1,333	1,381	1,452	1,522	1,609	1,697	1,785	1,875	1,968	2,065	2,162
	10,409	10,366	10,611	10,829	11,080	11,405	11,336	11,123	11,387	11,622	11,845	11,836	12,351	12,861	13,479	14,097	14,355
Debt:Equity Ratio	79:21	79:21	80:20	80:20	80:20	80:20	80:20	80:20	79:21	78:22	77:23	76:24	76:24	76:24	76:24	76:24	77:23

Wuskwatim 2020 Low Price Scenario

PROJECTED BALANCE SHEET
Electric Operations
(In Millions of Dollars)

For year ending March 31:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
ASSETS:																
Plant in Service	16,849	18,552	19,063	19,584	22,394	24,719	25,271	25,834	26,408	26,993	27,590	28,202	28,822	29,454	30,301	30,958
Accum Depreciation	(8,761)	(9,189)	(9,632)	10,086)	(10,578)	(11,117)	(11,657)	(12,205)	(12,760)	(13,322)	(13,892)	(14,470)	(15,056)	(15,650)	(16,252)	(16,872)
Net Plant in Service	8,088	9,363	9,431	9,499	11,816	13,603	13,614	13,629	13,648	13,671	13,698	13,732	13,766	13,804	14,049	14,086
Construct in Progress	2,411	1,925	2,696	3,536	1,983	364	366	369	372	374	377	397	476	567	388	391
Current & Other Assets	4,644	4,554	3,962	4,043	4,347	4,678	4,730	5,090	5,472	5,819	5,999	5,846	6,285	6,762	6,972	7,201
	15,143	15,842	16,090	17,078	18,147	18,644	18,710	19,088	19,491	19,864	20,074	19,974	20,526	21,133	21,409	21,679
LIABILITIES:																
Long Term Debt (Net)	10,161	10,072	10,865	11,864	12,664	12,564	12,764	12,764	12,904	12,854	12,454	12,646	12,846	12,746	12,646	13,046
Current & Other Liab.	2,438	3,118	2,464	2,339	2,484	2,954	2,693	2,947	3,086	3,383	3,869	3,454	3,686	4,274	4,528	4,276
NCN Investment in Wuskwatim Project	77	81	80	78	77	76	75	73	72	71	70	69	68	66	65	64
Contrib for Construct.	204	201	199	197	195	193	191	190	189	188	188	188	189	190	191	194
Retained Earnings	2,263	2,370	2,482	2,600	2,727	2,857	2,987	3,114	3,242	3,368	3,493	3,618	3,738	3,858	3,979	4,100
	15,143	15,842	16,090	17,078	18,147	18,644	18,710	19,088	19,491	19,864	20,074	19,974	20,526	21,133	21,409	21,679
Debt:Equity Ratio	77:23	78:22	79:21	79:21	80:20	79:21	78:22	78:22	77:23	76:24	76:24	75:25	75:25	74:26	74:26	73:27

Wuskwatim 2020 Low Price Scenario

FINANCING REQUIREMENTS STATEMENTS
Electric Operations
(In Millions of Dollars)

For year ending March 31:	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
FUNDS FROM OPERATIONS																	
Net Income	71	68	38	24	32	14	33	48	70	70	87	88	88	90	93	97	97
Provision for Deprec	256	270	287	307	316	330	337	345	354	364	374	375	382	380	387	396	405
Other (Net)	(40)	(39)	(29)	(30)	(41)	(51)	(53)	(48)	(35)	(51)	(67)	(79)	(85)	156	47	61	83
	286	299	296	301	307	293	317	345	389	383	395	384	385	625	527	554	585
APPLICATION OF FUNDS																	
Capital Expenditures	373	419	430	394	392	483	435	407	334	289	273	481	494	604	691	812	921
Repayment of LTD	316	0	211	103	94	292	0	0	103	0	0	0	0	0	451	255	377
Sinking Fund Deposit	81	68	84	84	90	83	89	128	172	175	174	179	181	53	53	58	71
Other	380	158	81	100	46	39	39	40	52	51	57	78	105	330	239	205	226
	1,150	645	806	680	622	896	563	575	661	515	504	738	780	987	1,434	1,330	1,595
FINANCING REQUIREMENTS	864	346	510	379	315	604	246	231	272	132	110	354	395	362	907	777	1,010

Wuskwatim 2020 Low Price Scenario

FINANCING REQUIREMENTS STATEMENTS
Electric Operations
(In Millions of Dollars)

For year ending March 31:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
FUNDS FROM OPERATIONS																
Net Income	100	107	112	118	127	130	130	128	127	126	126	124	120	121	121	120
Provision for Deprec	413	435	450	460	496	542	544	551	559	567	574	583	592	600	609	627
Other (Net)	53	3	(52)	(15)	(12)	(14)	(16)	(19)	(22)	(25)	(29)	(35)	(41)	(47)	(53)	(62)
	566	545	510	564	611	659	657	660	664	668	671	673	671	674	677	685
APPLICATION OF FUNDS																
Capital Expenditures	1,115	1,196	1,271	1,349	1,246	694	543	554	565	577	588	621	688	713	658	649
Repayment of LTD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sinking Fund Deposit	70	89	118	133	144	158	166	159	166	174	180	177	156	164	173	167
Other	187	105	52	55	56	60	62	66	69	72	76	78	82	86	90	92
	1,372	1,391	1,440	1,536	1,446	911	771	779	800	823	844	876	926	963	920	909
FINANCING REQUIREMENTS	806	846	930	973	835	253	114	120	136	156	173	203	255	289	243	223

Wuskwatim 2009 High Price Scenario

PROJECTED BALANCE SHEET
Electric Operations
(In Millions of Dollars)

For year ending March 31:	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
ASSETS:																	
Plant in Service	9,462	9,894	10,308	10,633	11,067	11,342	11,710	12,972	13,571	13,862	14,121	14,778	15,273	15,776	16,290	16,796	17,279
Accum Depreciation	(3,037)	(3,300)	(3,573)	(3,858)	(4,151)	(4,459)	(4,773)	(5,106)	(5,451)	(5,805)	(6,168)	(6,540)	(6,916)	(7,299)	(7,690)	(8,091)	(8,501)
Net Plant in Service	6,425	6,594	6,735	6,775	6,915	6,883	6,937	7,866	8,120	8,057	7,953	8,239	8,357	8,477	8,600	8,705	8,778
Construct in Progress	428	509	633	741	880	1,284	1,522	721	459	466	491	319	321	471	536	637	842
Current & Other Assets	3,560	3,289	3,375	3,605	3,773	3,939	3,766	3,445	3,691	3,954	4,260	4,044	4,370	4,468	4,693	4,863	4,571
	10,412	10,392	10,743	11,121	11,568	12,107	12,225	12,032	12,269	12,477	12,703	12,602	13,048	13,416	13,828	14,206	14,190
LIABILITIES:																	
Long Term Debt (Net)	7,187	7,167	7,478	7,429	8,307	8,719	8,386	8,466	8,650	8,626	8,122	8,294	8,469	8,207	8,665	8,323	8,907
Current & Other Liab.	1,783	1,770	1,755	2,133	1,633	1,693	2,053	1,654	1,534	1,545	2,026	1,634	1,822	2,368	2,236	2,868	2,183
NCN Investment in Wuskwatim Project	0	0	15	25	36	49	59	62	61	60	59	58	57	56	55	54	53
Contrib for Construct.	266	262	259	255	251	246	242	238	234	231	227	223	219	216	212	209	206
Retained Earnings	1,176	1,193	1,237	1,279	1,341	1,399	1,485	1,612	1,790	2,015	2,270	2,393	2,481	2,569	2,660	2,752	2,841
	10,412	10,392	10,743	11,121	11,568	12,107	12,225	12,032	12,269	12,477	12,703	12,602	13,048	13,416	13,828	14,206	14,190
Debt:Equity Ratio	79:21	79:21	80:20	80:20	80:20	80:20	80:20	79:21	77:23	74:26	71:29	70:30	70:30	70:30	69:31	69:31	69:31

Wuskwatim 2009 High Price Scenario

PROJECTED BALANCE SHEET
Electric Operations
(In Millions of Dollars)

For year ending March 31:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
ASSETS:																
Plant in Service	17,774	18,276	18,787	19,308	22,118	24,443	24,995	25,558	26,132	26,717	27,317	27,926	28,546	29,178	30,025	30,684
Accum Depreciation	(8,920)	(9,350)	(9,788)	(10,238)	(10,725)	(11,260)	(11,796)	(12,340)	(12,890)	(13,448)	(14,013)	(14,587)	(15,169)	(15,758)	(16,356)	(16,971)
Net Plant in Service	8,854	8,926	8,999	9,071	11,393	13,183	13,199	13,218	13,242	13,269	13,304	13,339	13,377	13,420	13,669	13,713
Construct in Progress	1,264	1,905	2,677	3,516	1,963	344	347	349	352	354	357	377	456	547	369	372
Current & Other Assets	4,625	4,561	3,966	4,044	4,346	4,678	4,733	5,097	5,486	5,841	6,033	5,893	6,350	6,850	7,088	7,351
	14,744	15,392	15,642	16,631	17,702	18,205	18,278	18,665	19,079	19,465	19,694	19,609	20,183	20,817	21,125	21,435
LIABILITIES:																
Long Term Debt (Net)	9,161	9,072	9,665	10,664	11,664	11,564	11,764	11,764	11,904	11,854	11,454	11,646	12,046	11,946	12,046	12,246
Current & Other Liab.	2,395	3,041	2,601	2,488	2,447	2,933	2,691	2,964	3,124	3,445	3,959	3,568	3,633	4,256	4,352	4,350
NCN Investment in Wuskwatim Project	53	52	51	50	49	48	47	46	45	44	44	43	42	41	40	39
Contrib for Construct.	204	201	199	197	195	193	191	190	189	188	188	188	189	190	191	194
Retained Earnings	2,931	3,026	3,127	3,233	3,349	3,467	3,585	3,702	3,818	3,934	4,050	4,164	4,274	4,385	4,496	4,607
	14,744	15,392	15,642	16,631	17,702	18,205	18,278	18,665	19,079	19,465	19,694	19,609	20,183	20,817	21,125	21,435
Debt:Equity Ratio	70:30	71:29	72:28	74:26	74:26	74:26	73:27	73:27	72:28	72:28	71:29	71:29	70:30	70:30	70:30	69:31

Wuskwatim 2009 High Price Scenario

FINANCING REQUIREMENTS STATEMENTS
Electric Operations
(In Millions of Dollars)

For year ending March 31:	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
FUNDS FROM OPERATIONS																	
Net Income	71	68	45	42	62	58	85	127	178	225	254	124	87	88	90	92	89
Provision for Deprec	256	270	282	301	310	324	331	350	363	372	381	390	396	394	402	410	420
Other (Net)	(40)	(40)	149	96	93	98	64	40	13	16	10	11	11	(18)	(28)	(18)	(11)
	286	298	475	440	465	480	481	517	554	613	645	525	495	464	464	484	498
APPLICATION OF FUNDS																	
Capital Expenditures	377	424	518	536	570	675	602	447	331	289	273	477	488	497	511	599	678
Repayment of LTD	316	0	211	103	94	292	0	0	103	0	0	0	0	0	451	255	377
Sinking Fund Deposit	81	68	84	84	90	83	89	128	178	181	180	185	187	53	55	59	72
Other	380	174	257	227	181	191	159	111	82	94	101	128	147	159	166	128	133
	1,154	667	1,070	949	936	1,241	851	686	693	564	554	789	822	709	1,182	1,040	1,259
FINANCING REQUIREMENTS	868	369	595	510	470	761	370	169	139	(49)	(91)	265	327	244	718	556	762

Wuskwatim 2009 High Price Scenario

FINANCING REQUIREMENTS STATEMENTS
Electric Operations
(In Millions of Dollars)

For year ending March 31:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
FUNDS FROM OPERATIONS																
Net Income	90	95	100	107	115	119	118	117	116	116	115	114	110	111	111	111
Provision for Deprec	427	437	446	456	491	538	540	547	555	562	570	579	587	596	605	623
Other (Net)	3	20	41	78	82	80	77	74	71	67	62	57	47	40	32	20
	520	553	587	641	688	736	735	738	742	745	747	750	745	747	748	754
APPLICATION OF FUNDS																
Capital Expenditures	907	1,131	1,271	1,349	1,246	694	543	554	565	577	592	617	688	713	658	652
Repayment of LTD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sinking Fund Deposit	70	89	110	123	134	150	158	152	158	167	174	171	152	163	172	169
Other	138	145	149	154	157	162	166	170	175	180	184	190	192	197	203	206
	1,115	1,364	1,531	1,626	1,537	1,006	867	877	899	924	949	978	1,032	1,073	1,033	1,027
FINANCING REQUIREMENTS	595	811	944	985	849	269	132	139	157	179	202	228	287	326	285	273

ATTACHMENT CCC/NFAAT/S/7a Table: A.24 (cont'd)

Wuskwatim 2020 High Price Scenario

PROJECTED BALANCE SHEET
Electric Operations
(In Millions of Dollars)

For year ending March 31:	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
ASSETS:																	
Plant in Service	9,462	9,894	10,308	10,633	11,067	11,342	11,710	11,995	12,649	12,940	13,199	13,856	14,351	14,854	15,368	15,874	16,357
Accum Depreciation	(3,037)	(3,300)	(3,573)	(3,858)	(4,151)	(4,459)	(4,773)	(5,095)	(5,425)	(5,764)	(6,112)	(6,469)	(6,831)	(7,199)	(7,576)	(7,962)	(8,357)
Net Plant in Service	6,425	6,594	6,735	6,775	6,915	6,883	6,937	6,901	7,224	7,176	7,087	7,387	7,520	7,655	7,792	7,913	8,000
Construct in Progress	444	503	454	419	380	592	662	789	479	486	511	459	513	771	1,015	1,331	1,778
Current & Other Assets	3,540	3,269	3,422	3,635	3,785	3,930	3,738	3,434	3,684	3,994	4,292	3,989	4,318	4,429	4,661	4,837	4,553
	10,409	10,366	10,611	10,829	11,080	11,405	11,336	11,123	11,387	11,656	11,890	11,836	12,351	12,855	13,469	14,080	14,331
LIABILITIES:																	
Long Term Debt (Net)	7,187	7,167	7,478	7,429	7,907	8,119	7,786	7,666	7,850	8,026	7,522	7,694	8,069	8,007	8,465	8,323	9,107
Current & Other Liab.	1,780	1,744	1,644	1,884	1,607	1,672	1,859	1,658	1,577	1,492	2,026	1,722	1,784	2,247	2,305	2,955	2,318
NCN Investment in Wuskwatim Project	0	0	0	0	0	0	0	0	0	0	0	0	0	21	34	49	64
Contrib for Construct.	266	262	259	255	251	246	242	238	234	231	227	223	219	216	212	209	206
Retained Earnings	1,176	1,193	1,230	1,262	1,316	1,368	1,449	1,562	1,725	1,908	2,115	2,197	2,280	2,364	2,452	2,544	2,635
	10,409	10,366	10,611	10,829	11,080	11,405	11,336	11,123	11,387	11,656	11,890	11,836	12,351	12,855	13,469	14,080	14,331
Debt:Equity Ratio	79:21	79:21	80:20	80:20	79:21	79:21	79:21	78:22	76:24	73:27	71:29	70:30	70:30	70:30	71:29	71:29	72:28

ATTACHMENT CCC/NFAAT/S/7a Table: A.24 (cont'd)

Wuskwatim 2020 High Price Scenario

PROJECTED BALANCE SHEET
Electric Operations
(In Millions of Dollars)

For year ending March 31:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
ASSETS:																
Plant in Service	16,849	18,552	19,063	19,584	22,394	24,719	25,271	25,834	26,408	26,993	27,590	28,202	28,822	29,454	30,301	30,958
Accum Depreciation	(8,761)	(9,189)	(9,632)	(10,086)	(10,578)	(11,117)	(11,657)	(12,205)	(12,760)	(13,322)	(13,892)	(14,470)	(15,056)	(15,650)	(16,252)	(16,872)
Net Plant in Service	8,088	9,363	9,431	9,499	11,816	13,603	13,614	13,629	13,648	13,671	13,698	13,732	13,766	13,804	14,049	14,086
Construct in Progress	2,411	1,925	2,696	3,536	1,983	364	366	369	372	374	377	397	476	567	388	391
Current & Other Assets	4,614	4,500	3,886	3,941	4,217	4,527	4,570	4,922	5,296	5,635	5,808	5,646	6,075	6,546	6,749	6,973
	15,112	15,788	16,014	16,976	18,016	18,493	18,551	18,920	19,315	19,680	19,883	19,774	20,317	20,917	21,187	21,451
LIABILITIES:																
Long Term Debt (Net)	9,561	9,672	10,265	11,264	12,064	11,964	12,164	12,164	12,304	12,254	11,654	11,846	12,246	12,146	12,046	12,446
Current & Other Liab.	2,540	3,002	2,531	2,385	2,508	2,962	2,698	2,948	3,083	3,379	4,062	3,643	3,671	4,256	4,509	4,256
NCN Investment in Wuskwatim Project	77	81	80	78	77	76	75	73	72	71	70	69	68	66	65	64
Contrib for Construct.	204	201	199	197	195	193	191	190	189	188	188	188	189	190	191	194
Retained Earnings	2,730	2,832	2,939	3,052	3,174	3,298	3,423	3,545	3,668	3,789	3,909	4,029	4,144	4,260	4,376	4,492
	15,112	15,788	16,014	16,976	18,016	18,493	18,551	18,920	19,315	19,680	19,883	19,774	20,317	20,917	21,187	21,451
Debt:Equity Ratio	73:27	74:26	75:25	76:24	76:24	76:24	75:25	75:25	74:26	73:27	73:27	72:28	72:28	71:29	71:29	71:29

Wuskwatim 2020 High Price Scenario

FINANCING REQUIREMENTS STATEMENTS
Electric Operations
(In Millions of Dollars)

For year ending March 31:	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
FUNDS FROM OPERATIONS																	
Net Income	71	68	38	31	54	52	81	113	164	182	207	82	83	85	88	92	92
Provision for Deprec	256	270	287	307	316	330	337	345	354	364	374	375	382	380	387	396	405
Other (Net)	(40)	(39)	(29)	(30)	(41)	(51)	(53)	(48)	(35)	(51)	(67)	(79)	(85)	156	47	61	83
	286	299	296	308	329	331	366	410	483	495	515	378	379	620	522	548	580
APPLICATION OF FUNDS																	
Capital Expenditures	373	419	430	394	392	483	435	407	334	289	273	481	494	604	691	812	921
Repayment of LTD	316	0	211	103	94	292	0	0	103	0	0	0	0	0	451	255	377
Sinking Fund Deposit	81	68	84	84	90	83	89	128	172	175	174	179	181	47	49	52	65
Other	380	158	81	100	46	39	39	40	52	51	57	78	105	330	239	205	226
	1,150	645	806	680	622	896	563	575	661	515	504	738	780	981	1,430	1,324	1,588
FINANCING REQUIREMENTS	864	346	510	372	293	566	197	166	179	20	(10)	359	401	361	908	776	1,009

ATTACHMENT CCC/NFAAT/S/7a Table: A.24 (cont'd)

Wuskwatim 2020 High Price Scenario

FINANCING REQUIREMENTS STATEMENTS
Electric Operations
(In Millions of Dollars)

For year ending March 31:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
FUNDS FROM OPERATIONS																
Net Income	95	102	107	113	122	125	124	123	122	121	121	119	115	116	116	116
Provision for Deprec	413	435	450	460	496	542	544	551	559	567	574	583	592	600	609	627
Other (Net)	53	69	36	76	82	74	61	59	57	54	51	47	43	37	31	23
	561	606	593	650	700	741	729	733	738	742	746	749	750	754	757	766
APPLICATION OF FUNDS																
Capital Expenditures	1,115	1,196	1,271	1,349	1,246	694	543	554	565	577	588	621	688	713	658	649
Repayment of LTD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sinking Fund Deposit	63	82	112	125	136	149	157	150	156	165	170	165	143	153	161	155
Other	187	155	123	127	131	135	139	144	149	154	159	163	169	175	180	184
	1,365	1,433	1,506	1,601	1,512	978	840	849	871	895	917	949	1,000	1,040	999	988
FINANCING REQUIREMENTS	804	827	913	952	812	238	110	116	133	153	171	199	251	287	242	223

CCC/NFAAT/S/8

CAC/MSOS/NFAAT/S/8

CONSOLIDATION ACCOUNTING

Request: The Crown Corporations Council and CAC/MSOS requested more background on the manner in which the Partnership will be consolidated.

Response: Manitoba Hydro's consolidated financial statements must fairly reflect its majority ownership interest in the Wuskwatim partnership. Section 1600 of the CICA Handbook recommends the parent-company approach as a basis for consolidation in cases where a non-controlling interest exists. The parent-company consolidation approach includes Manitoba Hydro's 67% share of the fair values of the Wuskwatim Project's assets and liabilities plus the book value of NCN's 33% share and 100% of the revenues and expenses. Since Manitoba Hydro's and NCN's investments in the Wuskwatim Project are the initial investments in a parent-founded subsidiary, the book value is the fair value at the time of investment and the distinction between book and fair values for consolidation purposes is irrelevant. The Partnership's net assets on the consolidated balance sheet must then be offset by an amount for NCN's non-controlling interest in or near the equity section of Manitoba Hydro's consolidated balance sheet. Similarly, when 100% of the Wuskwatim Partnership's revenues and expenses are included in the consolidated income statement, NCN's share of net income must be subtracted, so that net income on Manitoba Hydro's income statement will reflect only the share of the Wuskwatim Partnership's income that is attributable to Manitoba Hydro's interest in the Partnership.

The parent-company approach focuses on the control of the assets and related risks rather than ownership interests. Control is defined by the Handbook as the extent of holdings of voting shares as well as other factors that reflect the substance of the investor's relationship, including but not limited to the composition of the Board of Directors and active participation in the management of the subsidiary. Since Manitoba Hydro appoints at least two-thirds of the General Partner's Board of Directors and maintains control over the day-to-day operation of the plant, the parent-company approach is anticipated to be the appropriate method for consolidating the Wuskwatim partnership with Manitoba Hydro, subject to a review by Manitoba Hydro's external auditors. By recording 100% of the assets and liabilities of the Partnership with no "off-balance sheet accounts" being utilized., the accounting is more transparent under this approach compared to other alternatives available

An alternative approach to consolidating non-wholly owned subsidiaries is discussed in Section 3055 of the CICA Handbook – Interests in Joint Ventures. Proportionate consolidation would include only Manitoba Hydro's 67% share of assets and liabilities and revenues and expenses on the consolidated statements (exclude NCN's interest entirely) and is an accepted approach for joint ventures. Control in a joint venture is typically shared equally among the investors and is the key distinguishing factor in selecting either the parent-company or proportionate consolidation approach. As stated previously, Manitoba Hydro's majority representation on the General Partner's Board and its responsibility for the day-to-day operations of the Partnership defines control over the assets of the Partnership in accordance with the Handbook definition, rendering proportionate consolidation inappropriate for accounting for this business combination.

The expected presentation of this information is illustrated in the pro forma income statements provided in the main submission in **Attachment 7 Tables A.21 to A.24** and balance sheets provided in **Attachment CCC/NFAAT/S/7a Tables A.21 to A.24** of this supplemental filing.

Under consolidation accounting all transactions between Manitoba Hydro and the Partnership would be eliminated, including the following:

- Inter-company export sales and power purchases
- Inter-company fees and charges
- Transmission cost recovery
- Inter-company receivables and payables

- Inter-company investment and share capital accounts

The net incremental effect on Manitoba Hydro's financial statements of the Project and any related loans to NCN will involve the following line items:

BALANCE SHEET:

Capital assets:

- 100% of Wuskwatim capital cost from Partnership
- Transmission facilities associated with the Project but not owned by the Partnership
- Additional amount to capitalize full interest on Manitoba Hydro's equity share

Accounts receivable:

- Equity loans to NCN and associated accrued interest receivable

Liabilities:

- 100% of Partnership liabilities (including operating loans, if required, from Manitoba Hydro to the Partnership)
- Debt to finance Manitoba Hydro's equity interest in Wuskwatim
- Debt to finance NCN's equity interest in Wuskwatim

Non-controlling interest:

- NCN's 33% share of the Partnership's assets as calculated as follows:

	NCN's 33% investment in the generating station
plus	NCN's 33% share of Partnership net income
less	dividends distributed to NCN

Equity:

- Manitoba Hydro's 67% share of cumulative net earnings

INCOME STATEMENT:

- 100% of the Partnership revenues and expenses are reported on a line-by-line basis on the consolidated income statement

- NCN's 33% share of Partnership net income is deducted from other revenue, representing the non-controlling interest (this was done to simplify the modeling – the Handbook requires that it be disclosed separately as an expense item)
- Operating and carrying costs associated with the transmission facilities not owned by the partnership
- Interest income accruing on the equity loans to NCN are offset against finance expense

FINANCING REQUIREMENTS STATEMENT:

- Manitoba Hydro's 67% share of the Partnership's net income and depreciation expense
- 100% of the Partnership's capital expenditures
- Capital expenditures for the transmission facilities not owned by the Partnership
- Payments on NCN's equity loan outstanding via NCN dividends re-allocated to Manitoba Hydro

Note that consolidation accounting does not apply to loans advanced by Manitoba Hydro to NCN itself, but only to the Partnership in which Manitoba Hydro is assumed to have at least a 67% interest.

CCC/NFAAT/S/9

CAC/MSOS/NFAAT/S/9

FINANCIAL SENSITIVITY – 15% INCREASE/DECREASE IN BASE CAPITAL COSTS

Request: The Crown Corporations Council and CAC/MSOS requested a capital cost sensitivity for the financial evaluation similar to that for the economic evaluation for the economic evaluation in **Table 6.5** of the main submission.

Response: Section 6.4.2 of the main submission analyzes the economic sensitivity to a $95 million cost deviation in the base capital estimates for the generating station and transmission facilities. This supplemental section will analyze the financial impacts of the same capital cost deviation on Manitoba Hydro's consolidated profitability, performance on financial targets and cumulative rates charged to customers, within a range of low and high export prices. **Table 1** shows the range of incremental in-service costs that equates to a $95 million change in base cost, assuming both a 2009 and 2020 in-service date. Carrying costs associated with the assets have been modified accordingly while export revenues and production costs remain unchanged.

Table 1

	Change in Wuskwatim In-Service Cost (Generation & Transmission)		
	-15%	BASE	+15%
2009 ISD	(127.2)	0.0	131.0
2020 ISD	(171.6)	0.0	173.3

Figure 1 shows the difference in the impact of a 15% cost deviation on Manitoba Hydro's consolidated net income due to the advancement of Wuskwatim. Assuming the same general rate increases as the 2020 case, Manitoba Hydro's net income is projected to be higher in every year in all but the higher capital cost scenario under low prices. In this scenario the incremental effect

of the increased capital price is to drive net income slightly negative from 2011 to 2015 and again in 2017. However, from 2018 on, higher capital cost scenario even with low prices result in beneficial impacts on net income due to the advancement of Wuskwatim. The benefit to net income grows to between $83 to $233 million by the end of the study period. Interest coverage (**Figure 2**) follows the same pattern as net income, showing improvements in ratios in all years for the capital sensitivities under high prices. Under low prices, the lower capital cost scenario shows improvements for most years and even under the higher capital cost scenario, improvements to interest coverage ratios occur prior to the 2020 in-service date.

Figure 1

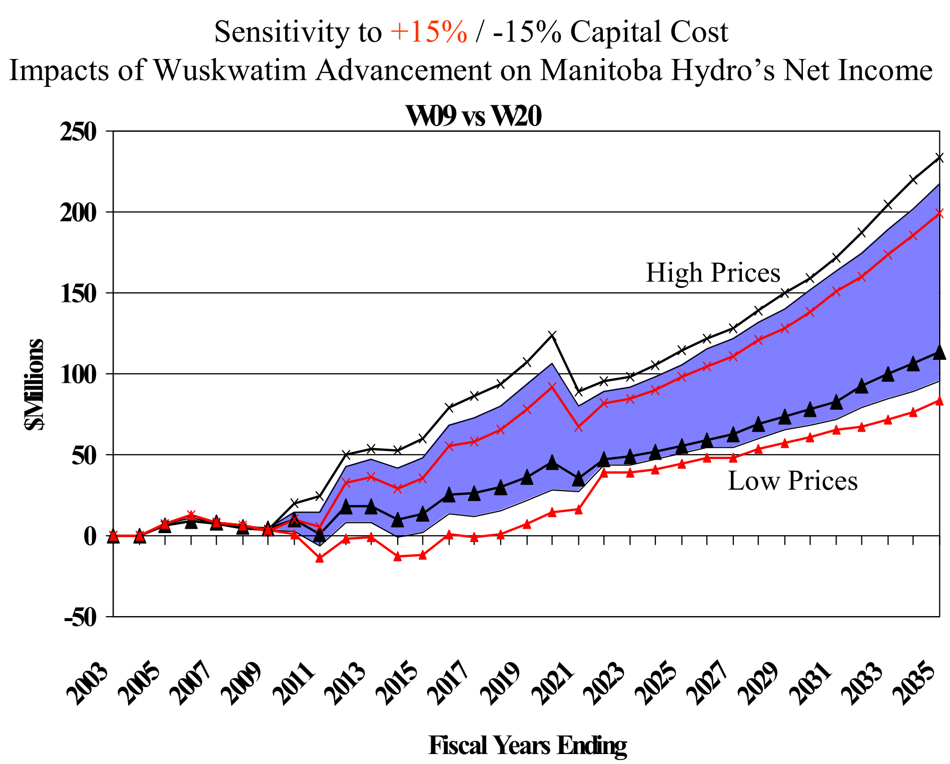
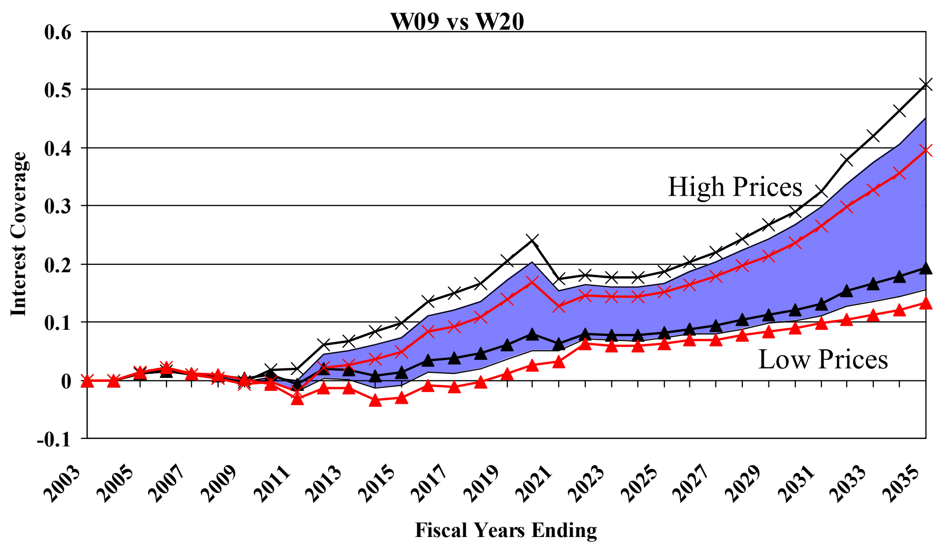


Figure 2

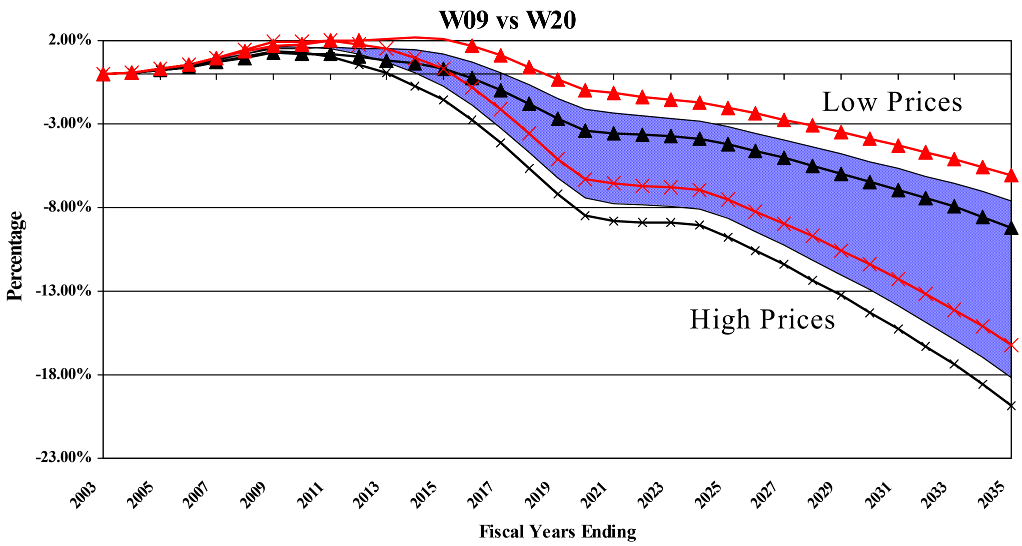
Sensitivity to +15% / -15% Capital Cost
Impacts of Wuskwatim Advancement on
Manitoba Hydro's Interest Coverage



The advancement of Wuskwatim coupled with higher capital costs would not adversely affect Manitoba Hydro's financial stability. Changes to the Corporation's debt ratio relative to the base case are shown in **Figure 3**. A 15% increase in capital costs, increases the debt ratio by no more than 2.1% over the 2020 base case. Even under low export prices, the debt ratio would recover to the same level as the base case by 2019.

Figure 3

Sensitivity to +15% / -15% Capital Cost
Impacts of Wuskwatim Advancement on Manitoba Hydro's Debt Ratio



Figures 4 and 5 show the potential cumulative percent customer rate benefits and present value of customer bill benefits. As in other financial scenarios, rates with Wuskwatim 2009 are held constant until the same level of debt ratio is attained relative to the corresponding 2020 base case. Once this has been achieved, the potential rate benefits are calculated by applying the same 1.15 annual interest coverage target in both cases. As expected, the lower capital cost scenarios yield the higher rate benefits to customers during the advancement period. In the Wuskwatim 2009 case, the long-term rate benefits are project to range from 1.8% to 3.3% under the various capital scenarios compared to 1.9% to 3.0% using the base capital costs.

Figure 4

Sensitivity to +15% / -15% Capital Cost
Impacts of Wuskwatim Advancement on Customer Rates

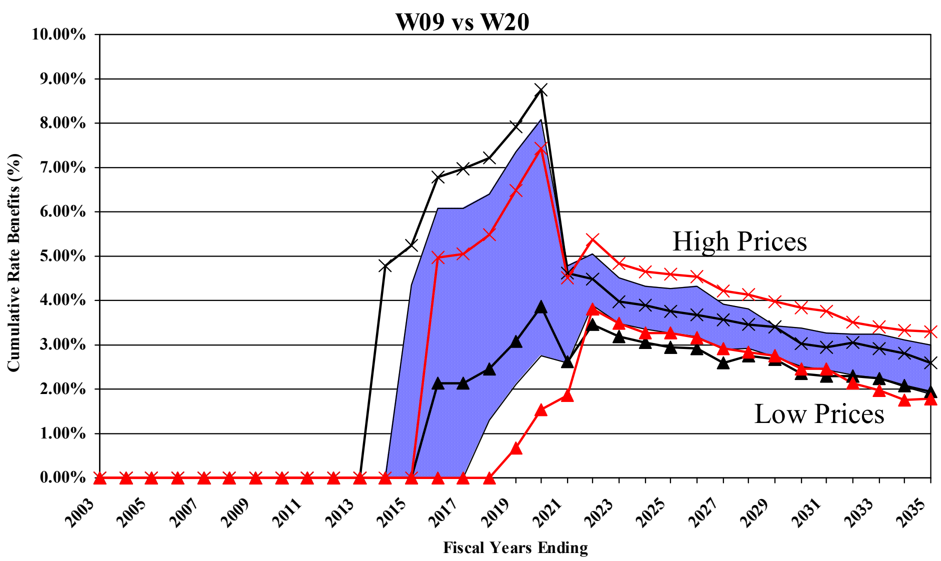
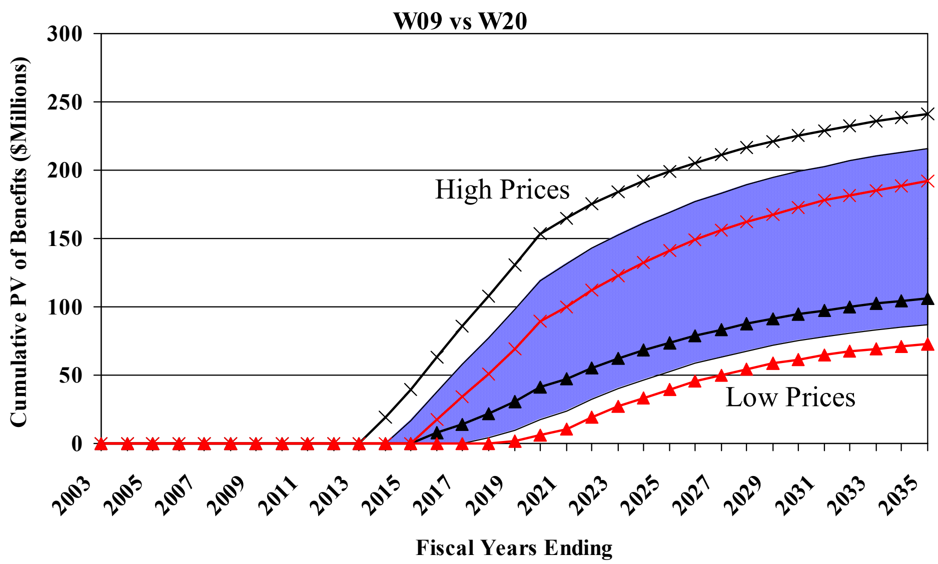


Figure 5 shows the relative value of higher cumulative rate benefits during the advancement period versus at the end of the study period. On a present value basis, the advancement of Wuskwatim could yield cumulative reductions to customers' bills ranging from $87 to $216 million by 2035. Changes in capital cost widen this range by $14 million for low export prices and $25 million for high export prices.

Figure 5

Sensitivity to +15% / -15% Capital Cost
Impacts of Wuskwatim Advancement on Customer Bills



The advancement of Wuskwatim to 2009 is still positive for Manitoba Hydro even with a hypothetical 15% increase in the cost of the generating station and in the related transmission facilities from the amounts which are currently expected. The small increase to the Corporation's debt ratio of 2.1% resulting from the advancement of Wuskwatim under a scenario of with higher capital costs is only slightly higher than the 1.6% increase in the main submission with base capital costs, and will not impair Manitoba Hydro's financial stability nor require offsetting customer rate increases to cover the start-up costs. Higher capital costs result in a deferral of rate benefits to customers by no more than one year compared to the base capital cost scenarios. However, even when higher capital costs are combined with low export prices, rate benefits are projected to be achievable prior to the 2020 in-service and continue over the long-term.

CCC-NFAAT-S-10

FINANCIAL IMPACT OF 2003 POWER RESOURCE PLAN UPDATE

Request: The Crown Corporations Council requested an updated financial analysis resulting from updated data and assumptions assumed in the 2003 Power Resource Plan.

Response: To be filed at a later date when available.

CAC/MSOS/NFAAT/S/10

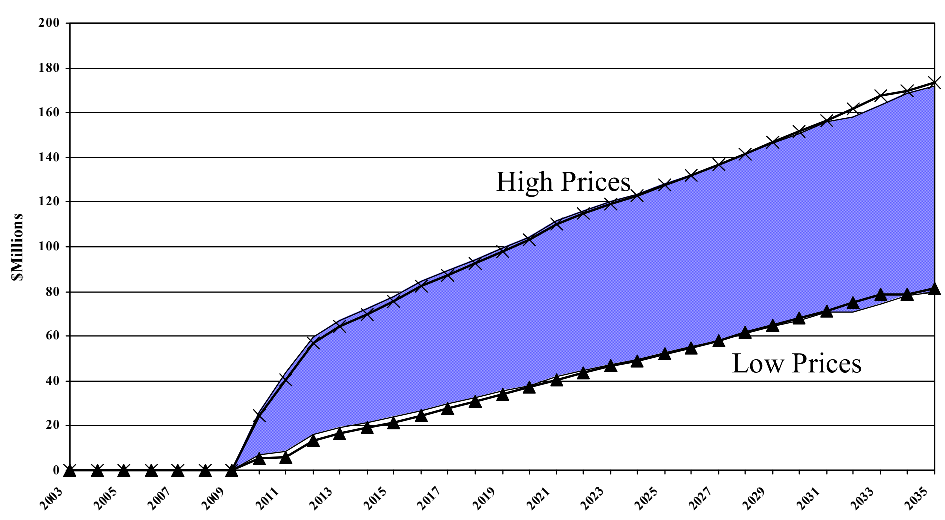
IMPACT OF PARTNERSHIP DIVIDEND POLICY ON MANITOBA HYDRO

Request: CAC/MSOS asked how dividend policy could be utilized to provide for capital reserves.

Response: **Figure 7.1** of the NFAAT filing (**Chapter 7**) showed the range of annual dividends anticipated to flow to the Partners from the Project if all cash is paid out beyond that which is required to maintain a debt ratio of 75%. **Figure 1** below indicates the slightly smaller payments projected to be received by the Partners if dividends are limited to net income. (The Partners may decide to base dividends on all or a proportion of net income in order to build up reserves for future capital contingencies.) In this event the equity ratio in the Partnership would rise above 25% (to 40% by 2035 if no unexpected capital requirements occur.)

Figure 1

Wuskwatim Partnership Dividends
2009 In-Service



The amount of cash paid out as dividends versus that which is retained in the Partnership does not affect Manitoba Hydro's own financial statements due to the elimination of offsetting entries described in the response to consolidation accounting (**CCC/NFAAT/S/8**).

The net effect on Manitoba Hydro's debt/equity position is as shown in **Figure 7.4** of the main filing. This result will not differ even if the Partnership decides to pay out lower dividends in order to create additional capital reserves. This is because, under consolidation accounting, the full amount of Manitoba Hydro's 67% share in the net income of the Partnership will be allocated to the Corporation regardless of dividend payouts. Dividends to the parent company are eliminated upon consolidation. Manitoba Hydro will make provision for future contingencies in the Project and elsewhere in the Corporation through its normal equity ratio and self-insurance policies. (Establishment of capital reserves within the Partnership may be more of a benefit to NCN in limiting the need for future unanticipated cash calls.

CAC/MSOS/NFAAT/S/11

SUMMARIZED PARTNERSHIP PROJECTED INCOME STATEMENTS

Request: CAC/MSOS requested that simplified statements be provided for the Partnership.

Response: See **Attachments CAC/MSOS/NFAAT/S/11a Tables A.25 to A.28**.

Wuskwatim 2009 Low Export Price Scenario

PROJECTED OPERATING STATEMENT WUSKWATIM PARTNERSHIP
(x 1,000,000)

For year ending March 31:	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
REVENUES:																	
Net Revenue	0	0	0	0	0	0	0	58	84	86	89	91	93	95	97	100	102
	0	0	0	0	0	0	0	58	84	86	89	91	93	95	97	100	102
EXPENSES:																	
Finance Expense	0	0	0	0	0	0	0	24	42	41	40	40	39	39	38	37	37
Other Operating	0	0	0	0	0	0	0	28	37	32	32	32	32	33	33	33	33
	0	0	0	0	0	0	0	53	79	73	73	72	72	71	71	70	70
Net Income (Loss)	0	0	0	0	0	0	0	5	6	13	16	18	21	24	27	30	33
Dividends	0	0	0	0	0	0	0	7	10	14	19	21	24	27	30	32	36
Financial Ratios																	
Debt Ratio	N/A	N/A	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%
Interest Coverage	N/A	N/A	1.00	1.00	1.00	1.00	1.00	1.14	1.13	1.32	1.40	1.46	1.53	1.62	1.70	1.79	1.89

Wuskwatim 2009 Low Export Price Scenario

PROJECTED OPERATING STATEMENT WUSKWATIM PARTNERSHIP
(x 1,000,000)

For year ending March 31:

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
REVENUES:																
Net Revenue	105	108	110	112	113	116	118	121	123	126	128	131	134	137	139	141
	105	108	110	112	113	116	118	121	123	126	128	131	134	137	139	141
EXPENSES:																
Finance Expense	36	36	35	34	34	33	32	32	31	30	30	29	32	31	30	29
Other Operating	33	33	33	33	33	33	34	34	34	34	34	34	34	34	34	35
	69	69	68	68	67	66	66	65	65	64	64	63	66	65	64	64
Net Income (Loss)	36	39	42	45	46	50	52	55	59	62	65	68	68	72	75	77
Dividends	38	42	45	47	49	52	55	58	61	64	67	71	71	74	78	80
Financial Ratios																
Debt Ratio	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%
Interest Coverage	1.98	2.09	2.19	2.30	2.38	2.50	2.61	2.75	2.89	3.03	3.19	3.35	3.16	3.33	3.51	3.66

Wuskwatim 2020 Low Export Price Scenario

PROJECTED OPERATING STATEMENT WUSKWATIM PARTNERSHIP
(x 1,000,000)

For year ending March 31:	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
REVENUES:																	
Net Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EXPENSES:																	
Finance Expense	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Operating	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Income (Loss)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dividends	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Financial Ratios																	
Debt Ratio	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	75%	75%	75%	75%
Interest Coverage	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.00	1.00	1.00	1.00

Wuskwatim 2020 Low Export Price Scenario

PROJECTED OPERATING STATEMENT WUSKWATIM PARTNERSHIP
(x 1,000,000)

For year ending March 31:

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
REVENUES:																
Net Revenue	0	77	110	112	113	116	118	121	123	126	128	131	134	137	139	141
	0	77	110	112	113	116	118	121	123	126	128	131	134	137	139	141
EXPENSES:																
Finance Expense	0	31	54	54	53	52	51	51	50	49	48	47	47	46	45	44
Other Operating	0	33	41	41	41	41	42	42	42	42	42	42	42	42	43	43
	0	63	95	95	94	94	93	92	92	91	90	90	89	88	88	87
Net Income (Loss)	0	13	15	17	19	22	25	28	32	35	38	42	45	48	52	54
Dividends	0	15	18	21	23	26	29	32	35	38	42	44	48	52	55	58
Financial Ratios																
Debt Ratio	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%
Interest Coverage	1.00	1.25	1.27	1.32	1.36	1.43	1.49	1.56	1.63	1.71	1.79	1.87	1.96	2.05	2.15	2.22

Wuskwatim 2009 High Export Price Scenario

PROJECTED OPERATING STATEMENT WUSKWATIM PARTNERSHIP
(x 1,000,000)

For year ending March 31:	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
REVENUES:																	
Net Revenue	0	0	0	0	0	0	0	77	118	129	136	140	146	152	156	160	165
	0	0	0	0	0	0	0	77	118	129	136	140	146	152	156	160	165
EXPENSES:																	
Finance Expense	0	0	0	0	0	0	0	24	41	40	39	39	38	37	37	36	35
Other Operating	0	0	0	0	0	0	0	28	37	32	32	32	32	33	33	33	33
	0	0	0	0	0	0	0	52	78	72	72	71	71	70	69	69	68
Net Income (Loss)	0	0	0	0	0	0	0	25	41	57	64	69	75	82	87	91	96
Dividends	0	0	0	0	0	0	0	26	43	60	67	72	78	84	89	94	99
Financial Ratios																	
Debt Ratio	N/A	N/A	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%
Interest Coverage	N/A	N/A	1.00	1.00	1.00	1.00	1.00	1.63	1.99	2.42	2.63	2.79	2.97	3.18	3.35	3.53	3.73

Wuskwatim 2009 High Export Price Scenario

PROJECTED OPERATING STATEMENT WUSKWATIM PARTNERSHIP
(x 1,000,000)

For year ending March 31:

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
REVENUES:																
Net Revenue	170	176	180	183	186	190	193	198	202	206	210	214	219	223	228	231
	170	176	180	183	186	190	193	198	202	206	210	214	219	223	228	231
EXPENSES:																
Finance Expense	35	34	33	33	32	31	31	30	29	28	28	27	30	29	28	27
Other Operating	33	33	33	33	33	33	34	34	34	34	34	34	34	34	34	35
	68	67	67	66	65	65	64	64	63	62	62	61	64	63	62	62
Net Income (Loss)	102	109	113	117	121	125	129	134	139	143	148	153	155	160	166	170
Dividends	104	111	116	120	123	128	132	137	142	146	150	156	158	163	168	172
Financial Ratios																
Debt Ratio	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%
Interest Coverage	3.94	4.19	4.38	4.58	4.76	4.99	5.21	5.47	5.75	6.04	6.34	6.66	6.24	6.58	6.95	7.27

ATTACHMENT CAC/MSOS/NFAAT/S/11a Table: A.28

Wuskwatim 2020 High Export Price Scenario

PROJECTED OPERATING STATEMENT WUSKWATIM PARTNERSHIP
(x 1,000,000)

For year ending March 31:	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
REVENUES:																	
Net Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EXPENSES:																	
Finance Expense	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Operating	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Income (Loss)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dividends	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Financial Ratios																	
Debt Ratio	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	75%	75%	75%	75%
Interest Coverage	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.00	1.00	1.00	1.00

ATTACHMENT CAC/MSOS/NFAAT/S/11a Table: A.28 (Cont'd)

Wuskwatim 2020 High Export Price Scenario

PROJECTED OPERATING STATEMENT WUSKWATIM PARTNERSHIP
(x 1,000,000)

For year ending March 31:

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
REVENUES:																
Net Revenue	0	125	180	183	186	190	193	198	202	206	210	214	219	223	228	231
	0	125	180	183	186	190	193	198	202	206	210	214	219	223	228	231
EXPENSES:																
Finance Expense	0	29	53	52	51	51	50	49	48	47	46	45	45	44	43	42
Other Operating	0	33	41	41	41	41	42	42	42	42	42	42	42	42	43	43
	0	62	94	93	93	92	91	91	90	89	88	88	87	86	86	85
Net Income (Loss)	0	63	86	90	93	98	102	107	112	117	122	127	132	137	142	146
Dividends	0	65	89	94	97	102	106	111	116	120	125	130	135	141	146	150
Financial Ratios																
Debt Ratio	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%
Interest Coverage	1.00	2.23	2.62	2.73	2.82	2.94	3.05	3.19	3.33	3.47	3.62	3.78	3.94	4.12	4.31	4.47

CCC/NFAAT/S/11

Request: General Comments, provide updates to key documents. Page 1 of Crown Corporation Council letter dated June 27, 2003.

Response: The updates to the following key documents have been included in the appendices:

Appendix 2: Current Strategic Plan 2003/04
Appendix 4: Newsletter #4
Appendix 7: Economic Outlook 2003-2004
Appendix 8: System Load Forecast 2003/04 to 2023/24

NOTABLE CHANGES

Appendix 2: Corporate Strategic Plan 2003/04

The first nine goals represented in the 2003/04 CSP are unchanged from last year and reflect a focus on competing effectively in today's business environment and to being a responsible corporate citizen. The 2003/04 CSP introduces the tenth corporate goal, which is "Be a leader in implementing cost-effective energy conservation and alternate energy programs." This new goal provides more focus on Manitoba Hydro's efforts to provide customers with a full spectrum of energy and energy conservation solutions. (Refer to CCC/NFAAT/S/12)

Appendix 4: Newsletter #4 - Fourth Round of Public Involvement.

Since the last round of public involvement during mid-winter, separate Environmental impact Statements for the Wuskwatim Generating Project and Wuskwatim Transmission Project have been prepared as well as a report that considers the need for and alternatives to the Wuskwatim Project. The Government of Manitoba has provided a Terms of Reference to the Clean Environment Commission (CEC) to conduct a public review of these documents.

The newsletter goes on to provide an overview of the documents submitted. (Refer to CCC/NFAAT/S/13)

Appendix 7: Economic Outlook 2003

Key changes - The results of the key variables in the 2003 Economic Outlook are similar to those in the 2002 Economic Outlook and therefore, would not have a significant impact on the Wuskwatim analysis. Please refer to Page 2 of the 2003 Economic Outlook for a comparison of the key variables. (Refer to CCC/NFAAT/S/14)

Appendix 8: System Load Forecast 2003/04 to 2023/24

The most significant change in the forecast compared to last year's forecast is significantly higher load in the future. This has implications on the Power Resource Plan including an advancement of plant. The load actually experienced in 2002/03 was higher than contained in the previous forecast. Net Firm Energy over the forecast period has increased from the previous forecast over the five (1039 GWh), ten (752 GWh) and twenty (1055 GWh) year intervals into the future. This increase is mainly due to higher expected loads in the Residential, General Service and Transmission Losses categories.

The Net Total Peak over the forecast period has increased from the previous forecast over the five (181 MW), ten (132 MW) and twenty (179 MW) year intervals into the future.

The other significant change to the forecasting process resulted from the purchase of Winnipeg Hydro. In previous forecasts, the Winnipeg Hydro load was forecasted at the Common Bus level. This year, the load is forecasted at the sales level.

Separate econometric forecasts were prepared for Winnipeg Hydro customers in the Residential Standard, Residential All-electric and General Service Mass Market classification. The sales forecasts contained in this document represent all Manitoba Customers. The results were calculated by adding the Manitoba Hydro and Winnipeg Hydro forecasts together.

Of note is the load growth over the previous 20 years, which amounts to a 52% increase, while the population growth over the same period has increased only 8.5% over the same period. This indicates a past trend of load growth increasing at a greater rate than population growth over the same time. (Refer to CCC/NFAAT/S/15)

CCC/NFAAT/S/12

Provide current Corporate Strategic Plan

The Corporate Strategic Plan 2003 2004 "Powerful Solutions" is attached. (see CCC/NFAAT/S/11 for comparison)

Compact fluorescent lamps use up to 75% less energy than incandescent lamps and last up to 10 times longer, while providing the same amount of light.

POWERFUL SOLUTIONS

THE CORPORATE STRATEGIC PLAN 2003 | 2004

Manitoba Hydro's Vision of the Future

"Be a leader in implementing cost-effective energy conservation and alternative energy programs."

Since the **Corporate Strategic Plan** was first introduced to employees in its official, published form four years ago, it has proven to be a highly successful communications tool – both for our staff and our stakeholders. I'm always encouraged to see employees referring to the CSP in their daily business lives, at meetings, and in general discussions. In those situations it becomes clear to me that the document is achieving its intended purpose – to serve as the framework, or constitution, for all of Manitoba Hydro's present and future activities.

I've also been asked many times if the information published in the CSP is meant to represent all of the activities of the company. It's important to make the distinction that the CSP is intended to provide employees with the strategic direction that represents the things we stand for, our most important corporate goals, and the strategies and targets necessary to achieve them. The CSP can then be translated into business plans across the organization at the business unit, division, and department levels. The CSP clearly does not represent the bulk of the operational work that employees perform every day – but you should be able to trace the work you do back to the core elements contained in the CSP and, ultimately, our vision of being the best utility in North America.

Last year was once again a historic one for Manitoba Hydro. With the acquisition of Winnipeg Hydro we added over 500 more employees to our workforce. The synergies that have occurred as a result will greatly benefit the citizens of Winnipeg, and all Manitobans, through more streamlined operations. We are now, very literally, the one-stop energy services provider for all of Winnipeg and Manitoba.

The first nine corporate goals represented in the 2003/04 CSP are unchanged from last year and reflect a focus on managing effectively in today's business environment and being a responsible corporate citizen. The 2003/04 CSP also introduces the 10th corporate goal, which is to *"Be a leader in implementing cost-effective energy conservation and alternative energy programs."* This new goal provides more focus on our efforts to provide customers with a full spectrum of energy and energy conservation solutions. As a living document, the CSP also gives us the flexibility to succeed across a wide range of possible futures.

Through the basic commodities and services of electricity and natural gas, Manitoba Hydro is a vital contributor to all aspects of life in the province. I'm incredibly proud of our company and its achievements – I know the future promises to be an exciting and challenging one. I'm confident that our employees will continue to do what they've always done – take personal responsibility for their own contributions and embrace these new challenges head on.

Bob Brennan, President and CEO

VISION

To be recognized as the best utility in North America with respect to safety, rates, reliability, customer satisfaction, and environmental management, and to be considerate of all people with whom we have contact.

MISSION

To provide for the continuance of a supply of energy adequate for the needs of the province, to promote economy and efficiency in the development, generation, transmission, distribution, supply, and end-use of energy, and to market energy services within and outside the province.

OPERATING PRINCIPLES

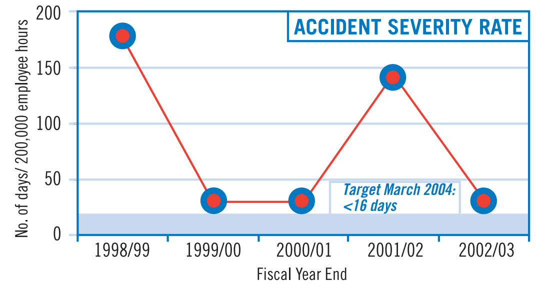
- Work together for the success of the organization as a whole, recognizing that all our activities are interrelated.
- Establish long-term, cooperative relationships with all employees, customers, suppliers, and other stakeholders, aimed at achieving our shared Vision.
- Create a working environment that removes barriers to effective performance and which fosters mutual respect, trust, and open communication.
- Provide opportunities for all employees to develop their full potential, recognizing people's inherent desire to do their best.
- Measure outcomes, develop an understanding of the causes of variation from planned performance, and take appropriate action.
- Practise continuous improvements through ongoing coaching, learning, and innovation, focused on the needs and wants of internal and external customers.

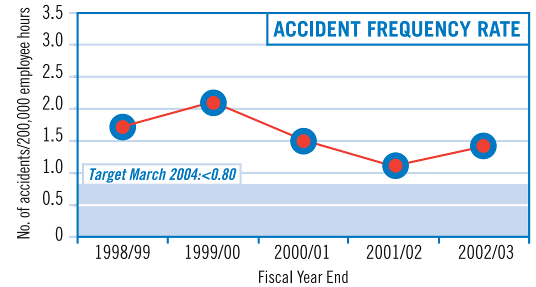
MANITOBA HYDRO GOAL

CONTINUOUSLY IMPROVE SAFETY IN THE WORK ENVIRONMENT

Safety continues to be the Corporation's first priority and most important goal. Manitoba Hydro is committed to protecting its employees from personal injury and occupational illness by providing and maintaining the highest standard of safety and health in the workplace. Safety programs are constantly being improved to provide employees with the most comprehensive direction and guidance to ensure a safe and hazard-free work environment.

MEASURE	TARGET	STRATEGIES
High-risk accidents	0	Ensure adherence to the Corporate-wide Safety Management System Implement the behaviour-based safety program
Accident severity rate	< 16.0 days per 200,000 hours worked	
Accident frequency rate	< 0.80 accidents per 200,000 hours worked	





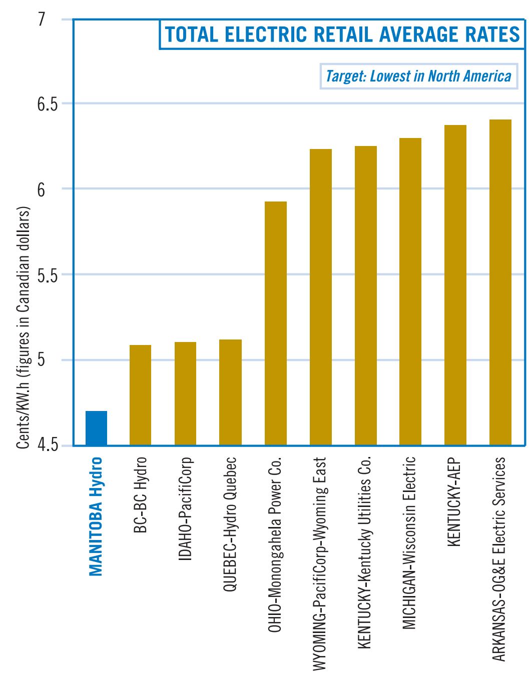
M A N I T O B A   H Y D R O   G O A L

PROVIDE CUSTOMERS WITH EXCEPTIONAL VALUE (rates, service, public safety, reliability, and power quality)

Manitoba Hydro has consistently maintained electrical rates among the lowest in North America while delivering environmentally friendly, renewable energy from its hydroelectric generation. The Corporation's public safety, reliability, and power quality continue to rank high among Canada's power supply leaders.

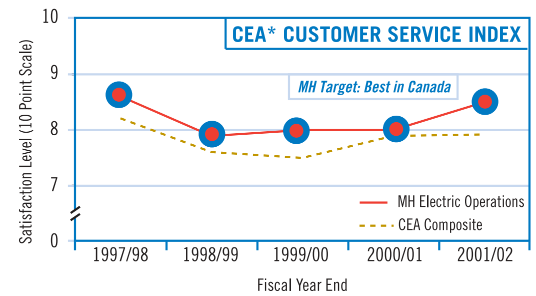
Since July 1999, Manitoba Hydro has been the province's major distributor of natural gas, providing safe, dependable natural gas service to more than 250,000 of its customers.

MEASURE	TARGET	STRATEGIES
Retail Rates: Electricity	Lowest in North America	Anticipate customer expectations and pursue opportunities to increase customer value and reduce costs
Retail Distribution Rates: Natural Gas	Among the lowest in North America	
Average Electric Customer Outage Time	≤ 92 minutes Cumulative Average (2000–04)	Develop energy marketing plan including energy options
Average Electric Customer Outage Frequency	≤ 1.3 per year Cumulative Average (2000–04)	Pursue expansion of economically feasible natural gas distribution
CEA Customer Service Index	Best in Canada	Develop natural gas commodity pricing products and service levels
Public Contacts (natural gas and electric)	20% injury reduction	Continue to deliver effective and innovative public safety programs that target safety issues with respect to the use of electricity and natural gas
Natural gas market share	100% of new franchises 60% of commodity sales by 2005	

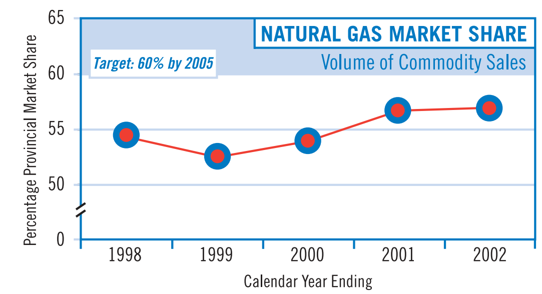


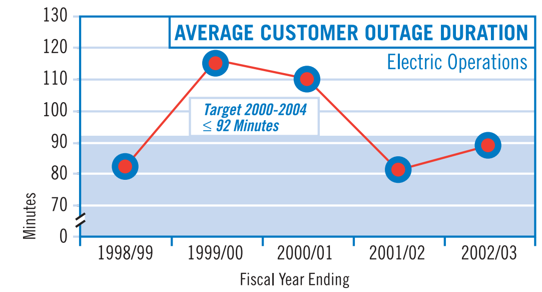
Ten lowest cost utilities in North America

Source: Edison Electric Institute, January 1, 2003



*Source: Canadian Electricity Association Public Attitudes Survey May 2002



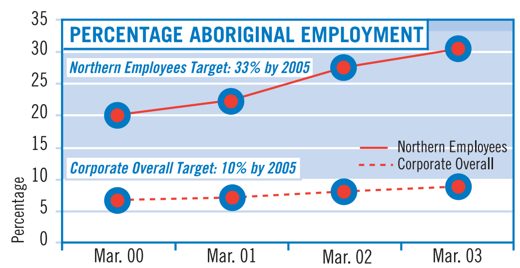


M A N I T O B A   H Y D R O   G O A L

BE A LEADER IN STRENGTHENING WORKING RELATIONSHIPS WITH ABORIGINAL PEOPLES

The commitment of Manitoba Hydro to strengthen its Aboriginal relationships provides critical leadership in the resource and corporate sector by identifying and supporting the positive capacity of the Aboriginal communities in Manitoba. A critical component of a company's competitive advantage lies with the strength and capabilities of its employees. A rapidly increasing Aboriginal labour force offers excellent opportunities to recruit Aboriginal employees at various levels throughout the Corporation.

MEASURE	TARGET	STRATEGIES
% of impacted Aboriginal communities with a workable management framework	100%	Coordinate the implementation of Aboriginal policies throughout the Corporation Resolve and manage ongoing obligations from past development Increase employment opportunities at Manitoba Hydro for Aboriginal peoples Continue to enhance training and support programs for Aboriginal employees Promote and pursue business relationships with Aboriginal companies and with companies who employ Aboriginal peoples
% Aboriginal Employment		
Corporate overall	10% by 2005	
Northern	33% by 2005	

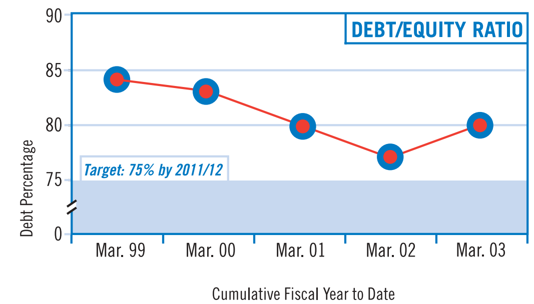


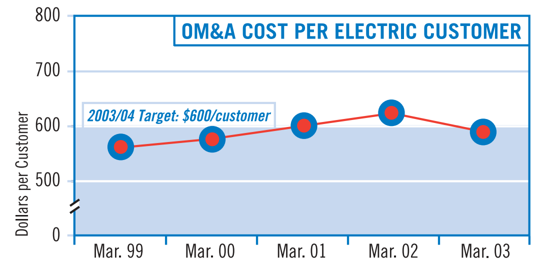
M A N I T O B A   H Y D R O   G O A L

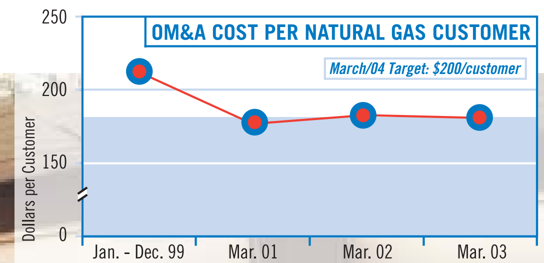
IMPROVE CORPORATE FINANCIAL STRENGTH

Achieving its financial targets is the key to economic well-being at Manitoba Hydro. Maintaining low rates and high reliability, while being responsive to new economic opportunities, are high priorities for the corporation.

MEASURE	TARGET	STRATEGIES
Interest Coverage	> 1.10	Continue to reduce the relative proportion of debt to fixed assets Implement corporate e-business opportunities Leverage technology to reduce costs Continue to achieve synergies associated with the acquisition of Winnipeg Hydro Improve productivity performance measurement Benchmark costs against other low-cost service providers Commence implementation of transfer pricing
Debt/equity ratio	75/25 by the year 2011/12	
Capital financing ratio	> 1.0	
Cost per customer (OM&A) – Electric	$600 per customer (March 2004)	
Cost per customer (OM&A) – Natural Gas	$200 per customer (March 2004)	





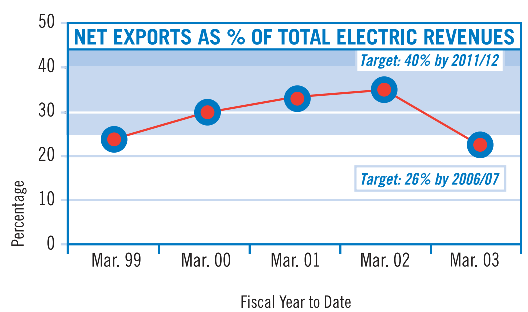


M A N I T O B A   H Y D R O   G O A L

MAXIMIZE EXPORT POWER NET REVENUES

Strong export revenues allow for low, reliable, electricity rates which benefit individuals and businesses in Manitoba by helping keep costs down. Low rates give Manitoba businesses a cost advantage over their competition in other provinces and countries.

MEASURE	TARGET	STRATEGIES
Net Export Revenue as a % of Total Electric Revenue	26% in 2006/07 40% in 2011/12	Aggressively pursue export sales and protect in-service dates for future plants Continue being a Canadian leader in U.S. market access Expand the transmission capacity to support export markets Influence international industry restructuring and maintain flexibility to adapt as appropriate Promote new hydro and/or transmission as part of the Canadian solution to climate change

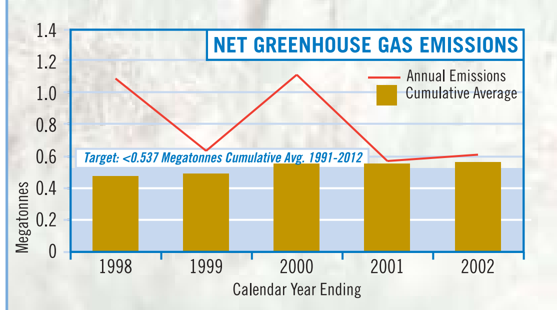


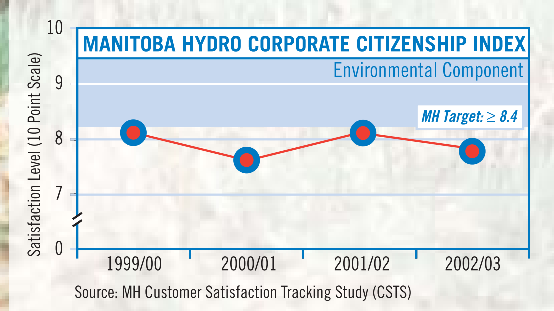
M A N I T O B A   H Y D R O   G O A L

HAVE HIGHLY SKILLED, EFFECTIVE, INNOVATIVE EMPLOYEES AND A DIVERSE WORKFORCE THAT REFLECTS THE DEMOGRAPHICS OF MANITOBA

Without the dedication, effort, and skill of a highly trained workforce none of our goals could be accomplished. The acquisitions of Centra Gas and Winnipeg Hydro have added to Manitoba Hydro's skilled group of energy professionals. Simply put, the staff at Manitoba Hydro are second to none and the utility continues to attract, develop, and retain skilled workers from the highly diverse population in Manitoba.

MEASURE	TARGET	STRATEGIES
Percentage of non-entry positions filled by external applicants	Range 8% – 12%	Continue staff development to cover key strategic and operational positions Recruit, develop and retain members of designated groups Ensure appropriate resource allocation to meet workload needs Encourage balanced approach to family, work, and community Enhance the employment recruitment strategy
Percentage of designated group members in Manitoba Hydro workforce	Women: 24% Women in Mgmt: 12% Women Professionals: 31% Persons with Disabilities: 4.6% Visible Minorities: 3.8%	





MANITOBA HYDRO GOAL

BE PROACTIVE IN PROTECTING THE ENVIRONMENT AND BE A RECOGNIZED LEADER IN DOING SO

Manitoba Hydro is committed to sustaining a diverse and healthy environment for present and future Manitobans by maintaining a high standard of environmental responsibility. The Corporation plans to integrate climate change management into its plans and operations. This is consistent with our environmental management policy and principles of sustainable development, including a practical preference for renewable resources, encouragement of efficient resource use and recognition of our global responsibility.

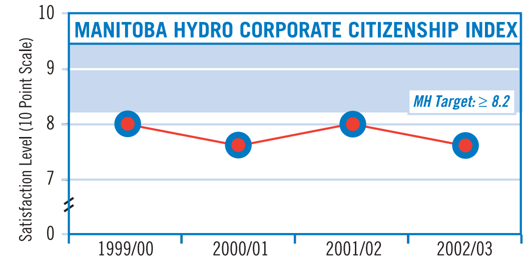
MEASURE	TARGET	STRATEGIES
Environmental component of CEA Customer Service Index	≥ 8.5	Complete and maintain ISO corporate certification Continue working to improve understanding of Manitoba Hydro environmental efforts by Manitobans and extra-provincial customers
Corporate Citizenship Index – environmental component	≥ 8.4	Continue to develop & implement a plan for compliance with anticipated changes in federal PCB regulation
Net Green House Gas Emissions	Cumulative annual average 1991–2012 6% below 1990 levels (< 0.537 megatonnes for electric and natural gas operations)	Continue to provide input in the development of new environmental regulatory requirements Ensure compliance with the requirements of the Sustainable Development Act Be a leader in contributing to effective climate change solutions
ISO 14001 Corporate Certification	Achieve & Maintain	Improve employee knowledge of environmental issues

MANITOBA HYDRO GOAL

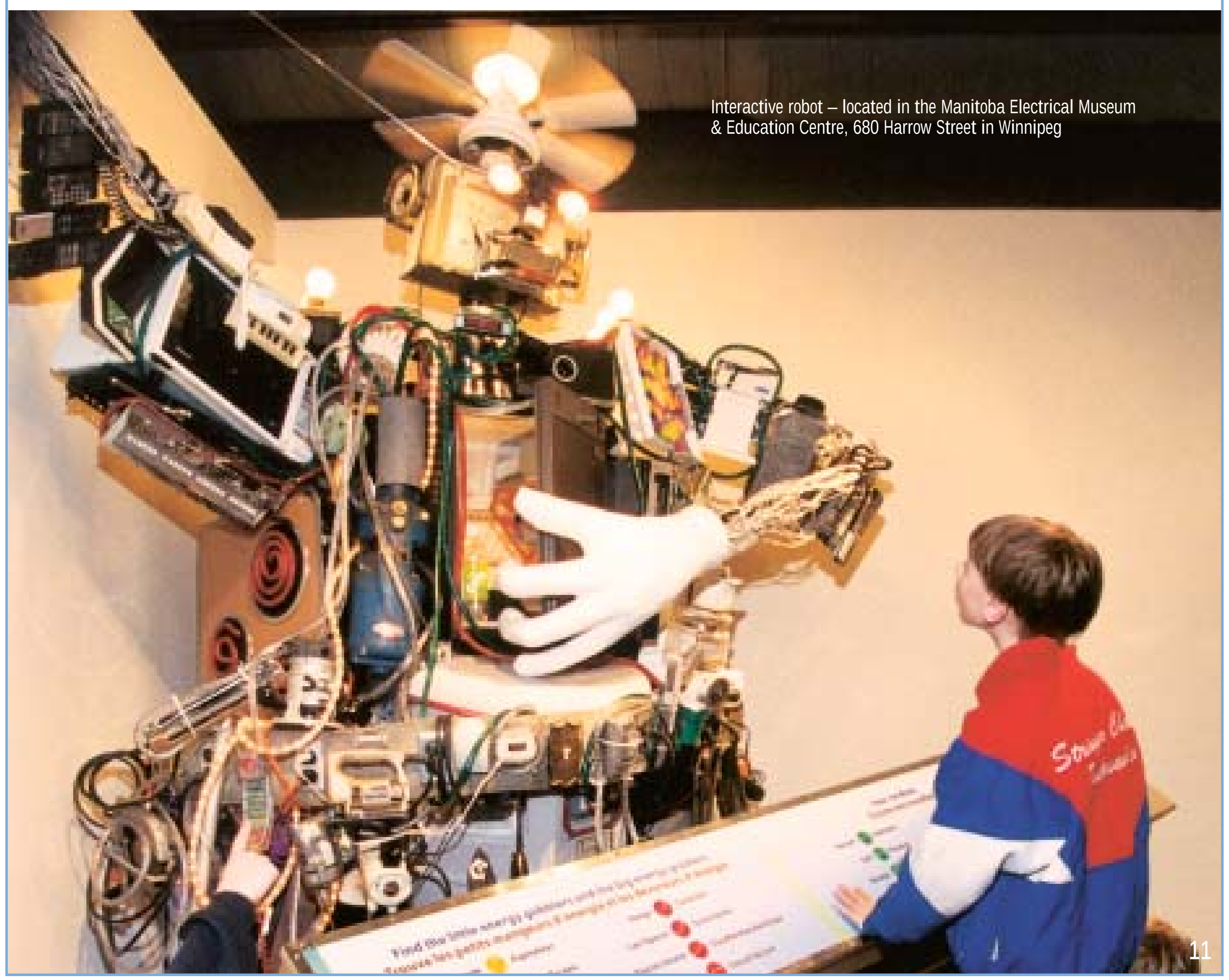
BE AN OUTSTANDING CORPORATE CITIZEN

As a corporate citizen, Manitoba Hydro is committed to making a positive contribution toward improving the quality of life enjoyed by Manitobans. Besides powering the province with electricity and providing natural gas services, Manitoba Hydro proudly supports public safety, education, sponsorship of events, and many community initiatives.

MEASURE	TARGET	STRATEGIES
CEA Public Attitude Index	≥ 8.5	Continue to take a leadership role in community activities and support programs
Manitoba Hydro Corporate Citizenship Index	≥ 8.2	Encourage and support staff participation in community activities Continue to deliver effective and innovative public education and safety programs



Main Street Murals – located at Manitoba Hydro's West Kildonan/ Semple Avenue Station in Winnipeg



Interactive robot – located in the Manitoba Electrical Museum & Education Centre, 680 Harrow Street in Winnipeg

MANITOBA HYDRO GOAL

PROACTIVELY SUPPORT AGENCIES RESPONSIBLE FOR BUSINESS DEVELOPMENT IN MANITOBA

As a world leader in harnessing hydroelectric resources, Manitoba Hydro works together with government and the private sector to create an economic environment that is conducive to developing new ideas and ways of doing business.

MEASURE	TARGET	STRATEGIES
Agency satisfaction	100% satisfied	Be proactive in working with economic development agencies to maximize wealth and jobs in Manitoba for each new MW of industrial demand Partner with customers with respect to their energy cost structures and productivity

MANITOBA HYDRO GOAL

BE A LEADER IN IMPLEMENTING COST EFFECTIVE ENERGY CONSERVATION AND ALTERNATIVE ENERGY PROGRAMS

Whether you have natural gas, electricity, or both, being Power Smart* saves you money. Manitoba Hydro programs provide a broad array of educational materials, ranging from how to retrofit a home to energy efficient products and practices. These programs also provide financial assistance to customers making home efficiency improvements. Hydro also works with commercial and industrial customers to improve their electrical and gas energy efficiency and their business processes.

Manitoba Hydro is undertaking initiatives to address opportunities provided by emerging energy related technologies. Alternative energy programs will provide new economic opportunities to provide energy resources in a cost-effective way.

*Manitoba Hydro is a licensee of the official mark.

MEASURE	TARGET	STRATEGIES
DSM – GW.h saved	600 GW.h/yr by March 2004	Aggressively promote Power Smart programs Determine feasibility and economics of wind generating technology in Manitoba Work with potential Independent Power Producers (IPPs) and customers to encourage development of economic alternate energy sources Continue to research and monitor technological and economical developments in all energy related technologies
DSM – MW saved (at winter peak)	200 MW by March 2004	
Alternative Capacity Installed (or delivered)	Under review	

Close-up of a modern utility scale wind turbine, consisting of a tower, rotor, and nacelle

Blue flame from a natural gas burner

820 Taylor Avenue | P.O. Box 815 | Winnipeg, Manitoba, Canada
TEL: 204.474.4169 | FAX: 204.474.4276 | www.hydro.mb.ca

CCC/NFAAT/S/13

Provide Nisichawayasihk Cree Nation Newsletter #4

Nisichawayasihk Cree Nation Newsletter #4 is attached. (see CCC/NFAAT/S/11 for comparison)

PROPOSED WUSKWATIM GENERATION AND TRANSMISSION PROJECTS

Newsletter #4

- Fourth Round of Public Involvement -

Round Four of public consultation and involvement for the Wuskwatim Generation Project and Wuskwatim Transmission Project addresses the Wuskwatim submissions recently filed with provincial and federal regulators by Manitoba Hydro and the Nisichawayasihk Cree Nation (NCN).

The Wuskwatim Generation Project involves development of a 200 megawatt generating station at Taskinigup Falls on the Burntwood River, and associated access road, construction camp and other infrastructure. The Generation Project is located in the Nelson House Resource Management Area (RMA) southwest of Thompson and southeast of Nelson House. Manitoba Hydro and NCN selected a design for the Project that minimizes the effects on the environment (e.g., selection of a "low head" design).

A separate project, the Wuskwatim Transmission Project, involves development of associated transmission lines and stations to connect the new generating station to the existing Manitoba Hydro transmission system. These transmission facilities extend beyond the Nelson House RMA to Thompson, Snow Lake and The Pas.

Power from the Wuskwatim Generation Project will be available in 2009, several years ahead of projected domestic power needs for Manitobans. By advancing the in-service date from about 2020 to 2009, additional export revenues and profits are possible. The Project will also contribute to reliable power supply for Manitobans, which will be available if domestic growth is higher than expected.

An important feature of the projects has been the involvement of NCN. NCN and Manitoba Hydro have jointly undertaken all of the necessary engineering, environmental, consultation and other related activities associated with the projects. A decision about whether to commence construction of the Wuskwatim projects is expected to be made in December 2003.

Provincial and federal regulatory approvals are needed before any decision to construct can be made. In addition, the Government of Manitoba has requested a "Need For and Alternatives To" review of Manitoba Hydro's proposal to construct and develop the Wuskwatim Generating Station and associated transmission facilities.

No decisions will be made to proceed with the Project pursuant to the current environmental applications until a Project Development Agreement has been completed, voted upon by NCN members, and approved both by NCN and Manitoba Hydro, which is expected by mid-October 2003.

Since the last round of public involvement during mid-winter, separate Environmental Impact Statements (EISs) for the Wuskwatim Generation Project and Wuskwatim Transmission Project have been prepared, as well as a report that considers the need for and alternatives to the Wuskwatim Project. The Government of Manitoba has provided a Terms of Reference to the Clean Environment Commission (CEC) to conduct a public review of these documents.

Further information on the projects and the conclusions from the submissions are summarized in the Integrated Executive Summary of the Environmental Impact Statements and the Project Overview of the *Need for and Alternatives to* report. An overview of the submission documents is provided in this Newsletter.

What Information has been Filed with Governments?

On April 30, 2003, three separate submissions were made to the federal and provincial regulators:

- Manitoba Hydro submitted the report Submission to the Manitoba Clean Environment Commission: *Need for and Alternatives to the Wuskwatim Project.* This report talks about the reasons that the Wuskwatim Generation Project was selected instead of other alternatives for generating power. The report includes a main volume and a supporting volume.
- Manitoba Hydro and NCN together submitted the report *Wuskwatim Generation Project* - Environmental Impact Statement. This report describes the Project in detail and talks about the anticipated effects of the proposed Generation Project on the physical and biological environment, as well as on people, and includes methods to reduce adverse effects and improve positive effects. It also talks about the effects of this project in combination with others (cumulative effects). The report is large - in addition to the main volume of more than 600 pages, there are 9 supporting volumes covering:
    - Public Consultation and Involvement (Volume 2)
    - Project Description and Evaluation of Alternatives (Volume 3)
    - Physical Environment (Volume 4)
    - Aquatic Environment (Volume 5)
    - Terrestrial Environment (Volume 6)
    - Resource Use (Volume 7)
    - Socio-Economic Environment (Volume 8)
    - Heritage Resources (Volume 9)
    - Cumulative Effects Assessment (Volume 10)
- Manitoba Hydro submitted the report *Wuskwatim Transmission Project* - Environmental Impact Statement. This report describes the Project in detail and talks about the anticipated effects of the proposed Transmission Project on the physical and biological environment, as well as on people, and includes methods to reduce adverse effects and improve positive effects. The report also describes the process through which the routes for the transmission lines were selected, and reviews effects of this project in combination with other projects (cumulative effects). This report is large as well - in addition to the main volume of more than 500 pages, there are 7 supporting volumes covering:
    - Terrain Analysis and Ecological Land Classification (Volume 2)
    - Aquatic Environment (Volume 3)
    - Wildlife Environment (Volume 4)
    - Forestry and Vegetation Environment (Volume 5)
    - Land and Resource Use (Volume 6)
    - Socio-Economic Environment (Volume 7)
    - Heritage Resources (Volume 8)

An Integrated Executive Summary covering the Environmental Impact Statements for both the Generation and Transmission Projects was included in each report, as was a Cree Translation of a PowerPoint presentation based on the Executive Summary.

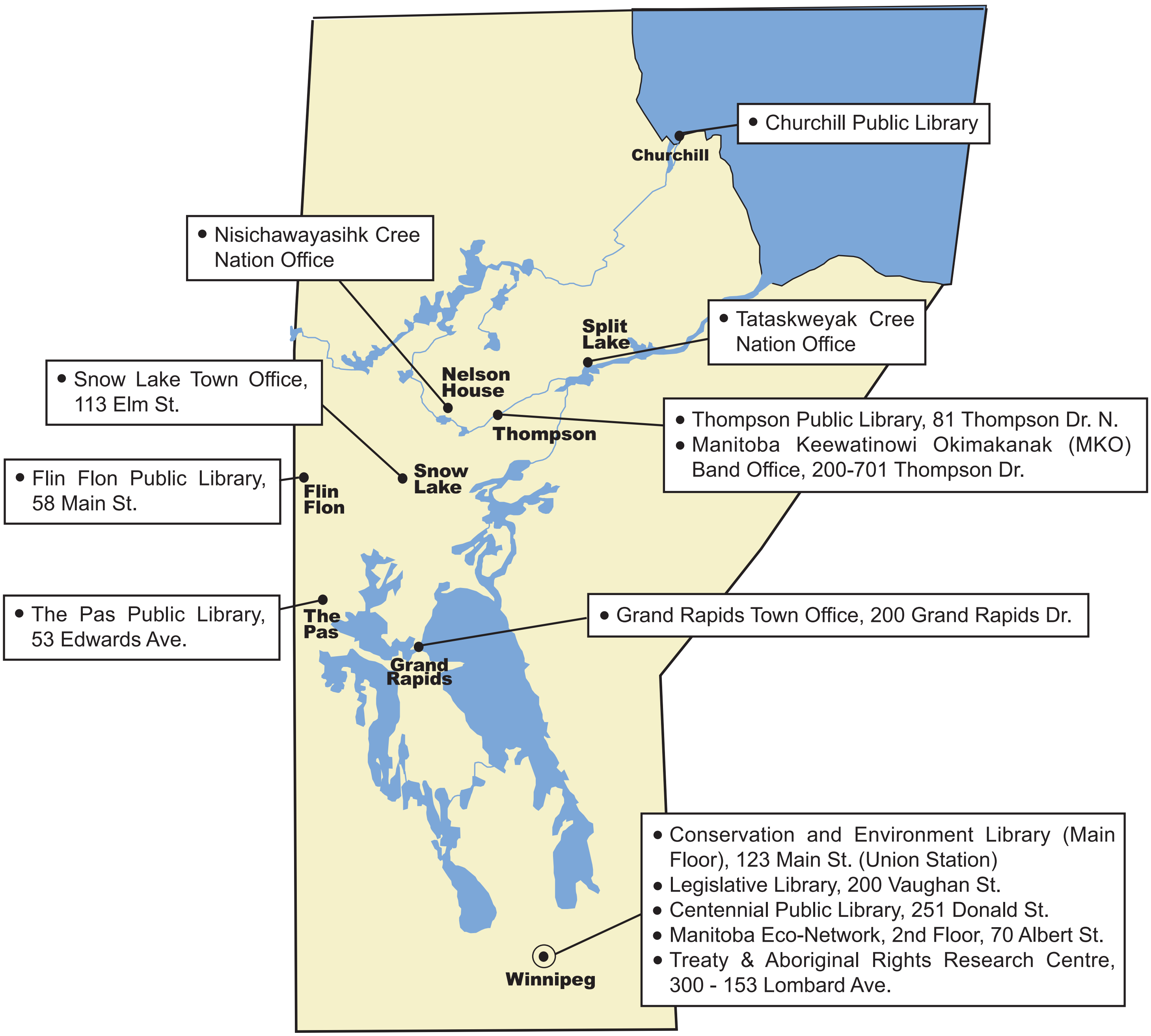
The proposed Wuskwatim Generating Station will be located at Taskinigup Falls (shown at right - looking downstream from the Falls) near the outlet of Wuskwatim Lake in the Nelson House Resource Management Area.

Where Can These Reports be Seen?

All of these reports are available in Manitoba Conservation's Public Registries, as shown in the map below.

The main report for each of the three submissions can also be seen on Manitoba Hydro's Web site (www.hydro.mb.ca/wuskwatim). The Integrated EIS Executive Summary and Cree Translation are also included there. A CD of all documents can be ordered through the web site.

Location of Manitoba Conservation Public Registries where reports on the Wuskwatim Projects can be viewed



What's Ahead?

Next steps in the Wuskwatim Projects include:

- The Manitoba Government has placed the submissions on the public registry for an initial 60 day public review period. Anyone who wishes to provide comments on the EISs for the Wuskwatim Proposals, and/or the Need and Alternatives Submissions, should contact Manitoba Conservation in writing or by E-mail no later than June 30, 2003. Comments can be submitted in writing to Mr. Trent Hreno at Manitoba Conservation, Suite 160, 123 Main St., Winnipeg, Manitoba R3C 1A5 (tel: (204) 945-7080); or by email at threno@gov.mb.ca.
- After consideration of all submissions, Manitoba Conservation will provide comments, questions and deficiencies to Manitoba Hydro and NCN. Shortly thereafter, Manitoba Hydro and NCN will file the necessary supplemental information requested by Manitoba Conservation.
- Following submission of supplementary information, Round Five of public consultation and involvement will focus on communicating the supplemental information to parties directly interested in the materials.
- The timing of the CEC public hearings will be determined in the next few months, probably to occur in the Fall of 2003. The terms of reference of this hearing have been provided to the CEC by the Minister (see CEC web site at www.cecmanitoba.ca).
- Final licensing authorizations are anticipated near the end of 2003.

Further information about the Wuskwatim Projects can be found on Manitoba Hydro's Web site at:

www.hydro.mb.ca/wuskwatim

How to Contact Us

We invite your questions and comments about the Wuskwatim Projects or what's ahead in the Public Involvement Plan program. Please contact us:

Nick Barnes (Manitoba Hydro; Generation Project)
(204) 474-3999 (phone) 474-4543 (fax)

Ron Rawluk (Manitoba Hydro; Transmission Project)
(204) 474-3119 (phone) 474-4974 (fax)

Norman Linklater (NCN Future Development)
(204) 484-3019 (phone) 484-2980 (fax)

Marcel Moody (NCN Future Development)
(204) 484-3018 (phone) 484-2980 (fax)

CCC/NFAAT/S/14

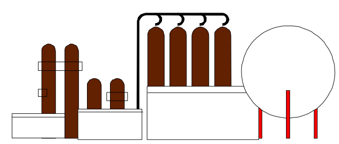
Provide current Economic Outlook 2003 2004

The Economic Outlook 2003 2004 attached. (see CCC/NFAAT/S/11 for comparison)

CCC/NFAAT/S/14

Economic Outlook

2003 - 2024



Manitoba Hydro

Economic Analysis Department
Spring, 2003
EO03-1

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Preface

The objective of this annual forecast is to provide a set of economic parameters for corporate use.

This information is used in several areas of the corporation; for example, in load forecasting, project evaluation, and financial planning.

The document is derived from a variety of sources, including forecasts from Global Insight, the Conference Board of Canada, Consensus Forecasts, Manitoba Bureau of Statistics, several financial and banking institutions such as Bank of Montreal, CIBC, Royal Bank, Scotiabank and TD Bank. As a final step prior to publication, the forecast is refined to reflect information available in early spring.

This forecast is based on what was known and could reasonably be foreseen at the time of its preparation. Users should be cognizant that conditions can and do change and should apply sensitivity analysis accordingly.

The variables are presented in both calendar year and fiscal year format. Fiscal year data have been derived from the calendar year data. Fiscal year data which conform with data found in G911 are presented on pages 1 to 4 following. The balance of the text relates to calendar year information.

Executive Summary - Base Case

Fiscal Year

MANITOBA	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	
Real GDP (%)	3.1	3.1	2.9	2.4	2.0	2.0	1.9	1.8	*
CPI (%)	2.3	2.9	2.4	2.0	2.0	2.0	2.0	2.0	& on
Population (000's)	1,152	1,155	1,159	1,162	1,165	1,169	1,172	1,175	*
Residential Customers (000's)	338	340	343	344	346	348	350	352	*
Unemployment Rate (%)	5.1	5.0	5.0	5.0	5.0	4.9	4.9	4.9	*

*for 2010/11 and beyond, see page 3

CANADA	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	
Real GDP (%)	3.3	3.2	3.2	3.0	3.0	3.0	3.0	3.0	**
CPI (%)	3.0	3.3	2.4	2.0	2.0	2.0	2.0	2.0	& on
90 Day T-Bill (%)	2.79	3.75	4.50	4.50	4.50	4.50	4.50	4.50	& on
GOC 10Yr+ Rate (%)	5.58	5.65	6.00	6.00	6.00	6.00	6.00	6.00	& on
U.S. Exchange Rate (C$/US$)	1.55	1.48	1.47	1.46	1.45	1.44	1.44	1.43	**
Unemployment Rate (%)	7.6	7.2	7.1	7.0	6.9	6.8	6.7	6.6	**

**for 2010/11 and beyond, see page 4

USA	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	
Real GNP (%)	2.6	3.0	3.4	3.0	3.0	3.0	3.0	3.0	
CPI (%)	2.0	2.3	2.3	2.5	2.5	2.5	2.5	2.5	& on
GDP Deflator (%)	1.20	1.65	2.05	2.25	2.25	2.30	2.50	2.50	& on
90 Day T-Bill (%)	1.46	1.80	3.05	4.00	4.15	4.50	4.50	4.50	& on
Long Term Bond Rate (%)	4.29	4.90	5.40	5.75	5.75	5.75	5.75	5.75	& on
Unemployment Rate (%)	5.0	5.6	5.4	5.2	5.2	5.0	5.0	5.0	& on

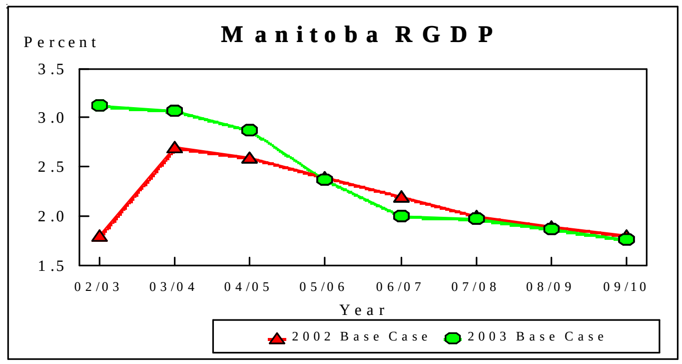
Manitoba Hydro Key Variables

Changes from Previous Forecast

RGDP (%)*

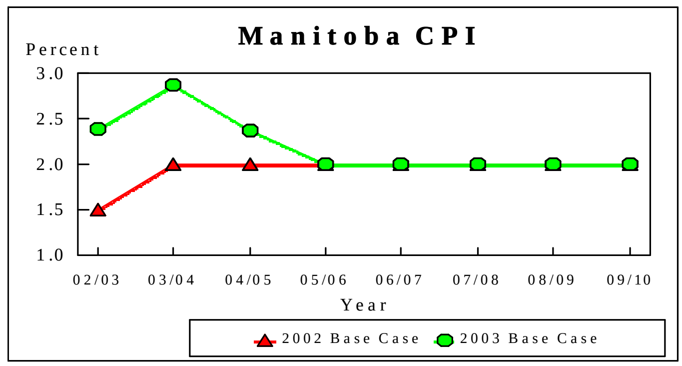
Fiscal Year	2002 Base Case		2003 Base Case
01/02	1.5		1.9
02/03	1.8		3.1
03/04	2.7		3.1
04/05	2.6		2.9
05/06	2.4		2.4
06/07	2.2		2.0
07/08	2.0		2.0
08/09	1.9		1.9
09/10	1.8		1.8

*for 10/11 and beyond, see page 3



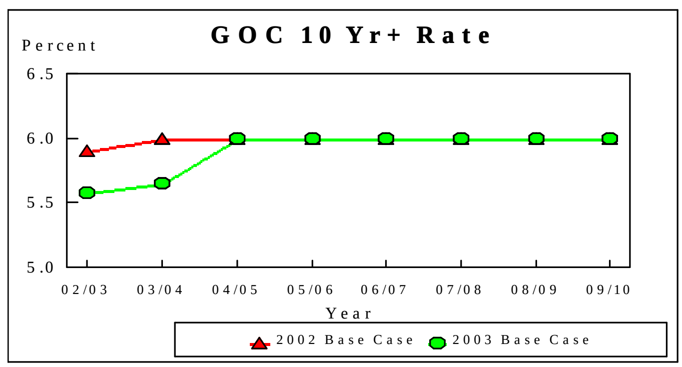
CPI - Inflation (%)

Fiscal Year	2002 Base Case		2003 Base Case
01/02	2.15		2.1
02/03	1.50		2.3
03/04	2.00		2.9
04/05	2.00		2.4
05/06	2.00		2.0
06/07	2.00		2.0
07/08	2.00		2.0
08/09	2.00		2.0
09/10 & on	2.00		2.0



GOC 10 Yr+ Rate (%)

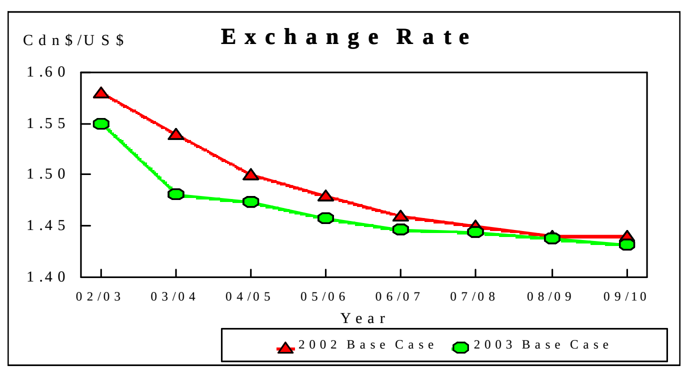
Fiscal Year	2002 Base Case		2003 Base Case
01/02	5.81		5.81
02/03	5.75		5.58
03/04	5.90		5.65
04/05	6.00		6.00
05/06	6.00		6.00
06/07	6.00		6.00
07/08	6.00		6.00
08/09	6.00		6.00
09/10 & on	6.00		6.00



Foreign Exchange (Cdn$/U.S.$)**

Fiscal Year	2002 Base Case		2003 Base Case
01/02	1.57		1.57
02/03	1.58		1.55
03/04	1.54		1.48
04/05	1.50		1.47
05/06	1.48		1.46
06/07	1.46		1.45
07/08	1.45		1.44
08/09	1.44		1.44
09/10	1.44		1.43

**for 10/11 and beyond, see page 4



Manitoba Economic Statistics

Year	Population '000	Population %	Unempl. Rate %	Real GDP 97$m	Real GDP %	CPI 92=100	CPI %	M.H. Res. Cus. '000
1978/79	1,040	0.7	6.3	21,256	1.4	46.2	8.7	256
1979/80	1,037	-0.3	5.3	21,256	0.0	50.5	9.4	263
1980/81	1,035	-0.2	5.5	21,776	2.4	55.6	10.1	262
1981/82	1,039	0.4	6.6	22,729	4.4	61.6	10.8	265
1982/83	1,050	1.1	8.6	22,703	-0.1	66.7	8.3	266
1983/84	1,064	1.3	9.4	23,349	2.8	70.8	6.0	271
1984/85	1,074	1.0	8.7	24,748	6.0	73.1	3.3	277
1985/86	1,085	0.9	8.2	25,455	2.9	76.4	4.5	281
1986/87	1,093	0.8	7.6	26,304	3.3	79.7	4.3	288
1987/88	1,099	0.5	7.4	26,547	0.9	83.0	4.2	295
1988/89	1,102	0.3	7.5	26,734	0.7	86.6	4.4	300
1989/90	1,104	0.1	7.3	27,368	2.4	90.7	4.7	304
1990/91	1,107	0.2	7.6	27,576	0.8	95.2	4.9	307
1991/92	1,110	0.3	8.8	26,629	-3.4	98.8	3.8	309
1992/93	1,114	0.4	9.4	26,710	0.3	100.7	1.8	311
1993/94	1,120	0.5	9.3	27,126	1.6	103.1	2.4	314
1994/95	1,125	0.5	8.1	27,909	2.9	104.7	1.6	317
1995/96	1,131	0.5	7.2	28,289	1.4	107.3	2.5	320
1996/97	1,135	0.4	6.9	29,094	2.8	110.0	2.5	322
1997/98	1,137	0.2	6.2	30,071	3.4	111.8	1.6	325
1998/99	1,139	0.2	5.5	31,155	3.6	113.4	1.4	328
1999/00	1,144	0.4	5.4	31,774	2.0	116.0	2.3	331
2000/01	1,147	0.3	4.8	32,465	2.2	118.9	2.5	333
2001/02	1,150	0.3	5.0	33,095	1.9	121.4	2.1	335
2002/03	1,152	0.2	5.1	34,127	3.1	124.2	2.3	338
Forecast								
2003/04	1,155	0.3	5.0	35,177	3.1	127.8	2.9	340
2004/05	1,159	0.3	5.0	36,187	2.9	130.8	2.4	343
2005/06	1,162	0.3	5.0	37,046	2.4	133.4	2.0	344
2006/07	1,165	0.3	5.0	37,787	2.0	136.1	2.0	346
2007/08	1,169	0.3	4.9	38,533	2.0	138.8	2.0	348
2008/09	1,172	0.3	4.9	39,252	1.9	141.6	2.0	350
2009/10	1,175	0.3	4.9	39,943	1.8	144.4	2.0	352
2010/11	1,178	0.3	4.9	40,648	1.8	147.3	2.0	354
2011/12	1,181	0.3	4.9	41,336	1.7	150.3	2.0	356
2012/13	1,184	0.3	4.8	41,989	1.6	153.3	2.0	358
2013/14	1,187	0.3	4.7	42,672	1.6	156.3	2.0	360
2014/15	1,190	0.2	4.6	43,356	1.6	159.5	2.0	361
2015/16	1,193	0.2	4.5	44,041	1.6	162.6	2.0	363
2016/17	1,196	0.2	4.5	44,728	1.6	165.9	2.0	365
2017/18	1,198	0.2	4.4	45,416	1.5	169.2	2.0	367
2018/19	1,201	0.2	4.3	46,107	1.5	172.6	2.0	369
2019/20	1,203	0.2	4.2	46,799	1.5	176.0	2.0	371
2020/21	1,206	0.2	4.1	47,495	1.5	179.6	2.0	372
2021/22	1,208	0.2	4.0	48,192	1.5	183.2	2.0	374
2022/23	1,210	0.2	3.9	48,893	1.5	186.8	2.0	376
2023/24	1,212	0.2	3.8	49,595	1.4	190.6	2.0	377

Canada Economic Statistics

Year	Real GDP 97$b	Real GDP %	CPI 92=100	CPI %	90 Day TBill Rate %	GOC 10 Yr+ Rate %	Unempl. Rate %	Cdn$/ US$
1978/79	560	4.1	44.6	9.0	9.54	9.46	8.2	1.15
1979/80	579	3.5	48.8	9.3	12.50	10.95	7.5	1.17
1980/81	589	1.7	54.0	10.6	13.45	12.59	7.5	1.18
1981/82	596	1.2	60.6	12.2	17.21	15.73	8.5	1.20
1982/83	587	-1.5	66.5	9.8	12.32	13.40	11.2	1.24
1983/84	608	3.5	70.0	5.2	9.49	11.92	11.8	1.24
1984/85	641	5.5	72.8	4.0	11.15	12.60	11.1	1.32
1985/86	668	4.2	75.8	4.1	9.52	10.58	10.3	1.38
1986/87	687	2.9	78.9	4.1	8.06	9.27	9.4	1.37
1987/88	718	4.4	82.3	4.4	8.47	10.15	8.6	1.31
1988/89	749	4.4	85.7	4.1	10.26	10.37	7.7	1.21
1989/90	764	2.0	90.2	5.2	12.33	9.95	7.7	1.18
1990/91	761	-0.4	94.8	5.0	12.07	10.72	8.7	1.16
1991/92	751	-1.4	98.9	4.4	8.02	9.53	10.6	1.15
1992/93	760	1.2	100.5	1.6	6.09	8.59	11.3	1.23
1993/94	783	3.0	102.0	1.5	4.46	7.62	11.0	1.31
1994/95	816	4.3	102.4	0.4	6.46	9.01	10.2	1.38
1995/96	837	2.5	104.6	2.1	6.17	7.95	9.6	1.36
1996/97	856	2.3	106.4	1.7	3.68	7.31	9.6	1.36
1997/98	892	4.2	107.8	1.4	3.62	6.09	9.0	1.40
1998/99	931	4.4	108.9	0.9	4.81	5.37	8.1	1.50
1999/00	979	5.2	111.2	2.2	4.82	5.91	7.4	1.47
2000/01	1,016	3.7	114.3	2.8	5.42	5.78	6.9	1.50
2001/02	1,036	2.0	116.9	2.2	3.10	5.81	7.3	1.57
2002/03	1,071	3.3	120.3	3.0	2.79	5.58	7.6	1.55
Forecast								
2003/04	1,104	3.2	124.2	3.3	3.75	5.65	7.2	1.48
2004/05	1,140	3.2	127.2	2.4	4.50	6.00	7.1	1.47
2005/06	1,174	3.0	129.7	2.0	4.50	6.00	7.0	1.46
2006/07	1,209	3.0	132.3	2.0	4.50	6.00	6.9	1.45
2007/08	1,246	3.0	135.0	2.0	4.50	6.00	6.8	1.44
2008/09	1,283	3.0	137.7	2.0	4.50	6.00	6.7	1.44
2009/10	1,322	3.0	140.4	2.0	4.50	6.00	6.6	1.43
2010/11	1,360	2.9	143.2	2.0	4.50	6.00	6.5	1.43
2011/12	1,398	2.7	146.1	2.0	4.50	6.00	6.4	1.42
2012/13	1,435	2.7	149.0	2.0	4.50	6.00	6.2	1.41
2013/14	1,471	2.5	152.0	2.0	4.50	6.00	6.1	1.40
2014/15	1,508	2.5	155.0	2.0	4.50	6.00	6.0	1.40
2015/16	1,546	2.5	158.2	2.0	4.50	6.00	5.9	1.39
2016/17	1,584	2.5	161.3	2.0	4.50	6.00	5.8	1.38
2017/18	1,623	2.4	164.5	2.0	4.50	6.00	5.7	1.38
2018/19	1,659	2.3	167.8	2.0	4.50	6.00	5.6	1.37
2019/20	1,697	2.3	171.2	2.0	4.50	6.00	5.5	1.36
2020/21	1,735	2.3	174.6	2.0	4.50	6.00	5.4	1.36
2021/22	1,774	2.3	178.1	2.0	4.50	6.00	5.3	1.35
2022/23	1,814	2.3	181.7	2.0	4.50	6.00	5.1	1.34
2023/24	1,855	2.2	185.3	2.0	4.50	6.00	5.0	1.34

Executive Summary - Base Case

Calendar Year

MANITOBA	2002	2003	2004	2005	2006	2007	2008	2009	
Real GDP (%)	3.1	3.1	3.0	2.5	2.0	2.0	1.9	1.8	*
CPI (%)	1.6	3.0	2.5	2.0	2.0	2.0	2.0	2.0	& on
Population (000's)	1,151	1,154	1,158	1,161	1,165	1,168	1,171	1,174	*
Residential Customers (000's)	336	339	341	343	345	347	349	350	*
Unemployment Rate (%)	5.2	5.0	5.0	5.0	5.0	5.0	4.9	4.9	*

*for 2010 and on, see page 21

CANADA	2002	2003	2004	2005	2006	2007	2008	2009	
Real GDP (%)	3.4	3.1	3.3	3.0	3.0	3.0	3.0	3.0	**
CPI (%)	2.2	3.5	2.5	2.0	2.0	2.0	2.0	2.0	& on
90 Day TBill (%)	2.59	3.50	4.50	4.50	4.50	4.50	4.50	4.50	& on
GOC 10 Yr+ Rate (%)	5.66	5.50	6.00	6.00	6.00	6.00	6.00	6.00	& on
U.S. Exchange Rate (C$/US$)	1.57	1.48	1.48	1.46	1.45	1.44	1.44	1.43	**
Unemployment Rate (%)	7.7	7.2	7.1	7.0	6.9	6.8	6.7	6.6	**

**for 2010 and on, see page 22

USA	2002	2003	2004	2005	2006	2007	2008	2009	
Real GNP (%)	2.4	2.8	3.5	3.0	3.0	3.0	3.0	3.0	& on
CPI (%)	1.6	2.3	2.3	2.5	2.5	2.5	2.5	2.5	& on
GDP Deflator (%)	1.14	1.50	2.00	2.25	2.25	2.25	2.50	2.50	& on
90 Day TBill (%)	1.60	1.50	2.75	4.00	4.00	4.50	4.50	4.50	& on
Long Term Bond Rate (%)	4.61	4.75	5.25	5.75	5.75	5.75	5.75	5.75	& on
Unemployment Rate (%)	5.8	5.7	5.4	5.2	5.2	5.0	5.0	5.0	& on

Manitoba Hydro Key Variables

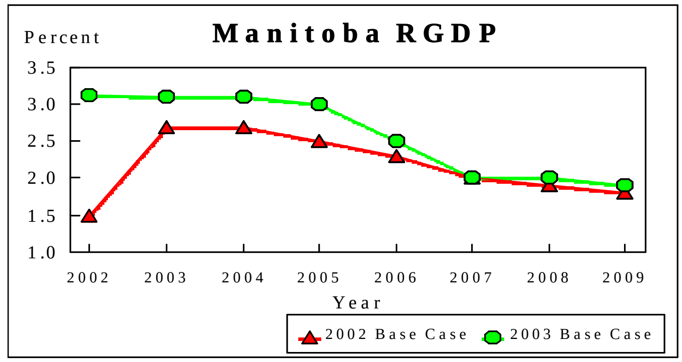
Changes from Previous Forecast

Calendar Year	2002 Base Case		2003 Base Case

RGDP (%)*

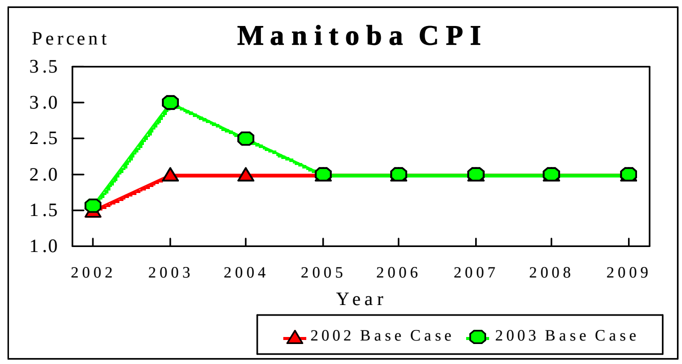
2002	1.5		3.1
2003	2.7		3.1
2004	2.7		3.0
2005	2.5		2.5
2006	2.3		2.0
2007	2.0		2.0
2008	1.9		1.9
2009	1.8		1.8

*for 2010 and beyond, see page 21



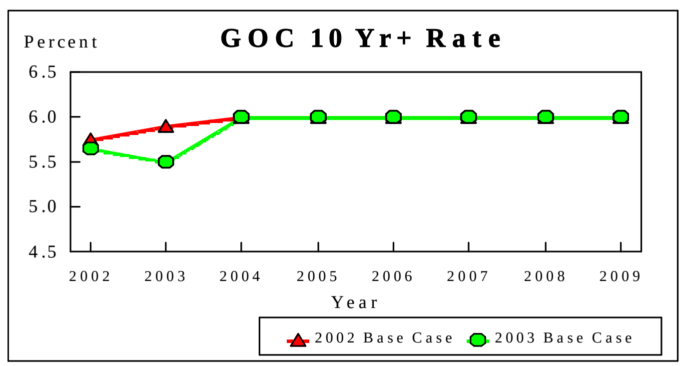
CPI - Inflation (%)

2002	1.50		1.6
2003	2.00		3.0
2004	2.00		2.5
2005	2.00		2.0
2006	2.00		2.0
2007	2.00		2.0
2008	2.00		2.0
2009	2.00		2.0



GOC 10yr+ Rate (%)

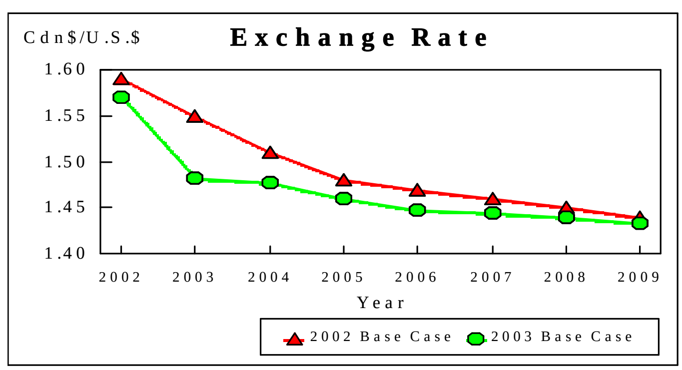
2002	5.75		5.66
2003	5.90		5.50
2004	6.00		6.00
2005	6.00		6.00
2006	6.00		6.00
2007	6.00		6.00
2008	6.00		6.00
2009	6.00		6.00



Foreign Exchange (Cdn$/U.S.$)**

2002	1.59		1.57
2003	1.55		1.48
2004	1.51		1.48
2005	1.48		1.46
2006	1.47		1.45
2007	1.46		1.44
2008	1.45		1.44
2009	1.44		1.43

**for 2010 and beyond, see page 22



Highlights

Executive Summary

The Manitoba economy grew by 3.1% in 2002, and is expected to grow by 3.1% in 2003 and 3.0% in 2004. In the long term, the economy is expected to grow at similar rates to last year's forecast. Long term forecasts are based on annual productivity growth and anticipated employment growth. The economy is expected to grow: 2.5% by the year 2005, 1.8% by 2010, 1.6% by 2015, and 1.4% by 2024.

Consumer expenditures, particularly in durable goods, and government purchase of goods and services were the driving force behind Canada's real growth of 3.4% in 2002. Exports of goods and services increased only 0.8% as a result of a weakening U.S. economy while imports were also up 0.8%. The long term real growth for the Canadian economy is forecast to be 2.4%, down slightly from last year's forecast.

The Bank of Canada continues to target inflation at approximately 2.0% plus or minus 1.0%. In the medium to long term, price stability is expected to be maintained. The 2003 Economic Outlook forecasts a 2.00% long term inflation rate similar to the past four outlooks.

Manitoba Hydro's cost of new debt is calculated from the expected long-term Canadian government bond rate plus the provincial guarantee fee of 0.95% as well as an adjustment to reflect the difference in borrowing costs for Manitoba. The 2003 Economic Outlook forecasts GOC 10 year+ rate at 6.00%. The real interest rate will be 3.92%, similar to last year's forecast.

In the near term, the Canadian dollar is expected to improve from current levels of $1.5703 US to $1.51 US in 2003. In 2010, the exchange rate is forecast to be at the $1.43 US level based on lower Canadian inflation rates relative to the United States and $1.33 US by 2024. A lower Canadian inflation rate relative to the United States is the principal cause behind the Canadian dollar's relative improved performance in the long term.

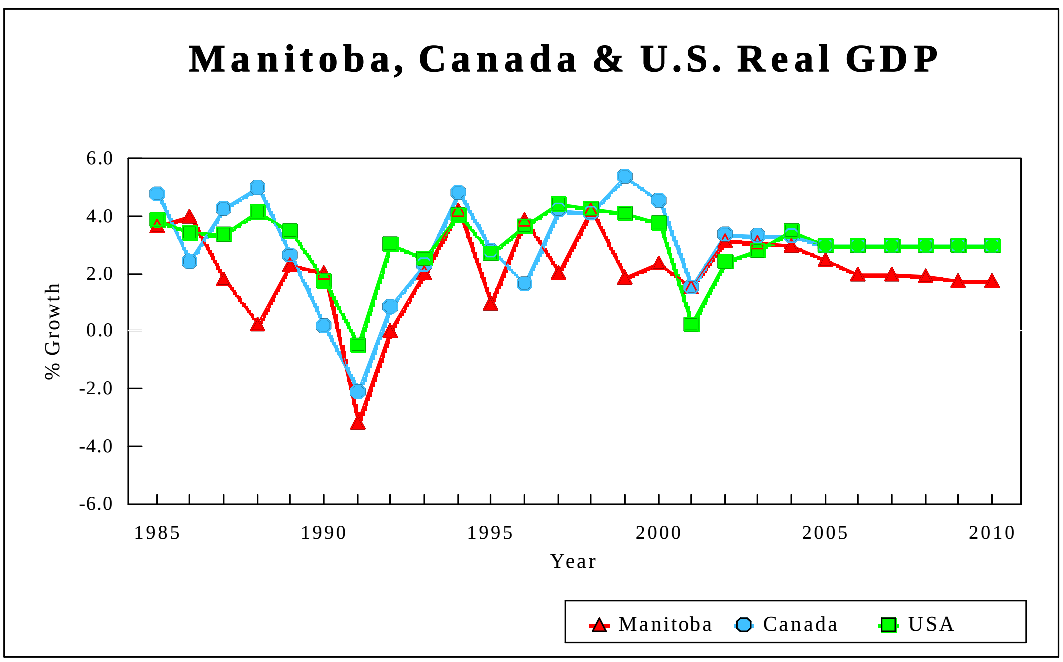
The Canadian unemployment rate is expected to trend towards 7.0% by the year 2005 and 5.0% in 2020 as a result of a slightly higher growth rate in employment compared to the growth rate in the labour force.

Uncertainties

What impact will the pending war have on the economy in general and on the price of oil in particular?

What will the cost of the Kyoto accord, ratified by Canada, be on the Canadian economy?

How will the U.S. fiscal and trade deficits impact the economic recovery?



2002 in Review

Manitoba and Canada

Consumption of goods and services and business and government investments helped sustain the Manitoba economy to grow at 3.1% real in 2002.

As a result of weak exports to the United States, manufacturing shipments in Manitoba increased moderately by 0.6% in 2002 over 2001 levels. Canada's shipments increased by 1.9% over the same period. Increases in Manitoba shipments were experienced in agricultural products and the energy sector as well as manufacturing products compared to 2001.

The Manitoba population grew at an annual rate of 0.15% in 2002, down from a revised growth of 0.23% in 2001.

Manitoba housing starts were up 22.1% to 3,617 units in 2002 from 2,963 units in 2001. Single housing units were up 22.6% to 3,016 while multiple units were up 19.5% to 601 for the same period.

Manitoba's retail sales registered a 6.9% increase in 2002, in line with strong growth in consumption. Canada's retail sector enjoyed another good year posting a 6.0% increase over 2001 levels.

Manitoba farm cash receipts increased by 2.9% in 2002 over 2001 levels. Total crop cash receipts increased by 24.4%, while livestock cash receipts decreased by 5.2% and direct payments decreased from $382 million in 2001 to $219 million in 2002.

The value of mineral production was $0.982 billion in 2002 which represents a decrease of 4.4% over the 2001 value of production of $1.023 billion.

The Canadian economy grew at an annual rate of 3.4% in 2002. Consumer expenditures of goods and services grew 2.9% while government expenditures were up 2.8%. Business investments decreased by 3.8% while residential investment was up 16.0% as a result of the strong demand for new housing units. Exports and imports were up 0.8% over last year's level.

The bank rate was raised three times by the Bank of Canada in 2002. In early January, it stood at 2.25% but at year end it stood at 3.00%.

The short term Canadian-US interest rate differential stood at 0.98% while the long term Canadian-US interest rate differential was 1.06%. The short-term real interest rate decreased from 1.24% in 2001 to 0.34% in 2002. The long-term real interest increased slightly in 2002 from 3.24% in 2001 to 3.41%.

On an annual basis, the Canadian dollar depreciated from $1.5489 US in 2001 to $1.5703 US in 2002. The Canadian dollar started the year at $1.6003 US and appreciated steadily and finished the year at $1.5593 US as a result of Canada's superior economic fundamentals and wider interest-rate spreads vis-à-vis the United States' rates.

United States

In 2002, the United States' economy grew at an annual rate of 2.4% boosted by strong consumer demand and business investments. Retail sales advanced by 2.1% in 2002 over 2001 levels.

The United States' CPI, commonly used to measure overall price inflation, increased by 1.6% in 2002 compared to 2.8% in 2001.

U.S. short-term interest rates held steady throughout most of 2002 and were dropped in November as a result of continued weakness in the United States' economy. The international trade deficit in goods and services increased from $427.2 billion in 2001 to $484.4 billion in 2002.

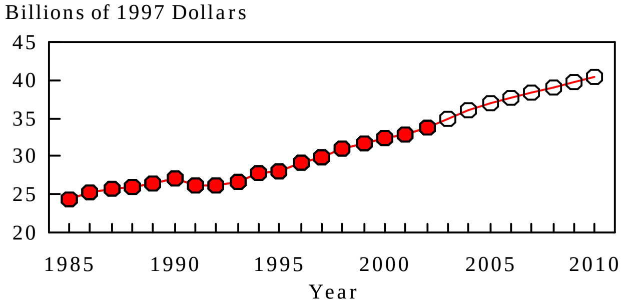
Manitoba

Real Gross Domestic Product

The Manitoba economy registered a higher than expected real increase of 3.1% in 2002, compared to the 3.4% growth posted by the national economy. The key forces driving the provincial economy in 2002 were consumer expenditures, government investments, and business investments. Those sectors posted increases of 3.4%, 3.6%, and 2.0% respectively.

The downfall of the North American stock market, terrorist attacks, and corporate accounting scandals have not dampened consumer and business confidence in Manitoba. Sales of automobiles, furniture and appliances, and other interest items such as housing starts and resale of existing houses grew at double-digit rates.

Fig. 1 - Manitoba RGDP



A sharp increase in residential repair and renovation and housing starts boosted residential investment spending by 13.3%. Infrastructure spending on health, social services, and education institutions pushed non-residential construction spending by 2.8%. Govern-ment investment in capital increased by 3.6% in 2002.

Total exports of goods and services decreased by 0.3% in 2002 after increasing by 3.8% in 2001. Corresponding to the surge in consumer expenditures, total imports of goods and services increased by 1.2% in 2002, compared to a small drop of 0.3% in 2001.

Although most base and precious metal prices were improving throughout 2002, the value of mineral production increased marginally from $1.047 billion in 2001 to $1.050 billion in 2002 as a result of weak world economic growth. The price of silver increased from $4.40 US/oz in 2001 to $4.63 US/oz in 2002, while gold increased from $271.02 US/oz to $309.79 US/oz over the same period. Nickel prices increased by 13.2% in 2002 and copper prices fell 1.1%. Zinc prices were down 12.2% in 2002 from 2001 price levels.

Total farm cash receipts increased by 2.9% from $3.648 billion in 2001 to $3.755 billion in 2002. After several years of weak prices all cereal and oilseeds grain prices rebounded in 2002. Livestock receipts were down 5.2% while direct payments decreased from $382 million in 2001 to $219 million in 2002. Cash crop receipts were up 24.4% in 2002 over 2001 levels. Canola and flaxseed prices were up 20.2% and 26.2% respectively while wheat prices experienced an increase of 16.0% after experiencing four years of successive drops in the past five years. Wheat prices were $175.95 per US tonne in 2002 compared to $151.64 per US tonne in 2001 — an increase of 16.0%.

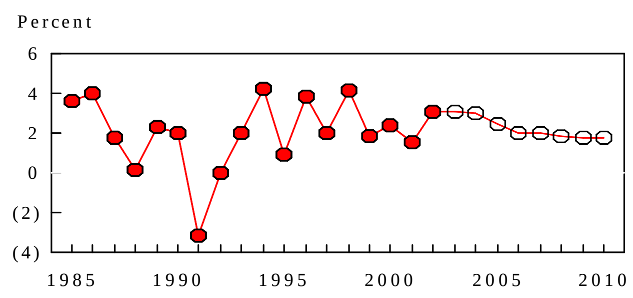
Retail sales posted a 6.9% growth in 2002 from $9.9 billion in 2001 to $10.6 billion in 2002.

Table I - Manitoba Real GDP

Year	Average 5 Year Growth Rate (%)
1965-1970	3.9
1970-1975	2.8
1975-1980	3.0
1980-1985	3.3
1985-1990	2.1
1990-2000	1.5
2000-2005	2.7
2005-2009	1.9
2009-2024	1.6

In the short term, the Manitoba economy is expected to gain by 3.1% in 2003, and trend at a 2.2% real annual growth rate during the 2004-2009 period. In the long term, the factors of production are on a downward trend relative to the past: employment is expected to grow at a slower rate than experienced in the past (0.5%) and output per employee is expected to grow at approximately 1.1%. Consequently, the economy is forecast to grow at an annual rate of 1.6% similar to the 2002 Economic Outlook.

Fig. 2 - Change in Manitoba RGDP

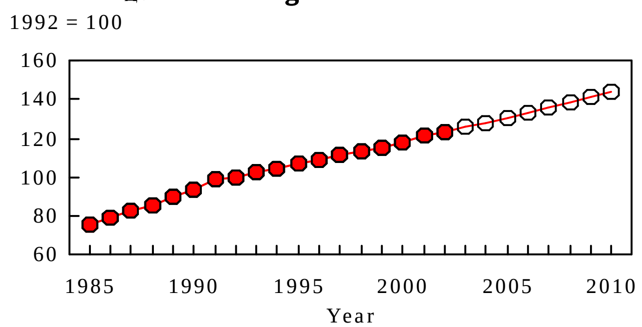


Manitoba

Consumer Price Index

Manitoba's 2002 rate of inflation, measured by the rate of change in the Consumer Price Index, increased at an annual average rate of 1.6%. The increase is below last year's increase of 2.6% and lower than Canada's 2002 rate of inflation of 2.2%.

Fig. 3 - Change in Manitoba CPI



Besides a huge increase in Alcohol, Beverage and Tobacco (15.7%), other sub-components of the CPI index experienced modest increases such as food (2.4%), household operations (2.6%), and health and personal care (1.7%). Transportation and recreation and reading increased at 1.0% and 0.9% respectively, while shelter dropped 0.5% and clothing and footwear fell 0.9%.

The inflation rate "all items less food and energy" increased at an annual rate of 2.0% in 2002 versus 1.8% in 2001. The energy price index decreased by 3.7% in 2002, as a result of a drop in all sub-components led by a natural gas price decrease of 10.3% and a fuel oil price decrease of 8.3%. The electricity price index decreased, although modestly, by 0.3%.

The overall composite Prairie Construction Index increased by 2.5% in 2002 over 2001 levels. The material component (cement and lumber) increased by 2.1% while the labour component increased by 3.0%.

Table III - Manitoba CPI by Component vs. Canada CPI by Component - 2002 over 2001

	Manitoba CPI % change	Canada CPI % change
All Items	1.6	2.2
Food	2.4	2.6
Shelter	-0.5	0.9
Household Operations	2.6	1.4
Clothing & Footwear	-0.9	-0.8
Transportation	1.0	2.8
Health & Personal Care	1.7	1.1
Recreation, Education & Reading	0.9	1.6
Alcohol, Beverage, & Tobacco	15.7	17.6
Goods	1.2	1.7
Services	1.9	2.9
All Items excluding Food & Energy	2.0	2.7
Energy	-3.7	-2.0

Manitoba's low unemployment rate, combined with strong employment growth in 2002, has had a minimal impact on wages. In fact, the aggregate industrial wage rate increased by 2.0% from $591.4 in 2001 to $603.1 in 2002.

In the near to medium term, the inflation rate is expected to be 3.0% in 2003 and 2.5% in 2004.

In the long term, a 2.0% rate of inflation is projected, similar to the 2002 Economic Outlook.

Table II - Manitoba CPI

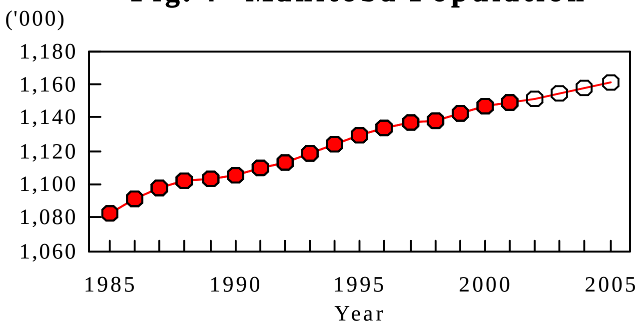
Year	Man. CPI All Items (%)	Food (%)	Household Operation (%)	Transportation (%)	Clothing (%)
1980-1985	6.9	4.7	5.8	8.4	4.3
1985-1990	4.4	4.3	3.9	4.2	3.9
1990-1995	1.2	1.2	0.6	1.4	1.4
1995-2002	2.0	2.2	2.4	2.3	1.2
2002-2007	2.3				
2007-2024	2.0				

Manitoba

Population

Manitoba's population increased by 1,726 in 2002 or 0.15% over 2001 levels — the second lowest increase in the past ten years. In 2001, the revised population increase was 2,674 people while there were revised increases of 3,899 people in 2000.

Fig. 4 - Manitoba Population



There were 13,940 births in 2002 — a new recorded low level for the last three decades, while deaths were up to 10,346. Consequently, there was a natural increase of 3,594 people — the lowest level in 40 years.

Table IV - Manitoba Population

Year	5 Year Average Growth (%)
1960-1965	1.2
1965-1970	0.4
1970-1975	0.8
1975-1980	0.2
1980-1985	0.9
1985-1990	0.4
1990-1995	0.4
1995-2000	0.3
2000-2005	0.3
2005-2024	0.2

A declining population growth rate as well as an aging population have attracted the attention of policy-makers in recent years. They believe that increased numbers in international migrants is a possible solution to the aging population, to the anticipated labour shortage, and to sustained economic growth in the future.

In 2002, the hopes of a boost from a positive net in-migration were dashed as net international in-migration was 3,085 while net interprovincial out-migration was 5,298, a net loss of 2,213.

Fig. 5 - Manitoba Population

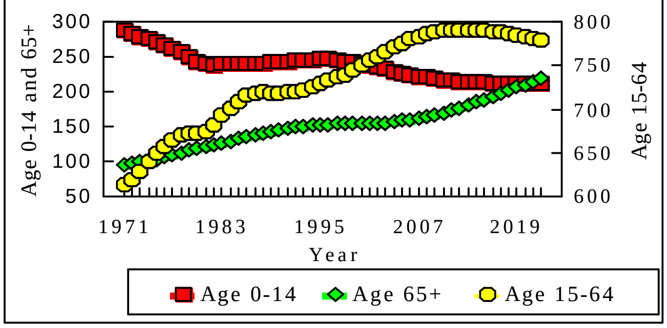
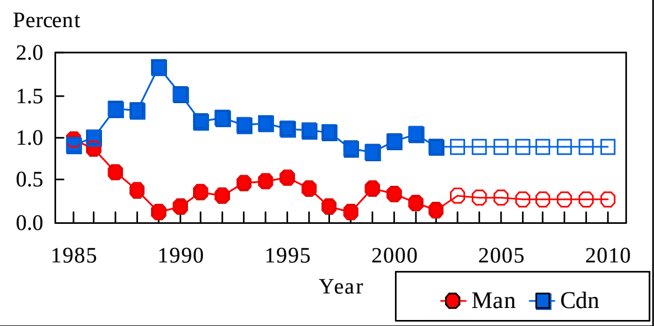


Figure 5 provides a picture of the Manitoba population age cohorts. The age cohort 0-14 falls at an annual rate of 0.45% from 232,498 in 2003 to 211,583 in 2024. The 15-64 age cohort grows at an annual rate of 0.06% from 765,695 in 2003 to 775,497 people in 2024. By the year 2012, the first baby boomers will be 65 years old. The 65+ age cohort grows steadily at an annual rate of 1.77% to 225,771 in 2024. It has been observed that the 25-34 age cohort has declined from 184,869 in 1992 to 155,790 in 2002 — a drop of 29,079 people. This drop may explain the low levels of new housing units throughout the last ten years.

The 2003 population forecast is based on a fertility rate of 1.77 per female of child-bearing age, down from 1.82 in last year's economic outlook, a net interprovincial out-migration of 2,000, as well as an annual increase of international in-migration of 1% starting at 4,040 in 2003, while international out-migration will be at 1,600 annually.

Fig. 6 - Change in Man. & Cdn. Population



As a result, the Manitoba population is expected to grow by approximately 2,781 people annually over the forecast period or at an annual rate of 0.24%, as compared to 0.54% over the 1961 to 2002 period.

Manitoba

Housing

Housing starts increased by 22.1% in 2002 with 3,617 units compared to 2,963 units in 2001. Single dwelling units increased by 22.6% from 2,460 units in 2001 to 3,016 in 2002 while new multiple units were up 19.5% from 503 units in 2001 to 601 units in 2002. Total Manitoba building permits were up 19.2% in 2002 with residential building permits leading the way with an increase of 28.3% over 2001 levels. The value of institutional and governmental permits was $117 million in 2002 compared to $59 million in 2001.

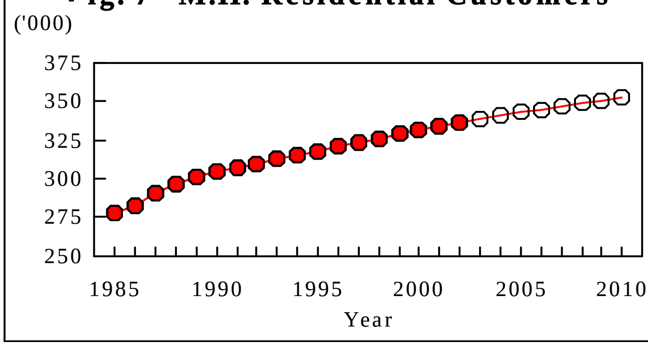
Table V - Manitoba Housing Starts

Year	Total	Single Detach.	Mult. Dwell.
1989	4084	2966	1118
1990	3297	2847	450
1991	1950	1589	361
1992	2310	1683	627
1993	2425	1874	551
1994	3197	2441	756
1995	1963	1564	399
1996	2318	1875	443
1997	2612	2019	593
1998	2895	2368	527
1999	3133	2231	902
2000	2560	2348	212
2001	2963	2460	503
2002	3617	3016	601

The housing sector has experienced a significant decline throughout the last decade. On an annual basis, there were approximately 2,727 new housing units added during the last ten years relative to 6,813 new units in the previous three decades. Falling real disposable income as a result of poor job conditions for young adults, declining transfer payments, and a declining population in the 25-34 age cohort have contributed to lower demand for housing units. In fact, we have witnessed a drop of over 29,079 people in the 25-34 age cohort over the 1992 to 2002 period. This age cohort is commonly associated with first time home buyers.

Manitoba Hydro residential customers increased by 2,403 units in 2002, an increase of 289 units relative to 2001's increase of 2,114 units. The keys to housing affordability are low interest rates, stable house prices, and rising household income. The latter two variables have been rising slowly in the past year and falling mortgage rates have stimulated housing affordability in 2002.

Fig. 7 - M.H. Residential Customers



With a modest increase expected in interest rates, and low population and higher income growth as a result of lower taxes, the number of new housing starts should trend towards the 2,250 units annually in the near and long term — down from the 2,500 units forecast in the 2002 Economic Outlook.

Table VI - M.H. Residential Customers

Year	Manitoba Hydro Residential Customers ('000)
1975	222
1980	261
1985	278
1990	305
1995	318
2001	334
2005	343
2010	352
2024	377

Manitoba Hydro residential metered customers are expected to increase by 2,639 units in 2003 and 2,234 units in 2004. The number of residential metered customers is expected to grow by an annual average of 1,830 units from 2005 to 2024. Throughout the forecast period, the level of new Manitoba Hydro residential customers is a function of Manitoba housing starts. The latter is a function of real per capita non-financial disposable income, people per housing stock, the spread between the 90 day T-Bill rate and the inflation rate, and the spread between the level of current unemployment rate and past unemployment rate.

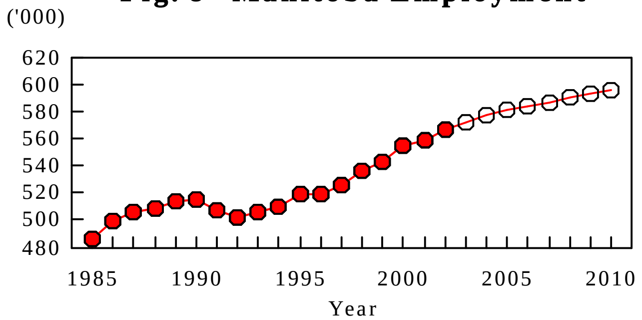
Manitoba natural gas residential customers are expected to increase by 1,431 units in 2003 and 1,355 units in 2004. The number of residential metered customers is expected to grow by an annual average of 1,450 units from 2005 to 2024. This is also a function of Manitoba housing starts

Manitoba

Employment

The Manitoba economy created an unexpected 9,100 new jobs in 2002 — an increase of 1.6%.

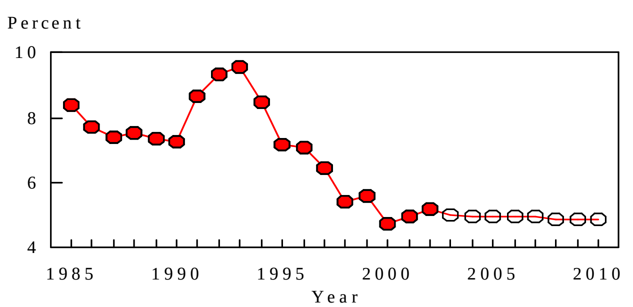
Fig. 8 - Manitoba Employment



The goods sector lost 2,662 jobs with 1,988 new jobs in the agriculture sector. The other primary sector, which includes mining, lost 512 jobs while utilities created 88 jobs in 2002. The construction and manufacturing sectors lost 2,312 and 1,914 jobs respectively in 2002.

The service sector created 11,762 new jobs with community, business, and personal services leading the way with the addition of 12,212 new jobs while transportation lost 1,513 jobs. However, trade added 1,287 jobs and public admin lost 212 jobs. The fire insurance and real estate sector lost 12 jobs in 2002.

Fig. 9 - Manitoba Unemployment Rate



Manitoba's participation rate increased from 68.1% in 2001 to 69.2% in 2002 — a record annual high. Male's participation rate increased to 75.7% in 2002 from 74.9% in 2001. Female's participation rate increased from 61.5% in 2001 to 62.8% in 2002. The ranks of the labour force grew by 10,433 people or 1.8% while the population 15 years and over increased moderately by 2,117 people or 0.2% growth. Growth of 1.6% in job creation compared to 1.8% growth in the labour force pushed the unemployment rate from 5.0% in 2001 to 5.2% in 2002.

As the unemployment rate falls relative to the past and economic growth strengthens, the labour participation rate will increase.

Table VII - Manitoba Unemployment Rate

Year	Unemployment Rate (%)
1965	2.5
1970	5.2
1975	4.3
1980	5.3
1985	8.4
1990	7.3
1995	7.2
2001	4.9
2005	5.0
2010	4.9
2015	4.6
2024	3.7

Over the last three decades, female and male participation rates haves been going in opposite directions (male's declining while female's increasing). Because female's participation has been climbing faster than male's is decreasing, the overall rate has been climbing. In the future, the participation rate should trend around current levels of 69.2%.

As a result of strong demand for labour in 2002, Manitoba's industrial weekly wage rate rose by 2.0% in 2002 from $591.4 in 2001 to $603.2 in 2002.

The labour market is expected to change dramatically over the next two decades as a result of two factors: aging population and baby boomers. The latter are expected to retire in great numbers over the next ten years. Public officials claim that up to 25% of public employees, 130,000 in total, can retire in the next five years. The lower fertility rates and net out-migration will cause the 15-64 year old cohort to shrink during the 2010-2024 period if current trends are maintained.

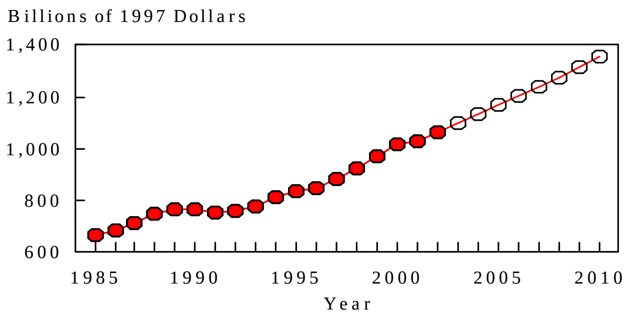
Employment is expected to grow at an annual rate of 0.5% over the forecast period, compared to 0.4% per annum growth in the labour force. Consequently, the unemployment rate is expected to trend from 5.0% in 2003 to 3.7% in 2024.

Canada

Real Gross Domestic Product

The Canadian economy posted an unexpected strong growth rate of 3.4% in 2002 — the strongest in the G-7 countries. Demand for durable goods such as cars and household appliances increased by 6.4% in 2002, while demand for semi-durable goods such as clothing increased by 3.8%. Demand for non-durables posted the weakest growth at 1.8%. The service sector, the steadiest component of all four consumption sectors, increased at an annual rate of 2.4%. Residential investment posted an increase of 16.0% as a result of strong demand in the housing sector. Business fixed investment was down 3.8% despite the healthy recovery in corporate profits of 6.2% over 2001 levels.

Fig. 10 - Canada RGDP



After a drop in business investments in 2002, the trade sector was the second source of weakness as both imports and exports posted a 0.8% increase in 2002.

Canadian retail trade was up 6.0% in 2002 with total sales of $306.4 billion for the year compared to $289.9 billion in 2001.

Canadian manufacturing shipments increased 1.9% in 2002 with total shipments of $518.5 billion in 2002 compared to $508.8 billion in 2001.

Table VIII - Canada RGDP $97B

Year	Average 5 Year Growth (%)
1965-1970	4.6
1970-1975	6.8
1975-1980	3.7
1980-1985	2.6
1985-1990	2.9
1990-1995	1.7
1995-2000	4.0
2000-2005	2.9
2005-2009	3.0
2009-2024	2.4

Real disposable income was up 2.5% in 2002, similar to the increase registered in 2001. The increase is due to higher employment growth and a drop in provincial and federal personal income taxes. On the other hand, there were sharp increases in cigarette taxes and transport taxes in 2002. Patterns in disposable income are critical to retailers and others depending on consumer spending. Real disposable income per capita is one measure of the standard of living. It measures ability to purchase in the marketplace. As Canada's population growth slows, it is important to examine the pace of per capita growth.

Canadian housing starts increased 26% from 162,733 units in 2001 to 205,034 units in 2002. Strong job growth, low mortgage rates, and the emergence of first-time home buyers were the main factors behind the highest level of new housing units since 1989. The housing market is expected to cool off in 2003, but it will remain a key source of strength within the Canadian economy. Residential building permits increased by 32.1% in 2002.

Unlike the recessions experienced at the beginning of the last two decades (1981-82 and 1991-92), the Canadian economy fared much better and posted 1.5% and 3.4% in 2001 and in 2002 respectively. The economy is expected to grow on average approximately 2.7% over the 2003-2009 period, anticipating a rebound in the United States' economy.

The 2003 Economic Outlook calls for a 2.4% long term growth, down slightly from last year's forecast. In the long term, the Canadian growth rate is based on employment growth of 1.0% and productivity growth of 1.4%.

Canada

Consumer Price Index

The Canadian annual rate of inflation dropped from 2.6% in 2001 to 2.2% in 2002. Throughout 2002, the monthly year-to-year rate of inflation oscillated between 1.0% and 4.3%. On an annual basis, food, transportation, and alcohol, beverage and tobacco were the major forces behind the increase. The shelter, household operation, health and personal care and recreation components of the CPI experienced moderate increases in 2002 while the clothing component experienced a modest drop of 0.8%. The inflation rate, which excludes food and energy due to their cyclical and seasonal nature, escalated at an annual rate of 2.7% in 2002. Both goods and service components of the CPI escalated at an annual rate of 1.7% and 2.9% respectively.

Fig. 11 - Change in Canada CPI

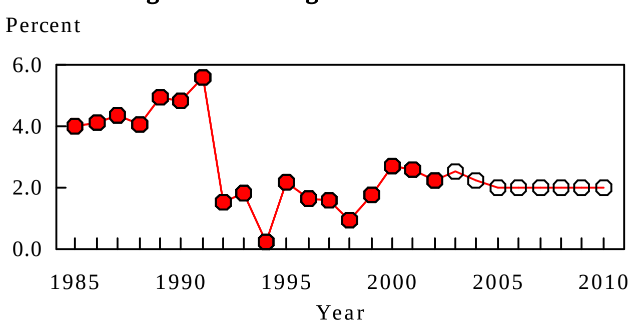


Table IX - Canada CPI - Year over Year Change

	2002 Average %
All Items	2.2
Food	2.6
Shelter	0.9
Household Operations	1.4
Clothing & Footwear	-0.8
Transportation	2.8
Health & Personal Care	1.1
Recn, Edu & Reading	1.6
Alc., Bev. & Tobacco	17.6
Goods	1.7
Services	2.9
All Items excl Food & Energy	2.7
Energy	-2.0

In 2002 the annual Canadian rate of inflation for food was 2.6% compared to 4.5% in 2001; 0.9% for shelter compared to 3.7% in 2001; 1.4% for household operation compared to 2.0% in 2001; -0.8% for clothing compared to 0.5% in 2001; 2.8% for transportation compared to 0.1% in 2001; 1.1% for health compared to 2.0% in 2001; 1.6% for recreation compared to 1.5% in 2001; 17.6% for tobacco and alcohol compared to 7.7% in 2001.

Weakening economic growth worldwide has contributed to lower energy price increases and the energy component dropped 2.0% in 2002. The Canadian fuel oil sub-component of the CPI decreased by 8.1% in 2002. Natural gas prices increased in 2000/01 but decreased by 18.1% in 2002 over 2001 levels. The electricity sub-component posted a significant price increase of 7.4% in 2002.

The GDP implicit price deflator, which is an overall measure of inflation for all goods and services produced and consumed, increased by 1.2% in 2002, up from the 1.0% increase posted in 2001.

The composite construction price index for Canada increased by 2.3% in 2002, down from the 2.9% increase registered for 2001. The increase was generated by an increase of 2.1% in the material component and a 2.5% increase in the wage component. The composite index is split approximately 50/50 between materials and wages.

The raw material price index decreased by 0.7% in 2002, led by decreases in mineral fuels, animal products, wood and non-ferrous metals. Vegetable products rebounded with an increase of 16.4% compared to 2001.

The industrial product price index (IPPI) rose mildly from 107.5 in 2001 to 107.6 in 2002. It should be noted that fluctuations in the IPPI are affected by fluctuations in the Canadian dollar. It is estimated that a 1% change in the Canadian dollar will change the IPPI by approximately 0.2%.

The rate of inflation is expected to be 3.5% in 2003, 2.5% in 2004, and to trend at 2.0%, the middle of the target range 1.0% to 3.0%, throughout the remainder of the forecast period, assuming that the current Bank of Canada monetary policy prevails.

Table X - Canada Inflation Rate

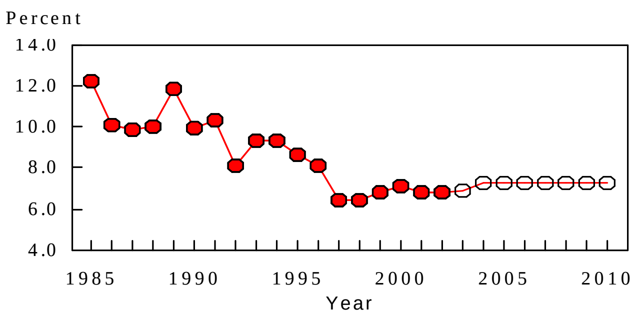
Year	CPI (%)
1965-1970	3.8
1970-1975	7.4
1975-1980	8.7
1980-1985	7.4
1985-1990	4.5
1990-1995	2.2
1995-2000	1.7
2000-2005	2.3
2005-2009	2.0
2009-2024	2.0

Canada

Interest Rates

The bank rate was raised three times by the Bank of Canada in 2002. In early January, it stood at 2.25% but after three successive increases the bank rate stood at 3.00% at year-end. On an annual basis, the bank rate decreased from 4.31% in 2001 to 2.71% in 2002. The prime rate (the rate chartered banks charge their best customers) followed a similar trend to the bank rate. The annual average prime rate dropped from 5.81% in 2001 to 4.21% in 2002. Throughout 2002, the yield curve (spread between long-term and short-term interest rates) became steeper relative to 2000 and 2001. A steep yield curve tends to stimulate lending activity and domestic spending.

Fig. 12 - Manitoba Hydro Cost of Debt



Throughout 2002, the Government of Canada long term bond rate oscillated between 5.37% and 6.02% and posted an annual rate of 5.66% for 2002 — a drop of 12 basis points relative to 2001. In the first half of 2002, the long-term rate oscillated in the 5.68%-6.00% range. It fell throughout the second half and finished at 5.37% at year end.

Table X I - Range in Canadian Interest Rates

	2002 Average %	12 Month Low %	12 Month High %
Bank Rate	2.71	2.25	3.00
T-Bill Rate	2.59	1.97	3.00
Prime Rate	4.21	3.75	4.50
GOC 10Yr+ Rate	5.66	5.37	6.00

The Canada-US T-Bill interest rate differential was at its highest level in seven years in 2002. Except for 1999 and 2001, the short-term rate differential was negative for most of the 1996-2001 period. The annualized short-term interest rate differential was 0.98% in 2002 compared to 0.39% in 2001. On the other hand, the Canadian short term real rate was 0.34% in 2002 down from the 1.24% posted in 2001. The short term real interest rate in 2002 was about 300 basis points below the previous ten year average. The U.S. equivalent was 0.01% in 2002 compared to 0.56% in 2001.

As stated above, long term rates fell moderately throughout 2002. On an annual basis, the long term rates fell 12 basis points from 5.78% in 2001 to 5.66% in 2002. The long term Canadian-US interest rate differential was positive at 1.06% in 2002 compared to 0.30% in 2001. The long term Canadian real interest rate increased slightly to 3.41% in 2002 from 3.24% in 2001 while the comparable US rate increased from 2.66% in 2001 to 3.02% in 2002. The long term Canadian-US interest real rate differential decreased from 0.59% in 2001 to 0.40% in 2002.

The 90 Day T-Bill rate is expected to be 4.5% while the GOC 10 year+ rate is forecast to trend at 6.0%.

The forecast for Manitoba Hydro's long term new debt rates, largely based on the GOC 10 year+ rate, includes a small differential reflecting the credit rating of the Province relative to the government of Canada and the Provincial guarantee fee.

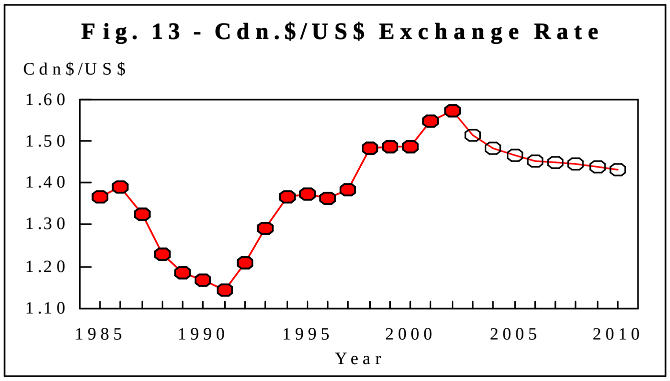
Table XII - Interest Rates

Year	90 Day T-Bill Rate (%)	GOC 10 Yr+ Rate (%)
1970	5.99	7.91
1975	7.40	9.04
1980	12.79	12.48
1985	9.43	11.04
1990	12.81	10.85
1995	6.89	8.28
1999	4.72	5.69
2000	5.49	5.89
2001	3.78	5.78
2002	2.59	5.66
2005	4.50	6.00
2010	4.50	6.00
2015	4.50	6.00
2024	4.50	6.00

Canada

Exchange Rate

The Canadian dollar posted an annual rate of $1.5703 US, a depreciation of 1.4% with respect to 2001 where the Canadian dollar was $1.5489 US. However, the dollar stood at $1.6003 US in January and started to appreciate until the middle of the year. After depreciating for most of the third quarter, the Canadian dollar appreciated in the final quarter to reach $1.5593 US by year end.



In spite of a modest decline in 2002, the Canadian dollar is starting to appreciate. Owing to the sharp contrast in employment trends with respect to the U.S., investors have taken notice of Canada's superior economic fundamentals and wider interest-rate spreads vis-à-vis the United States. However, the Canadian currency continues to underperform other major currencies, especially the Euro. It has also stumbled in the past during periods of political uncertainty. Morever, the dollar has also been undermined by fears that an Iraqi war will torpedo the United States' economy and as a result, harm Canadian exports and commodity prices. This negative assessment is despite the fact that Canada is a net exporter of energy products.

Table XIII - Range in Exchange Rate

	2002 Average	12 Month Low	12 Month High
Cdn. $/US $	1.57	1.60	1.53
US $/Cdn. $	0.64	0.62	0.65

Nevertheless, the medium-term outlook for the Canadian dollar remains bright. President Bush's recent fiscal package of hefty tax cuts underscores the diverging trends in fiscal balances between the two countries, with the United States racking up bigger deficits and Canada running surpluses. Similarly, external balances continue to trend in opposite directions, with Canada running a current account surplus of 2% of GDP while the United States is racking up deficits in the order of 5%. The "overvalued" US currency is bound to depreciate further in the medium term to stabilize the deterioration in the United States' external accounts.

Consequently, the Canadian dollar will appreciate to $1.51 US in 2003 and $1.48 US in 2004 as Canada's economic fundamentals remain intact.

Table XIV - Exchange Rate

Year	US$/ Cdn.$	Cdn.$/ US$
1970	0.96	1.04
1975	0.98	1.02
1980	0.86	1.17
1985	0.73	1.37
1990	0.86	1.17
1995	0.73	1.37
1996	0.73	1.36
1997	0.72	1.38
1998	0.67	1.48
2000	0.67	1.49
2001	0.65	1.55
2002	0.64	1.57
2005	0.68	1.46
2010	0.70	1.43
2024	0.75	1.33

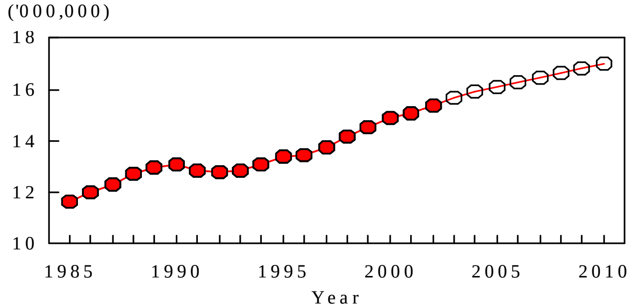
The fundamentals for the Canadian dollar are still intact and strong for the long term. A lower Canadian inflation rate, vis-à-vis that of the United States, a positive current account balance, and surpluses in Federal and provincial fiscal balances should help the Canadian currency to appreciate towards $1.43 US by 2010 and $1.33 US in 2024.

Canada

Employment

The Canadian economy generated an unexpected total of 335,000 jobs in 2002, up from 167,000 jobs created in 2001. The employment level increased by 2.2% in 2002. However, the Help-Wanted Index, an indicator of labour demand, dropped 17.4% in 2002 from 149 in 2001 to 123 in 2002.

Fig. 14 - Canada Employment

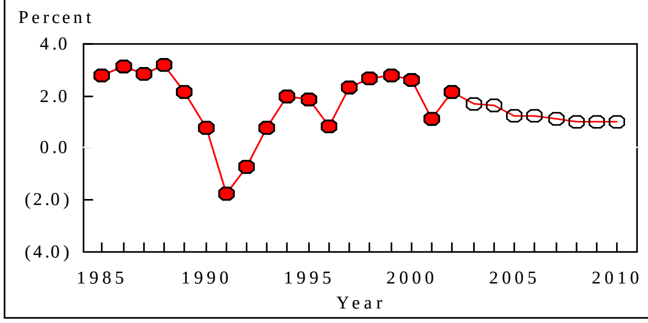


The goods producing sector gained 81,000 jobs in 2002 versus a drop of 6,000 jobs in 2001. The agriculture sector added 1,000 jobs, while manufacturing added 51,000 jobs and construction added 40,000 jobs. The primary sector lost 20,000 jobs in 2002 while the utilities sector added 9,000 jobs. Although experiencing a loss in employment in 2001, the goods sector has added 604,000 jobs over the 1993-2002 period and current levels of employment are approximately equal to the levels experienced in the late 1980's.

Growth in the service sector created 254,000 jobs in 2002 compared to 171,000 jobs in 2001. The community and personal business sector created the bulk of the new service jobs as 192,000 jobs were added. The wholesale and retail trade sector added 46,000 jobs, the transportation and communication sector lost 17,000 jobs and the fire insurance and real estate sector added 21,000 jobs. The public administration sector added 12,000 jobs.

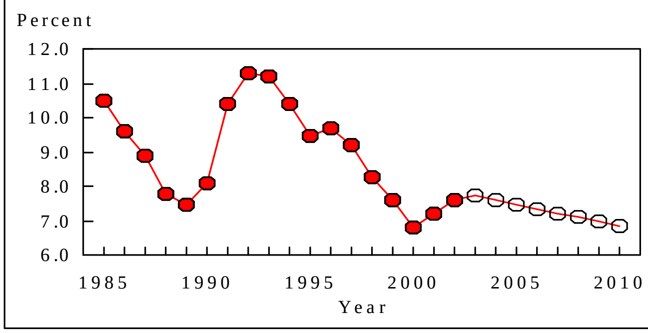
In 2002, there was a higher increase in the labour force of 2.7% relative to the creation of jobs of 2.2% and as a result the unemployment rate increased from 7.2% in 2001 to an annual average of 7.7% in 2002. The participation rate increased from 66.0% in 2001 to 66.9% in 2002 and the ranks of the population age group 15+ years increased by 332,000 people and the labour force increased by 443,000 people. Male's participation rate increased from 72.5% in 2001 to 73.3% in 2002 while female's participation rate increased from 59.7% to 60.7% for the same period. Male's participation rate has fallen from 76-77% levels experienced in the early 1990's while female's participation rate has trended in the 58-59% range in the 1990's.

Fig. 15 - Change in Canada Employment



The increase in the unemployment rate helped to increase the ranks of the jobless by 108,000 from 1,169,000 in 2001 to 1,277,000 in 2002. It should be noted that 186,000 new jobs created in 2002 were full-time — about 55% of the total. The employment/population group 15 years and over increased from 61.3% in 2001 to 61.8% in 2002. The industrial wage escalated from $665.09 in 2001 to $677.93 in 2002 — an increase of 1.9%.

Fig. 16 - Canada Unemployment Rate



In the long term, the unemployment rate should trend from current levels of 7.2% towards 5.0% by 2024, resulting from a higher growth rate in employment relative to the labour force. The slower growth in the labour force is, in part, due to an aging population.

U.S.A.

Real Gross National Product

In 2002, the United States' economy registered an annual real growth of 2.4% after posting a modest real gain of 0.3% in 2001. The U.S. economy had a year of fits and starts characterized with strong growth in demand of consumer goods and new housing units, but experienced negative employment growth as a result of scandals and a shortfall in business investments.

The U.S. economy was fueled by two sectors, consumption and government expenditures. Personal consumption expenditures were up 3.1% over last year's level while the government sector posted an increase of 4.4% growth. Exports fell 1.3% in 2002 while imports increased by 3.5% — this has a positive effect on Canadian exports. Consequently, the merchandise trade imbalance continues to dog the U.S. economy and has fueled protectionist sentiments in key sectors and regions.

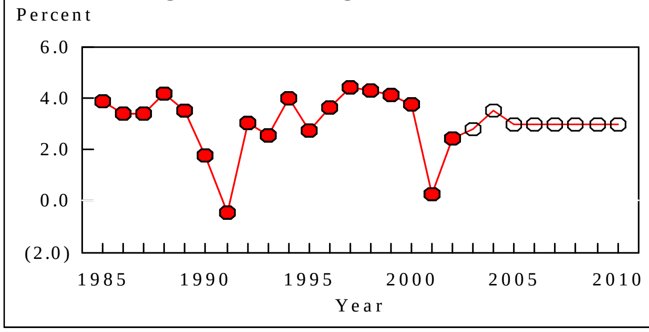
The U.S. housing sector increased significantly in 2002. Housing starts were up 6.8% in 2002 from 1,603,000 units in 2001 to 1,711,000 units in 2002. Retail sales were up by 2.1% in 2002 from $3,488.6 billion in 2001 to $3,560.2 billion in 2002.

The U.S. economy and its thirst for non-US goods caused the merchandise trade deficit to increase from $427.2 billion in 2001 to a record $484.4 billion in 2002, 4.6% of GDP.

The U.S. economy continues to be a source of growth in the Canadian economy. With the Canadian consumption-output ratio falling throughout the 1990's, external trade now represents well over 40% of the total Canadian economy. U.S. exports represent some 86% of that amount. Canada and the U.S. are the two biggest trading nations in the world.

The U.S. economy is expected to grow 2.8% in 2003 and rebound in 2004 and post an annual growth rate of 3.5%. Between 2005 and 2009, real GDP growth is expected to grow at 3.0% per year. From 2009 to the end of the forecast period, real economic growth is anticipated to be 3.0%. The long-term growth in real GDP is based on 1.9% growth in productivity and 1.1% in employment growth. The tax cuts announced in the last federal budget are expected to stimulate long-term investments.

Fig. 17 - Change in U.S. RGNP

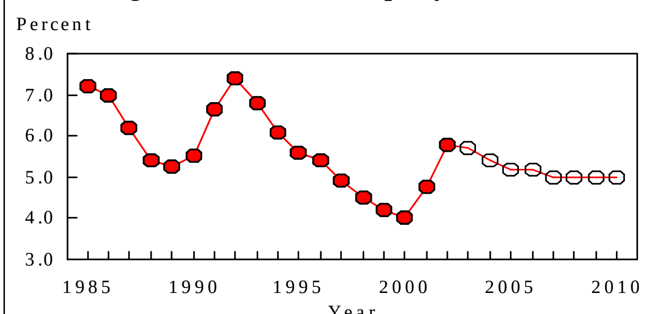


Employment

For a second consecutive year, the U.S. economy experienced a drop in employment. The U.S. economy lost 815,000 jobs in 2002 compared to a loss 187,000 jobs in 2001. The ranks of the labour force increased by 671,000 people or 0.5% growth. A slightly lower growth of 0.5% in the labour force compared to 1.0% in the source population 15 years and over caused the participation rate to decrease from 67.0% in 2001 to 66.6% in 2002. Weak economic growth along with massive layoffs in technology and airline industries helped pushed the annual unemployment rate from 4.8% in 2001 to 5.8% in 2002. The unemployment rate oscillated within a band of 5.5 to 6.0 throughout 2002. The weekly average hours remained at 34.16 hours in 2002 similar to 2001, while the hourly pay increased by 3.0% from $14.34 per hour in 2001 to $14.78 per hour in 2002.

In the short term, the U.S. unemployment rate should decrease from current levels of 5.7% to 5.2% in 2006. In the long term, the unemployment rate should trend towards the 5.0% level as employment is expected to grow at an annual rate of 1.1% throughout the forecast period.

Fig. 18 - U.S. Unemployment Rate



U.S.A.

Consumer Price Index

The U.S. rate of inflation, as measured by the annual rate of change in the CPI, increased by 1.6% in 2002 compared to 2.8% in 2001. The U.S. price deflator increased at an annual rate of 1.1% in 2002. Commodity prices, as measured by the PPI — manufactured goods, increased by 1.4% in 2002 compared to the decrease of 2.0% registered in 2001. The lower increase was the result of weakening energy prices.

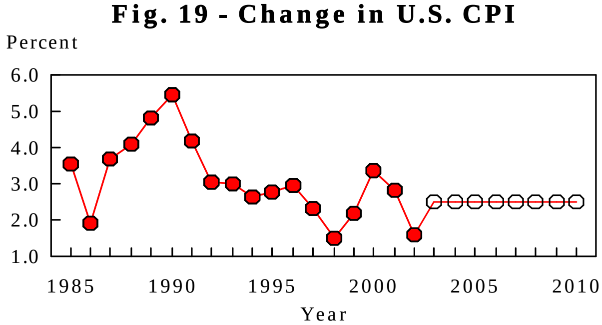
Table XV - USA CPI Year Over Year Change

	2002 Average %
All items	1.6
Food	1.8
Housing	2.2
Transportation	-0.9

The average hourly earnings escalated by 3.0% which is above the measures of inflation stated above. It should be noted that wage costs represent 60% of the total cost of producing most goods and services and wage increases are usually added on to the price of goods and services. Weaker economic growth and falling goods prices are responsible for moderating the inflation increase in 2002.

The current rate of unemployment at 5.8%, combined with lower economic growth compared to the potential growth rate, had dampened the inflation threat in 2002.

Fig. 19 - Change in U.S. CPI



In the long run, excluding the occurrence of supply shocks, inflation is primarily under the control of the central bank. In the near term, the USA CPI is expected to be 2.25% for 2003 and 2004 respectively. The long-term inflation rate should trend around the 2.5% level.

Interest Rates

The Federal Open Market Committee (FOMC), the arm of the Federal Reserve Board responsible for monetary policy that sets short-term interest rates, intervened only once in 2002. The rate was dropped to 1.25% in November after sitting at 1.75% for most of 2002.

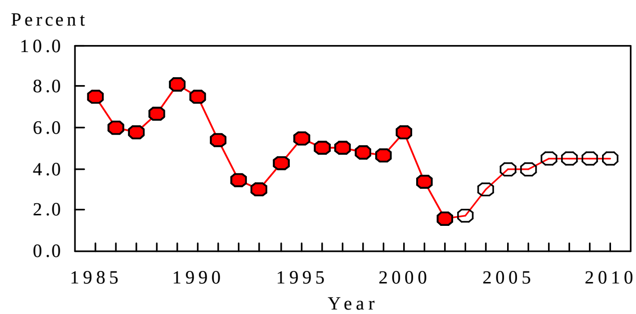
Table XVI - USA Interest Rates

	2002 Average %	12 Month Low %	12 Month High %
Federal Fund	1.66	1.23	1.79
T-Bill	1.60	1.19	1.79
Govt 5 Year	3.76	2.83	4.85
Govt 10 Year +	4.61	3.77	5.41

In 2002, the T-Bill rate oscillated between 1.19% and 1.79%. At an annual rate, the T-Bill rate was 1.60% in 2002 compared to 3.39% in 2001. The prime rate stood at 4.75% from January to October but fell to 4.25% in November and December. The annual prime rate was 4.67% in 2002 compared to 6.79% in 2001.

The long term government bond rate decreased from 5.49% in 2001 to 4.61% in 2002.

Fig. 20 - U.S. 90 Day TBill Rate



In the long term, as the economy eases up, short-term interest rates should trend towards 4.5%, while long term rates trend around current levels of 5.75% — slightly higher relative to last year's Economic Outlook.

Manitoba Economic Statistics

Year	Population '000	Population %	Unempl. Rate %	Real GDP 97$m	Real GDP %	CPI 92=100	CPI %	M.H. Res. Cus. '000
1978	1,041	0.3	6.6	21,277	2.0	45.2	8.5	249
1979	1,037	-0.4	5.3	21,193	-0.4	49.3	9.1	259
1980	1,035	-0.3	5.3	21,447	1.2	54.2	9.9	261
1981	1,036	0.2	6.1	22,763	6.1	60.2	11.1	263
1982	1,047	1.0	8.3	22,627	-0.6	65.5	8.8	265
1983	1,061	1.4	9.6	22,932	1.4	69.9	6.7	267
1984	1,072	1.0	8.7	24,597	7.3	72.5	3.7	273
1985	1,082	1.0	8.4	25,198	2.4	75.5	4.1	278
1986	1,092	0.9	7.7	26,227	4.1	78.9	4.5	283
1987	1,098	0.6	7.4	26,536	1.2	82.2	4.2	291
1988	1,102	0.4	7.5	26,581	0.2	85.6	4.1	297
1989	1,104	0.1	7.3	27,193	2.3	89.7	4.8	301
1990	1,106	0.2	7.3	27,894	2.6	93.8	4.6	305
1991	1,110	0.4	8.6	26,621	-4.6	98.6	5.1	307
1992	1,113	0.3	9.3	26,652	0.1	100.0	1.4	310
1993	1,118	0.5	9.6	26,885	0.9	102.7	2.7	312
1994	1,124	0.5	8.5	27,848	3.6	104.1	1.4	315
1995	1,130	0.5	7.2	28,094	0.9	106.9	2.7	318
1996	1,134	0.4	7.1	28,872	2.8	109.2	2.2	320
1997	1,137	0.2	6.4	29,758	3.1	111.6	2.2	323
1998	1,138	0.1	5.4	31,011	4.2	113.0	1.3	326
1999	1,143	0.4	5.6	31,585	1.9	115.2	1.9	329
2000	1,146	0.3	4.7	32,341	2.4	118.1	2.5	331
2001	1,149	0.2	4.9	32,838	1.5	121.2	2.6	334
2002	1,151	0.2	5.2	33,865	3.1	123.1	1.6	336
Forecast								
2003	1,154	0.3	5.0	34,915	3.1	126.8	3.0	339
2004	1,158	0.3	5.0	35,962	3.0	130.0	2.5	341
2005	1,161	0.3	5.0	36,861	2.5	132.6	2.0	343
2006	1,165	0.3	5.0	37,599	2.0	135.2	2.0	345
2007	1,168	0.3	5.0	38,351	2.0	137.9	2.0	347
2008	1,171	0.3	4.9	39,080	1.9	140.7	2.0	349
2009	1,174	0.3	4.9	39,767	1.8	143.5	2.0	350
2010	1,177	0.3	4.9	40,472	1.8	146.4	2.0	352
2011	1,180	0.3	4.9	41,176	1.7	149.3	2.0	354
2012	1,183	0.3	4.9	41,818	1.6	152.3	2.0	356
2013	1,186	0.3	4.8	42,501	1.6	155.3	2.0	358
2014	1,189	0.2	4.7	43,185	1.6	158.4	2.0	360
2015	1,192	0.2	4.6	43,869	1.6	161.6	2.0	362
2016	1,195	0.2	4.5	44,556	1.6	164.8	2.0	363
2017	1,198	0.2	4.4	45,243	1.5	168.1	2.0	365
2018	1,200	0.2	4.3	45,934	1.5	171.5	2.0	367
2019	1,203	0.2	4.2	46,626	1.5	174.9	2.0	369
2020	1,205	0.2	4.1	47,320	1.5	178.4	2.0	371
2021	1,207	0.2	4.0	48,018	1.5	182.0	2.0	372
2022	1,209	0.2	3.9	48,717	1.5	185.6	2.0	374
2023	1,211	0.2	3.8	49,419	1.4	189.3	2.0	376
2024	1,213	0.2	3.7	50,124	1.4	193.1	2.0	377

Canada Economic Statistics

Year	Real GDP 97$b	Real GDP %	CPI 92=100	CPI %	90 Day TBill Rate %	GOC 10 Yr+ Rate %	Unempl. Rate %	Cdn./ U.S. $
1978	554	4.1	43.6	9.0	8.68	9.27	8.4	1.14
1979	577	4.2	47.6	9.0	11.69	10.21	7.5	1.17
1980	585	1.4	52.4	10.2	12.79	12.48	7.5	1.17
1981	600	2.6	58.9	12.4	17.72	15.22	7.6	1.20
1982	583	-2.9	65.3	10.8	13.66	14.26	11.0	1.23
1983	599	2.7	69.1	5.9	9.31	11.79	11.9	1.23
1984	634	5.8	72.1	4.3	11.06	12.75	11.3	1.30
1985	664	4.8	75.0	4.0	9.43	11.04	10.5	1.37
1986	680	2.4	78.1	4.2	8.97	9.52	9.6	1.39
1987	709	4.3	81.5	4.3	8.15	9.95	8.9	1.33
1988	744	5.0	84.8	4.0	9.48	10.22	7.8	1.23
1989	764	2.6	89.0	5.0	12.05	9.92	7.5	1.18
1990	765	0.2	93.3	4.8	12.81	10.85	8.1	1.17
1991	749	-2.1	98.5	5.6	8.73	9.76	10.4	1.15
1992	756	0.9	100.0	1.5	6.41	8.77	11.3	1.21
1993	774	2.3	101.8	1.9	4.84	7.84	11.2	1.29
1994	811	4.8	102.0	0.2	5.54	8.63	10.4	1.37
1995	833	2.8	104.2	2.2	6.89	8.28	9.5	1.37
1996	847	1.6	105.9	1.6	4.21	7.49	9.7	1.36
1997	883	4.2	107.6	1.6	3.25	6.42	9.2	1.38
1998	919	4.1	108.6	0.9	4.73	5.47	8.3	1.48
1999	968	5.4	110.5	1.7	4.72	5.69	7.6	1.49
2000	1,012	4.5	113.5	2.7	5.49	5.89	6.8	1.49
2001	1,028	1.5	116.4	2.6	3.78	5.78	7.2	1.55
2002	1,062	3.4	119.0	2.2	2.59	5.66	7.7	1.57
	Forecast							
2003	1,095	3.1	123.2	3.5	3.50	5.50	7.2	1.48
2004	1,132	3.3	126.2	2.5	4.50	6.00	7.1	1.48
2005	1,165	3.0	128.8	2.0	4.50	6.00	7.0	1.46
2006	1,200	3.0	131.3	2.0	4.50	6.00	6.9	1.45
2007	1,236	3.0	134.0	2.0	4.50	6.00	6.8	1.44
2008	1,274	3.0	136.7	2.0	4.50	6.00	6.7	1.44
2009	1,312	3.0	139.4	2.0	4.50	6.00	6.6	1.43
2010	1,351	3.0	142.2	2.0	4.50	6.00	6.5	1.43
2011	1,388	2.8	145.0	2.0	4.50	6.00	6.4	1.42
2012	1,426	2.8	147.9	2.0	4.50	6.00	6.3	1.41
2013	1,462	2.5	150.9	2.0	4.50	6.00	6.2	1.41
2014	1,499	2.5	153.9	2.0	4.50	6.00	6.1	1.40
2015	1,536	2.5	157.0	2.0	4.50	6.00	5.9	1.39
2016	1,575	2.5	160.1	2.0	4.50	6.00	5.8	1.39
2017	1,614	2.5	163.3	2.0	4.50	6.00	5.7	1.38
2018	1,650	2.3	166.6	2.0	4.50	6.00	5.6	1.37
2019	1,687	2.3	169.9	2.0	4.50	6.00	5.5	1.36
2020	1,725	2.3	173.3	2.0	4.50	6.00	5.4	1.36
2021	1,764	2.3	176.8	2.0	4.50	6.00	5.3	1.35
2022	1,804	2.3	180.3	2.0	4.50	6.00	5.2	1.34
2023	1,844	2.3	183.9	2.0	4.50	6.00	5.1	1.34
2024	1,886	2.3	187.6	2.0	4.50	6.00	5.0	1.33

CCC-NFAAT-S-15

Provide System Load Forecast 2003/04 to 2023/24

System Load Forecast 2003/04 to 2023/24 attached. (see CCC/NFAAT/S/11 for comparison)

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Table 1

MANITOBA HYDRO NET ELECTRIC LOAD FORECAST
2002/03 - 2023/24

Fiscal Year	Net Firm Energy (GW.h)	%	Net Total Peak (MW)	%	Load Factor %
2002/03 Actual	21940	7.1%	3916	4.1%	64.0%
Weather	-272		14		
2002/03 Adjusted	21668	4.5%	3930	4.3%	62.9%
2003/04	22171	2.3%	3956	0.7%	64.0%
2004/05	22690	2.3%	4028	1.8%	64.3%
2005/06	22976	1.3%	4053	0.6%	64.7%
2006/07	23262	1.2%	4088	0.9%	65.0%
2007/08	23554	1.3%	4126	0.9%	65.2%
2008/09	23783	1.0%	4153	0.7%	65.4%
2009/10	24009	1.0%	4180	0.7%	65.6%
2010/11	24203	0.8%	4201	0.5%	65.8%
2011/12	24430	0.9%	4228	0.6%	66.0%
2012/13	24680	1.0%	4258	0.7%	66.2%
10 Year Avg.		1.3%		0.8%	
2013/14	24927	1.0%	4296	0.9%	66.2%
2014/15	25191	1.1%	4338	1.0%	66.3%
2015/16	25458	1.1%	4380	1.0%	66.4%
2016/17	25729	1.1%	4422	1.0%	66.4%
2017/18	26001	1.1%	4465	1.0%	66.5%
2018/19	26274	1.1%	4508	1.0%	66.5%
2019/20	26576	1.1%	4556	1.1%	66.6%
2020/21	26847	1.0%	4599	0.9%	66.6%
2021/22	27143	1.1%	4646	1.0%	66.7%
2022/23	27436	1.1%	4692	1.0%	66.8%
2023/24	27675	0.9%	4730	0.8%	66.8%
21 Year Avg.		1.2%		0.9%	

- See the Glossary of Terms for a definition of Net Firm Energy and Net Total Peak.

Table 2

ENERGY SALES TO MANITOBA HYDRO CUSTOMERS
2002/03 - 2023/24 (GW.h)
(Base Forecast)

Fiscal Year	Residential	General Service	Area & Roadway Lighting	Manitoba Hydro Sales Incl Diesel		Total Diesel	Manitoba Hydro Sales Excl Diesel
2002/03 Actual	6361	12796	90	19246	8.1%	10	19236
2003/04	6148	13075	90	19314	0.4%	11	19303
2004/05	6191	13548	91	19830	2.7%	12	19818
2005/06	6229	13729	92	20051	1.1%	13	20038
2006/07	6268	13931	93	20292	1.2%	14	20278
2007/08	6309	14117	93	20519	1.1%	15	20504
2008/09	6348	14278	94	20720	1.0%	16	20704
2009/10	6388	14435	95	20919	1.0%	16	20903
2010/11	6428	14594	96	21118	1.0%	17	21101
2011/12	6469	14762	96	21327	1.0%	18	21309
2012/13	6510	14939	97	21546	1.0%	19	21527
2013/14	6552	15113	98	21762	1.0%	20	21742
2014/15	6596	15299	99	21994	1.1%	20	21974
2015/16	6637	15487	99	22224	1.0%	21	22203
2016/17	6680	15676	100	22457	1.0%	22	22435
2017/18	6724	15865	101	22690	1.0%	23	22667
2018/19	6768	16054	102	22924	1.0%	23	22901
2019/20	6814	16244	103	23160	1.0%	24	23136
2020/21	6861	16434	103	23398	1.0%	25	23373
2021/22	6909	16625	104	23638	1.0%	25	23613
2022/23	6958	16818	105	23880	1.0%	26	23854
2023/24	7007	17011	106	24124	1.0%	27	24097

Table 3

NET FIRM ENERGY
2002/03 - 2023/24 (GW.h)
(Base Forecast)

Fiscal Year	Dist. Losses	Const. Power	MLCB	Trans. Losses & Stn Service	Gross Total Energy	Non Firm	Station Service	Net Firm Energy
2002/03 Actual	671	46	19953	2182	22135	24	170	21940
2003/04	830	45	20241	2138	22379	35	173	22171
2004/05	852	45	20715	2187	22902	35	177	22690
2005/06	862	45	20944	2211	23156	0	179	22976
2006/07	872	55	21205	2238	23443	0	181	23262
2007/08	882	85	21471	2266	23738	0	184	23554
2008/09	890	85	21680	2288	23969	0	186	23783
2009/10	899	85	21886	2311	24197	0	187	24009
2010/11	907	55	22063	2328	24391	0	189	24203
2011/12	916	45	22270	2350	24620	0	191	24430
2012/13	926	45	22498	2375	24872	0	193	24680
2013/14	935	45	22723	2399	25121	0	194	24927
2014/15	945	45	22963	2424	25387	0	196	25191
2015/16	955	50	23207	2449	25657	0	199	25458
2016/17	965	55	23454	2475	25930	0	201	25729
2017/18	975	60	23702	2502	26204	0	203	26001
2018/19	985	65	23951	2528	26479	0	205	26274
2019/20	995	95	24226	2557	26783	0	207	26576
2020/21	1005	95	24474	2583	27056	0	209	26847
2021/22	1015	115	24743	2612	27355	0	212	27143
2022/23	1026	130	25010	2640	27650	0	214	27436
2023/24	1036	95	25228	2663	27891	0	216	27675

- See the Glossary of Terms for a definition of Gross Total Energy, Non Firm Energy, Station Service and Net Firm Energy.

EXECUTIVE SUMMARY

Recommendation

It is recommended that the Corporation approve this report as Manitoba Hydro's best estimate of Net Firm Energy and Net Total Peak requirements in Manitoba for the 2003/04 to 2023/24 period.

Demand Side Management in the Forecast

This forecast is based on historical billing data and therefore includes the Demand Side Management (DSM) savings achieved to date because DSM savings are inherently contained within the customers' billing records. The cumulative savings by the end of 2002/03 for all Residential, Commercial, Industrial and Street Lighting DSM programs (excluding the Curtailable Rates Program) is estimated to be 94 MW and 436 GW.h at the customers' meter. Including the reduction to T&D losses, the cumulative savings at generation are estimated to be 104 MW and 488 GW.h.

This forecast contains a reduction for future DSM savings associated with the Basic Customer Information and Service. This DSM level is the minimum amount of DSM services and activity that Manitoba Hydro will provide to customers in the future. All other DSM options are analyzed on an incremental basis to this level. Beyond 2002/03, the incremental savings associated with other DSM options are treated as supply side resources and therefore are not included in this forecast. By 2023/24, the Basic Customer Option is estimated to result in a total of 135 MW and 573 GW.h of savings at the customers' meter. These savings are expected to occur in the Residential sector (93 MW and 402 GW.h) and in the General Service sector (42 MW and 171 GW.h). Adding another 10-14% savings due to reduced T & D losses, the total savings at generation will be 153 MW and 652 GW.h by 2023/24.

Summary of Forecast Changes

The most significant change to the forecasting process resulted from the purchase of Winnipeg Hydro. In previous forecasts, the Winnipeg Hydro load was forecasted at the Common Bus level. This year, the Winnipeg Hydro load is forecasted at the sales level.

Separate, econometric forecasts were prepared for Winnipeg Hydro customers in the Residential Standard, Residential All-Electric and General Service Mass Market classification. The sales forecasts contained in this document represent all Manitoba customers. The results were calculated by adding the Manitoba Hydro and Winnipeg Hydro forecasts together.

In fact, all customers are now Manitoba Hydro customers, but this forecast will refer to customers in the Manitoba Hydro service area and the Winnipeg Hydro service area, which is the basis that the forecast was prepared.

This distinction is necessary because the Winnipeg Hydro lacks sufficient market information, at this time, to prepare a detailed end-use forecast for the Residential sector. Manitoba Hydro has recently issued a Residential Energy Use Survey. The results will be incorporated into next year's forecasting process.

The chart below shows the change from the previous forecast for the five, ten and twenty year intervals into the future. The changes are reported for each sector. The reasons causing the load changes are explained afterwards.

CHANGE FROM PREVIOUS FORECAST				
Sector		Fiscal Year		
		2007/08	2012/13	2022/23
Residential	GW.h	170	191	240
General Service	GW.h	564	333	456
Area & Roadway Lighting	GW.h	22	23	24
Diesel	GW.h	3	5	9
Distribution Losses	GW.h	70	57	57
Construction Power	GW.h	43	(3)	88
Transmission Losses	GW.h	167	145	181
Net Firm Energy	GW.h	1039	752	1055
Net Total Peak	MW	181	132	179

Residential - The Residential forecast was increased as a result of higher average use predictions for Standard and All-Electric customers which reflect the large increase experienced over the last three years.

General Service - The General Service forecast was increased to reflect higher energy consumption expectations in the Chemical and Petroleum/Oil/Natural Gas sectors. The General Service Mass Market and General Service Top Consumers categories were revised to include the significant growth experienced over the 2002/03 fiscal year.

Area and Roadway Lighting - This category increased due to the inclusion of street lights in the Winnipeg Hydro service area.

Distribution Losses - The distribution loss percentage was lowered from 4.7% of Manitoba Hydro sales to 4.3% of all Manitoba Hydro and Winnipeg Hydro sales. The distribution loss forecast increased as a result because losses from the Winnipeg Hydro system are now being included in this category.

Construction Power - The Construction Power forecast was changed to reflect the updated in-service dates for the Wuskwatim and Gull generating stations.

Transmission Losses - The transmission loss percentage was raised from 9.3% to 9.7%, which reflects the level of transmission losses experienced over the last six years.

Net Firm Energy - All of the sectors listed before this category will influence Net Firm Energy. The increase is mainly due to higher expected loads in the Residential, General Service and Transmission Losses classifications.

Net Total Peak - The Net Total Peak increased as a result of higher growth levels for Net Firm Energy and because the initial starting point is much higher, reflecting the significant peak load growth experienced in the last two fiscal years. This growth is reflected in the parameters of the Hourly Load Model.

Table 4

NET FIRM ENERGY AND NET TOTAL PEAK CHANGE FROM PREVIOUS FORECAST						
	NET FIRM ENERGY			NET TOTAL PEAK		
Fiscal Year	Forecast Prepared May 2003 (GW.h)	Forecast Prepared May 2002 (GW.h)	Difference (GW.h)	Forecast Prepared May 2003 (MW)	Forecast Prepared May 2002 (MW)	Difference (MW)
2003/04	22171	21504	667	3956	3828	128
2004/05	22690	21708	982	4028	3850	178
2005/06	22976	21975	1001	4053	3882	171
2006/07	23262	22251	1011	4088	3914	174
2007/08	23554	22515	1039	4126	3945	181
2008/09	23783	22774	1009	4153	3975	178
2009/10	24009	23031	978	4180	4005	175
2010/11	24203	23322	881	4201	4041	160
2011/12	24430	23630	800	4228	4080	148
2012/13	24680	23928	752	4258	4126	132
2013/14	24927	24215	712	4296	4170	126
2014/15	25191	24464	727	4338	4210	128
2015/16	25458	24705	753	4380	4248	132
2016/17	25729	24985	744	4422	4293	129
2017/18	26001	25255	746	4465	4336	129
2018/19	26274	25517	757	4508	4378	130
2019/20	26576	25776	800	4556	4419	137
2020/21	26847	25949	898	4599	4446	153
2021/22	27143	26158	985	4646	4478	168
2022/23	27436	26381	1055	4692	4513	179

- See the Glossary of Terms for a definition of Net Firm Energy and Net Total Peak.

METHODOLOGY

The Base Forecast, Medium-Low and Medium-High scenarios were prepared to analyze the sensitivity towards changes in economic and demographic assumptions. These forecasts were prepared using a combination of forecasting techniques. Detailed explanations of the forecast models are contained in the Residential, General Service and Net Total Peak sections of this report. A brief summary of the methods used is described below:

Residential - Econometric and end-use analysis were performed and equations were developed to explain the relationship of Residential electricity consumption to various economic and demographic factors. The Residential Forecast for the Manitoba Hydro service area is calculated using a detailed multi-step, end-use approach. Econometrics are used to forecast the total number of Residential customers and to separate the customers into Standard (non-electric primary space heat) and All-Electric (electric primary space heat) categories. The 1998 Residential Survey provided an update for appliance saturation rates. This information was combined with previous survey results to prepare a forecast of future appliance saturation rates. Conditional Demand Analysis was performed on the appliance survey data to update unit energy consumption (UEC) for each appliance type. Energy Management staff provided estimates for appliance lifetimes and for future unit energy consumption of each major appliance. The information is used to calculate an energy forecast for each end-use. The Residential forecast for the Winnipeg Hydro service area was calculated using regression analysis of Standard and All-Electric sales by rate class because detailed market sector data was not available.

General Service - The energy use requirements of our Top Consumers in the Manitoba Hydro service area were reviewed individually. Regression equations were developed to predict the electricity consumption for the Mass Market of all other General Service customers in the Manitoba Hydro service area. A separate regression analysis was performed for all General Service customers in the Winnipeg Hydro service area. Estimates of the load reduction associated with Commercial lighting standards were then deducted from the regression output. The forecast has been modified to reflect any major customers' plans as well as applications for service from new customers.

Area and Roadway Lighting - Trends in the historical average use and number of customers were derived and extrapolated for the sentinel and street lighting classifications. Street Lighting for both service areas were combined for this analysis.

Net Total Peak - Annual energy is distributed to all 8 760 hours of the year using the base load, heating slope and cooling slope as calculated by the Hourly Load Model.

ASSUMPTIONS

Forecast assumptions for energy prices, real economic growth, population and housing are taken from the 2003 Economic Outlook and the 2003 Energy Price Outlook. The following is a general overview of the Electric Load Forecast assumptions:

Electricity - The electricity price forecast is based on CPI and rate increase projections contained in the Integrated Financial Forecast. After ten years the CPI is forecast to increase 2.0% per year and the electricity price increases are assumed to be 1.0% per year. The real price of electricity is forecast to decrease 12% throughout the forecast period.

Natural Gas - The real price of natural gas is expected to drop 12% over the next three years of the forecast. Natural gas prices are expected to return to normal levels and continue to dominate the space heating market.

Oil - This forecast assumes that new customers in no-gas available areas will choose to install an electric heating system rather than an oil heating system. The real price of oil is expected to decrease 5% throughout the forecast period. In 2002/03, electricity had a 50% price advantage over oil and is expected to maintain a significant price advantage throughout the forecast period.

Economic Activity - The forecast for real economic growth in Manitoba is 3.1% in 2003/04, 2.9% in 2004/05, 2.4% in 2005/06, 2.0% in 2006/07 and decreases slightly each year until reaching 1.4% by 2023/24. The real economic growth rate averages 1.8% throughout the forecast period.

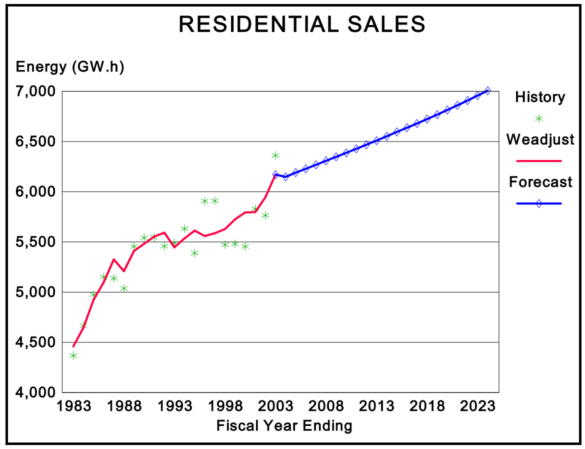
Population - The population of Manitoba is forecast to increase by 2 847 per year, compared to a historical average increase of 3 733 per year over the last ten years.

Housing - The number of homes in Manitoba area is forecast to increase 1 544 per year, compared to a historical average of 2 407 homes per year over the last decade.

RESIDENTIAL

The Residential sector represents 33.0% of all sales within Manitoba. It includes electricity sales to individually-metered Residential and Farm customers for non-business operations. The Residential sector is comprised of four forecast groups - Basic, Seasonal, Water Heating and Diesel. The last three groups represent only 1.5% of all Residential sales. These groups are forecasted separately because they have unique rates, distinct usage patterns or different billing periods. The adjacent graph shows that the load grew rapidly in the 80's due to conversions of oil to electric space heating systems.

Figure 1



The Residential sector is forecast to increase from a weather-adjusted base of 6 171 GW.h in 2002/03 to 7 007 GW.h by 2023/24. This represents an average growth of 40 GW.h per year, which is much lower than the ten year annual growth rate of 72 GW.h. The lower annual growth is primarily due to less housing starts and lower space heating requirements for new all-electric homes.

RESIDENTIAL HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Sales	Adjustment	Adjusted Sales	Fiscal Year	Forecast Sales
1982/83	4369	91	4460	2003/04	6148
1983/84	4666	-18	4648	2004/05	6191
1984/85	4975	-51	4924	2005/06	6229
1985/86	5152	-54	5098	2006/07	6268
1986/87	5138	188	5326	2007/08	6309
1987/88	5037	172	5209	2008/09	6348
1988/89	5455	-45	5410	2009/10	6388
1989/90	5543	-61	5482	2010/11	6428
1990/91	5545	9	5554	2011/12	6469
1991/92	5458	134	5592	2012/13	6510
1992/93	5489	-42	5447	2013/14	6552
1993/94	5632	-96	5536	2014/15	6596
1994/95	5388	225	5613	2015/16	6637
1995/96	5907	-348	5559	2016/17	6680
1996/97	5910	-323	5587	2017/18	6724
1997/98	5473	156	5629	2018/19	6768
1998/99	5482	243	5725	2019/20	6814
1999/00	5455	339	5794	2020/21	6861
2000/01	5830	-33	5797	2021/22	6909
2001/02	5765	180	5945	2022/23	6958
2002/03	6361	-190	6171	2023/24	7007

RESIDENTIAL BASIC METHODOLOGY

The forecast for Residential Basic customers was prepared separately for the Manitoba Hydro and Winnipeg Hydro service areas. A detailed multi-step, end-use approach was used to forecast the Manitoba Hydro service area. Regression analysis of Standard and All-Electric sales by rate class was used to forecast the Winnipeg Hydro service area. A detailed multi-step, end-use approach could not be used for these customers because survey data was unavailable for this market at the time of forecast preparation.

The Basic category represents 98.5% of the total Residential sales. This category is separated in two distinct groups - Basic Standard and Basic All-Electric. The Standard classification includes all Residential customers that are incapable of heating the premises with electricity. The All-Electric classification includes all Residential customers that are capable of heating the premises with electricity. This distinction is very important because the average Standard customer uses around 10,000 kW.h per year and the average All-Electric customer uses around 26,500 kW.h per year. Electric space heating is the dominant end-use in the Residential sector.

MANITOBA HYDRO SERVICE AREA

Residential Basic Customer Forecast - The Residential Basic category is forecast to increase 1 863 customers per year compared to the ten year annual of 2 724 customers. The number of housing starts is expected to be lower due to lower population growth rates and an aging population.

Standard and All-Electric customer data (1989-2002) is collected from the Customer Information Data Base (CIDB) by combination of town and zone. There are 649 town and zone combinations in Manitoba. The Residential Basic Customer Forecast is then allocated into these areas based on historical growth patterns. The area of the province in which a new home is built is a determining factor as to whether the house will use electric space heat. Homes built in natural gas available areas tend to use natural gas space as their space heating fuel; whereas homes built in areas where natural gas is not available tend to use electricity as their primary space heating fuel. This information is input to the Market Share Model.

Market Share Model - This model predicts the proportion of customers that will install electric heat in each of the forecast areas. This proportion is called the market share of electricity (MSE). It is calculated by dividing the number of All-Electric Basic customers by the number of total (Standard and All-Electric) Basic customers. This model employs an econometric equation that predicts the future MSE in each area based on the previous market share and the relative prices of oil and natural gas compared to electricity. Our analysis incorporates a dynamic logit model which assumes that the market shares will grow in the shape of an "S" or saturation curve. Our model produces the following results (with t statistics shown above):

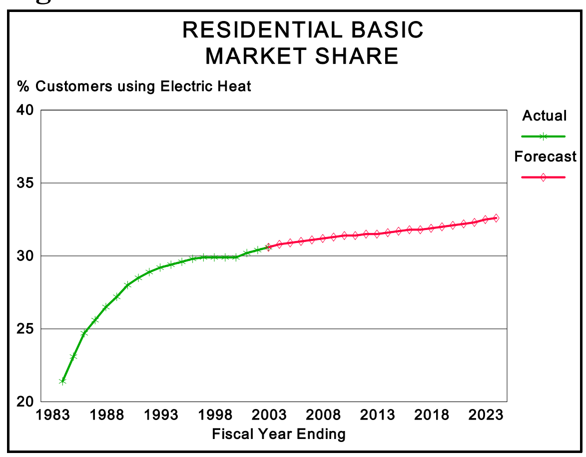
$$
\begin{array}{lllll}
 & (205.5) & (12.9) & & (-6.8) \\
LOGIT = & (.942 \times LOGIT1) & + (.075 \times Price) & - & .05416
\end{array}
$$

$$R^2 = 98.8\% \qquad DF = 8306$$

LOGIT	- Logit of the market share of electricity (MSE)
LOGIT1	- Logit of the market share of electricity for the previous year
Price	- Relative price of natural gas compared to electricity if natural gas is available or Relative price of oil compared to electricity if natural gas is not available

The adjacent graph shows that the MSE grew rapidly in the 1980's due to the Canadian Oil Substitution Program (COSP), the instability of oil and natural gas prices, the perception of fossil fuel shortages and the expectation of high price increases. The saturation of electric space heating is expected to increase slightly as natural gas prices return to more normal historic levels. There is a slight increase in the saturation of electric space heat in the last ten years because real electricity prices are forecast to decline 1% per year.

Figure 2



The Market Share Model is used to separate the Residential Basic Customer Forecast into Standard and All-Electric customer groups. All-Electric customers are calculated by multiplying the number of customers by the MSE. Standard customers are calculated by multiplying by (1-MSE).

Residential End Use Model - This model uses the Standard and All-Electric customer forecasts from the Market Share Model and incorporates appliance end-use assumptions. The appliance end-use assumptions include an appliance saturation forecast, current appliance usage information, appliance age distributions and appliance efficiency improvement information. This information is combined into a spreadsheet to prepare the Residential End Use Forecast.

a) Appliance Saturations - Historical appliance saturation data was collected from previous Manitoba Hydro Residential Surveys. Appliance saturations were forecast using a combination of historical appliance saturation information and professional judgement.

b) Appliance Usage - The current estimates of appliance usage or unit energy consumption (UEC) were calculated using 1998 Residential Survey information and Conditional Demand Analysis techniques. The survey results were screened for consumption records and survey completeness. Missing values for the size of home, people per household and income questions were imputed. Degree days heating/cooling and demographic factors such as income, people per household and size of household were added to help explain usage variations. The forecast specifies over thirty end-uses, including details of space heating by building type.

c) Efficiency Improvements - New appliances are much more efficient than existing appliance stock. The average use per appliance will decline due to the amount of efficiency improvement and the rate that older, inefficient stock is replaced. The future consumption levels of each end-use were analyzed and forecasted independently based on literature, contact with other utilities and professional judgment. Some end-uses such as fridges and freezers were forecasted to become significantly more efficient. The number of replacement appliances were calculated using a modified Weibull distribution with estimated appliance lifetimes.

The Residential Basic End Use Forecast is divided into Basic Standard and Basic All-Electric groups. The electric space heating end-uses are added to the All-Electric classification. The other end-uses are proportioned into the Standard and All-Electric classifications.

WINNIPEG HYDRO SERVICE AREA

Energy forecasts for both the Standard and All-Electric sectors were developed by modelling historical, weather-adjusted GW.h as a function of the previous years weather-adjusted GW.h and gross domestic product using log-log models. The model results for the Standard sector were as follows (with t-statistics shown above):

$$LNGW = \overset{(7.25)}{(.814 \times LNGW1)} + \overset{(1.70)}{(.084 \times LGDP)} + \overset{(0.5)}{0.28288}$$

R^2 = 82.1% DF = 21

LNGW - Log of the weather-adjusted GW.h
LNGW1 - Log of the weather-adjusted GW.h for the previous year
LGDP - Log of the Gross Domestic Product

The results for the All-Electric sector were as follows (with t-statistics shown above):

$$LNGW = \underset{(.870 \times LNGW1)}{(15.58)} + \underset{(.0008 \times LGDP)}{(0.01)} + \underset{0.59118}{(0.6)}$$

$R^2 = 96.9\%$ DF = 21

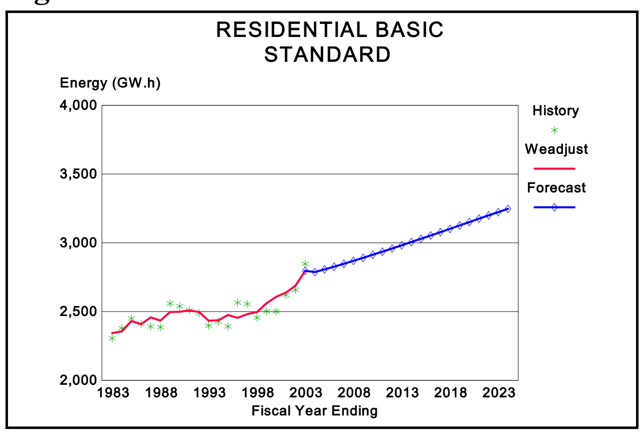
LNGW - Log of the weather-adjusted GW.h
LNGW1 - Log of the weather-adjusted GW.h for the previous year
LGDP - Log of the Gross Domestic Product

COMBINED SERVICE AREA

The Residential Standard and All-Electric forecasts for the Manitoba Hydro and Winnipeg Hydro service areas were combined to produce the following results:

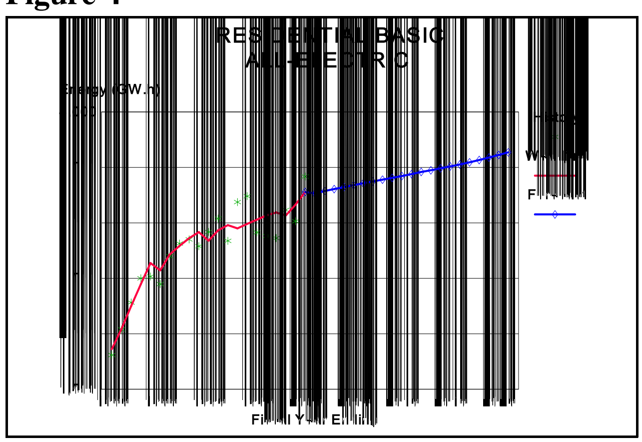
The Residential Basic Standard energy use remained quite constant during the 80's because many rural oil heated customers switched to electric space heat. The effect of appliance efficiency standards limited load growth in the early 90's. This sector has grown in the last five years. The forecast contains limited growth in the next few years as customers react to relatively high natural gas prices. The forecast assumes that most new homes will install electric water heaters.

Figure 3



The Residential Basic All-Electric energy grew rapidly in the 1980's as rural customers switched from oil to electric space heating. This sector continued to grow because most new homes in rural areas installed electric water and space heat. Many of the new, all-electric homes are being built in First Nations communities that do not have access to natural gas. This category will continue to grow due to new housing construction in rural areas.

Figure 4



RESIDENTIAL - OTHER

This category includes the three Residential groups that represent only 1.5% of all Residential sales. These groups are forecasted separately because they have unique rates, distinct usage patterns or different billing periods. These groups have a very minor effect on the overall load forecast and are not discussed in detail in this report. These groups are forecasted using trend analysis and extrapolation techniques.

Seasonal

There were 13 171 Residential Seasonal Standard customers by the end of the 2002/03 fiscal year. The number of customers is expected to decrease 1% per year throughout the forecast period. Average use was 2 111 kW.h per customer in 2002/03 and is forecast to be 2 200 kW.h per customer in 2003/04 and grow 50 kW.h per year. There were 7 059 Residential Seasonal All-Electric customers by the end of the 2002/03 fiscal year. The number of customers is forecast to be 7 400 in 2003/04 and increase 300 per year throughout the forecast period. Average use was 3 658 kW.h per customer in 2002/03 and is forecast to be 3 700 kW.h per customer in 2003/04 and grow 50 kW.h per year.

Water Heating

Residential Water Heating is a flat rate unmetered service. This service has not been available to new customers since November 12, 1969. There were 6 878 remaining customers in 2002/03. The ten year trend is an annual decrease of 4.9% in the number of customers. The number of customers is expected to decrease 5% per year throughout the forecast period. Average use was 5 121 kW.h per customer in 2002/03 and is forecasted to be 5 120 kW.h per customer.

Diesel

This group includes the remaining diesel sites in Manitoba - Brochet, Lac Brochet, Tadoule Lake and Shamattawa. These sites consumed 6 GW.h in 2002/03. Consumption is expected to increase to 14 GW.h by 2023/24. Consumption at these sites is expected to grow because the service limitations have been upgraded from 15 amps to 60 amps.

Table 5

TOTAL RESIDENTIAL SALES						
Fiscal Year	Basic GW.h	Diesel GW.h	Seasonal GW.h	FRWH GW.h	Total Residential GW.h	%
1991/92	5280	11	51	116	5458	12.0%
1992/93	5317	12	52	108	5489	0.6%
1993/94	5467	13	51	103	5632	2.6%
1994/95	5230	13	47	97	5388	-4.3%
1995/96	5753	15	48	92	5907	9.6%
1996/97	5797	16	48	49	5910	0.1%
1997/98	5370	13	46	45	5473	-7.4%
1998/99	5384	11	44	43	5482	0.2%
1999/00	5364	5	46	40	5455	-0.5%
2000/01	5737	5	49	39	5830	6.9%
2001/02	5674	6	49	37	5765	-1.1%
2002/03	6266	6	54	35	6361	10.3%
2003/04	6053	6	56	33	6148	-3.3%
2004/05	6094	7	58	32	6191	0.7%
2005/06	6132	7	60	30	6229	0.6%
2006/07	6170	8	62	29	6268	0.6%
2007/08	6210	8	64	27	6309	0.7%
2008/09	6248	9	66	26	6348	0.6%
2009/10	6287	9	67	25	6388	0.6%
2010/11	6326	10	69	23	6428	0.6%
2011/12	6365	10	71	22	6469	0.6%
2012/13	6405	10	73	21	6510	0.6%
2013/14	6445	11	76	20	6552	0.6%
2014/15	6488	11	78	19	6596	0.7%
2015/16	6528	12	80	18	6637	0.6%
2016/17	6569	12	82	17	6680	0.6%
2017/18	6611	12	84	16	6724	0.7%
2018/19	6654	13	86	16	6768	0.7%
2019/20	6698	13	88	15	6814	0.7%
2020/21	6743	13	90	14	6861	0.7%
2021/22	6789	14	93	13	6909	0.7%
2022/23	6836	14	95	13	6958	0.7%
2023/24	6884	14	97	12	7007	0.7%

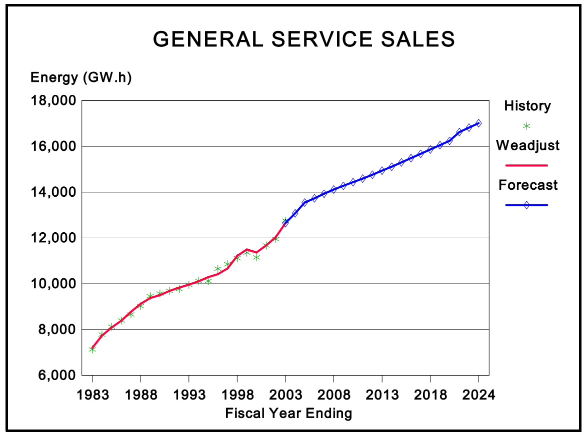
Table 6

RESIDENTIAL BASIC SALES										
Fiscal Year	Basic Standard			Basic All-Electric			Total Basic			MSE
	Mtrs.	GW.h	Avg.	Mtrs.	GW.h	Avg.	Mtrs.	GW.h	Avg.	
1991/92	279478	2490	8909	113436	2790	24595	392914	5280	13438	28.87%
1992/93	279767	2398	8571	115272	2918	25314	395039	5316	13457	29.18%
1993/94	280620	2428	8652	117071	3039	25959	397691	5467	13747	29.44%
1994/95	281511	2392	8497	118470	2838	23955	399981	5230	13076	29.62%
1995/96	282141	2565	9091	119789	3188	26613	401930	5753	14313	29.80%
1996/97	283461	2556	9017	120894	3241	26809	404355	5797	14336	29.90%
1997/98	285900	2456	8590	121658	2914	23952	407558	5370	13176	29.85%
1998/99	286626	2502	8729	122126	2882	23599	408752	5384	13172	29.88%
1999/00	288850	2501	8658	123156	2863	23247	412006	5364	13019	29.89%
2000/01	289796	2621	9044	125096	3117	24917	414892	5738	13830	30.15%
2001/02	290255	2659	9161	126515	3015	23831	416770	5674	13614	30.36%
2002/03	290830	2848	9793	128280	3418	26645	419110	6266	14951	30.61%
2003/04	291413	2788	9567	129756	3265	25163	421169	6053	14372	30.81%
2004/05	292035	2807	9612	130833	3287	25124	422868	6094	14411	30.94%
2005/06	292650	2827	9660	131722	3305	25091	424372	6132	14450	31.04%
2006/07	293357	2848	9708	132574	3322	25058	425931	6170	14486	31.13%
2007/08	294127	2870	9758	133437	3340	25031	427564	6210	14524	31.21%
2008/09	294878	2891	9804	134243	3357	25007	429121	6248	14560	31.28%
2009/10	295638	2914	9857	135024	3373	24981	430662	6287	14598	31.35%
2010/11	296407	2936	9905	135785	3390	24966	432192	6326	14637	31.42%
2011/12	297151	2959	9958	136521	3406	24949	433672	6365	14677	31.48%
2012/13	297913	2982	10010	137247	3422	24933	435160	6404	14716	31.54%
2013/14	298679	3006	10064	137984	3440	24930	436663	6446	14762	31.60%
2014/15	299411	3030	10120	138768	3459	24926	438179	6489	14809	31.67%
2015/16	300116	3054	10176	139608	3474	24884	439724	6528	14846	31.75%
2016/17	300792	3078	10233	140485	3492	24857	441277	6570	14889	31.84%
2017/18	301462	3102	10290	141347	3509	24825	442809	6611	14930	31.92%
2018/19	302097	3127	10351	142212	3527	24801	444309	6654	14976	32.01%
2019/20	302655	3151	10411	143124	3546	24776	445779	6697	15023	32.11%
2020/21	303162	3176	10476	144069	3567	24759	447231	6743	15077	32.21%
2021/22	303637	3200	10539	145044	3589	24744	448681	6789	15131	32.33%
2022/23	304075	3224	10603	146043	3612	24732	450118	6836	15187	32.45%
2023/24	304473	3248	10668	147065	3636	24724	451538	6884	15246	32.57%

GENERAL SERVICE

The General Service sector represents 66.5% of all sales in Manitoba. It includes sales to all Commercial and Industrial businesses in Manitoba. This sector consists of six forecast groups - Top Consumers, Mass Market, Seasonal, Water Heating, Diesel and Surplus Energy Program (SEP). The last four groups represent only 0.4% of all General Service sales. The adjacent graph shows continuous load growth over the last twenty years, except for a slight downturn in 1999/00.

Figure 5



The General Service sector is forecast to increase from a weather-adjusted base of 12 686 GW.h in 2002/03 to 17 011 GW.h by 2023/24. This represents an average growth of 206 GW.h per year, which is lower than the ten year annual growth rate of 272 GW.h per year. The increase in General Service consumption can be primarily attributed to steady economic performance and low electricity prices. The chemical and oil/petroleum sectors are expected to lead the way.

GENERAL SERVICE
HISTORICAL/WEATHER ADJUSTMENT/FORECAST

Fiscal Year	Sales	Adjustment	Adjusted Sales	Fiscal Year	Forecast Sales
1982/83	7132	66	7198	2003/04	13075
1983/84	7782	-46	7736	2004/05	13548
1984/85	8126	-38	8088	2005/06	13729
1985/86	8395	-9	8386	2006/07	13931
1986/87	8661	113	8774	2007/08	14117
1987/88	9021	98	9119	2008/09	14278
1988/89	9458	-82	9376	2009/10	14435
1989/90	9574	-70	9504	2010/11	14594
1990/91	9689	2	9691	2011/12	14762
1991/92	9772	60	9832	2012/13	14939
1992/93	9954	8	9962	2013/14	15113
1993/94	10126	-18	10108	2014/15	15299
1994/95	10120	169	10289	2015/16	15487
1995/96	10659	-242	10417	2016/17	15676
1996/97	10855	-186	10669	2017/18	15865
1997/98	11121	94	11215	2018/19	16054
1998/99	11360	139	11499	2019/20	16244
1999/00	11152	215	11367	2020/21	16434
2000/01	11673	4	11677	2021/22	16625
2001/02	11951	89	12040	2022/23	16818
2002/03	12796	-110	12686	2023/24	17011

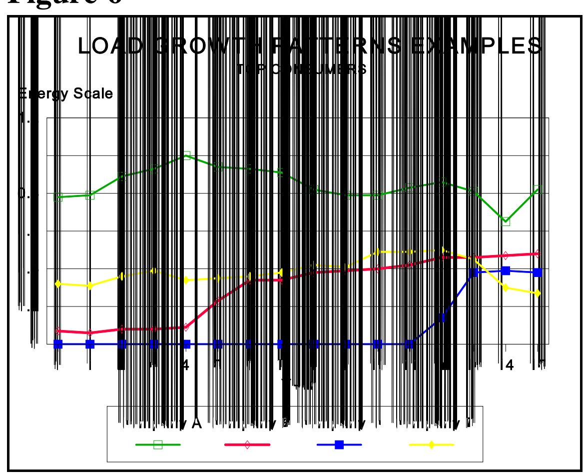
GENERAL SERVICE TOP CONSUMERS METHODOLOGY

This category includes the top energy consuming businesses in the Manitoba Hydro service area and represents 41.3% of all electricity consumed in the General Service sector. The Top Consumers group includes: INCO, HBM&S (Flin Flon/Stall), Gerdau (MRM), HBM&S (Ruttan), Griffin Canada, TVX Gold, Nexen Chemicals, Simplot, TransCanada Power (TCP), Enbridge, Tembec (Pine Falls Paper), Tolko, Louisiana Pacific, University of Manitoba, Maple Leaf (Brandon), Midwest Foods, McCain Foods, Albchem, and Simplot Potato. The Top Consumers category includes all future energy requirements for the above mentioned customers. Some customers are planning major expansions, some customers are expected to remain at current operating levels and some customers are planning to reduce their levels of consumption in the future.

This category must also contain some speculative load growth because new, large Industrial customers will be energized to the Manitoba system in the future. Therefore, starting in 2007/08, we have created a classification called Potential Large Industrial Loads. This classification is used to represent the load requirements of potential Industrial loads that will be energized throughout the forecast period, but at this time, these loads are unspecified. Since 1980/81, seven new Industrial loads have been energized in Manitoba - HBM&S at Flin Flon, TransCanada Power at Iles Des Chenes, Maple Leaf at Brandon, Louisiana Pacific, New Britannia (TVX Gold) mine, Albchem and Simplot Potato. The forecast must contain an allotment for new Industrial customers to set up operations in Manitoba.

Each customer in the Top Consumers group is forecasted individually. Information on individual company operating plans is collected by Manitoba Hydro Key and Major Account representatives. This information is used to prepare company specific forecasts. Information of this nature can be very sensitive and, as such, is treated as confidential and not available for public review.

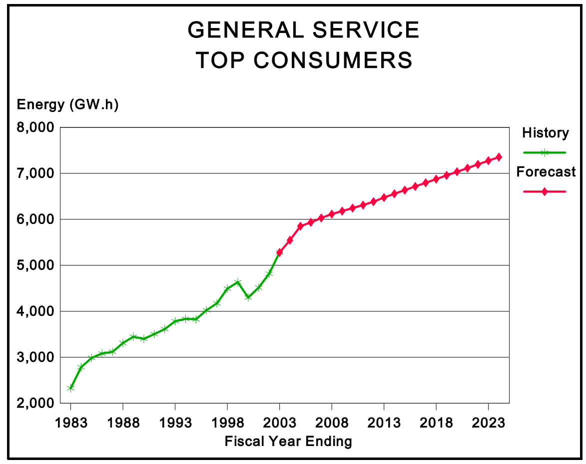
Figure 6



The Top Consumers must be forecast individually because their loads do not grow in a slow, steady, predictable pattern. Their loads can change abruptly and in distinct stages. If a customer decides to expand operations, the load will increase quickly. Conversely, if a customer decides to down size or cease operations, the load will decrease dramatically. These type of load changes are not conducive to econometric forecasting models and must be examined on an individual basis. The adjacent graph illustrates the example of annual load variation that can occur with large Industrial customers. Company A had a strike in year fourteen. Company B grew steadily throughout, but had a major expansion in years five and six. Company C started operations in year twelve. Company D increased production in year fourteen, but lowered electricity consumption due to plant efficiency improvements.

The adjacent graph shows that the Top Consumers category has grown consistently over the last two decades, except for a downturn in 1999/00 caused by reduced consumption by INCO, Enbridge and Simplot. Seven new loads (HBM&S at Flin Flon, TransCanada Power, Maple Leaf, Louisiana Pacific, New Britannia, Albchem and Simplot Potato) have been added to the system since 1981. These new customers have added 1 618 GW.h of load over the period, averaging 74 GW.h per year. Expansion at Nexen Chemicals has also contributed to the growth of this sector.

Figure 7



The Top Consumer category is forecast to increase from a base of 5 279 GW.h in 2002/03 to 7 355 GW.h by 2023/24. This represents an average growth of 99 GW.h per year, which is lower than the ten year annual growth rate of 150 GW.h per year.

In 2003/04, this group is expected to grow significantly due to increased pumping requirements of Enbridge as Phase III of the Terrance Expansion is completed, increased production at Albchem and the addition of the Simplot Potato manufacturing facility. This growth will be offset slightly as Ruttan ceases operations and Tolko is expected to add self-generation.

The forecast includes some potential for conversion of natural gas pipelines to electric drive motors, further expansion in the chemicals sector and 80 GW.h per year by 2007/08, increasing to 100 GW.h per year by 2013/14 for other Potential Large Industrial loads.

GENERAL SERVICE MASS MARKET METHODOLOGY

Separate econometric forecasts were prepared for the Manitoba Hydro and Winnipeg Hydro service areas. The results were combined to produce a General Service Mass Market forecast for Manitoba.

MANITOBA HYDRO SERVICE AREA

This category includes all other Commercial and Industrial businesses located in the Manitoba Hydro service area, excluding the Top Consumers group. This group is forecasted using econometric techniques. The General Service Mass Market econometric model was derived using sales data over the 1989-2002 period and produced the following results (with t-statistics shown above):

$$LGSNG = \underset{(0.5)}{(.106 \times LGSNG1)} + \underset{(-0.7)}{(-.187 \times LRPE1)} + \underset{(3.7)}{(.746 \times LGDP)} + \underset{(0.1)}{0.18388}$$

$R^2 = 99.2\%$ DF = 7

LGSNG - Log of the weather-adjusted General Service Mass Market sales
LGSNG1 - Log of the weather-adjusted General Service Mass Market sales for the previous year
LRPE1 - Log of the real price of electricity for the previous year
LGDP - Log of the real gross domestic product

The Mass Market forecast is finalized by reducing the econometric results by the amount of expected savings from Commercial and Industrial DSM programs. The forecast is then allocated to the Small Non-Demand, Small Demand, Medium and Large rate classes based on historical growth proportions.

WINNIPEG HYDRO SERVICE AREA

The Energy forecast for the Winnipeg Hydro General Service Mass Market was developed by modelling historical weather-adjusted GW.h as a function of the previous years weather-adjusted GW.h and gross domestic product. The model results were derived over the 1988-2003 period and produced which follow (with t-statistics shown above):

$$LNGW = \overset{(2.70)}{(.528 \times LNGW1)} + \overset{(1.65)}{(.128 \times LGDP)} + \overset{(2.5)}{2.211}$$

$R^2 = 82.8\%$ DF = 13

LNGW - Log of the weather-adjusted GW.h

LNGW1 - Log of the weather-adjusted GW.h for the previous year
LGDP - Log of the Gross Domestic Product

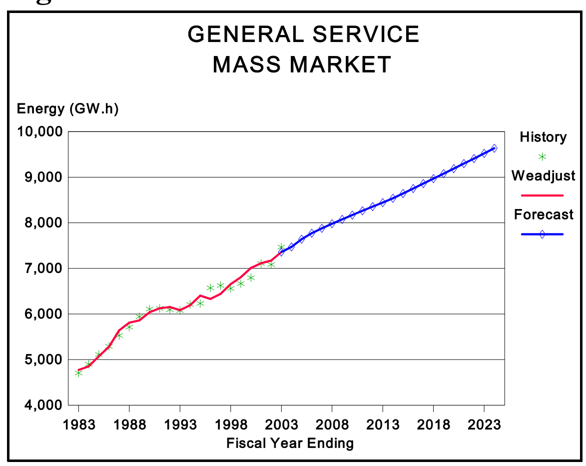
The Mass Market forecast is finalized by reducing the econometric results by the amount of expected savings from Commercial and Industrial DSM programs. The forecast is then allocated to the Small Non-Demand, Small Demand, Medium and Large rate classes based on historical growth proportions.

COMBINED SERVICE AREA

The General Service Mass Market forecasts for the Manitoba Hydro and Winnipeg Hydro service areas were combined to produce a General Service Mass Market forecast for Manitoba, resulting in the following:

The Mass Market load has grown steadily throughout the last two decades, except for brief periods of inactivity during the economic downturn of the early 1990's. This load is resilient and does not decrease dramatically due to economic fluctuations, plant closures and strikes. Many of the larger businesses in this group are schools, hospitals, grocery stores, hotels, large offices and government buildings that provide necessary services. These businesses are fairly stable, electricity consumption is not as dependent on volatile market conditions.

Figure 8



The Mass Market category is forecast to increase from 7 469 GW.h in 2002/03 to 9 636 GW.h by 2023/24. This represents an average growth of 103 GW.h per year, which is lower than the ten year annual growth rate of 139 GW.h per year. The Mass Market growth is based on expectations of steady economic growth, constant real electricity prices in the first ten years of the forecast and declining real electricity prices in the second ten years of the forecast.

GENERAL SERVICE - OTHER

This category includes the four General Service groups that represent only 0.4% of all General Service sales. These groups have unique rate codes and are forecasted separately for rate and billing purposes. These groups have a very minor effect on the overall load forecast and therefore will not be discussed in detail in this report. These groups are forecasted using trend analysis and extrapolation techniques.

Seasonal

There were 783 General Service Seasonal customers by the end of the 2002/03 fiscal year. The five year trend is an annual decrease of 2% in the number of customers per year. The number of customers is expected to be 767 in 2003/04 and decline 2 % year. Average use was 5 534 kW.h per customer in 2002/03 and is forecast to remain constant at 5 550 kW.h per customer throughout the forecast period.

Water Heating

General Service Water Heating is a flat rate unmetered service that has not been available since November 12, 1969. There were 633 remaining customers by the end of the 2002/03 fiscal year. The five year trend is an annual decrease of 4.2% in the number of customers. The number of customers is expected to decrease 5% per year throughout the forecast period. Average use was 21 730 kW.h per customer in 2002/03 and is forecast to be 21 700 kW.h per customer throughout the forecast period.

Diesel

The Diesel Full Cost classification consumed 4 GW.h in 2002/03. Consumption is expected to increase to 12 GW.h by 2023/24.

Surplus Energy Program

Participants in the Surplus Energy Program (SEP) are expected to consume 35 GW.h per year during the 2003/04 to 2004/05 period and then the program will be discontinued or altered in some fashion.

Table 7

Fiscal Year	Mass Market (GW.h)	Top Consumers (GW.h)	Diesel (GW.h)	Seasonal (GW.h)	FRWH (GW.h)	SEP/DFH (GW.h)	Total General Service (GW.h)	%
1991/92	6094	3611	11	7	42	6	9772	0.9%
1992/93	6077	3783	12	7	39	37	9954	1.9%
1993/94	6210	3836	13	6	35	27	10126	1.7%
1994/95	6233	3825	14	6	32	10	10120	-0.1%
1995/96	6573	4021	16	5	30	14	10659	5.3%
1996/97	6627	4173	17	5	18	15	10855	1.8%
1997/98	6562	4493	14	5	16	31	11121	2.5%
1998/99	6668	4632	9	5	15	30	11360	2.1%
1999/00	6796	4299	4	5	15	33	11152	-1.8%
2000/01	7110	4515	4	4	15	26	11673	4.7%
2001/02	7084	4818	5	4	14	24	11951	2.4%
2002/03	7469	5279	4	4	14	25	12796	7.1%
2003/04	7472	5546	5	4	13	35	13075	2.2%
2004/05	7641	5850	5	4	12	35	13548	3.6%
2005/06	7773	5935	6	4	12	0	13729	1.3%
2006/07	7880	6030	6	4	11	0	13931	1.5%
2007/08	7981	6115	6	4	11	0	14117	1.3%
2008/09	8077	6180	7	4	10	0	14278	1.1%
2009/10	8170	6245	7	4	10	0	14435	1.1%
2010/11	8264	6310	8	4	9	0	14594	1.1%
2011/12	8356	6385	8	4	9	0	14762	1.2%
2012/13	8444	6475	8	4	8	0	14939	1.2%
2013/14	8538	6555	9	3	8	0	15113	1.2%
2014/15	8644	6635	9	3	7	0	15299	1.2%
2015/16	8752	6715	10	3	7	0	15487	1.2%
2016/17	8861	6795	10	3	7	0	15676	1.2%
2017/18	8970	6875	10	3	6	0	15865	1.2%
2018/19	9079	6955	11	3	6	0	16054	1.2%
2019/20	9189	7035	11	3	6	0	16244	1.2%
2020/21	9300	7115	11	3	5	0	16434	1.2%
2021/22	9410	7195	12	3	5	0	16625	1.2%
2022/23	9523	7275	12	3	5	0	16818	1.2%
2023/24	9636	7355	12	3	5	0	17011	1.1%

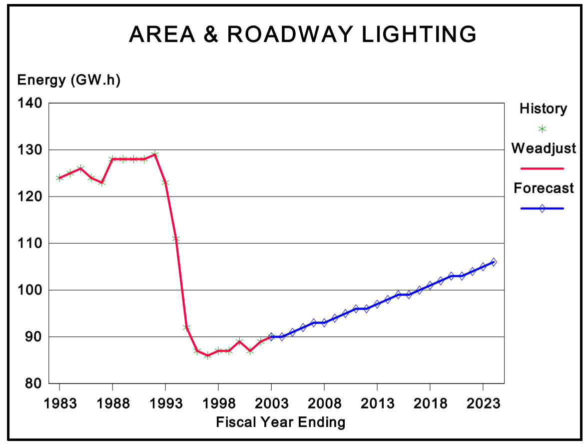
Table 8

GENERAL SERVICE BASIC SALES									
Fiscal Year	Mass Market			Top Consumers			Total Basic		
	Mtrs.	GW.h	Avg.	Mtrs.	GW.h	Avg. (MW.h)	Mtrs.	GW.h	Avg.
1991/92	57339	6094	106280	18	3611	200611	57357	9705	169203
1992/93	57543	6077	105608	20	3783	189150	57563	9860	171291
1993/94	57713	6210	107601	21	3836	182667	57734	10046	174005
1994/95	57954	6233	107551	21	3825	182143	57975	10058	173489
1995/96	58194	6573	112950	23	4021	174826	58217	10594	181974
1996/97	58134	6627	113995	28	4173	149036	58162	10800	185688
1997/98	58717	6562	111756	33	4493	136152	58750	11055	188170
1998/99	59214	6668	112609	34	4632	136235	59248	11300	190724
1999/00	59612	6796	114004	35	4299	122829	59647	11095	186011
2000/01	59938	7110	118623	31	4515	145645	59969	11625	193850
2001/02	60184	7084	117706	25	4818	192720	60209	11902	197678
2002/03	60470	7469	123516	26	5279	203038	60496	12748	210725
2003/04	60817	7472	122860	27	5546	205407	60844	13018	213957
2004/05	61164	7641	124926	26	5850	225000	61190	13491	220477
2005/06	61512	7773	126366	26	5935	228269	61538	13708	222757
2006/07	61860	7880	127384	26	6030	231923	61886	13910	224768
2007/08	62208	7981	128295	27	6115	226481	62235	14096	226496
2008/09	62557	8077	129114	27	6180	228889	62584	14257	227806
2009/10	62906	8170	129876	27	6245	231296	62933	14415	229053
2010/11	63255	8264	130646	26	6310	242692	63281	14574	230306
2011/12	63604	8356	131375	26	6385	245577	63630	14741	231667
2012/13	63954	8444	132032	26	6475	249038	63980	14919	233182
2013/14	64304	8538	132776	26	6555	252115	64330	15093	234618
2014/15	64654	8644	133696	26	6635	255192	64680	15279	236224
2015/16	65005	8752	134636	26	6715	258269	65031	15467	237840
2016/17	65356	8861	135581	26	6795	261346	65382	15656	239454
2017/18	65707	8970	136515	26	6875	264423	65733	15845	241051
2018/19	65058	9079	139552	26	6955	267500	65084	16034	246359
2019/20	66410	9189	138368	26	7035	270577	66436	16224	244205
2020/21	66762	9300	139301	26	7115	273654	66788	16415	245778
2021/22	67114	9410	140209	26	7195	276731	67140	16605	247319
2022/23	67467	9523	141150	26	7275	279808	67493	16798	248885
2023/24	67820	9636	142082	26	7355	282885	67846	16991	250435

AREA & ROADWAY LIGHTING

The Area and Roadway Lighting sector represents only 0.5% of all sales within Manitoba. It includes electricity sales for the Sentinel Lighting and Street Lighting rate classes. Sentinel Lighting is an outdoor lighting service where units are available as rentals to an existing metered service or on an unmetered flat rate basis. Street Lighting includes all municipal roadway lighting in Manitoba. In the early 1990's, usage dropped due to conversion to energy-efficient, high-pressure, sodium vapour street lighting.

Figure 9



The Area and Roadway Lighting sector is forecast to increase from 90 GW.h in 2002/03 to 106 GW.h by 2023/24. Sentinel Lighting is forecast to increase by 300 rentals per year with an estimated usage of 515 kW.h each. Street Lighting is forecast to increase an average of 0.6 GW.h per year because most of the existing street lights have been converted through the DSM initiative. New street lighting additions should increase overall consumption.

AREA & ROADWAY LIGHTING HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Sales	Adjustment	Adjusted Sales	Fiscal Year	Forecast Sales
1982/83	124	0	124	2003/04	90
1983/84	125	0	125	2004/05	91
1984/85	126	0	126	2005/06	92
1985/86	124	0	124	2006/07	93
1986/87	123	0	123	2007/08	93
1987/88	128	0	128	2008/09	94
1988/89	128	0	128	2009/10	95
1989/90	128	0	128	2010/11	96
1990/91	128	0	128	2011/12	96
1991/92	129	0	129	2012/13	97
1992/93	123	0	123	2013/14	98
1993/94	111	0	111	2014/15	99
1994/95	92	0	92	2015/16	99
1995/96	87	0	87	2016/17	100
1996/97	86	0	86	2017/18	101
1997/98	87	0	87	2018/19	102
1998/99	87	0	87	2019/20	103
1999/00	89	0	89	2020/21	103
2000/01	87	0	87	2021/22	104
2001/02	89	0	89	2022/23	105
2002/03	90	0	90	2023/24	106

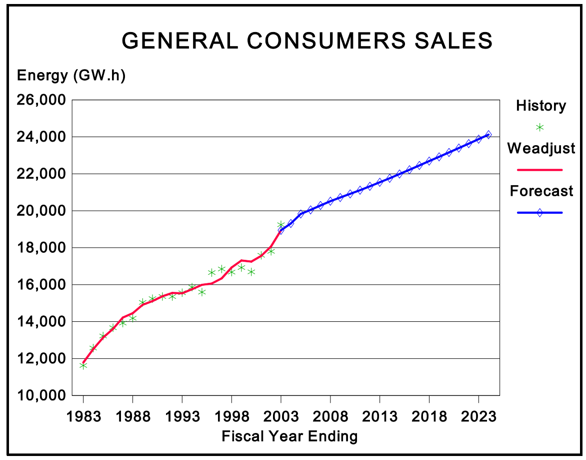
Table 9

AREA AND ROADWAY LIGHTING								
Fiscal Year	Sentinel Flat Rates		Sentinel Rentals		Street Lighting		Total Lighting	
	Mtrs	GW.h	Mtrs	GW.h	Mtrs	GW.h	Mtrs	GW.h
1991/92	14505	15	5447	0	805	113	20757	128
1992/93	15103	13	5399	0	830	110	21332	123
1993/94	15597	14	5422	0	841	97	21860	111
1994/95	15945	8	5394	0	781	84	22120	92
1995/96	16461	8	5383	0	753	79	22597	87
1996/97	17146	9	5431	0	738	78	23315	87
1997/98	17723	9	5482	0	736	78	23941	87
1998/99	18144	9	5507	0	768	78	24419	87
1999/00	18875	10	5468	0	740	79	25083	89
2000/01	19029	10	5483	0	738	77	25250	87
2001/02	19364	10	5475	0	743	79	25582	89
2002/03	19556	10	5501	0	748	80	25805	90
2003/04	19700	10	5475	0	750	80	25925	90
2004/05	20000	10	5475	0	752	81	26227	91
2005/06	20300	10	5475	0	754	81	26529	91
2006/07	20600	11	5475	0	756	82	26831	93
2007/08	20900	11	5475	0	758	83	27133	94
2008/09	21200	11	5475	0	760	83	27435	94
2009/10	21500	11	5475	0	762	84	27737	95
2010/11	21800	11	5475	0	764	84	28039	95
2011/12	22100	11	5475	0	766	85	28341	96
2012/13	22400	12	5475	0	768	86	28643	98
2013/14	22700	12	5475	0	770	86	28945	98
2014/15	23000	12	5475	0	772	87	29247	99
2015/16	23300	12	5475	0	774	87	29549	99
2016/17	23600	12	5475	0	776	88	29851	100
2017/18	23900	12	5475	0	778	89	30153	101
2018/19	24200	12	5475	0	780	89	30455	101
2019/20	24500	13	5475	0	782	90	30757	103
2020/21	24800	13	5475	0	784	91	31059	104
2021/22	25100	13	5475	0	786	91	31361	104
2022/23	25400	13	5475	0	788	92	31663	105
2023/24	25700	13	5475	0	790	92	31965	105

GENERAL CONSUMERS

The General Consumers category consists of all sales delivered to customers in Manitoba. This category includes the total of all sales from the Residential, General Service and Lighting groups. The General Service sector makes up about two-thirds, the Residential sector makes up about one-third and the Lighting group is only 0.5% of all sales. The adjacent graph shows that General Consumers sales have grown steadily over the last twenty years. The high growth rates in the 80's were due to electric space heating conversions.

Figure 10



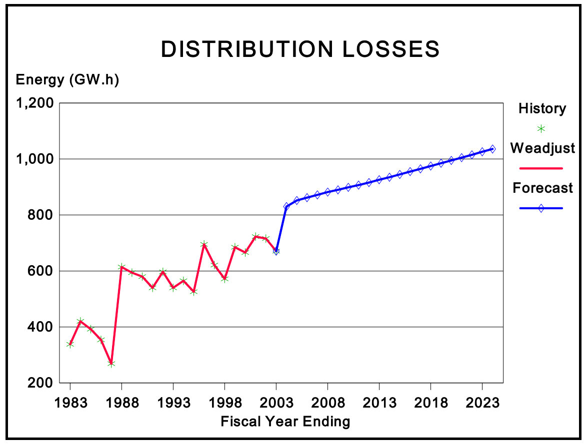
The General Consumers category is forecast to increase from a weather-adjusted base of 18 947 GW.h in 2002/03 to 24 124 GW.h by 2023/24. This represents an average growth of 247 GW.h per year, which is significantly lower than the ten year annual growth rate of 342 GW.h. The reasons for growth are previously specified in the Residential and General Service sections of this report.

GENERAL CONSUMERS HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Sales	Adjustment	Adjusted Sales	Fiscal Year	Forecast Sales
1982/83	11626	157	11783	2003/04	19314
1983/84	12573	-64	12509	2004/05	19830
1984/85	13226	-89	13137	2005/06	20051
1985/86	13670	-63	13607	2006/07	20292
1986/87	13922	301	14223	2007/08	20519
1987/88	14186	271	14457	2008/09	20720
1988/89	15041	-128	14913	2009/10	20919
1989/90	15245	-131	15114	2010/11	21118
1990/91	15362	12	15374	2011/12	21327
1991/92	15358	195	15553	2012/13	21546
1992/93	15566	-34	15532	2013/14	21762
1993/94	15870	-115	15755	2014/15	21994
1994/95	15600	394	15994	2015/16	22224
1995/96	16654	-590	16064	2016/17	22457
1996/97	16851	-509	16342	2017/18	22690
1997/98	16681	250	16931	2018/19	22924
1998/99	16929	382	17311	2019/20	23160
1999/00	16696	553	17249	2020/21	23398
2000/01	17590	-29	17561	2021/22	23638
2001/02	17805	269	18074	2022/23	23880
2002/03	19246	-299	18947	2023/24	24124

DISTRIBUTION LOSSES

The Distribution Losses category represents the resistence losses incurred in delivering power from the distribution station to the customers' meter. These losses are the difference between Manitoba Load at Common Bus less Construction and General Consumers less Diesel. Diesel sales are excluded because they are not part of the Integrated System. The losses vary because General Consumers sales are measured on a cycle billing basis and Common Bus is measured on a calendar month basis. Use at the customers' meter lags the delivery of power to the Common Bus.

Figure 11



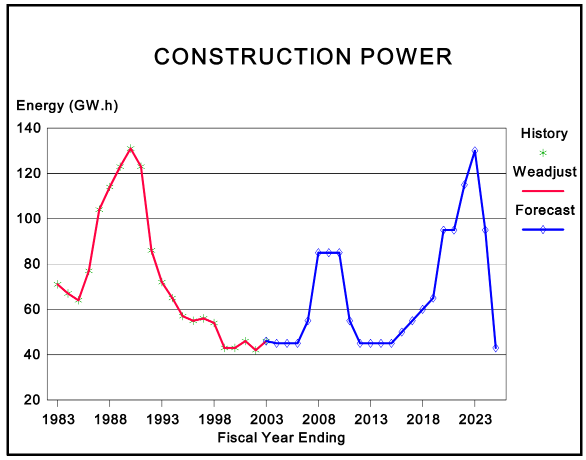
This category also includes unbilled sales and the error associated with flat rate estimates. Unbilled sales include energy used by Manitoba Hydro offices, Customer Accounting adjustments and energy lost through theft. Flat rate estimates include a number of unmetered services where energy is estimated and subject to inaccuracy. Distribution losses are forecast to be 4.3% higher than General Consumers less Diesel.

DISTRIBUTION LOSSES HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Losses	Adjustment	Adjusted Losses	Fiscal Year	Forecast Losses
1982/83	338	0	338	2003/04	830
1983/84	419	0	419	2004/05	852
1984/85	389	0	389	2005/06	862
1985/86	354	0	354	2006/07	872
1986/87	269	0	269	2007/08	882
1987/88	614	0	614	2008/09	890
1988/89	508	0	508	2009/10	899
1989/90	487	0	487	2010/11	907
1990/91	455	0	455	2011/12	916
1991/92	559	0	559	2012/13	926
1992/93	530	0	530	2013/14	935
1993/94	565	0	565	2014/15	945
1994/95	526	0	526	2015/16	955
1995/96	696	0	696	2016/17	965
1996/97	621	0	621	2017/18	975
1997/98	572	0	572	2018/19	985
1998/99	685	0	685	2019/20	995
1999/00	666	0	666	2020/21	1005
2000/01	723	0	723	2021/22	1015
2001/02	716	0	716	2022/23	1026
2002/03	671	0	671	2023/24	1036

CONSTRUCTION POWER

The Construction Power category represents the energy used by Manitoba Hydro and its contractors in the construction of major capital works such as generating stations, converter stations and major transmission lines. This category also includes station service until a plant is commissioned. The adjacent graph shows that consumption increased significantly during the peak of Limestone development. Recently, the Construction figures include about 45 GW.h for consumption at the Gillam, Limestone and Kettle townsites.

Figure 12



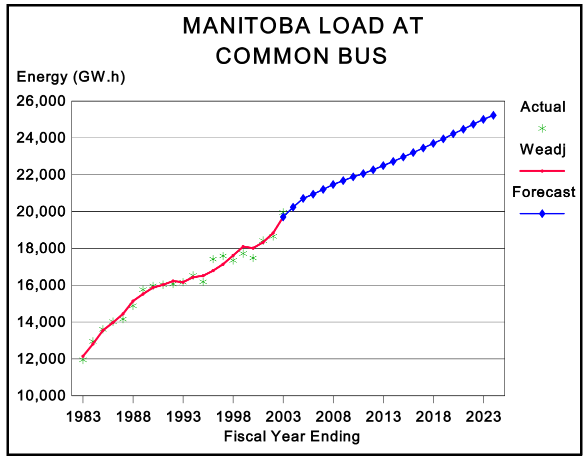
The Construction Power category is forecast to be 45 GW.h per year until the construction of Wuskwatim and Gull generating stations commence. The most recent, approved development plans project for a first power date of 2009 and 2023 for the Wuskwatim and Gull generating stations, respectively. The sequencing of generation development plans are subject to change given an appropriate business case.

CONSTRUCTION POWER HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Use	Adjustment	Adjusted Use	Fiscal Year	Forecast Use
1982/83	71	0	71	2003/04	45
1983/84	67	0	67	2004/05	45
1984/85	64	0	64	2005/06	45
1985/86	77	0	77	2006/07	55
1986/87	104	0	104	2007/08	85
1987/88	114	0	114	2008/09	85
1988/89	123	0	123	2009/10	85
1989/90	131	0	131	2010/11	55
1990/91	123	0	123	2011/12	45
1991/92	86	0	86	2012/13	45
1992/93	72	0	72	2013/14	45
1993/94	65	0	65	2014/15	45
1994/95	57	0	57	2015/16	50
1995/96	55	0	55	2016/17	55
1996/97	56	0	56	2017/18	60
1997/98	54	0	54	2018/19	65
1998/99	43	0	43	2019/20	95
1999/00	43	0	43	2020/21	95
2000/01	46	0	46	2021/22	115
2001/02	42	0	42	2022/23	130
2002/03	46	0	46	2023/24	95

MANITOBA LOAD AT COMMON BUS

Manitoba Load at Common Bus is the sum of all Manitoba Hydro and Winnipeg Hydro loads at Common Bus. It represents the total load measured from all the distribution points within Manitoba. It includes all sales to Manitoba customers plus associated distribution losses. This category excludes transmission losses and station service. In the 1980's, load growth was due to rural electric space heat conversions and downtown development in Winnipeg. In the 1990's, load growth was due to Industrial development in the Manitoba Hydro service area.

Figure 13



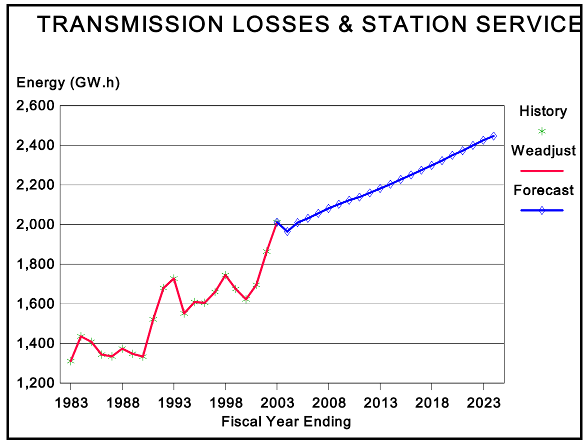
The Manitoba Load at Common Bus category is forecast to increase from a weather-adjusted base of 19 706 GW.h in 2002/03 to 25 228 GW.h by 2023/24. This represents an average growth of 263 GW.h per year, which is significantly lower than the ten year annual growth rate of 354 GW.h. Most of this load growth will occur due to Industrial development in the Manitoba Hydro service area.

MANITOBA LOAD AT COMMON BUS HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	MLCB	Adjustment	Adjusted MLCB	Fiscal Year	Forecast MLCB
1982/83	11949	193	12142	2003/04	20241
1983/84	12951	-141	12810	2004/05	20715
1984/85	13605	-56	13549	2005/06	20944
1985/86	14021	-49	13972	2006/07	21205
1986/87	14160	284	14444	2007/08	21471
1987/88	14886	251	15137	2008/09	21680
1988/89	15760	-239	15521	2009/10	21886
1989/90	15964	-94	15870	2010/11	22063
1990/91	16031	-6	16025	2011/12	22270
1991/92	16067	160	16227	2012/13	22498
1992/93	16166	2	16168	2013/14	22723
1993/94	16523	-87	16436	2014/15	22963
1994/95	16185	330	16515	2015/16	23207
1995/96	17418	-626	16792	2016/17	23454
1996/97	17590	-447	17143	2017/18	23702
1997/98	17350	269	17619	2018/19	23950
1998/99	17722	373	18095	2019/20	24226
1999/00	17479	538	18017	2020/21	24474
2000/01	18428	-96	18332	2021/22	24743
2001/02	18655	184	18839	2022/23	25010
2002/03	19953	-247	19706	2023/24	25228

TRANSMISSION LOSSES

Transmission Losses category represents the amount of energy that is lost in delivering power from the generation stations to all of the distribution points on the Common Bus. This category only contains losses associated with supplying Manitoba customers. Losses attributable to exports and the gains attributable to imports are excluded. It is calculated as the difference between Net Total Energy minus the Manitoba Load at Common Bus. Transmission losses are substantial because most of the northern generation is transmitted to southern distribution points - 900 kilometres away. Transmission losses vary significantly depending on system configuration, outages and the magnitude of the load being transmitted over the lines. Note that the Transmission losses increased dramatically in 2002/03 due to the failure of two transformers on the HVDC system.

Figure 14



Transmission Losses are forecasted to be 9.7% of the Manitoba Load at Common Bus. Transmission Losses will increase as the Manitoba Load at Common Bus increases.

TRANSMISSION LOSSES HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Losses	Adjustment	Adjusted Losses	Fiscal Year	Forecast Losses
1982/83	1311	0	1311	2003/04	1965
1983/84	1436	0	1436	2004/05	2010
1984/85	1409	0	1409	2005/06	2032
1985/86	1344	0	1344	2006/07	2057
1986/87	1335	0	1335	2007/08	2082
1987/88	1374	0	1374	2008/09	2103
1988/89	1348	0	1348	2009/10	2123
1989/90	1334	0	1334	2010/11	2139
1990/91	1522	0	1522	2011/12	2160
1991/92	1680	0	1680	2012/13	2182
1992/93	1728	0	1728	2013/14	2204
1993/94	1552	0	1552	2014/15	2228
1994/95	1609	0	1609	2015/16	2251
1995/96	1606	0	1606	2016/17	2275
1996/97	1660	0	1660	2017/18	2299
1997/98	1745	0	1745	2018/19	2323
1998/99	1675	0	1675	2019/20	2350
1999/00	1623	0	1623	2020/21	2373
2000/01	1696	0	1696	2021/22	2400
2001/02	1894	0	1894	2022/23	2426
2002/03	2012	0	2012	2023/24	2447

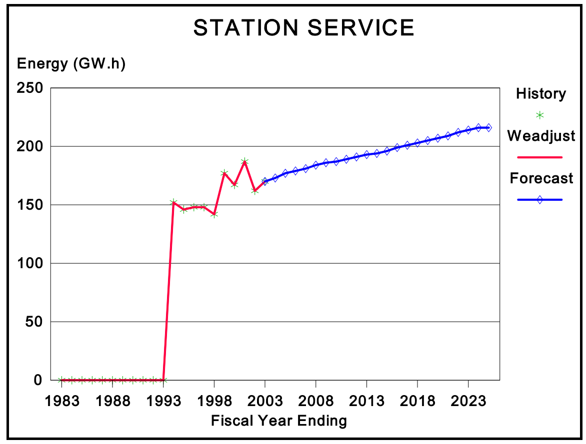
Table 10

MONTHLY TRANSMISSION LOSSES Energy (GW.h)													
Fiscal Year	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Total**
2002/03 Actual	152	146	151	150	150	141	189	168	208	196	151	209	2012
2003/04	147	145	144	146	150	143	156	171	200	205	181	178	1965
2004/05	150	148	148	149	154	147	158	176	206	210	180	182	2010
2005/06	151	150	149	151	156	148	160	178	208	213	182	184	2032
2006/07	153	152	151	153	159	150	162	180	210	215	184	187	2057
2007/08	155	154	153	155	161	152	164	183	213	218	186	189	2082
2008/09	156	155	155	157	163	153	165	184	216	220	188	191	2103
2009/10	157	157	156	159	165	154	167	186	218	222	190	193	2123
2010/11	158	158	157	161	166	155	168	187	219	224	191	195	2139
2011/12	159	159	159	163	168	157	169	189	222	226	193	196	2160
2012/13	161	161	161	165	170	158	171	191	224	228	195	199	2182
2013/14	162	162	162	166	172	160	172	193	227	231	197	201	2204
2014/15	164	164	164	168	174	161	174	195	229	233	199	203	2228
2015/16	165	165	165	169	175	163	176	197	232	236	201	205	2251
2016/17	167	167	167	171	177	164	177	199	235	239	204	208	2275
2017/18	169	168	168	172	179	166	179	201	238	242	206	210	2299
2018/19	170	170	170	174	180	167	181	204	241	245	209	212	2323
2019/20	172	172	172	176	182	169	183	206	244	248	211	215	2350
2020/21	174	173	173	177	184	170	185	208	247	251	214	217	2373
2021/22	176	175	175	179	186	172	186	211	250	254	216	220	2400
2022/23	177	177	177	181	188	174	188	213	253	257	219	222	2426
2023/24	179	178	178	182	189	175	190	215	255	260	221	224	2447

STATION SERVICE

The Station Service category measures the energy used by power plants to generate power and service their own load. Energy and peak estimates can either include or exclude station service, depending on the purpose for which they are to be used. Most energy and peak numbers in this document exclude station service. "Net" numbers exclude station service and "Gross" numbers include station service. This is explained in the Glossary of Terms. Station Service energy was not measured prior to 1993/94 and was included in the Transmission Losses category.

Figure 15



Station Service energy is forecast to be 0.9% of the Manitoba Load at Common Bus. Station Service energy is forecast to increase from 170 GW.h in 2002/03 to 216 GW.h by 2023/24. Station Service at the time of peak is forecast to increase from 32 MW in 2002/03 to 42 MW by 2023/24.

STATION SERVICE HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Use	Adjustment	Adjusted Use	Fiscal Year	Forecast Use
1982/83	0	0	0	2003/04	173
1983/84	0	0	0	2004/05	177
1984/85	0	0	0	2005/06	179
1985/86	0	0	0	2006/07	181
1986/87	0	0	0	2007/08	184
1987/88	0	0	0	2008/09	186
1988/89	0	0	0	2009/10	187
1989/90	0	0	0	2010/11	189
1990/91	0	0	0	2011/12	191
1991/92	0	0	0	2012/13	193
1992/93	0	0	0	2013/14	194
1993/94	152	0	152	2014/15	196
1994/95	146	0	146	2015/16	199
1995/96	148	0	148	2016/17	201
1996/97	148	0	148	2017/18	203
1997/98	142	0	142	2018/19	205
1998/99	177	0	177	2019/20	207
1999/00	167	0	167	2020/21	209
2000/01	187	0	187	2021/22	212
2001/02	162	0	162	2022/23	214
2002/03	170	0	170	2023/24	216

Table 11

MONTHLY STATION SERVICE Energy (GW.h)													
Fiscal Year	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Total**
2002/03 Actual	16	14	9	14	9	8	11	14	18	20	19	19	170
2003/04	16	13	9	12	10	8	12	14	19	21	19	19	173
2004/05	16	13	9	12	10	8	12	15	20	22	20	20	177
2005/06	16	13	9	12	10	9	12	15	20	22	20	20	179
2006/07	17	13	9	13	10	9	13	15	20	22	20	20	181
2007/08	17	13	9	13	11	9	13	15	21	23	21	20	184
2008/09	17	13	9	13	11	9	13	15	21	23	21	21	186
2009/10	17	14	9	13	11	9	13	15	21	23	21	21	187
2010/11	17	14	10	13	11	9	13	16	21	23	21	21	189
2011/12	17	14	10	13	11	9	13	16	21	24	21	21	191
2012/13	18	14	10	13	11	9	13	16	21	24	22	21	193
2013/14	18	14	10	14	11	9	14	16	22	24	22	22	194
2014/15	18	14	10	14	11	9	14	16	22	24	22	22	196
2015/16	18	14	10	14	11	9	14	16	22	24	22	22	199
2016/17	18	15	10	14	12	10	14	17	22	25	23	22	201
2017/18	19	15	10	14	12	10	14	17	23	25	23	23	203
2018/19	19	15	10	14	12	10	14	17	23	25	23	23	205
2019/20	19	15	11	14	12	10	14	17	23	26	23	23	207
2020/21	19	15	11	15	12	10	15	17	23	26	24	23	209
2021/22	19	15	11	15	12	10	15	18	24	26	24	24	212
2022/23	20	16	11	15	12	10	15	18	24	26	24	24	214
2023/24	20	16	11	15	12	10	15	18	24	27	24	24	216

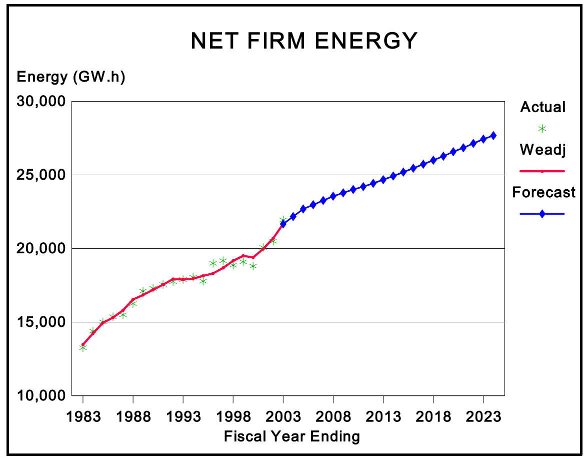
Table 12

MONTHLY STATION SERVICE Peak (MW)													
Fiscal Year	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Annual
2002/03 Actual	26	26	18	19	17	10	15	32	27	33	32	29	32
2003/04	27	24	15	15	17	14	19	34	32	36	36	28	35
2004/05	27	25	15	15	18	14	20	35	33	36	37	29	36
2005/06	27	25	15	16	18	14	20	35	33	37	37	29	36
2006/07	28	26	16	16	18	14	20	35	33	37	37	29	37
2007/08	28	26	16	16	19	15	20	36	34	37	38	29	37
2008/09	28	26	16	16	19	15	20	36	34	38	38	30	37
2009/10	28	26	16	16	19	15	21	36	34	38	38	30	37
2010/11	28	27	16	17	19	15	21	36	35	38	38	30	38
2011/12	29	27	16	17	20	15	21	37	35	38	39	30	38
2012/13	29	27	17	17	20	15	21	37	35	38	39	31	38
2013/14	29	27	17	17	20	15	21	37	35	39	39	31	38
2014/15	29	28	17	17	20	16	21	37	36	39	40	31	39
2015/16	30	28	17	18	20	16	22	38	36	40	40	31	39
2016/17	30	28	17	18	21	16	22	38	36	40	40	32	40
2017/18	30	29	17	18	21	16	22	39	37	40	41	32	40
2018/19	31	29	18	18	21	16	22	39	37	41	41	32	40
2019/20	31	29	18	18	21	17	23	39	37	41	42	33	41
2020/21	31	29	18	19	22	17	23	40	38	41	42	33	41
2021/22	32	30	18	19	22	17	23	40	38	42	42	33	42
2022/23	32	30	18	19	22	17	23	41	39	42	43	34	42
2023/24	32	30	19	19	22	17	23	41	39	43	43	34	42

NET FIRM ENERGY

The Net Firm Energy category includes all electricity that is generated to meet the firm energy requirements of all customers within Manitoba. It excludes non-firm (interruptible loads) and station service loads. It is calculated by subtracting non-firm sales and station service loads from the Gross Total Energy requirements. Net Firm Energy is a critical factor in determining Manitoba Hydro's future development plans. Net Firm Energy has grown steadily during the past two decades, except for the economic slow down in the early 1990's.

Figure 16



The Net Firm Energy category is forecast to increase from a weather-adjusted base of 21 668 GW.h in 2002/03 to 27 675 GW.h by 2023/24. This represents an average growth of 286 GW.h per year, which is much lower than the ten year annual growth rate of 377 GW.h.

NET FIRM ENERGY
HISTORICAL/WEATHER ADJUSTMENT/FORECAST

Fiscal Year	Energy	Adjustment	Adjusted Energy	Fiscal Year	Forecast Energy
1982/83	13260	212	13472	2003/04	22171
1983/84	14387	-155	14232	2004/05	22690
1984/85	15014	-62	14952	2005/06	22976
1985/86	15366	-53	15313	2006/07	23262
1986/87	15495	313	15808	2007/08	23554
1987/88	16260	276	16536	2008/09	23783
1988/89	17108	-263	16845	2009/10	24009
1989/90	17298	-104	17194	2010/11	24203
1990/91	17553	-7	17546	2011/12	24430
1991/92	17748	176	17924	2012/13	24680
1992/93	17894	2	17896	2013/14	24927
1993/94	18048	-95	17953	2014/15	25191
1994/95	17784	363	18147	2015/16	25458
1995/96	19000	-689	18311	2016/17	25729
1996/97	19173	-491	18682	2017/18	26001
1997/98	18872	296	19168	2018/19	26274
1998/99	19095	411	19506	2019/20	26576
1999/00	18804	592	19396	2020/21	26847
2000/01	20075	-106	19969	2021/22	27143
2001/02	20494	202	20696	2022/23	27436
2002/03	21940	-272	21668	2023/24	27675

Table 13

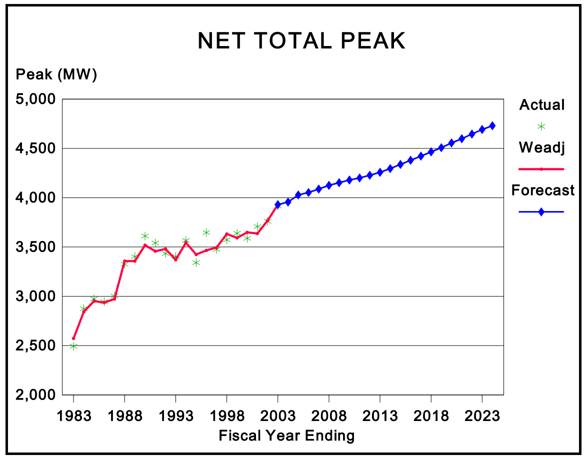
MONTHLY SCHEDULE OF NET FIRM ENERGY (GW.h) Base Forecast													
Fiscal Year	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Total**
2002/03 Actual	**1711**	**1615**	**1528**	**1603**	**1545**	**1527**	**1800**	**1950**	**2132**	**2321**	**2124**	**2084**	**21940**
2003/04	**1684**	**1613**	**1556**	**1612**	**1642**	**1546**	**1738**	**1952**	**2293**	**2358**	**2106**	**2071**	**22171**
2004/05	**1728**	**1654**	**1612**	**1654**	**1698**	**1591**	**1774**	**2008**	**2354**	**2411**	**2084**	**2121**	**22690**
2005/06	**1748**	**1682**	**1632**	**1685**	**1725**	**1609**	**1801**	**2032**	**2372**	**2438**	**2106**	**2147**	**22976**
2006/07	**1768**	**1705**	**1656**	**1712**	**1753**	**1631**	**1822**	**2054**	**2398**	**2462**	**2128**	**2172**	**23262**
2007/08	**1789**	**1728**	**1680**	**1741**	**1781**	**1654**	**1844**	**2077**	**2425**	**2487**	**2150**	**2198**	**23554**
2008/09	**1805**	**1747**	**1700**	**1764**	**1804**	**1671**	**1861**	**2094**	**2446**	**2506**	**2167**	**2218**	**23783**
2009/10	**1821**	**1765**	**1719**	**1787**	**1828**	**1689**	**1878**	**2111**	**2467**	**2524**	**2184**	**2238**	**24009**
2010/11	**1834**	**1781**	**1736**	**1808**	**1848**	**1704**	**1892**	**2126**	**2484**	**2539**	**2198**	**2254**	**24203**
2011/12	**1850**	**1799**	**1755**	**1831**	**1872**	**1722**	**1908**	**2143**	**2504**	**2557**	**2214**	**2274**	**24430**
2012/13	**1868**	**1820**	**1776**	**1857**	**1897**	**1741**	**1927**	**2162**	**2527**	**2578**	**2233**	**2296**	**24680**
2013/14	**1887**	**1839**	**1795**	**1876**	**1916**	**1759**	**1947**	**2183**	**2551**	**2602**	**2254**	**2318**	**24927**
2014/15	**1907**	**1859**	**1815**	**1897**	**1937**	**1779**	**1968**	**2206**	**2577**	**2628**	**2277**	**2342**	**25191**
2015/16	**1928**	**1879**	**1834**	**1917**	**1958**	**1798**	**1989**	**2229**	**2603**	**2655**	**2300**	**2366**	**25458**
2016/17	**1949**	**1900**	**1855**	**1938**	**1980**	**1818**	**2011**	**2252**	**2629**	**2682**	**2324**	**2391**	**25729**
2017/18	**1970**	**1921**	**1875**	**1959**	**2001**	**1838**	**2033**	**2276**	**2656**	**2709**	**2347**	**2416**	**26001**
2018/19	**1991**	**1942**	**1895**	**1981**	**2023**	**1858**	**2055**	**2299**	**2683**	**2736**	**2371**	**2440**	**26274**
2019/20	**2014**	**1965**	**1918**	**2004**	**2046**	**1881**	**2079**	**2325**	**2712**	**2766**	**2398**	**2468**	**26576**
2020/21	**2035**	**1986**	**1938**	**2025**	**2068**	**1900**	**2100**	**2349**	**2739**	**2793**	**2421**	**2493**	**26847**
2021/22	**2058**	**2008**	**1960**	**2048**	**2091**	**1922**	**2124**	**2374**	**2768**	**2823**	**2447**	**2520**	**27143**
2022/23	**2081**	**2031**	**1982**	**2071**	**2114**	**1944**	**2147**	**2399**	**2797**	**2852**	**2473**	**2546**	**27436**
2023/24	**2099**	**2049**	**2000**	**2089**	**2133**	**1961**	**2166**	**2420**	**2820**	**2875**	**2493**	**2568**	**27675**

- See the Glossary of Terms for a definition of Net Firm Energy.

NET TOTAL PEAK

The Net Total Peak is defined to be the maximum integrated hourly load at generation adjusted for losses associated with exports or imports, less station service, but with curtailed loads added back in. The term "integrated" indicates that the average load within that peak hour is used. The Net Total Peak did not grow very much during the 1990's because many of our large Industrial customers have improved their efficiency. Manitoba Hydro is very diligent in helping our Industrial customers to improve the efficiency of their business operations.

Figure 17



The Net Total Peak is forecast to increase from a weather-adjusted base of 3 930 MW in 2002/03 to 4 730 MW by 2023/24. This represents an average growth of 38 MW per year, which is lower than the ten year annual growth rate of 56 MW.

NET TOTAL PEAK HISTORICAL/WEATHER ADJUSTMENT/FORECAST					
Fiscal Year	Peak	Adjustment	Adjusted Peak	Fiscal Year	Forecast Peak
1982/83	2494	79	2573	2003/04	3956
1983/84	2875	-32	2843	2004/05	4028
1984/85	2974	-22	2952	2005/06	4053
1985/86	2945	-8	2937	2006/07	4088
1986/87	3003	-30	2973	2007/08	4126
1987/88	3326	32	3358	2008/09	4153
1988/89	3403	-46	3357	2009/10	4180
1989/90	3611	-92	3519	2010/11	4201
1990/91	3542	-84	3458	2011/12	4228
1991/92	3435	46	3481	2012/13	4258
1992/93	3404	-34	3370	2013/14	4296
1993/94	3567	-22	3545	2014/15	4338
1994/95	3342	82	3424	2015/16	4380
1995/96	3647	-181	3466	2016/17	4422
1996/97	3476	19	3495	2017/18	4465
1997/98	3573	60	3633	2018/19	4508
1998/99	3639	-46	3593	2019/20	4556
1999/00	3588	61	3649	2020/21	4599
2000/01	3708	-71	3637	2021/22	4646
2001/02	3760	9	3770	2022/23	4692
2002/03	3916	14	3930	2023/24	4730

Table 14

MONTHLY SCHEDULE OF NET TOTAL PEAK (MW)
Base Forecast

Fiscal Year	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Annual
2002/03 Actual	3061	2794	2764	2894	2722	2681	3024	3365	3633	3816	3916	3796	3916
2003/04	2996	2733	2735	2744	2838	2708	2917	3427	3871	3928	3791	3503	3956
2004/05	3059	2786	2803	2810	2906	2777	2982	3496	3955	3983	3862	3589	4028
2005/06	3088	2824	2843	2853	2955	2807	3015	3528	3979	4014	3891	3609	4053
2006/07	3119	2858	2882	2897	3000	2843	3046	3560	4016	4048	3925	3645	4088
2007/08	3150	2893	2922	2941	3046	2880	3078	3593	4056	4084	3960	3683	4126
2008/09	3174	2921	2954	2978	3084	2909	3102	3617	4086	4110	3986	3711	4153
2009/10	3198	2949	2987	3015	3122	2938	3125	3641	4115	4136	4012	3739	4180
2010/11	3217	2972	3015	3047	3156	2964	3145	3660	4139	4156	4032	3762	4201
2011/12	3241	3000	3048	3084	3194	2993	3169	3684	4168	4181	4057	3790	4228
2012/13	3267	3031	3084	3124	3235	3026	3195	3711	4200	4209	4086	3821	4258
2013/14	3298	3061	3114	3154	3266	3055	3226	3746	4238	4247	4123	3856	4296
2014/15	3332	3092	3146	3187	3299	3087	3259	3783	4279	4288	4163	3894	4338
2015/16	3366	3125	3179	3220	3333	3119	3293	3820	4321	4330	4204	3933	4380
2016/17	3401	3157	3212	3253	3367	3152	3327	3858	4363	4372	4245	3972	4422
2017/18	3435	3190	3245	3286	3402	3185	3361	3897	4405	4414	4286	4011	4465
2018/19	3470	3223	3279	3320	3436	3218	3395	3935	4448	4457	4328	4051	4508
2019/20	3509	3259	3316	3358	3475	3254	3433	3978	4495	4505	4374	4095	4556
2020/21	3543	3292	3349	3391	3509	3287	3467	4016	4537	4547	4415	4134	4599
2021/22	3581	3328	3385	3428	3547	3322	3505	4058	4584	4594	4461	4177	4646
2022/23	3619	3363	3421	3464	3584	3358	3542	4100	4630	4640	4506	4219	4692
2023/24	3649	3392	3450	3493	3614	3386	3571	4133	4667	4676	4542	4253	4730

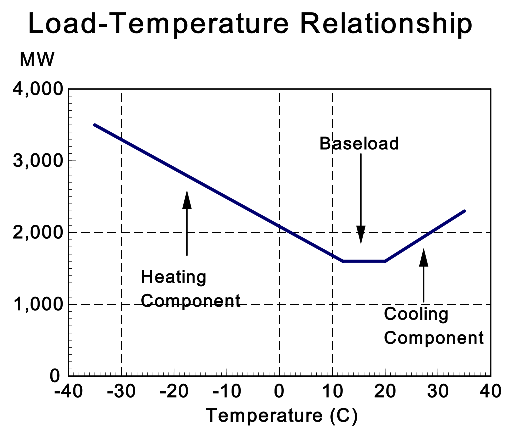
- See the Glossary of Terms for a definition of Net Total Peak.

HOURLY LOAD MODEL

The Hourly Load Model is designed to accurately estimate total electricity usage in Manitoba. Hourly system energy readings are related to the hour of day, day of week, month of year, and the current and past temperatures.

Figure 18

The adjacent graph illustrates the model's concepts. The base load is the temperature-insensitive part that varies by hour of day. The heating component is the additional load required as the temperature decreases. The cooling component is the additional load required as the temperature increases. The base load, heating coefficients and cooling coefficients are estimated from historical Net Total Generation data obtained from Energy Supply and Sales.



The Hourly Load Model predicts the hourly energy for every hour of each year. This is done for 25 different years of historical temperatures (from April 1978 to March 2003). In the first two years of the forecast, these 25 replications are summarized to get expected values and their standard deviations and represent the exact day-of-week pattern that will occur in these two years.

In the remaining years of the forecast, each of the 25 years of temperatures are combined with four day-of-week variations. These 100 replications are summarized to produce an average year. This smooths out the variation that would otherwise occur due to extra weekends in a month or leap years.

Output from the Hourly Load Model produces monthly energy distributions, monthly peaks, annual peaks, on-peak and off-peak energy splits, probabilities of peak occurrence, load duration curves, hourly load estimates and other types of information.

Table 15

HISTORICAL NET FIRM ENERGY, NET TOTAL PEAK AND LOAD FACTOR					
Fiscal Year	Net Firm Energy (GW.h)	%	Net Total Peak (MW)	%	Load Factor %
1967/68	6062	6.8%	1162	11.1%	59.6%
1968/69	6709	10.7%	1263	8.7%	60.6%
1969/70	7517	12.0%	1409	11.6%	60.9%
1970/71	8313	10.6%	1551	10.1%	61.2%
1971/72	9080	9.2%	1720	10.9%	60.3%
1972/73	9528	4.9%	1785	3.8%	60.9%
1973/74	10581	11.1%	1959	9.7%	61.7%
1974/75	10872	2.8%	1991	1.6%	62.3%
1975/76	11432	5.2%	2202	10.6%	59.3%
1976/77	11768	2.9%	2350	6.7%	57.2%
1977/78	11962	1.6%	2446	4.1%	55.8%
1978/79	12483	4.4%	2405	-1.7%	59.3%
1979/80	12797	2.5%	2465	2.5%	59.3%
1980/81	12529	-2.1%	2536	2.9%	56.4%
1981/82	13527	8.0%	2713	7.0%	56.9%
1982/83	13260	-2.0%	2494	-8.1%	60.7%
1983/84	14387	8.5%	2875	15.3%	57.1%
1984/85	15014	4.4%	2974	3.4%	57.6%
1985/86	15366	2.3%	2945	-1.0%	59.6%
1986/87	15495	0.8%	3003	2.0%	58.9%
1987/88	16260	4.9%	3326	10.8%	55.8%
1988/89	17108	5.2%	3403	2.3%	57.4%
1989/90	17298	1.1%	3611	6.1%	54.7%
1990/91	17553	1.5%	3542	-1.9%	56.6%
1991/92	17748	1.1%	3435	-3.0%	59.0%
1992/93	17894	0.8%	3404	-0.9%	60.0%
1993/94	18048	0.9%	3567	4.8%	57.8%
1994/95	17784	-1.5%	3342	-6.3%	60.7%
1995/96	19000	6.8%	3647	9.1%	59.5%
1996/97	19173	0.9%	3476	-4.7%	63.0%
1997/98	18872	-1.6%	3573	2.8%	60.3%
1998/99	19095	1.2%	3639	1.8%	59.9%
1999/00	18804	-1.5%	3588	-1.4%	59.8%
2000/01	20075	6.8%	3708	3.3%	61.8%
2001/02	20494	2.1%	3760	1.4%	62.2%
2002/03	21940	7.1%	3916	4.1%	64.0%

- See the Glossary of Terms for a definition of Net Firm Energy and Net Total Peak.

ALTERNATE SCENARIOS

A Medium-Low and Medium-High scenario have been prepared to represent the sensitivity of the forecast based on various economic and demographic assumptions. Each scenario represents a different version of future economic growth in Manitoba. Although any number of assumptions could be made, these two scenarios were chosen as being representative of Medium-Low and Medium-High economic growth.

When compared to the Base Forecast, the Medium-Low scenario includes lower population growth, lower housing formation rates, lower economic growth, lower oil and natural gas price increases, lower electric space heat saturation rates, lower business formation rates, lower business electricity usage, more shutdowns/closures of existing large customers and lower probabilities of large electrical-intensive industries locating in the province.

When compared to the Base Forecast, the Medium-High scenario includes higher population growth, higher housing formation rates, higher economic growth, higher oil and natural gas price increases, higher electric space heat saturation rates, higher business formation rates, higher business electricity usage, less shutdowns/closures of existing large customers and higher probabilities of large electrical-intensive industries locating in the province.

Table 16

MEDIUM LOW SCENARIO 2002/03 - 2023/24					
Fiscal Year	Net Firm Energy (GW.h)	%	Net Total Peak (MW)	%	Load Factor %
2002/03 Actual	21940	7.1%	3916	4.1%	64.0%
Weather	-272		14		
2002/03 Adjusted	21668	4.5%	3930	4.3%	62.9%
2003/04	21725	0.3%	3891	-1.0%	63.7%
2004/05	21934	1.0%	3920	0.7%	63.9%
2005/06	22071	0.6%	3923	0.1%	64.2%
2006/07	22193	0.6%	3935	0.3%	64.4%
2007/08	22336	0.6%	3948	0.3%	64.6%
2008/09	22453	0.5%	3959	0.3%	64.7%
2009/10	22570	0.5%	3969	0.3%	64.9%
2010/11	22680	0.5%	3978	0.2%	65.1%
2011/12	22803	0.5%	3990	0.3%	65.2%
2012/13	22927	0.5%	4002	0.3%	65.4%
10 Year Avg.		0.6%		0.2%	
2013/14	23040	0.5%	4020	0.5%	65.4%
2014/15	23172	0.6%	4042	0.5%	65.4%
2015/16	23325	0.7%	4067	0.6%	65.5%
2016/17	23481	0.7%	4092	0.6%	65.5%
2017/18	23638	0.7%	4117	0.6%	65.5%
2018/19	23797	0.7%	4142	0.6%	65.6%
2019/20	23957	0.7%	4168	0.6%	65.6%
2020/21	24119	0.7%	4194	0.6%	65.6%
2021/22	24283	0.7%	4220	0.6%	65.7%
2022/23	24450	0.7%	4247	0.6%	65.7%
2023/24	24618	0.7%	4274	0.6%	65.8%
21 Year Avg.		0.6%		0.4%	

- See the Glossary of Terms for a definition of Net Firm Energy and Net Total Peak.

Table 17

MONTHLY SCHEDULE OF NET FIRM ENERGY (GW.h) Medium-Low Scenario													
Fiscal Year	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Total**
2002/03 Actual	1711	1615	1528	1603	1545	1527	1800	1950	2132	2321	2124	2084	21940
2003/04	1649	1578	1522	1576	1606	1512	1702	1914	2251	2315	2067	2031	21725
2004/05	1668	1594	1554	1594	1637	1533	1712	1944	2284	2340	2021	2054	21934
2005/06	1676	1610	1563	1613	1652	1540	1726	1955	2287	2352	2030	2067	22071
2006/07	1684	1620	1574	1627	1667	1550	1735	1963	2298	2361	2038	2077	22193
2007/08	1693	1632	1587	1644	1683	1561	1745	1973	2310	2371	2048	2089	22336
2008/09	1700	1642	1598	1659	1698	1570	1753	1981	2320	2378	2055	2099	22453
2009/10	1708	1652	1609	1673	1712	1580	1760	1988	2330	2386	2062	2109	22570
2010/11	1714	1661	1619	1687	1726	1588	1768	1996	2340	2393	2069	2118	22680
2011/12	1722	1671	1631	1702	1741	1598	1776	2004	2350	2402	2077	2128	22803
2012/13	1730	1681	1642	1717	1756	1608	1785	2013	2361	2410	2085	2139	22927
2013/14	1739	1690	1650	1726	1764	1616	1794	2022	2373	2421	2095	2149	23040
2014/15	1749	1700	1660	1736	1775	1626	1804	2034	2386	2435	2107	2162	23172
2015/16	1760	1711	1671	1748	1787	1637	1816	2047	2401	2450	2120	2175	23325
2016/17	1772	1723	1683	1760	1799	1648	1829	2061	2416	2466	2134	2190	23481
2017/18	1785	1735	1695	1772	1811	1660	1841	2074	2432	2482	2148	2204	23638
2018/19	1797	1747	1706	1784	1824	1671	1854	2088	2447	2498	2162	2219	23797
2019/20	1809	1760	1718	1797	1836	1683	1867	2102	2463	2514	2176	2233	23957
2020/21	1822	1772	1730	1809	1849	1695	1879	2116	2479	2530	2190	2248	24119
2021/22	1834	1784	1742	1822	1862	1707	1892	2130	2495	2546	2204	2263	24283
2022/23	1847	1797	1755	1835	1875	1719	1906	2144	2512	2563	2219	2278	24450
2023/24	1860	1810	1767	1848	1888	1731	1919	2159	2529	2580	2234	2294	24618
- See the Glossary of Terms for a definition of Net Firm Energy.													

Table 18

MONTHLY SCHEDULE OF NET TOTAL PEAK (MW)
Medium-Low Scenario

Fiscal Year	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Annual
2002/03 Actual	3061	2794	2764	2894	2722	2681	3024	3365	3633	3816	3916	3796	3916
2003/04	2940	2681	2682	2692	2784	2656	2863	3368	3807	3864	3728	3443	3891
2004/05	2966	2697	2714	2720	2815	2688	2889	3396	3848	3875	3757	3488	3920
2005/06	2976	2717	2736	2746	2845	2700	2904	3408	3850	3885	3764	3487	3923
2006/07	2986	2732	2755	2769	2870	2716	2915	3418	3864	3895	3774	3501	3935
2007/08	2999	2749	2777	2795	2897	2735	2928	3430	3880	3908	3787	3517	3948
2008/09	3009	2763	2795	2818	2921	2751	2938	3439	3893	3917	3797	3530	3959
2009/10	3019	2778	2815	2842	2945	2768	2949	3448	3906	3926	3806	3543	3969
2010/11	3028	2791	2833	2864	2968	2783	2958	3456	3918	3934	3815	3554	3978
2011/12	3038	2807	2853	2888	2993	2800	2969	3466	3932	3944	3825	3568	3990
2012/13	3049	2822	2873	2912	3018	2818	2981	3476	3946	3955	3836	3582	4002
2013/14	3064	2836	2887	2926	3033	2831	2995	3493	3965	3973	3854	3599	4020
2014/15	3081	2852	2904	2942	3050	2847	3012	3512	3986	3995	3875	3619	4042
2015/16	3101	2871	2923	2961	3069	2866	3031	3534	4010	4019	3899	3641	4067
2016/17	3121	2890	2942	2981	3089	2885	3051	3556	4035	4044	3923	3664	4092
2017/18	3141	2909	2961	3000	3109	2904	3071	3578	4060	4069	3947	3687	4117
2018/19	3161	2928	2980	3020	3129	2923	3091	3601	4085	4094	3972	3710	4142
2019/20	3182	2947	3000	3040	3150	2942	3111	3624	4110	4119	3996	3733	4168
2020/21	3203	2967	3020	3060	3170	2962	3131	3647	4136	4145	4022	3757	4194
2021/22	3224	2987	3040	3080	3191	2982	3152	3670	4162	4171	4047	3781	4220
2022/23	3245	3007	3061	3101	3213	3002	3173	3694	4189	4198	4073	3806	4247
2023/24	3267	3027	3081	3122	3234	3022	3194	3718	4215	4224	4099	3830	4274

- See the Glossary of Terms for a definition of Net Total Peak.

Table 19

MEDIUM HIGH SCENARIO 2002/03 - 2023/24					
Fiscal Year	Net Firm Energy (GW.h)	%	Net Total Peak (MW)	%	Load Factor %
2002/03 Actual	21940	7.1%	3916	4.1%	64.0%
Weather	-272		14		
2002/03 Adjusted	21668	4.5%	3930	4.3%	62.9%
2003/04	22564	4.1%	4012	2.1%	64.2%
2004/05	23131	2.5%	4094	2.0%	64.5%
2005/06	23663	2.3%	4155	1.5%	65.0%
2006/07	24141	2.0%	4218	1.5%	65.3%
2007/08	24582	1.8%	4277	1.4%	65.6%
2008/09	24983	1.6%	4329	1.2%	65.9%
2009/10	25384	1.6%	4382	1.2%	66.1%
2010/11	25752	1.5%	4428	1.1%	66.4%
2011/12	26154	1.6%	4481	1.2%	66.6%
2012/13	26568	1.6%	4535	1.2%	66.9%
10 Year Avg.		2.1%		1.4%	
2013/14	26953	1.4%	4595	1.3%	67.0%
2014/15	27360	1.5%	4660	1.4%	67.0%
2015/16	27794	1.6%	4728	1.5%	67.1%
2016/17	28201	1.5%	4792	1.4%	67.2%
2017/18	28634	1.5%	4861	1.4%	67.2%
2018/19	29067	1.5%	4930	1.4%	67.3%
2019/20	29540	1.6%	4989	1.2%	67.6%
2020/21	29850	1.0%	5052	1.3%	67.4%
2021/22	30256	1.4%	5116	1.3%	67.5%
2022/23	30695	1.5%	5186	1.4%	67.6%
2023/24	31140	1.5%	5257	1.4%	67.6%
21 Year Avg.		1.7%		1.4%	

- See the Glossary of Terms for a definition of Net Firm Energy and Net Total Peak.

Table 20

MONTHLY SCHEDULE OF NET FIRM ENERGY (GW.h)
Medium-High Scenario

Fiscal Year	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total
2002/03 Actual	1711	1615	1528	1603	1545	1527	1800	1950	2132	2321	2124	2084	21940
2003/04	1716	1644	1586	1643	1673	1576	1771	1985	2329	2395	2140	2106	22564
2004/05	1763	1689	1646	1689	1733	1624	1810	2046	2397	2454	2121	2161	23131
2005/06	1802	1736	1685	1739	1779	1661	1856	2090	2437	2504	2164	2209	23663
2006/07	1838	1774	1723	1782	1823	1698	1894	2129	2481	2547	2202	2251	24141
2007/08	1870	1809	1759	1822	1863	1731	1928	2164	2522	2586	2237	2290	24582
2008/09	1900	1841	1791	1859	1900	1762	1958	2197	2559	2621	2269	2325	24983
2009/10	1929	1873	1824	1896	1938	1793	1989	2229	2597	2656	2300	2361	25384
2010/11	1956	1903	1854	1931	1973	1821	2018	2258	2630	2687	2328	2393	25752
2011/12	1985	1935	1887	1968	2010	1852	2048	2290	2667	2722	2360	2428	26154
2012/13	2016	1968	1921	2007	2049	1884	2080	2323	2706	2759	2392	2465	26568
2013/14	2046	1998	1949	2037	2079	1912	2111	2356	2743	2797	2426	2499	26953
2014/15	2077	2029	1980	2068	2111	1942	2144	2391	2783	2837	2461	2536	27360
2015/16	2111	2062	2012	2102	2145	1974	2178	2428	2826	2880	2499	2576	27794
2016/17	2142	2093	2043	2134	2177	2004	2211	2464	2866	2921	2534	2613	28201
2017/18	2176	2126	2075	2167	2212	2036	2245	2501	2908	2964	2572	2652	28634
2018/19	2209	2159	2107	2201	2246	2068	2280	2538	2951	3007	2610	2692	29067
2019/20	2239	2189	2136	2231	2276	2096	2311	2571	2988	3045	2643	2727	29450
2020/21	2270	2219	2166	2262	2308	2125	2342	2606	3027	3085	2678	2763	29850
2021/22	2301	2251	2196	2293	2340	2155	2375	2641	3067	3125	2713	2800	30256
2022/23	2335	2284	2228	2327	2374	2187	2410	2679	3110	3169	2751	2840	30695
2023/24	2369	2318	2262	2362	2409	2220	2445	2717	3154	3214	2790	2880	31140

- See the Glossary of Terms for a definition of Net Firm Energy.

Table 21

MONTHLY SCHEDULE OF NET TOTAL PEAK (MW)
Medium-High Scenario

Fiscal Year	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Annual
2002/03 Actual	3061	2794	2764	2894	2722	2681	3024	3365	3633	3816	3916	3796	3916
2003/04	3044	2780	2781	2791	2885	2754	2965	3479	3926	3984	3846	3556	4012
2004/05	3115	2839	2856	2862	2959	2830	3036	3557	4021	4048	3926	3650	4094
2005/06	3174	2905	2925	2936	3039	2888	3099	3621	4079	4115	3989	3703	4155
2006/07	3228	2963	2987	3002	3107	2947	3154	3678	4144	4177	4051	3766	4218
2007/08	3279	3016	3045	3065	3172	3001	3204	3732	4206	4234	4108	3824	4277
2008/09	3324	3064	3098	3122	3231	3051	3249	3779	4260	4285	4158	3875	4329
2009/10	3369	3112	3151	3180	3291	3101	3294	3826	4315	4336	4208	3927	4382
2010/11	3410	3156	3201	3234	3346	3148	3335	3868	4364	4381	4253	3974	4428
2011/12	3455	3205	3255	3292	3406	3198	3380	3916	4418	4431	4303	4026	4481
2012/13	3502	3256	3311	3352	3468	3250	3427	3965	4475	4484	4356	4080	4535
2013/14	3551	3302	3358	3400	3517	3297	3475	4019	4535	4544	4414	4135	4595
2014/15	3603	3351	3408	3450	3568	3346	3527	4076	4598	4607	4476	4194	4660
2015/16	3658	3403	3461	3504	3623	3398	3581	4138	4666	4676	4542	4257	4728
2016/17	3710	3452	3510	3554	3675	3447	3632	4195	4729	4739	4604	4315	4792
2017/18	3766	3505	3563	3607	3730	3499	3687	4256	4797	4807	4671	4378	4861
2018/19	3821	3557	3616	3661	3785	3551	3741	4318	4865	4875	4737	4441	4930
2019/20	3870	3603	3663	3708	3833	3597	3789	4372	4924	4934	4795	4496	4989
2020/21	3921	3651	3712	3757	3884	3646	3839	4428	4986	4997	4856	4554	5052
2021/22	3973	3700	3762	3807	3935	3694	3890	4485	5050	5060	4917	4612	5116
2022/23	4029	3753	3815	3862	3991	3747	3945	4547	5119	5129	4985	4676	5186
2023/24	4086	3807	3870	3917	4048	3801	4002	4610	5188	5199	5053	4741	5257

- See the Glossary of Terms for a definition of Net Total Peak.

LOAD FORECAST UNCERTAINTY

The Medium-Low and Medium-High scenarios represent the expected forecast of loads given a set of specified economic conditions that correspond to assumptions of lower and higher economic growth. However, these scenarios do not imply a likelihood of occurrence. To establish these likelihoods (and for other probabilistic or risk analysis purposes), the following estimates of the variation in the forecast are provided. The variation in the forecast is divided into two parts:

1) **Weather and Random Variation** - is the variation caused by above or below normal temperatures, or by increased or decreased short-term consumption by groups of customers or industries. This variation is determined from the Hourly Load Model.

2) **Economic and Modelling Variation** - is the variation due to changes in economic conditions and modelling assumptions. This variation is obtained by taking the historical weather-adjusted annual energy and determining the year-to-year variation in its growth. A statistically-based method of estimating the year-to-year variation has been used this year, resulting in a lower estimate of future economic and modelling variation. This change has lowered the probability of exceeding either the Medium-Low or Medium-High scenarios.

The two variations are combined to determine the total uncertainty of the forecast. These are converted to a statistical measure known as a standard deviation. The future load is expected to be within one standard deviation of the Base Forecast 68% of the time and within three standard deviations of the Base Forecast 99% of the time.

Figure 19

NET FIRM ENERGY
Load Forecast Uncertainty

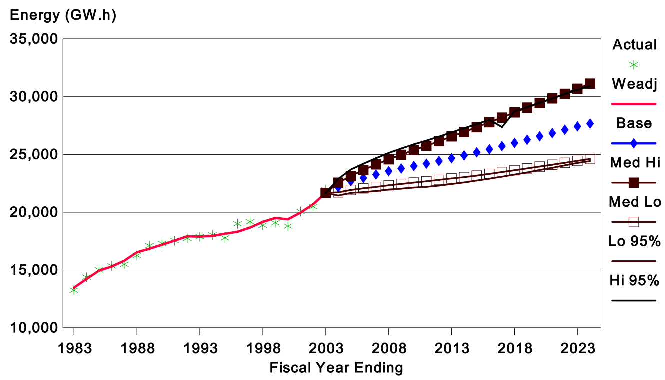


Table 22

Fiscal Year	Net Firm Energy Base Fcst	Wthr and Misc Std Dev	Econ and Model Std Dev	Total Std Dev	95% Lower Conf. Intrvl. (LCL)	Net Firm Energy MedLo Scenario	Net Firm Energy MedHi Scenario	95% Upper Conf. Intrvl. (UCL)	Prob. Actual > MedLo	Prob. Actual > MedHi
2003/04	22171	246	275	369	21448	21725	22564	22894	89%	14%
2004/05	22690	247	452	515	21680	21934	23131	23700	93%	20%
2005/06	22976	244	578	627	21747	22071	23663	24206	93%	14%
2006/07	23262	245	680	723	21844	22193	24141	24679	93%	11%
2007/08	23554	246	770	808	21970	22336	24582	25137	93%	10%
2008/09	23783	247	849	885	22049	22453	24983	25517	93%	9%
2009/10	24009	247	922	955	22138	22570	25384	25881	93%	8%
2010/11	24203	247	990	1020	22203	22680	25753	26202	93%	6%
2011/12	24430	248	1053	1082	22309	22803	26154	26550	93%	6%
2012/13	24680	249	1113	1140	22445	22927	26568	26915	94%	5%
2013/14	24927	250	1169	1196	22583	23040	26953	27271	94%	5%
2014/15	25191	252	1223	1249	22743	23172	27360	27639	95%	4%
2015/16	25458	254	1275	1300	22910	23325	27794	28006	95%	4%
2016/17	25729	256	1325	1349	23084	23481	28201	28374	95%	3%
2017/18	26001	258	1373	1397	23263	23638	28634	28739	96%	3%
2018/19	26274	260	1419	1443	23446	23797	29067	29101	96%	3%
2019/20	26576	263	1464	1487	23661	23957	29450	29491	96%	3%
2020/21	26847	265	1507	1530	23847	24119	29850	29847	96%	3%
2021/22	27143	267	1550	1572	24061	24283	30256	30225	97%	2%
2022/23	27436	269	1591	1613	24274	24450	30695	30598	97%	2%
2023/24	27675	271	1631	1653	24435	24618	31140	30915	97%	2%

Figure 20

NET TOTAL PEAK
Load Forecast Uncertainty

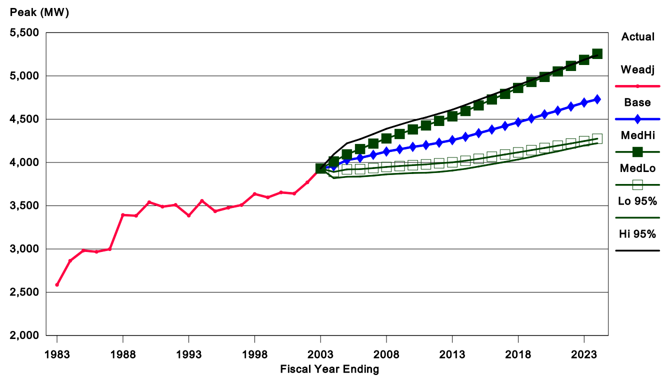


Table 23

Fiscal Year	Net Total Peak Base Fcst	Wthr and Misc Std Dev	Econ and Model Std Dev	Total Std Dev	95% Lower Conf. Intrvl. (LCL)	Net Total Peak MedLo Scenario	Net Total Peak MedHi Scenario	95% Upper Conf. Intrvl. (UCL)	Prob. Actual > MedLo	Prob. Actual > MedHi
2003/04	3956	58	40	70	3818	3891	4012	4094	82%	21%
2004/05	4028	73	66	98	3835	3920	4094	4221	86%	25%
2005/06	4053	71	84	110	3837	3923	4155	4269	88%	18%
2006/07	4088	72	99	122	3848	3935	4218	4328	90%	14%
2007/08	4126	73	113	134	3863	3948	4277	4389	91%	13%
2008/09	4153	74	124	145	3870	3959	4329	4436	91%	11%
2009/10	4180	74	135	154	3878	3969	4382	4482	91%	10%
2010/11	4201	75	145	163	3881	3978	4428	4521	91%	8%
2011/12	4228	76	154	172	3891	3990	4481	4565	92%	7%
2012/13	4258	76	163	180	3906	4002	4535	4610	92%	6%
2013/14	4296	77	172	188	3927	4020	4595	4665	93%	6%
2014/15	4338	77	181	196	3953	4042	4660	4723	93%	5%
2015/16	4380	78	189	204	3980	4067	4728	4780	94%	4%
2016/17	4422	79	196	212	4007	4092	4792	4837	94%	4%
2017/18	4465	79	204	219	4035	4117	4861	4895	94%	4%
2018/19	4508	80	212	227	4064	4142	4930	4952	95%	3%
2019/20	4556	81	219	233	4099	4168	4989	5013	95%	3%
2020/21	4599	81	226	240	4129	4194	5052	5069	95%	3%
2021/22	4646	82	232	246	4163	4220	5116	5129	96%	3%
2022/23	4692	83	239	253	4196	4247	5186	5188	96%	3%
2023/24	4730	83	246	259	4222	4274	5257	5238	96%	2%

FORECAST ACCURACY

Comparing previous load forecast to actual results has been complicated by changes in utility operations and reporting. Five major changes have occurred since 1990. Each of these changes will be discussed briefly.

1) Interruptible Sales - Since 1991/92, Manitoba Hydro has offered interruptible rates to its customers. These rates have created a distinction between firm and non-firm sales, which affect the calculation of Net Firm Energy because non-firm sales are excluded.

2) Demand Side Management - Since 1992/93, Manitoba Hydro has included Demand Side Management (DSM) as a supply side resource in the determination of System Capability and Energy Requirement. The load forecast contains DSM associated with the Basic Customer Information and Service option. The forecast includes savings from appliance efficiency improvements and other base DSM program. It does not include incentive-based DSM programs. These are reviewed as a supply-side resource that can be ramped up or down dependant on future need.

3) Curtailable Rates - Since 1993/94, Manitoba Hydro has offered a curtailable rate program to its customers. These rates affect the actual peak load experienced because customers are usually curtailed at the time of peak. When calculating the Net Total Peak for this report, the curtailments are added back to create a consistent hourly integrated load profile. The transformed hourly load data is used in the Hourly Load Model.

4) Station Service - Since 1993/94, transmission losses and station service have been metered separately at the generation stations. Previously, transmission losses and station service were indistinguishable and recorded under transmission losses. The separation of transmission losses and station service affect the calculation of Net Firm Energy because station services losses are excluded.

5) Peak Definition - Since 1993/94, Manitoba Hydro has defined the system peak as an hourly integrated value. Previously, the peak was recorded as an instantaneous or one minute peak.

Depending on when the forecast was created, adjustments have been made to the forecasted energy and peak values to account for these variances. This will present a more meaningful analysis of the long term forecast accuracy.

Figure 21

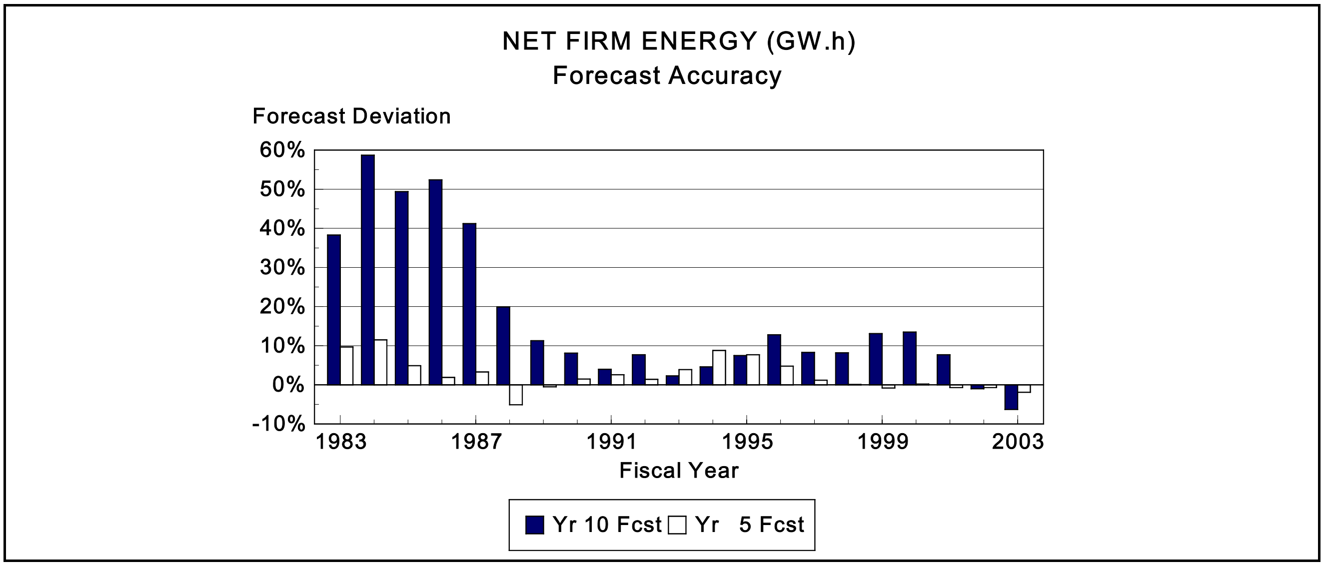


Table 24

Fiscal Year	Forecast Prepared 10 Years Previous	Forecast Prepared 5 Years Previous	Actual Net Firm Energy	Weather Adjustment	Weadj. Net Firm Energy	10 Year Percent Deviation	5 Year Percent Deviation
1982/83	18633	14778	13260	212	13472	38.3%	9.7%
1983/84	22587	15868	14387	-155	14232	58.7%	11.5%
1984/85	22332	15679	15014	-62	14952	49.4%	4.9%
1985/86	23339	15600	15366	-53	15313	52.4%	1.9%
1986/87	22325	16333	15495	313	15808	41.2%	3.3%
1987/88	19823	15692	16260	276	16536	19.9%	-5.1%
1988/89	18751	16753	17108	-263	16845	11.3%	-0.5%
1989/90	18585	17451	17298	-104	17194	8.1%	1.5%
1990/91	18254	17994	17553	-7	17546	4.0%	2.6%
1991/92	19311	18166	17748	176	17924	7.7%	1.4%
1992/93	18312	18592	17894	2	17896	2.3%	3.9%
1993/94	18773	19539	18048	-95	17953	4.6%	8.8%
1994/95	19508	19551	17784	363	18147	7.5%	7.7%
1995/96	20659	19194	19000	-689	18311	12.8%	4.8%
1996/97	20229	18913	19173	-491	18682	8.3%	1.2%
1997/98	20737	19186	18872	296	19168	8.2%	0.1%
1998/99	22059	19345	19095	411	19506	13.1%	-0.8%
1999/00	22018	19425	18804	592	19396	13.5%	0.2%
2000/01	21502	19829	20075	-106	19969	7.7%	-0.7%
2001/02	20482	20542	20494	202	20696	-1.0%	-0.7%
2002/03	20299	21252	21940	-272	21668	-6.3%	-1.9%

Figure 22

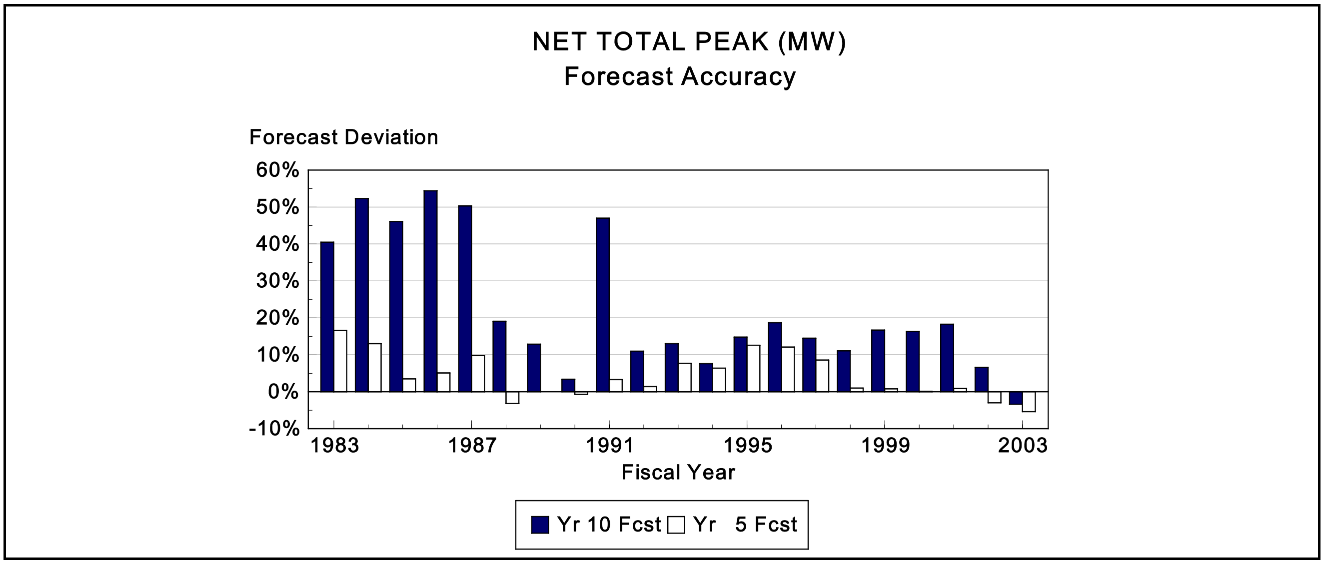


Table 25

Fiscal Year	Forecast Prepared 10 Years Previous	Forecast Prepared 5 Years Previous	Actual Net Total Peak	Curtailed and Weather Adjustment	Weadj. Net Total Peak	10 Year Percent Deviation	5 Year Percent Deviation
1982/83	3632	3013	2494	91	2585	40.5%	16.6%
1983/84	4361	3234	2875	-12	2863	52.3%	13.0%
1984/85	4356	3087	2974	8	2982	46.1%	3.5%
1985/86	4584	3119	2945	23	2968	54.4%	5.1%
1986/87	4506	3293	3003	-5	2998	50.3%	9.8%
1987/88	4041	3286	3326	67	3393	19.1%	-3.2%
1988/89	3822	3384	3403	-19	3384	12.9%	0.0%
1989/90	3659	3515	3611	-71	3540	3.4%	-0.7%
1990/91	3652	3603	3542	-53	3489	4.7%	3.3%
1991/92	3896	3557	3435	74	3509	11.0%	1.4%
1992/93	3809	3631	3404	-34	3370	13.0%	7.7%
1993/94	3816	3771	3567	-22	3545	7.6%	6.4%
1994/95	3930	3855	3342	82	3424	14.8%	12.6%
1995/96	4115	3884	3647	-181	3466	18.7%	12.1%
1996/97	4003	3796	3476	19	3495	14.5%	8.6%
1997/98	4036	3670	3573	60	3633	11.1%	1.0%
1998/99	4194	3623	3639	-46	3593	16.7%	0.8%
1999/00	4243	3652	3588	61	3649	16.3%	0.1%
2000/01	4303	3669	3708	-71	3637	18.3%	0.9%
2001/02	4019	3657	3760	9	3769	6.6%	-3.0%
2002/03	3798	3717	3916	14	3930	-3.4%	-5.4%

CALENDAR YEAR RESULTS

Table 26

ENERGY SALES TO MANITOBA HYDRO CUSTOMERS
2002-2023 (GW.h)
Base Forecast

Calendar Year	Residential	General Service	Area & Roadway Lighting	Manitoba Hydro Sales Incl Diesel		Total Diesel	Manitoba Hydro Sales Excl Diesel
2002 Actual	6145	12581	89	18815	5.5%	10	18805
2003	6207	12948	90	19245	2.3%	11	19234
2004	6176	13411	91	19679	2.3%	12	19667
2005	6216	13718	92	20026	1.8%	13	20013
2006	6255	13875	92	20222	1.0%	14	20208
2007	6295	14065	93	20454	1.1%	14	20440
2008	6335	14233	94	20662	1.0%	15	20647
2009	6375	14392	95	20861	1.0%	16	20845
2010	6415	14550	95	21060	1.0%	17	21043
2011	6455	14715	96	21267	1.0%	18	21249
2012	6496	14890	97	21484	1.0%	19	21465
2013	6538	15066	98	21701	1.0%	19	21682
2014	6581	15248	98	21928	1.0%	20	21908
2015	6624	15436	99	22159	1.1%	21	22138
2016	6666	15624	100	22390	1.0%	22	22368
2017	6710	15813	101	22624	1.0%	23	22601
2018	6754	16002	102	22858	1.0%	23	22835
2019	6799	16192	102	23093	1.0%	24	23069
2020	6845	16382	103	23330	1.0%	25	23305
2021	6892	16573	104	23569	1.0%	25	23544
2022	6941	16765	105	23810	1.0%	26	23784
2023	6991	16958	105	24054	1.0%	26	24028

Table 27

NET FIRM ENERGY
2002 - 2023 (GW.h)
Base Forecast

Calendar Year	Dist. Losses	Const. Power	Manitoba Load at Common Bus	Trans. Losses & Stn Service	Gross Total Energy	Non Firm Energy	Station Service	Net Firm Energy
2002 Actual	709	45	19560	2153	21713	29	170	21514
2003	956	46	20236	2128	22364	28	171	22165
2004	931	45	20643	2177	22819	35	176	22609
2005	829	45	20888	2204	23092	13	178	22901
2006	881	51	21142	2230	23372	0	181	23191
2007	893	74	21406	2258	23664	0	183	23481
2008	898	85	21630	2282	23912	0	185	23728
2009	967	85	21837	2304	24141	0	187	23955
2010	913	66	22022	2323	24346	0	188	24157
2011	923	49	22221	2344	24565	0	190	24375
2012	933	45	22443	2368	24811	0	192	24619
2013	935	45	22661	2391	25053	0	194	24859
2014	945	45	22898	2416	25314	0	196	25118
2015	955	48	23141	2441	25582	0	198	25384
2016	965	53	23387	2467	25854	0	200	25654
2017	975	58	23634	2493	26128	0	202	25926
2018	985	63	23883	2520	26402	0	204	26198
2019	998	84	24150	2548	26698	0	206	26492
2020	1005	95	24406	2575	26981	0	209	26772
2021	1018	107	24669	2603	27272	0	211	27061
2022	1028	124	24937	2631	27568	0	213	27354
2023	1034	108	25169	2655	27824	0	215	27609

- See the Glossary of Terms for a definition of Gross Total Energy, Non Firm Energy, Station Service and Net Firm Energy.

GLOSSARY OF TERMS

The two key differences in terminology used throughout this report are:

1) **GROSS vs NET** - for both energy and peak, gross figures include station service loads; whereas net figures exclude station service loads.

2) **TOTAL vs FIRM** - total energy includes non-firm energy; whereas firm energy excludes non-firm energy. Total peak adds back curtailed loads; whereas firm peak excludes curtailed loads.

Station Service - is electricity consumed by generating stations in the production of electric power.

Non-Firm Energy - includes all energy sold to Manitoba customers on a non-firm basis. This category includes all sales from the Surplus Energy Program (SEP).

Curtailable - is load that can be curtailed on short notice. Customers are given a discount for subscribing to this less firm source of power. Curtailable loads affects peak demand because most periods of curtailment tend to be at or near the system peak. It is assumed that this rate will have no effect on energy consumption because customers can purchase make-up energy after the curtailment.

Gross Total Energy - includes all energy needed to meet the requirements of Manitoba customers on the integrated system. This figure includes station service and non-firm energy. This figure does not include diesel generation, Industrial self-generation, exports, exports losses or import gains.

Net Total Energy - same as Gross Total Energy except station service loads are excluded.

Net Firm Energy - same as Gross Total Energy except station service and non-firm loads are excluded.

Gross Total Peak - is the maximum hourly demand in a given year, required to meet the needs of Manitoba customers on the integrated system. This figure includes (adds back in) station service loads and curtailable loads. This figure does not include diesel generation, Industrial self-generation, exports and losses associated with exports/imports.

Net Total Peak - same as Gross Total Peak except station service loads are excluded.

Net Firm Peak - same as Gross Total Peak except station service and curtailable loads are excluded.