PUB/CENTRA I-1

Subject: **Tab 2 Summary and Reasons for Application**

Reference: **Tab 2 Pages 1 and 2 of 8**

a) Please populate the following table consistent with PUB/MH I-2 from the 2012/13 & 2013/14 GRA for each of the years 2002/03 through 2013/14:

Year	% Non-Gas Rate Increase Requested	% Approved Final/ Interim	MB CPI	Annual Increase in Non-Gas Revenue	Cumulative % Increase	Cumulative MB CPI	Cumulative Additional Non-Gas Revenue From Rate Increases	Debt to Equity Ratio

ANSWER:

Please see the table below.

Approved General Rate Increases compared to Manitoba CPI

Year	Date	Order	Approved Revenue Requirement ($000's)	Requested Rate Increase(1)	Approved General Increase	Cumulative General Increase	CPI	Cumulative CPI
2003/04	August 1, 2003	118/03	498,788	3.0%	1.9%	1.9%	0.9%	0.9%
2004/05	No Rate Change		n/a	0.0%	0.0%	1.9%	2.7%	3.6%
2005/06	August 1, 2005	103/05	554,947	2.5%	2.0%	3.9%	2.4%	6.1%
2006/07	May 1, 2006	103/05	564,104	2.5%	1.0%	5.0%	2.0%	8.2%
2007/08	August 1, 2007	99/07	542,617	2.0%	2.0%	7.1%	1.9%	10.3%
2008/09	May 1, 2008	99/07	550,171	1.0%	1.0%	8.1%	2.2%	12.7%
2009/10	No Rate Change	128/09	n/a	1.0%	0.0%	8.1%	0.6%	13.4%
2010/11	May 1, 2010	128/09	478,476	1.0%	0.8%	9.0%	1.0%	14.5%
2011/12	No Rate Change		n/a	0.0%	0.0%	9.0%	2.8%	17.7%
2012/13	No Rate Change		n/a	0.0%	0.0%	9.0%	1.7%	19.7%
2013/14*	Proposed August 1, 2013		n/a	2.0%		11.2%	1.8%	21.9%

*Proposed and Forecasted MB CPI

With respect to the requested information on the debt-to-equity ratio, please see Centra's response to PUB/Centra I-2a for Centra's capital structure.

(1)Requested General Revenue Increase:

In the annual preparation of the IFF, Centra calculates the revenues that would be obtained on a normal weather basis by applying the previously approved rates to the new load forecast. The ongoing trend in energy conservation generally results in a year-over-year decline in forecast customer usage and therefore the previously approved rates will not generate the amount of revenue that is required. Centra then identifies the percentage increase over the total revenues at existing rates (including forecast gas costs) that would provide the required level of income. As such, Centra's requested general revenue increase reflects the effects of conservation and changes to both gas costs and non-gas costs. The percentage increase is not applied against the last-approved revenue requirement.

PUB/CENTRA I-1

Subject: **Tab 2 Summary and Reasons for Application**

Reference: **Tab 2 Pages 1 and 2 of 8**

b) Please tabulate the annual bills for a residential customer based on rates in effect November 1 of each year from 2000 until 2012, plus the annual bill based on proposed August 1, 2013 rates. In the calculations, please use the current typical annual consumption of 2363 m3 as well as the billing percentages in effect as of November 1 for each year.

ANSWER:

Please see the attached schedule. For purposes of the calculations, Centra used the 2013/14 typical annual residential customer consumption of 2,374 m^3 rather than the average annual SGS customer consumption of 2,363 m^3 reflected in the question.

Date	BMC	Transportation (to Centra)	Distribution (to Customer)	Primary Gas	Supplemental Gas	Billing % (PG)	Billing % (SG)	Usage	Total Bill
November 1, 2003	$10.00	$ 0.0419	$ 0.0716	$ 0.2332	$ 0.3874	96%	4%	2,374	$958
November 1, 2004	$10.00	$ 0.0373	$ 0.0645	$ 0.2661	$ 0.2861	99%	1%	2,374	$994
November 1, 2005	$10.00	$ 0.0425	$ 0.0784	$ 0.3207	$ 0.2860	98%	2%	2,374	$1,167
November 1, 2006	$10.00	$ 0.0357	$ 0.0783	$ 0.2932	$ 0.2669	100%	0%	2,374	$1,087
November 1, 2007	$12.00	$ 0.0332	$ 0.0873	$ 0.2731	$ 0.2686	100%	0%	2,374	$1,078
November 1, 2008	$13.00	$ 0.0379	$ 0.0885	$ 0.3018	$ 0.2686	97%	3%	2,374	$1,170
November 1, 2009	$13.00	$ 0.0429	$ 0.0896	$ 0.2213	$ 0.1578	96%	4%	2,374	$990
November 1, 2010	$14.00	$ 0.0397	$ 0.0899	$ 0.1600	$ 0.1827	81%	19%	2,374	$866
November 1, 2011	$14.00	$ 0.0536	$ 0.0849	$ 0.1436	$ 0.1344	97%	3%	2,374	$837
November 1, 2012	$14.00	$ 0.0462	$ 0.0869	$ 0.0967	$ 0.1344	90%	10%	2,374	$722
August 1, 2013	$14.00	$ 0.0510	$ 0.0875	$ 0.0967	$ 0.1638	90%	10%	2,374	$742

PUB/CENTRA I-1

Subject: **Tab 2 Summary and Reasons for Application**

Reference: **Tab 2 Pages 1 and 2 of 8**

c) Please repeat (b) for a LGS customer consuming 59,490 m3 per year.

ANSWER:

Please see the attached schedule.

Annual bills for a LGS customer (based on rates and billing percentages in effect on Nov 1 of each year)

Date	BMC	Transportation (to Centra)	Distribution (to Customer)	Primary Gas	Supplemental Gas	Billing % (PG)	Billing % (SG)	Usage (m^3)	Total Bill
November 1, 2003	$70.00	$ 0.0386	$ 0.0277	$ 0.2332	$ 0.3874	96%	4%	59,490	$19,024
November 1, 2004	$70.00	$ 0.0389	$ 0.0202	$ 0.2661	$ 0.2861	99%	1%	59,490	$20,198
November 1, 2005	$70.00	$ 0.0406	$ 0.0330	$ 0.3207	$ 0.2860	98%	2%	59,490	$24,256
November 1, 2006	$70.00	$ 0.0362	$ 0.0281	$ 0.2932	$ 0.2669	100%	0%	59,490	$22,108
November 1, 2007	$70.00	$ 0.0330	$ 0.0343	$ 0.2731	$ 0.2686	100%	0%	59,490	$21,090
November 1, 2008	$70.00	$ 0.0374	$ 0.0379	$ 0.3018	$ 0.2686	97%	3%	59,490	$23,216
November 1, 2009	$70.00	$ 0.0404	$ 0.0390	$ 0.2213	$ 0.1578	96%	4%	59,490	$18,578
November 1, 2010	$77.00	$ 0.0388	$ 0.0391	$ 0.1600	$ 0.1827	81%	19%	59,490	$15,333
November 1, 2011	$77.00	$ 0.0531	$ 0.0342	$ 0.1436	$ 0.1344	97%	3%	59,490	$14,643
November 1, 2012	$77.00	$ 0.0451	$ 0.0362	$ 0.0967	$ 0.1344	90%	10%	59,490	$11,737
August 1, 2013	$77.00	$ 0.0506	$ 0.0333	$ 0.0967	$ 0.1638	90%	10%	59,490	$12,069

PUB/CENTRA I-2 (Revised)

Subject: **Tab 2 Summary and Reasons for Application**

Reference: **Tab 2 Page 5 of 8**

a) Please re-file table 1 including the years 2004/05 through 2014/15 including the financial targets for gas operations, as well as the showing the Furnace Replacement Program in each of the years that it pertains.

ANSWER:

Please note that while financial targets have been calculated for gas operations only on the following attachment, as requested, Manitoba Hydro's financial targets apply to consolidated operations only.

Table 1 - Net Income - Centra Gas

(in millions of $)	Actual 2005	2006	2007	2008	2009	2010	2011	2012	Forecast 2013	2014
General Consumers Revenue										
- at approved rates	$ 507	$ 515	$ 506	$ 529	$ 582	$ 456	$ 406	$ 332	$ 322	$ 316
Furnace Replacement Program	-	-	-	(2)	(4)	(4)	(4)	(4)	(4)	(4)
Cost of Gas Sold	384	397	379	387	431	316	261	197	176	168
Gross Margin	*123*	*118*	*127*	*140*	*147*	*136*	*142*	*131*	*143*	*144*
Other Revenue	2	2	2	2	2	2	1	1	2	2
	125	120	129	142	149	138	143	132	145	146
Expenses										
Operating & Administrative	55	53	54	56	60	61	61	62	67	69
Finance Expense	17	18	22	22	20	19	18	19	18	17
Depreciation & Amortization	20	19	18	23	25	24	25	26	28	30
Capital & Other Taxes	23	23	22	23	23	23	20	19	18	19
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
	127	125	128	136	140	139	136	138	143	147
Net Income (loss) before proposed rate increases	$ (2)	$ (5)	$ 1	$ 6	$ 9	$ (1)	$ 7	$ (6)	$ 2	$ (1)
Proposed rate increases	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	-	6
Net Income (loss) after proposed rate increases	(2)	(5)	1	6	9	(1)	7	(6)	2	5
Retained Earnings before proposed rate increases	25	20	21	27	34	33	40	34	36	35
Retained Earnings after proposed rate increases	25	20	21	27	34	33	40	34	36	41
Financial Ratios - **with rate increase**										
Equity (PUB Methodology)	34%	32%	30%	30%	31%	32%	33%	33%	34%	33%
Interest Coverage	0.88	0.72	1.05	1.27	1.42	0.95	1.39	0.68	1.09	1.29
Capital Coverage	1.17	(0.07)	0.76	1.21	1.17	2.44	1.67	1.58	1.23	0.07
Financial Ratios - **without rate increase**										
Equity (PUB Methodology)	34%	32%	30%	30%	31%	32%	33%	33%	34%	32%
Interest Coverage	0.88	0.72	1.05	1.27	1.42	0.95	1.39	0.68	1.09	0.95
Capital Coverage	1.17	(0.07)	0.76	1.21	1.17	2.44	1.67	1.58	1.23	(0.10)

PUB/CENTRA I-2

Subject: **Tab 2 Summary and Reasons for Application**

Reference: **Tab 2 Page 5 of 8**

b) For the year 2013/14, please reconcile Table 1 with IFF12.

ANSWER:

Please see table included below:

Table 1 - Net Income - Centra Gas

(in millions of $)	IFF-12 2014	Test Year 2014	Difference	Notes
General Consumers Revenue				
- at approved rates	$ 312	$ 312	$ -	
Cost of Gas Sold	168	168	-	
Gross Margin	*144*	*144*	-	
Other Revenue	2	2	-	
	146	146	-	
Expenses				
Operating & Administrative	69	69	-	
Finance Expense	17	17	-	
Depreciation & Amortization	30	30	-	
Capital & Other Taxes	19	19	-	
Corporate Allocation	12	12	-	
	147	147	-	
Net Income (loss) before proposed rate increases	$ (1)	$ (1)	$ -	
Proposed rate increases	7	6	1	A
Net Income (loss) after proposed rate increases	6	5	1	A
Retained Earnings before proposed rate increases	35	35	-	
Retained Earnings after proposed rate increases	42	41	1	A

A - The proposed rate increase included in IFF-12 contemplated a rate increase on May 1, 2013. The Test Year 2014 reflects implementation of the rate increase on August 1, 2013, resulting in a reduction in the amount of the proposed rate increase by approximately $1 million in 2013/14.

PUB/CENTRA I-3

Subject: **Tab 3 Corporate Overview**

Reference: **Tab 3 Page 10 of 15**

a) Please file the Corporate organization charts provided at the 2007/08 & 2008/09 GRA and 2009/10 & 2010/11 GRA.

ANSWER:

Please see the Attachment to this response.

Manitoba Hydro

ORGANIZATION STRUCTURE
EXECUTIVE AND SENIOR MANAGEMENT

- BOARD
  - General Counsel & Corporate Secretary — **Ken Tennenhouse**
  - President and Chief Executive Officer — **Bob Brennan**
    - Vice-President Finance & Administration and Chief Financial Officer — **Vince Warden**
      - Corporate Treasurer — **Manny Schulz**
      - Corporate Controller — **Darren Rainkie**
      - Division Manager Financial Planning & Corporate Risk Management — **Lyn Wray**
      - Division Manager Human Resources — **Brian Ketcheson**
      - Division Manager Information Technology Services — **Glen Reitmeier**
      - Division Manager Rates & Regulatory Affairs — **Robin Wiens**
      - Division Manager Gas Supply — **Howard Stephens**
      - Division Manager Corporate Safety & Health — **Brad Ireland**
      - Business Solutions Manager Customer Projects
    - Vice-President Customer Service & Marketing — **Gerry Rose**
      - Division Manager Industrial & Commercial Solutions — **Mike Dudar**
      - Division Manager Customer Service Operations — **Brent Reed**
      - Division Manager Consumer Marketing & Sales — **Lloyd Kuczek**
      - Division Manager Business Support Services — **Lois Morrison**
      - Business Communications
      - Gas Markets – Policy, Administration & Development
      - Market Issues
    - Vice-President Transmission & Distribution — **Al Snyder**
      - Division Manager Transmission Planning & Design — **Gerald Neufeld**
      - Division Manager Transmission Construction & Line Maintenance — **Shane Mailey**
      - Division Manager Transmission System Operations — **Ed Tymofichuk**
      - Division Manager Distribution Planning & Design — **Erni Wiebe**
      - Division Manager Distributon Construction — **John Kreml**
      - Division Manager Apparatus Maintenance — **Ron Dacombe**
      - W.I.R.E. Services
      - HVDC Research Centre
      - Manitoba Hydro International Ltd.
      - Research & Development
    - Vice-President Power Supply — **Ken Adams**
      - Division Manager Power Projects Development — **Ed Wojczynski**
      - Division Manager HVDC — **John McNichol**
      - Division Manager Generation North — **Finlay MacInnes**
      - Division Manager Generation South — **John Clouston**
      - Division Manager Engineering Services — **Randy Raban**
      - Division Manager Power Sales & Operations — **David Cormie**
      - Division Manager New Generation Construction — **Ralph Wittebolle**
      - Division Manager Power Planning — **Joanne Flynn**
    - Vice-President Corporate Relations — **Ruth Kristjanson**
      - Division Manager Aboriginal Relations — **Andrew Miles**
      - Corporate Planning & Development
      - Purchasing
      - Economic Analysis
      - Economic Development Coordination
      - Government Relations & Current Issues
    - Division Manager Public Affairs — **Glenn Schneider**
    - Division Manager New Head Office — **Tom Gouldsborough**
    - Internal Audit

PUB/CENTRA I-3

Subject: **Tab 3 Corporate Overview**

Reference: **Tab 3 Page 10 of 15**

b) Provide and discuss all changes including executive and senior management positions and growth from the Corporate Structure presented at the 2009/10 and 2010/11 GRA.

ANSWER:

In February 2009 changes to the Corporate Structure were announced that saw the operational responsibilities of two Business Units (Customer Service & Marketing, and Transmission & Distribution) being reorganized into three new Business Units: Customer Care & Marketing, Customer Service Operations & Distribution, and Transmission. At that time, the new Business Unit of Corporate Planning & Strategic Analysis was also created. In February 2013 coincident with the retirement of the Senior Vice-President of Finance & Administration and CFO, a further reorganization of Business Units was announced that saw the Divisions in the Finance & Administration Business Unit being reallocated, and two new separate Business Units being created: Human Resources & Corporate Facilities; and Finance & Regulatory. The responsibilities within Corporate Planning & Strategic Analysis were reallocated to other existing Business Units as well. Implementation of the change associated with this reorganization is ongoing.

PUB/CENTRA I-3

Subject: **Tab 3 Corporate Overview**

Reference: **Tab 3 Page 10 of 15**

c) Please discuss the extent to which this has impacted the OM&A revenue requirement allocated to Centra.

ANSWER:

The OM&A expenditures allocated to Centra reflect the realignment of operational responsibilities between Customer Care & Marketing, Customer Service & Distribution and Transmission (as noted at Tab 3 page 10 of 15) and as such do not have a significant impact on the O&A revenue requirement.

The OM&A expenditures presented in this proceeding do not reflect the most recent organizational announcement noted in PUB/Centra I-3(b) as the implementation of these changes is still ongoing.

PUB/CENTRA I-3 (Revised)

Subject: **Tab 3 Corporate Overview**

Reference: **Tab 3 Page 10 of 15**

d) Please provide the total corporate cost of the management represented in the 2009/10 and 2013/14 Organization Chart and the amount from each division allocated to Centra.

ANSWER:

Total corporate cost of management in the table below includes Vice-Presidents and Division Managers. Please refer to PUB/Centra I-3(f) for a discussion of the variances.

CENTRA GAS MANITOBA INC.
Corporate Cost of Management in 2012/13 Organization Chart

($000's)

	Management Costs 2008/09 Actual	Centra Gas Allocation 2008/09 Actual	%	Management Costs 2009/10 Actual	Centra Gas Allocation 2009/10 Actual	%	Management Costs 2010/11 Actual	Centra Gas Allocation 2010/11 Actual	%	Management Costs 2011/12 Actual	Centra Gas Allocation 2011/12 Actual	%	Management Costs 2012/13 Test Year	Centra Gas Allocation 2012/13 Test Year	%	Management Costs 2013/14 Test Year	Centra Gas Allocation 2013/14 Test Year	%
President & CEO	2,458	239		3,203	319		3,390	184		3,615	217		3,568	139		3,639	142	
Senior VP Finance and Administration	1,689	297		1,800	289		1,846	303		2,117	288		2,134	81		2,176	82	
VP Corp Relations	1,118	34		633	51		492	18		453	16		586	22		598	22	
Senior VP Power Supply	1,715	46		1,717	51		1,642	16		1,840	31		2,078	123		2,119	125	
VP Transmission	1,273	40		948	36		956	17		969	18		1,044	66		1,065	67	
VP Cust Care & Marketing	1,287	311		1,179	262		941	259		1,187	260		1,234	106		1,258	108	
VP Cust Service & Distribution	-	-		723	72		964	141		1,097	143		1,184	78		1,208	79	
	9,539	967	10%	10,203	1,080	11%	10,230	939	9%	11,278	974	9%	11,826	614	5%	12,063	626	5%

PUB/CENTRA I-3 (Revised)

Subject: **Tab 3 Corporate Overview**

Reference: **Tab 3 Page 10 of 15**

e) A portion of Manitoba Hydro's senior management costs is allocated to Centra each year. Please detail these amounts per business unit for the years 2004/05 through 2013/14, considering only the costs associated with the management depicted in the organization charts. In the same table, detail the amount and the percentage of the total that is allocated to Centra.

ANSWER:

Please see the schedule below.

CENTRA GAS MANITOBA INC.
Corporate Cost of Management in 2012/13 Organization Chart

($000's)

	Management Costs 2004/05 Actual	Centra Gas Allocation (Estimated) 2004/05 Actual	%	Management Costs 2005/06 Actual	Centra Gas Allocation (Estimated) 2005/06 Actual	%	Management Costs 2006/07 Actual	Centra Gas Allocation (Estimated) 2006/07 Actual	%	Management Costs 2007/08 Actual	Centra Gas Allocation (Estimated) 2007/08 Actual	%
President & CEO	2,301	259		2,348	250		2,444	259		2,602	258	
VP Corporate Relations	746	59		1,079	69		1,124	72		1,069	70	
VP Finance and Administration	1,257	187		1,358	201		1,658	259		1,808	276	
VP Power Supply	1,321	13		1,692	12		1,934	9		1,702	7	
VP Transmission & Distribution	1,443	99		1,560	102		1,218	79		1,230	76	
VP Customer Service & Marketing	1,270	268		1,209	243		1,095	237		1,140	252	
	8,338	885	11%	9,246	877	9%	9,473	916	10%	9,551	938	10%

	Management Costs 2008/09 Actual	Centra Gas Allocation (Estimated) 2008/09 Actual	%	Management Costs 2009/10 Actual	Centra Gas Allocation (Estimated) 2009/10 Actual	%	Management Costs 2010/11 Actual	Centra Gas Allocation (Estimated) 2010/11 Actual	%	Management Costs 2011/12 Actual	Centra Gas Allocation (Estimated) 2011/12 Actual	%	Management Costs 2012/13 Test Year	Centra Gas Allocation (Estimated) 2012/13 Test Year	%	Management Costs 2013/14 Test Year	Centra Gas Allocation (Estimated) 2013/14 Test Year	%
President & CEO	2,458	239		3,203	319		3,390	184		3,615	217		3,568	139		3,639	142	
Senior VP Finance and Administration	1,689	297		1,800	289		1,846	303		2,117	288		2,134	81		2,176	82	
VP Corp Relations	1,118	34		633	51		492	18		453	16		586	22		598	22	
Senior VP Power Supply	1,715	46		1,717	51		1,642	16		1,840	31		2,078	123		2,119	125	
VP Transmission	1,273	40		948	36		956	17		969	18		1,044	66		1,065	67	
VP Cust Care & Marketing	1,287	311		1,179	262		941	259		1,187	260		1,234	106		1,258	108	
VP Cust Service & Distribution	-	-		723	72		964	141		1,097	143		1,184	78		1,208	79	
	9,539	967	10%	10,203	1,080	11%	10,230	939	9%	11,278	974	9%	11,826	614	5%	12,063	626	5%

Note: Information presented for years 2004/05 to 2007/08 is not directly comparable to years 2008/09 to 2013/14 as a result of changes to the Corporate organizational structure.

PUB/CENTRA I-3

Subject: **Tab 3 Corporate Overview**

Reference: **Tab 3 Page 10 of 15**

f) Please explain the basis for the allocation in (e).

ANSWER:

Over the past few years, Manitoba Hydro has been in a period of major electric capital development for projects such as Wuskwatim, Keeyask, Conawapa and Bipole III. As a result, the allocation of senior management costs to Centra has been reviewed and adjusted to reflect the Corporation's current operations. A summary of the allocation changes is as follows:

The Corporation has placed emphasis on the importance of direct time allocation for all staff which has increased the amount of senior management time directly allocated to electric projects.

In 2008/09, executive management costs were included in overhead and charged to Centra as a percentage add-on to activity charges. Since then the allocation driver has been changed to the asset base of the utility in order to reflect the Corporation's current operations.

Division Manager costs continued to be allocated to the departments they supported up to 2011/12. These costs were included in departmental activity rates and charged either to operating programs, capital projects or included in overhead, dependent on the nature of each department. In order to reflect the Corporation's current operations, these costs were removed from departmental activity rates in 2012/13 and allocated to Centra as follows: for governance areas such as Executive, General Counsel and Corporate Accounting, the driver has been modified to represent the asset base of the utility, similar to executive management costs. For service and functional areas such as Human Resources, Generation, Distribution and Transmission the costs have been included in overhead and charged to Centra as a percentage add-on to activity charges.

PUB/CENTRA I-3

Subject: **Tab 3 Corporate Overview**

Reference: **Tab 3 Page 10 of 15**

g) Please update the Organization Structure to identify those individuals responsible for department activities listed at the bottom of each Organizational Structure column and file an updated Organization chart.

ANSWER:

The attachment to this response provides an updated Organizational Chart reflecting the changes announced in February 2013, as well as the names of the individuals responsible for the activities of those departments listed at the bottom of the Organizational Chart on page 10 of Tab 3.

Manitoba Hydro

ORGANIZATION STRUCTURE
EXECUTIVE AND SENIOR MANAGEMENT

- BOARD
  - President and Chief Executive Officer — **Scott Thomson**
    - Vice-President Human Resources & Corporate Services — **Bryan Luce**
      - Division Manager Human Resources — **Gary Maksymyk**
      - Division Manager Corporate Safety & Health — **Brad Ireland**
      - Division Manager Information Technology Services — **Glen Reitmeier**
      - Division Manager Corporate Services — **Brian Ketcheson**
      - Corporate Environmental Management Department — **Alec Stuart**
    - Senior Vice-President Power Supply — **Ken Adams**
      - Division Manager Power Projects Development — **Shawna Pachal**
      - Division Manager HVDC — **John McNichol**
      - Division Manager Generation North — **Finlay MacInnes**
      - Division Manager Generation South — **Robert Dandenault**
      - Division Manager Engineering Services — **John Kreml**
      - Division Manager Power Sales & Operations — **David Cormie**
      - Division Manager New Generation Construction — **Ralph Wittebolle**
      - Division Manager Power Planning — **Joanne Flynn**
      - Division Manager Portfolio Projects Management — **Eduard Wojczynski**
    - Vice-President Transmission — **Ed Tymofichuk**
      - Division Manager Transmission System Operations — **Lorne Midford**
      - Division Manager Transmission Planning & Design — **Gerald Neufeld**
      - Division Manager Transmission Construction & Line Maintenance — **Shane Mailey**
      - Division Manager Apparatus Maintenance — **Wayne Wittmeier**
    - Vice-President Customer Care & Energy Conservation — **Lloyd Kuczek**
      - Division Manager Gas Supply — **Vacant**
      - Division Manager Industrial & Commercial Solutions — **Dale Friesen**
      - Division Manager Consumer Marketing & Sales — **Lois Morrison**
      - Division Manager Business Support Services — **Quinn Menec**
      - Business Communications Department — **Leona Herzog**
      - Power Smart Planning/ Evaluation & Research Department — **Cheryl Pilek**
      - Affordable Energy Department — **Vacant**
    - Vice-President General Counsel & Corporate Secretary — **Ken Tennenhouse**
      - Division Manager Internal Audit — **Lawrence Wilson**
      - Division Manager Law — **Patti Ramage**
      - Insurance Services Department — **Tino Brambilla**
      - Corporate Security Department — **Chris McColm**
      - Intellectual Property — **Leo Wong**
      - Human Rights & Respectful Workplace — **Paula Hamilton**
    - Vice-President Corporate Relations — **Ruth Kristjanson**
      - Division Manager Aboriginal Relations — **Elissa Neville**
      - Division Manager Corporate Planning & Strategic Review — **Ian Page**
      - Government Relations & Current Issues Department — **Nelly Rakita**
    - Vice-President Customer Service & Distribution — **Brent Reed**
      - Division Manager Distribution Engineering & Construction Rural — **Jamie Hall**
      - Division Manager Distribution Engineering & Construction Winnipeg — **Angie Adams**
      - Division Manager Customer Service Operations – South Region — **Scott Dunn**
      - Division Manager Customer Service Operations – Winnipeg & North Region — **Dave Case**
      - Division Manager Business Support & Capital Asset Management — **Mark Prydun**
    - Vice-President Finance & Regulatory — **Darren Rainkie**
      - Corporate Controller — **Hanri Jacobs**
      - Division Manager Rates & Regulatory Affairs — **Robin Wiens**
      - Corporate Treasurer — **Manny Schulz**
      - Managing Director Subsidiary Operations — **Paul Wilson**
      - Corporate Risk Management Department — **Don Deviaene**
    - Division Manager Public Affairs — **Glenn Schneider**

PUB/CENTRA I-3

Subject: Tab 3 Corporate Overview

Reference: Tab 3 Page 10 of 15

h) Please describe any changes in the activities of the five business units (or responsibility for the activities) that have either occurred since the last GRA filing or are planned over the next two years.

ANSWER:

Please see the response to PUB/Centra I-3(b), which reflects a realignment of the business unit organization structure and senior management positions at Manitoba Hydro. These changes support the goals of balancing the executive portfolios as well as realigning activities to deal with the challenges ahead and capitalize on the Corporation's strengths. Although the reporting structure has changed, there are no changes to the activities at the department level.

PUB/CENTRA I-4

Subject: **Tab 3 Corporate Overview**

Reference: **Tab 3 Page 12 and 13 of 15**

a) Please elaborate the productivity improvements Centra takes into consideration when developing its budget for OM&A expenses.

ANSWER:

Business Unit budgets consider a number of process or productivity improvements including utilization and coordination of resources, review of work procedures including standardization of work practices and other cost reduction opportunities in the development of the OM&A expenses for Centra. Some examples of productivity improvement initiatives are as follows:

Implementation of the Winnipeg Area Facilities Review – This review was undertaken to develop a plan to optimize the use of office, shop and storage facilities in the Winnipeg area to accommodate field operations in Customer Service and Apparatus Maintenance divisions and fully integrate the former Winnipeg Hydro and Centra Gas staff. The review recommended the consolidation of seven work locations into four and reduction of the number of districts from seven to five. It also included the full integration of electric and natural gas staff into each of the five districts. Benefits include lower facility operating and maintenance costs and capital upgrades, decreased material inventories, reduced overlap in responsibilities for customers in specific geographic locations, improved customer response times and productivity (staff are closer to the customer base), facilitate future workforce management opportunities and further centralization of administration functions.

<u>EDMS Gas Drawing Registration</u> – All current state drawings representing Gas Operation facilities were organized and relabeled with the Engineering Drawing Management system. This centrally stored repository of current gas asset drawings provides for more effective and efficient utilization.

<u>Customer Email Project</u> – This project creates a technical infrastructure to store and administer email contacts for the purpose of sending targeted email communication and on-line surveys. This centrally stored repository will increase productivity and customer satisfaction.

Please see PUB/Centra I-32(c) for further discussion regarding productivity measures.

In addition, Manitoba Hydro continues to employ specific measures to constrain the growth in OM&A costs for both Electric and Gas operations. These measures include:

- Restrictions on external hiring
- Restrictions on out-of-province travel
- Overtime restrictions (except to respond to system emergencies and to maintain the safety and reliability of the energy supply system)
- Reductions in community sponsorships and donations
- Further leveraging of technology to improve operational efficiencies

PUB/CENTRA I-4

Subject: **Tab 3 Corporate Overview**

Reference: **Tab 3 Page 12 and 13 of 15**

b) Please explain whether there is a specific factor that is assumed for productivity improvement, whether such a factor is department or division specific, and how the factor is determined. Please demonstrate its impact.

ANSWER:

A productivity factor in the order of 0.5% to 1% annually is incorporated in the setting of business unit OM&A targets. It is expected that wages and salaries for existing positions will experience increases ranging from 3% – 4% each year after considering merit, progression, general wage increases and the impacts of retirements and replacements. By having targets only including the allowed general target increase of 2% and considering other factors, an implicit productivity factor is assumed by business units to meet targets.

PUB/CENTRA I-5

Subject: **Tab 3 Corporate Overview**

Reference: **Tab 3 Appendix 3.2 - Corporate Strategic Plan**

a) Please provide a table which compares Centra-specific gas related measures, the CSP target with actual results for the fiscal years 2007/08 through 2011/12 and that forecast for 2012/13.

ANSWER:

Please see the attachment to the response.

CSP Gas Related Measures

Natural Gas Related Measures		**2007/08**		**2008/09**		**2009/10**		**2010/11**		**2011/12**		**2012/13**
Measure	CSP Target Definition	Target	Result	Target	Result	Target	Result	Target	Result	Target	Result	Target
Retail distribution rates: natural gas	Among the lowest in North America	As stated	3rd lowest in Canada	As stated	4th lowest in Canada	As stated	3rd lowest in Canada	As stated	4th lowest in Canada	As stated	3rd lowest in Canada	As stated
Natural gas market share	Percentage of new franchises	100%	100%	100%	100%	Discontinued						
Natural gas market share	Percentage of commodity sales	≥ 60%	58.4%	≥ 60%	59.2%	≥ 60%		Discontinued				
Cost per customer (OM&A): natural gas	$/customer by each March fiscal year end	$213	$215	$220	$227	$223	$231	$230	$228	$238	$232	$248
Greenhouse gas emissions: natural gas operations	Megatonnes	<0.017	.0216	<0.018		Discontinued						
Demand side management: natural gas energy saved	Million cubic metres per year by March fiscal year end	28	30	41	40	46	47	53	57	69	72	82

PUB/CENTRA I-5

Subject: **Tab 3 Corporate Overview**

Reference: **Tab 3 Appendix 3.2 - Corporate Strategic Plan**

b) Please provide Manitoba Hydro's metrics to determine the ranking of retail gas distribution rates.

ANSWER:

Please see below.

Natural Gas Distribution Rates, Average Annual Residential Gas Bill ($)

	Mar. 2008	Mar. 2009	Mar. 2010	Mar. 2011	Mar. 2012
ATCO N (Edmonton)	372	384	480	365	401
ATCO S (Calgary)	330	333	380	321	349
Centra/Manitoba Hydro (Winnipeg)	370	385	383	396	377
Enbridge/Consumers (Toronto)	426	426	448	455	466
Gaz Metropolitan (Montreal)	719	736	788	750	732
SaskEnergy (Regina)	377	401	426	426	398
Fortis BC (Vancouver)	461	477	519	527	466
Union Gas (Hamilton)	326	330	332	333	339

PUB/CENTRA I-5

Subject: **Tab 3 Corporate Overview**

Reference: **Tab 3 Appendix 3.2 - Corporate Strategic Plan**

c) Please explain why there are no outage targets for gas service.

ANSWER:

Due to the low number of gas-related outages experienced by Centra, it was determined that setting such targets for gas service was of limited value.

PUB/CENTRA I-5

Subject: **Tab 3 Corporate Overview**

Reference: **Tab 3 Appendix 3.2 - Corporate Strategic Plan**

d) **Please confirm whether Manitoba Hydro has a target response time for natural gas emergencies. If a target (or targets) exists, please state it (them) along with Manitoba Hydro's performance against this (these) target(s).**

ANSWER:

Manitoba Hydro does not have a target response time for natural gas emergency calls. Internal procedures indicate that the calls are "to be dispatched immediately to any capable Company personnel. Overtime to be used if required".

Emergency response times are monitored per occurrence by our Dispatch operation and/or the local areas. Below are emergency response times for the Winnipeg area, for the fiscal years shown. Winnipeg data was available due to the use of a Computer Aided Dispatch (CAD) software system and the real time recording of field performance statistics.

Fiscal Year (April 1 to March 31)	Total Calls	(Total time, Travel + Time on Site) (in minutes)
2007-08	1039	55
2008-09	1324	54
2009-10	1354	57
2010-11	1211	60
2011-12	1128	63
2012-13 (as of Mar 21st)	1206	60

PUB/CENTRA I-5

Subject: **Tab 3 Corporate Overview**

Reference: **Tab 3 Appendix 3.2 - Corporate Strategic Plan**

e) Please explain in more detail the opportunities that are being explored to further optimize the benefits of Manitoba Hydro's natural gas and electric systems, itemize these benefits, and indicate how they are quantified

ANSWER:

Manitoba Hydro is leveraging its natural gas system with efforts underway in the following areas:

- Educating customers on alternative space and water heating energy choices;
- Integrated Power Smart marketing programs to encourage the efficient use of natural gas and electricity; and
- Assessing the potential applications of natural gas and electric vehicles in Manitoba Hydro's fleet.

The benefits associated with Power Smart initiatives are provided in the Corporation's 2011 Power Smart Plan filed as Appendix 7.1 of this Application. The benefits of using natural gas or electricity for space and water heating are provided in the report "Economic, Load, and Environmental Impacts of Fuel Switching in Manitoba" filed as Appendix 15.4 of this Application.

PUB/CENTRA I-5

Subject: **Tab 3 Corporate Overview**

Reference: **Tab 3 Appendix 3.2 - Corporate Strategic Plan**

f) Please elaborate on "green" fleet initiatives that Centra is undertaking or plans to undertake.

ANSWER:

Green fleet initiatives focus on vehicle and equipment specifications and operation and alternative fuels and research. As diesel engines make up the largest portion of the fleet's carbon footprint, the bulk of green fleet activities and investment by Manitoba Hydro are currently focused on reducing emission on these types of engines.

Vehicle and equipment specification includes the selection of light vehicles based on the minimum life cycle cost, which is a calculation based on the combination of purchase cost, maintenance and lifetime fuel consumption. Consideration is also given to assessment of the appropriate overall fleet size, and reduction of vehicles with rapidly increasing operating costs and carbon foot print.

Vehicle and equipment operation includes remote monitoring to measure operating conditions such as idling, acceleration, and braking and route efficiency.

The use of alternative fuels, specifically electricity and natural gas as an alternative to conventional motor fuels are currently in the exploratory stage in the Manitoba Hydro fleet.

Field application of electric vehicles is focused in the area of off-road vehicles including forklifts and yard vehicles.

PUB/CENTRA I-6

Subject: **Tab 4 Integrated Financial Forecast & Economic Outlook**

Reference: **Tab 4 Page 3 of 7**

Please provide an update to PUB/MH I-28(a) through (c) from the 2012/13 & 2013/14 GRA in support of the interest rate forecasts in the Centra GRA.

ANSWER:

The interest rate forecast for 2012/13 – 2014/15 is provided in the following tables.

Table 1 depicts the sources used to derive the forecast of Canadian 3 month T-Bill rates (with end of period rates adjusted to a comparable average period basis) for each quarter of the 2012/13 – 2014/15 period.

Table 2 depicts the sources used to derive the forecast of Canadian 10 year+ bond yield rates (with end of period rates adjusted to a comparable average period basis) for each quarter of the 2012/13 – 2014/15 period.

Copies of the source forecasts are provided as an attachment to this response.

Table 1 – Canadian 3 Month T-Bill Rate - %

		End Period or Average	2012			2013				2014				2015
	Fcst Date		Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1
Bank A	2-Oct-12	Average	*	*	*	*	*	*	*	*	*	*	*	*
CIBC	27-Sep-12	End Period	0.98	0.98	0.96	0.95	0.95	0.95	1.08					
Desjardins	1-Sep-12	End Period	0.98	0.98	0.99	1.00	1.00	1.03	1.10	1.55	1.55	1.55	1.55	2.25
Laurentian	17-Sep-12	End Period	0.98	0.98	0.99	1.00	1.00	1.25	1.55					
National Bank	1-Sep-12	End Period	0.98	0.98	0.98	0.96	1.31	1.31	1.31					
Bank B	4-Oct-12	End Period	*	*	*	*	*	*	*					
Scotia Bank	27-Sep-12	End Period	0.98	0.98	0.99	1.00	1.00	1.00	1.00					
TD Bank	18-Sep-12	End Period	0.98	0.98	1.01	1.05	1.23	1.48	1.60	1.68	1.88	2.05	2.08	2.48
Informetrica	1-Oct-12	Average	0.98	0.98	1.20	1.80	1.80	1.80	1.80	2.80	2.80	2.80	2.80	3.90
HIS Global Insight	11-Sep-12	Average	0.98	0.98	1.03	1.03	1.06	1.13	1.42	1.63	1.93	2.17	2.39	2.73
Conference Board	19-Sep-12	Average	0.98	0.98	1.03	0.99	0.97	1.03	1.18	1.37	1.48	1.64	1.83	2.08

			2012/13	2013/14	2014/15
EO2012- Fiscal			1.00	1.30	2.10

NOTE: The forecast provided by Bank A and Bank B are proprietary and cannot be disclosed.

Table 2 – Canadian 10 Year+ Bond Yield Rate - %

	Fcst Date	End Period or Average	2012			2013				2014				2015
			Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1
Bank A	2-Oct-12	Average	*	*	*	*	*	*	*	*	*	*	*	*
CIBC	27-Sep-12	End Period	2.25	2.10	2.07	2.24	2.51	2.71	2.81	2.75	2.75	2.75	2.75	3.48
Desjardins	1-Sep-12	End Period	2.25	2.10	2.12	2.20	2.23	2.36	2.50					
Laurentian	17-Sep-12	End Period	2.25	2.10	2.07	2.15	2.25	2.59	2.98					
National Bank	1-Sep-12	End Period	2.25	2.10	2.04	1.98	2.28	2.28	2.28					
Bank B	4-Oct-12	End Period	*	*	*	*	*	*	*	*	*	*	*	*
Scotia Bank	27-Sep-12	End Period	2.25	2.10	2.02	2.05	2.19	2.34	2.59					
TD Bank	18-Sep-12	End Period	2.25	2.10	2.18	2.35	2.43	2.53	2.69	2.86	2.99	3.11	3.23	
Informetrica	1-Oct-12	Average	2.25	2.10	2.20	2.80	2.80	2.80	2.80	3.60	3.60	3.60	3.60	4.30
HIS Global Insight	11-Sep-12	Average	2.25	2.10	2.04	2.11	2.27	2.76	3.07	3.10	3.17	3.21	3.34	3.54
Conference Board	19-Sep-12	Average	2.25	2.10	2.08	2.03	1.98	1.98	2.01	2.08	2.12	2.19	2.29	

			2012/13	2013/14	2014/15
EO2012- Fiscal			2.15	2.55	3.20

NOTE: The forecast provided by Bank A and Bank B are proprietary and cannot be disclosed.

Calculations of the rates shown in Tables 1 and 2 were as follows:

- The 2012/13 forecast included the average of all data points within Q2, Q3, Q4 of 2012 and Q1 of 2013. The 2013/14 forecast included the average of all data points within Q2, Q3, Q4 of 2013 and Q1 of 2014. The 2014/15 forecast included the average of all data points within Q2, Q3, Q4 of 2014 and Q1 of 2015. For example, the Canadian 3 month T-Bill rate for 2013/14 of 1.30% in Table 1 was calculated as the average of the following data points:

	2013 Q2	**2013 Q3**	**2013 Q4**	**2014 Q1**
Bank A	*	*	*	*
CIBC	0.95%	0.95%	1.08%	1.55%
Desjardins	1.00%	1.03%	1.10%	
Laurentian	1.00%	1.25%	1.55%	
National Bank	1.31%	1.31%	1.31%	
Bank B	*	*	*	
Scotiabank	1.00%	1.00%	1.00%	
TD Bank	1.23%	1.48%	1.60%	1.68%
Informetrica	1.80%	1.80%	1.80%	2.80%
IHS Global Insight	1.06%	1.13%	1.42%	1.63%
Conference Board	0.97%	1.03%	1.18%	1.37%

**Information provided by Bank A and Bank B are proprietary and cannot be disclosed.*

The Manitoba Hydro Canadian short term interest rate was calculated by adding the provincial debt guarantee fee of 1.00% to the Canadian 3 month T-Bill rate as follows:

	Canadian 3 Month T-Bill	**Guarantee Fee**	**MH Canadian Short Term Interest Rate**
2012/13	1.00%	1.00%	2.00%
2013/14	1.30%	1.00%	2.30%
2014/15	2.10%	1.00%	3.10%

The Manitoba Hydro Canadian long term interest rate was calculated by adding the appropriate credit spread to the Canadian 10 year+ bond yield rate and a provincial debt guarantee fee as follows:

	Canadian 10 Year+ Bond Yield	**10 Year+ Credit Spread**	**Guarantee Fee**	**MH Canadian 10 Year+ Long Term Interest Rate**
2012/13	2.15%	1.00%	1.00%	4.15%
2013/14	2.55%	0.75%	1.00%	4.30%
2014/15	3.20%	0.65%	1.00%	4.85%

MARKET CALL

- While we expected the US to launch into a new round of QE before year-end, the open-ended plan, with more dovish language about how long rates will be kept near zero, altered our forecast for the Treasuries curve. Most notably, we no longer see any material upward pressure on 2-years in 2013. We also softened our projections for the degree of a US dollar rebound in 2013 against other majors.

- Our call that the Bank of Canada will remain on hold in 2013 remains intact, buttressed by disappointments in Q3 growth and a somewhat stronger trajectory for the Canadian dollar in light of US QE efforts. We have a rate hike penciled in for early 2014, expecting that by then, Canada's fiscal drag will be lighter and global growth more supportive for commodities exporters.

- Although a longer QE program had us also nudging down our yield targets further out the curve, the long end of the Treasuries curve is still vulnerable to a gradual improvement in economic sentiment that shifts investors out of the safest of safe-haven assets. Although Canada isn't in the QE game, its longer bonds could begin to outperform Treasuries again later in 2013 and beyond, reflecting superior credit ratings and less risk that the central bank will tolerate higher inflation when growth picks up down the road.

INTEREST & FOREIGN EXCHANGE RATES

		2012		2013				2014
END OF PERIOD:		**26-Sep**	**Dec**	**Mar**	**Jun**	**Sep**	**Dec**	**Mar**
CDA	Overnight target rate	1.00	1.00	1.00	1.00	1.00	1.00	1.25
	98-Day Treasury Bills	0.99	0.95	0.95	0.95	0.95	1.20	1.45
	2-Year Gov't Bond	1.09	1.15	1.25	1.35	1.40	1.65	1.75
	10-Year Gov't Bond	1.74	1.80	2.15	2.45	2.55	2.60	2.65
	30-Year Gov't Bond	2.33	2.40	2.60	2.85	3.00	3.10	3.10
U.S.	Federal Funds Rate	0.15	0.10	0.10	0.10	0.10	0.10	0.10
	91-Day Treasury Bills	0.10	0.10	0.10	0.15	0.15	0.15	0.15
	2-Year Gov't Note	0.26	0.30	0.30	0.35	0.40	0.45	0.45
	10-Year Gov't Note	1.61	1.60	1.95	2.25	2.45	2.55	2.60
	30-Year Gov't Bond	2.79	2.65	2.90	3.20	3.40	3.65	3.70
Canada - US T-Bill Spread		0.89	0.85	0.85	0.80	0.80	1.05	1.30
Canada - US 10-Year Bond Spread		0.13	0.20	0.20	0.20	0.10	0.05	0.05
Canada Yield Curve (30-Year — 2-Year)		1.24	1.25	1.35	1.50	1.60	1.45	1.35
US Yield Curve (30-Year — 2-Year)		2.53	2.35	2.60	2.85	3.00	3.20	3.25
EXCHANGE RATES	CADUSD	1.02	1.04	1.02	1.00	1.00	1.02	1.03
	USDCAD	0.99	0.96	0.98	1.00	1.00	0.98	0.97
	USDJPY	78	79	78	77	76	75	75
	EURUSD	1.29	1.29	1.27	1.24	1.27	1.29	1.31
	GBPUSD	1.62	1.62	1.59	1.55	1.59	1.62	1.63
	AUDUSD	1.04	1.02	1.02	1.00	0.98	1.02	1.04
	USDCHF	0.94	0.94	0.95	0.98	0.97	0.97	0.95
	USDBRL	2.03	2.02	2.02	2.11	2.14	2.18	2.23
	USDMXN	12.87	12.50	12.85	13.05	13.30	13.38	13.48

ECONOMIC UPDATE

CANADA	12Q2A	12Q3F	12Q4F	13Q1F	13Q2F	13Q3F	2011A	2012F	2013F
Real GDP Growth (AR)	1.8	1.8	2.0	1.8	2.0	2.1	2.4	2.0	2.0
Real Final Domestic Demand (AR)	1.7	2.1	1.9	2.0	2.1	2.3	3.0	1.7	2.1
All Items CPI Inflation (Y/Y)	1.6	1.3	2.0	1.9	2.0	2.4	2.9	1.8	2.1
Core CPI Ex Indirect Taxes (Y/Y)	2.0	1.6	1.9	2.0	2.0	2.1	1.7	1.9	2.0
Unemployment Rate (%)	7.2	7.3	7.3	7.2	7.1	7.1	7.5	7.3	7.1

U.S.	12Q2A	12Q3F	12Q4F	13Q1F	13Q2F	13Q3F	2011A	2012F	2013F
Real GDP Growth (AR)	1.7	2.1	1.7	1.5	1.7	2.1	1.8	2.3	1.8
Real Final Sales (AR)	2.0	2.3	1.7	1.7	1.8	2.3	2.0	2.1	1.9
All Items CPI Inflation (Y/Y)	1.9	1.6	2.2	2.1	2.1	2.5	3.2	2.1	2.2
Core CPI Inflation (Y/Y)	2.3	2.0	2.0	2.0	1.9	2.0	1.7	2.1	2.0
Unemployment Rate (%)	8.2	8.2	8.1	8.2	8.2	8.2	9.0	8.2	8.2

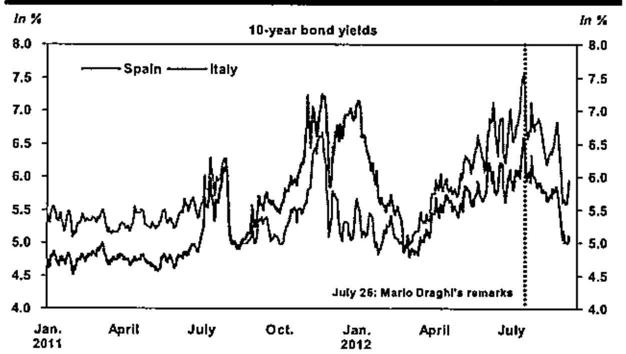
CANADA

Canada could pull a string of three back-to-back quarters of 1.8% growth, with activity in Q3 set to track that pace if our call for a flat GDP print for July (released shortly after this goes to print) materializes. While that's weaker than our initial call, better growth in subsequent months should help keep activity tracking near 2% in the quarters ahead. Surprisingly tame core inflation in recent readings suggests a 1.9% pace for the year—a touch below our previous call, but still close to the Bank's inflation bull's eye.

UNITED STATES

US growth remains sluggish, with early indications suggesting Q3 will fail to see the sort of acceleration we previously expected. As a result, we have downgraded our Q3 2013 forecast to 2.1%, and see growth around 2% continuing through year-end and 2013 as well. That is, of course, assuming the fiscal cliff is scaled back post-election. Falling participation has been the major driver of reductions in unemployment rate, and the latter risks edging up again should the current trend of tepid job gains continue.

Graph 22 – Mario Draghi and the European Central Bank manage to ease pressure on Spanish and Italian bond yields



Sources: Bloomberg and Desjardins, Economic Studies

the markets. This put new upside pressures on U.S. yields. The Fed gave an additional boost to yields on September 13, when it announced its third program for buying mortgage-backed bonds.

DO MARKETS BELIEVE IN MIRACLES?

If there is a silver lining to the Fed's announcement, it is the fact that it put an end to volatility and uncertainty with regard to its future moves. We remain nonetheless sceptical that the upswing in yields will last. Note that the long yields also rose during the first two programs. When the Fed announced QE1, in March 2009, the novelty and the magnitude of the gesture caused markets to react positively, taking risky assets and bond yields upward. With QE2, announced in November 2010, it was really the coincidental improvement of economic data and the tax cut announced by President Obama that had galvanized investors. The European crisis was then primarily limited to Greece, and the zone's economy was growing moderately. In the current case, the back up in yields seems to mainly reflect firmer inflation expectations (graph 23), rather than real hope for economic improvement.

Graph 23 – Inflation expectations shot up after the Federal Reserve's announcement

Sources: Bloomberg and Desjardins, Economic Studies

Table 11
Canada: fixed income market

End of period in %	2011 Q1	2011 Q2	2011 Q3	2011 Q4	2012 Q1	2012 Q2	2012 Q3f	2012 Q4f	2013 Q1f	2013 Q2f	2013 Q3f	2013 Q4f
Key rate												
Overnight funds	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Treasury bills												
3-month	0.96	0.93	0.81	0.82	0.92	0.88	1.00	1.00	1.00	1.00	1.05	1.15
Federal bonds												
2-year	1.83	1.60	0.88	0.96	1.20	1.03	1.20	1.10	1.10	1.15	1.30	1.60
5-year	2.77	2.33	1.39	1.28	1.57	1.25	1.45	1.30	1.30	1.45	1.70	1.95
10-year	3.35	3.11	2.15	1.94	2.11	1.74	1.95	1.90	1.90	1.95	2.20	2.25
30-year	3.80	3.58	2.77	2.49	2.66	2.33	2.55	2.50	2.50	2.55	2.75	2.80
Yield curve												
5-year - 3-month	1.81	1.40	0.58	0.46	0.65	0.37	0.45	0.30	0.30	0.45	0.65	0.80
10-year - 2-year	1.52	1.51	1.27	0.98	0.91	0.71	0.75	0.80	0.80	0.80	0.90	0.65
30-year - 3-month	2.84	2.65	1.96	1.67	1.74	1.45	1.55	1.50	1.50	1.55	1.70	1.65
Spreads (Canada - U.S.)												
3-month	0.87	0.90	0.79	0.80	0.85	0.79	0.90	0.90	0.90	0.90	0.95	1.05
2-year	1.08	1.16	0.62	0.73	0.85	0.72	0.95	0.85	0.85	0.90	1.00	1.25
5-year	0.58	0.62	0.45	0.47	0.54	0.53	0.70	0.60	0.60	0.65	0.75	0.90
10-year	-0.10	-0.05	0.22	0.06	-0.11	0.08	0.10	0.15	0.15	0.15	0.20	0.20
30-year	-0.71	-0.80	-0.15	-0.40	-0.69	-0.44	-0.50	-0.50	-0.50	-0.45	-0.40	-0.40

f: forecasts
Sources: Datastream and Desjardins, Economic Studies

BOND MARKET

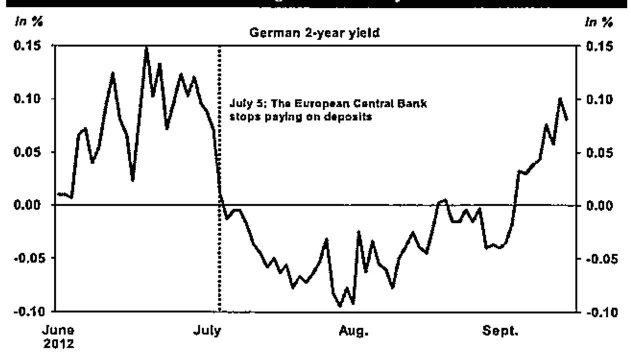
A familiar tune

Bond markets have gone up and down in tandem with fears of a euro zone collapse. Although the worst fears about the euro have eased somewhat, many others remain, as the two largest economies in the world are facing difficult times. Yields will remain low for an extended period, in a context in which risk aversion will have many opportunities to resurface. Patience will be required before a lasting upward trend emerges.

CONTINUING SHIFTS BETWEEN HOPE AND DESPAIR

Bond yields have gone through two distinct phases in recent months. First, between May and July, several U.S. yields dropped to new lows, capitalizing on the release of worrisome U.S. economic data and another surge in financial strains in the euro zone. Two-year yields in Germany, another country benefitting from safe haven status, went into negative territory (graph 21) after July's European Central Bank (ECB) meeting, at which it was announced that the deposit rate would be cut to zero. U.S. government bonds not only benefited from risk aversion world-wide, but also from stronger expectations of additional stimulus measures from the Federal Reserve (Fed).

Graph 21 – German short yields spent much of the summer in negative territory



Sources: Bloomberg and Desjardins, Economic Studies

Mario Draghi's speech on July 26 marked the beginning of the second phase. The ECB president insisted that everything would be done to preserve the euro zone, promising measures of a sufficient scope. A major turnaround then occurred for bond yields in Spain and Italy, which had substantially increased up until then (graph 22 on page 30). At the same time, U.S. yields, whose inverse correlation with Spanish and Italian yields had strengthened, began to climb, with improved economic data maintaining the spillover effect throughout August. In early September, the ECB announced a new bond-buying program, which was well-received by

Table 10
United States: fixed income market

	2011				2012				2013			
End of period in %	Q1	Q2	Q3	Q4	Q1	Q2	Q3f	Q4f	Q1f	Q2f	Q3f	Q4f
Key rate												
Federal funds	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Treasury bills												
3-month	0.09	0.03	0.02	0.02	0.07	0.09	0.10	0.10	0.10	0.10	0.10	0.10
Federal bonds												
2-year	0.76	0.44	0.26	0.23	0.35	0.32	0.25	0.25	0.25	0.25	0.30	0.35
5-year	2.19	1.72	0.94	0.81	1.03	0.72	0.75	0.70	0.70	0.80	0.95	1.05
10-year	3.45	3.16	1.93	1.88	2.22	1.66	1.85	1.75	1.75	1.80	2.00	2.05
30-year	4.51	4.38	2.92	2.89	3.35	2.77	3.05	3.00	3.00	3.00	3.15	3.20
Yield curve												
5-year - 3-month	2.10	1.69	0.92	0.79	0.96	0.63	0.65	0.60	0.60	0.70	0.85	0.95
10-year - 2-year	2.70	2.72	1.66	1.64	1.87	1.34	1.60	1.50	1.50	1.55	1.70	1.70
30-year - 3-month	4.42	4.35	2.90	2.87	3.28	2.68	2.95	2.90	2.90	2.90	3.05	3.10

f: forecasts
Sources: Datastream and Desjardins, Economic Studies

a real estate slowdown. Last June, fears of overheating also prompted the federal government to announce a fourth series of measures to curb the housing market[1]. Among other things, the maximum amortization period was lowered from 30 to 25 years and the maximum loan extended in the context of mortgage refinancing is now 80% of the value of the property, rather than 85%. The efforts seem to be working, as there are some signs that the housing market is starting to slow. Home resales fell by 5.8% in August. Our scenario calls for the real estate market to gradually slow over the coming quarters, meaning that the Canadian economy will likely no longer be able to bank on residential investment to support its growth.

WE HAVE TRIMMED OUR FORECASTS SLIGHTLY

Given the Canadian economy's shortage of pillars, real GDP growth should remain moderate in the next few quarters. This prompts us to somewhat reduce our growth targets. Instead of 2.1%, real GDP growth could be just 2.0% this year. A gain of 2.2% is expected in 2013, two tenths of a percentage point lower than the forecast we made at the start of the summer.

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[1] The new measures apply to insured loans and came into effect on July 9.

Table 5
Canada: major economic indicators

	2012				*2013*		*Annual average*			
Quarterly annualized variation in % (except if indicated)	Q1	Q2	Q3f	Q4f	Q1f	Q2f	2010	2011	2012f	2013f
Real gross domestic product*	1.8	1.8	1.9	2.2	2.1	2.3	3.2	2.4	2.0	2.2
Personal cons. expenditures	0.7	1.1	2.1	2.3	2.2	2.4	3.3	2.4	1.7	2.2
Residential construction	11.5	1.8	-3.2	-4.0	-2.1	-1.6	10.2	2.3	4.4	-2.2
Business fixed investment	5.8	9.4	7.5	7.0	6.5	6.8	7.3	13.1	6.6	6.8
Inventory change ($B)	8.2	15.2	16.3	16.5	16.5	17.8	8.9	12.8	14.0	19.1
Public expenditures	-2.0	-0.5	-0.6	-0.3	0.5	0.6	4.7	0.1	-1.7	0.2
Exports	4.0	0.8	1.8	5.5	3.5	2.5	6.4	4.6	4.6	3.3
Imports	5.2	6.4	2.0	4.0	3.0	3.0	13.1	7.0	3.8	3.4
Final domestic demand	1.3	1.7	1.7	1.8	2.0	2.2	4.5	3.0	1.6	2.0
Other indicators										
Real disposable personal income	0.1	3.5	1.5	2.0	2.5	3.0	3.6	1.3	1.5	2.6
Weekly earnings	0.6	4.1	1.0	1.5	2.5	3.0	3.6	2.5	2.1	2.6
Employment	0.9	2.8	0.0	0.8	1.0	1.1	1.4	1.6	1.0	1.1
Unemployment rate (%)	7.4	7.3	7.3	7.2	7.2	7.1	8.0	7.4	7.3	7.1
Housing starts (1)	206.3	230.1	214.3	196.7	185.0	177.5	189.9	194.0	211.8	179.7
Corporate profits*** (2)	4.2	0.4	3.0	3.0	5.0	7.0	21.2	15.4	2.7	5.2
Personal saving rate (%)	3.1	3.6	3.1	3.0	3.1	3.2	4.8	3.7	3.2	3.3
Total inflation rate (2)	2.3	1.6	1.3	1.8	2.1	2.0	1.8	2.9	1.7	1.9
Core inflation rate** (2)	2.1	2.0	1.4	1.2	1.6	1.4	1.8	1.6	1.7	1.7
Federal gov't balance ($B) (3)	-17.1	-21.3	-20.0	-15.0	-15.0	-12.0	-42.6	-31.9	-18.3	-11.3
Current account balance ($B)	-40.6	-64.1	-47.0	-40.0	-40.0	-42.0	-50.9	-48.4	-47.9	-44.0

f: forecasts; * 2002 $; ** Excluding the eight most volatile; *** Before taxes; (1) Thousands of units on an annualized basis; (2) Annual change; (3) National accounts.
Sources: Datastream and Desjardins, Economic Studies

looming over the short-term situation, the current situation may cause the long-term outlook to deteriorate. The employment ratio is not improving and the participation rate is at a 30-year low. Combined with long-term unemployment that is barely edging down, these factors could affect the economy's ability to return to the growth rates we used to see before the crisis.

POLITICAL DECISIONS AND BUDGETARY CHOICES

Employment remains the main obstacle for President Obama's race against Mitt Romney, a Republican and former governor of Massachusetts. The battle for the White House, which will end on Tuesday November 6, is primarily playing out in the realm of the economy. Note that the two parties' vision of the role of government and taxation are very different. The difference became even clearer when Paul Ryan, one of the main Republican spokesmen regarding budgetary issues, was chosen as Mitt Romney's running mate.

In addition to policy programs that cover several years, a decision concerning the fiscal cliff must be made in the short term. Our scenario still calls for a partial extension of the 2001 and 2003 tax cuts that were renewed for two years at the end of 2010. Growth will be hurt by tax hikes for the wealthiest and the impact of confidence being weakened by the uncertainty surrounding this debate. Our forecast for real GDP growth in 2012 is 2.2%, but slower growth is expected for 2013, at 1.9%.

Table 4
United States: major economic indicators

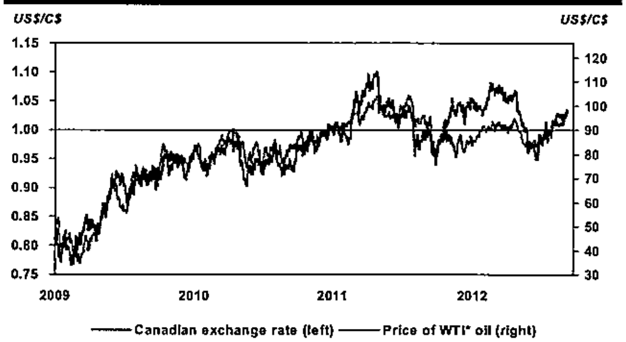
	2012				*2013*		*Annual average*			
Quarterly annualized variation in % (except if indicated)	Q1	Q2	Q3f	Q4f	Q1f	Q2f	2010	2011	2012f	2013f
Real gross domestic product*	2.0	1.7	1.6	2.0	1.0	2.3	2.4	1.8	2.2	1.9
Personal cons. expenditures	2.4	1.7	1.7	1.9	1.0	2.4	1.8	2.5	1.9	1.8
Residential construction	20.6	8.9	10.0	9.5	10.0	4.3	-3.7	-1.4	11.2	8.1
Business fixed investment	7.5	4.2	-0.6	5.0	3.1	7.6	0.7	8.6	7.7	5.0
Inventory change ($B)	56.9	49.9	55.0	62.5	62.0	58.0	50.9	31.0	56.1	60.0
Public expenditures	-3.0	-0.9	-1.0	-1.2	-1.3	-1.0	0.6	-3.1	-1.9	-1.1
Exports	4.4	6.0	2.0	1.0	3.0	3.5	11.1	6.7	3.8	3.0
Imports	3.1	2.9	0.0	1.0	2.0	2.2	12.5	4.8	2.9	1.8
Final domestic demand	2.2	1.6	1.1	1.8	1.0	2.3	1.3	1.8	1.9	1.7
Other indicators										
Real disposable personal income	3.7	3.1	1.5	1.9	-1.0	2.0	1.8	1.3	1.5	1.4
Employment (establishments)	2.1	1.0	0.9	1.2	0.9	1.4	-0.7	1.2	1.4	1.2
Unemployment rate (%)	8.3	8.2	8.2	8.0	8.1	7.8	9.6	9.0	8.2	7.8
Housing starts (1)	715	736	774	785	810	807	586	612	753	824
Corporate profits*** (2)	10.3	6.1	5.0	3.0	2.0	5.0	26.8	7.3	6.0	5.0
Personal saving rate (%)	3.6	4.0	4.1	4.1	3.6	3.6	5.1	4.3	4.0	3.7
Total inflation rate (2)	2.8	1.9	1.7	2.0	1.4	1.2	1.6	3.1	2.1	1.6
Core inflation rate** (2)	2.2	2.3	2.0	1.9	1.9	1.8	1.0	1.7	2.1	1.9
Federal gov't balance ($B) (3)	-1,059	-1,095	-950	-875	-725	-700	-1,308	-1,237	-995	-669
Current account balance ($B)	-534.5	-469.6	-455.8	-457.5	-454.4	-449.6	-442.0	-465.9	-479.4	-448.5

f: forecasts; * 2005 US$; ** Excluding food and energy; *** Before taxes; (1) Thousands of units on an annualized basis; (2) Annual change; (3) National accounts.
Sources: Datastream and Desjardins, Economic Studies

August, even reaching close to US$1.04, its highest level in over one year. Even if Canada's economy has not performed spectacularly since the beginning of the year, it has done much better than many developed nations. Consequently, the Bank of Canada has stuck to its guidance with regard to an eventual key rate increase while other major central banks began undertaking easing programs.

Robust oil prices also favoured the Canadian currency recently (graph 34), as did foreign interest in Canadian bonds, which has not waned in 2012. This is primarily because Canada is one of the few countries to still enjoy a AAA credit rating with a stable outlook.

Graph 34 – The correlation between the loonie and oil prices intensified last summer



* West Texas Intermediate.
Sources: Bloomberg and Desjardins, Economic Studies

In the near term, Canada's dollar seems more able to hold above parity, although there may be some periods of weakness stemming from spikes in risk aversion. We nevertheless expect parity to be sustained through the end of the year and in 2013.

Table 15
Currency market: history and forecasts

		2011		2012				2013			
End of period		Q3	Q4	Q1	Q2	Q3f	Q4f	Q1f	Q2f	Q3f	Q4f
American dollar											
Canadian dollar	(USD/CAD)	1.0501	1.0197	0.9979	1.0167	0.9709	0.9901	0.9901	0.9901	0.9804	0.9709
Euro	(EUR/USD)	1.3417	1.2981	1.3317	1.2691	1.3200	1.2800	1.2900	1.3000	1.3200	1.3400
British pound	(GBP/USD)	1.5578	1.5541	1.5978	1.5685	1.6200	1.6000	1.6100	1.6200	1.6400	1.6500
Yen	(USD/JPY)	77.07	76.96	82.82	79.81	78.00	78.00	79.00	80.00	81.00	82.00
Australian dollar	(AUD/USD)	0.9664	1.0222	1.0346	1.0240	1.0600	1.0300	1.0300	1.0300	1.0400	1.0400
Mexican peso	(USD/MXN)	13.90	13.95	12.81	13.36	12.75	13.10	12.90	12.80	12.60	12.50
Chinese yuan	(USD/CNY)	6.38	6.29	6.30	6.35	6.32	6.32	6.30	6.25	6.20	6.15
Effective dollar*	(1973 = 100)	72.81	73.33	72.74	74.47	71.46	73.01	72.80	72.70	72.00	71.40
Canadian dollar											
American dollar	(CAD/USD)	0.9523	0.9807	1.0021	0.9836	1.0300	1.0100	1.0100	1.0100	1.0200	1.0300
Euro	(EUR/CAD)	1.4089	1.3237	1.3289	1.2902	1.2816	1.2673	1.2772	1.2871	1.2941	1.3010
British pound	(GBP/CAD)	1.6358	1.5846	1.5944	1.5946	1.5728	1.5842	1.5941	1.6040	1.6078	1.6019
Yen	(CAD/JPY)	73.39	75.48	82.99	78.50	80.34	78.78	79.79	80.80	82.62	84.46
Australian dollar	(AUD/CAD)	1.0147	1.0423	1.0324	1.0411	1.0291	1.0198	1.0198	1.0198	1.0196	1.0097
Mexican peso	(CAD/MXN)	13.24	13.69	12.83	13.14	13.13	13.23	13.03	12.93	12.85	12.88
Chinese yuan	(CAD/CNY)	6.08	6.17	6.31	6.25	6.51	6.38	6.36	6.31	6.32	6.33

f: forecasts; * Trade-weighted against major U.S. partners.
Sources: Datastream, Federal Reserve Board and Desjardins, Economic Studies

Table 18
Canada: medium-term major economic and financial indicators

In % (except if indicated)	Annual average 2010	2011	2012f	2013f	2014f	2015f	2016f	Average 2004-2011	2012-2016f
Real GDP (var. in %)	3.2	2.4	2.0	2.2	2.5	2.5	2.0	1.8	2.2
Inflation rate (var. in %)	1.8	2.9	1.7	1.9	2.0	2.0	2.0	1.9	1.9
Employment (var. in %)	1.4	1.6	1.0	1.1	1.5	1.2	1.0	1.3	1.2
Employment (K)	228	265	174	188	273	207	181	205	205
Unemployment rate	8.0	7.4	7.3	7.1	6.8	6.6	6.5	7.0	6.8
Housing starts (K)	190	194	212	180	185	200	195	207	194
S&P/TSX* index (var. in %)	14.4	-11.1	2.9	7.3	9.0	8.5	8.5	6.9	7.2
Canadian dollar (US$/C$)	0.97	1.01	1.01	1.02	1.04	1.06	1.06	0.90	1.04
Overnight funds	0.59	1.00	1.00	1.00	1.50	2.15	2.65	2.29	1.66
Prime rate	2.59	3.00	3.00	3.00	3.50	4.15	4.65	4.14	3.66
Mortgage rate									
1-year	3.49	3.52	3.20	3.20	3.70	4.50	5.10	5.07	3.94
5-year	5.57	5.39	5.25	5.20	5.30	6.00	6.60	6.20	5.67
Treasury bills—3-month	0.57	0.92	0.95	1.05	1.55	2.25	2.75	2.16	1.71
Federal bonds									
2-year	1.55	1.37	1.15	1.30	1.85	2.75	3.45	2.64	2.10
5-year	2.44	2.03	1.40	1.60	2.25	3.05	3.60	3.20	2.38
10-year	3.24	2.78	1.90	2.10	2.45	3.30	3.85	3.75	2.72
30-year	3.77	3.31	2.50	2.65	3.05	3.65	4.10	4.14	3.19
U.S./Canada rate spreads									
Treasury bills—3-month	0.43	0.87	0.85	0.95	1.35	1.30	0.55	0.20	1.00
Federal bonds—10-year	0.04	0.02	0.05	0.20	0.10	0.15	-0.05	-0.10	0.09
Federal bonds—30-year	-0.48	-0.59	-0.55	-0.45	-0.40	-0.40	-0.40	-0.33	-0.44

f: forecasts; * The variations are based on observation of the end of period.
Sources: Statistics Canada, Canada Mortgage and Housing Corporation and Desjardins, Economic Studies

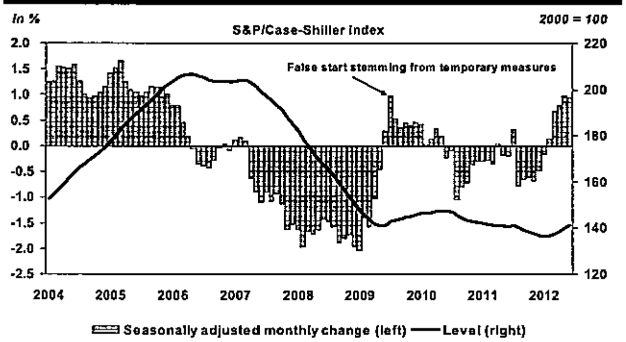
Table 19
Québec and Ontario: medium-term major economic indicators

Var. in % (except if indicated)	Annual average 2010	2011	2012f	2013f	2014f	2015f	2016f	Average 2004-2011	2012-2016f
Québec									
Real GDP	2.5	1.7	1.0	1.8	2.0	2.0	1.5	1.6	1.6
Inflation rate	1.2	3.0	2.2	2.0	2.0	2.1	2.0	1.8	2.1
Employment	1.7	1.0	0.4	1.1	0.7	0.6	0.5	1.1	0.7
Employment (K)	67	39	15	45	30	25	20	42	27
Unemployment rate (%)	8.0	7.8	7.8	7.3	7.0	6.5	6.0	8.0	6.9
Retail sales	6.2	2.9	1.5	4.0	4.0	3.5	3.0	3.8	3.2
Housing starts (K)	51	48	45	42	35	35	35	50	38
Ontario									
Real GDP	3.0	2.1	2.1	2.0	2.5	2.5	2.0	1.4	2.2
Inflation rate	2.5	3.1	1.6	1.8	2.0	2.0	1.8	2.0	1.8
Employment	1.7	1.8	0.7	1.0	1.5	1.2	1.0	1.0	1.1
Employment (K)	108	121	45	68	103	83	70	65	74
Unemployment rate (%)	8.7	7.8	7.8	7.7	7.4	7.2	7.0	7.3	7.4
Retail sales	5.4	3.6	2.0	2.5	5.0	4.2	3.8	3.3	3.5
Housing starts (K)	60	68	78	61	63	65	60	70	65

f: forecasts
Sources: Statistics Canada, Canada Mortgage and Housing Corporation and Desjardins, Economic Studies

in 2006 there. After a lengthy correction, home prices finally seem to start to come up, a rise that should persist over the medium term (graph 41). This, combined with the fact that households have substantially reduced their debt loads, means that we can hope the U.S. consumer will once again be a global economic driver over the medium range.

Graph 41 – In the United States, the trough for home prices finally seems to be a thing of the past



Sources: Standard & Poor's and Desjardins, Economic Studies

The tough environment of the last few years has meant that a development that could be very positive for the United States has gone almost unnoticed: the emergence of new sources of efficient and abundant energy, particularly oil and shale gas. Although the new methods for extracting natural gas and oil are still raising controversies and fears, they are already having major impacts on the U.S. economy. In the last few years, the long period of U.S. natural gas and oil production decline has turned around and the increase in recoverable reserves means that this trend will persist over the medium term. Plentiful and inexpensive natural gas could stimulate industrial activity in the United States and even be exported. This should substantially reduce the U.S. trade deficit.

However, there are two major obstacles to overcome before seeing lively U.S. economic growth. Firstly, the job market remains much too weak, continuing to affect consumer confidence. Secondly, a long-term solution must be found to tackle the huge U.S. deficit. Having a large deficit for several more years would not, in and of itself, be a major brake on the U.S. economy. The current political climate, in which tax cuts and government budgets must constantly be renewed for very short periods and no one knows what the regulatory and fiscal environment will look like next year, is however very harmful to U.S. activity. It could take some time to overcome these obstacles, which could remain a drag on growth in 2014 and 2015.

Table 17
United States: medium-term major economic and financial indicators

	Annual average							*Average*	
In % (except if indicated)	2010	2011	2012f	2013f	2014f	2015f	2016f	2004-2011	2012-2016f
Real GDP (var. in %)	2.4	1.8	2.2	1.9	2.5	2.5	3.0	1.5	2.4
Inflation rate (var. in %)	1.6	3.1	2.1	1.6	2.5	2.5	2.5	2.6	2.2
Unemployment rate	9.6	9.0	8.2	7.8	7.5	7.0	6.5	6.7	7.4
S&P 500 index (var. in %)*	12.8	0.0	13.3	7.0	8.0	7.0	7.0	3.4	8.5
Federal funds rate	0.25	0.25	0.25	0.25	0.25	0.80	2.15	2.17	0.74
Prime rate	3.25	3.25	3.25	3.25	3.25	3.80	5.15	5.17	3.74
Treasury bills—3-month	0.14	0.05	0.10	0.10	0.20	0.95	2.20	1.96	0.71
Federal bonds—10-year	3.20	2.76	1.85	1.90	2.35	3.15	3.90	3.85	2.63
Federal bonds—30-year	4.25	3.90	3.05	3.10	3.45	4.05	4.50	4.48	3.63
WTI** oil (US$/barrel)	80	95	96	92	105	115	120	72	106
Gold (US$/ounce)	1,226	1,572	1,700	1,800	1,600	1,400	1,300	850	1,560

f: forecasts; * The variations are based on observation of the end of period; ** West Texas Intermediate.
Sources: Datastream and Desjardins, Economic Studies

North American Forecasts

This Week's Forecasts

(%)	This Week	Next 4 Weeks	In 3 Months
Canada			
3-Month T-Bills	0.95 - 1.05	0.90 - 1.10	1.00
2-Year Bond	1.10 - 1.20	1.00 - 1.20	1.10
10-Year Bond	1.80 - 1.90	1.70 - 1.90	1.80
Canadian Dollar (CAN$/US$)	97.25 - 98.00	98.0 - 100.0	102.000
United States			
3-Month T-Bills	0.05 - 0.10	0.00 - 0.20	0.10
2-Year Bond	0.20 - 0.30	0.20 - 0.40	0.25
10-Year Bond	1.70 - 1.80	1.40 - 1.60	1.40
Yen (Yen/US$)	77.0 - 79.0	77.0 - 80.0	80.0
Euro (US$/Euro)	1.270 - 1.290	1.23 - 1.27	1.19

17/09/2012

Interest-Rate and Exchange-Rate Forecasts

	Historical Data												
	2009	2010	2011	2011Q4	2012Q1	2012Q2	2012Q3	2012Q4	2013Q1	2013Q2	2013Q3	2013Q4	2014Q4
Canada													
Overnight Rate	**0.43**	**0.59**	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**	**1.50**	**1.50**	**2.00**
3-Month Treasury Bills	0.33	0.56	0.91	0.85	0.91	0.87	0.95	1.00	1.00	1.00	1.50	1.60	2.10
2-Year Bond	1.23	1.54	1.36	0.95	1.20	1.03	1.10	1.10	1.15	1.20	1.70	1.80	2.25
5-Year Bond	2.34	2.48	2.05	1.27	1.57	1.25	1.35	1.35	1.65	1.70	2.20	2.40	2.85
10-Year Bond	3.23	3.24	2.78	1.94	2.11	1.74	1.75	1.80	1.90	2.00	2.55	2.75	3.50
30-Year Bond	3.85	3.77	3.29	2.49	2.66	2.33	2.35	2.40	2.50	2.60	3.20	3.40	4.15
United States													
Federal Funds Rate	**0.125**	**0.125**	**0.125**	**0.125**	**0.125**	**0.125**	**0.125**	**0.125**	**0.125**	**0.125**	**0.125**	**0.125**	**0.13**
3-Month Treasury Bills	0.15	0.14	0.05	0.02	0.07	0.09	0.10	0.10	0.10	0.10	0.10	0.10	0.10
2-Year Bond	0.96	0.70	0.45	0.25	0.33	0.33	0.25	0.25	0.30	0.30	0.35	0.35	0.35
5-Year Bond	2.19	1.93	1.52	0.83	1.04	0.72	0.75	0.85	0.95	0.95	1.10	1.20	1.35
10-Year Bond	3.26	3.22	2.78	1.89	2.23	1.67	1.35	1.40	1.50	1.60	1.75	2.00	3.00
30-Year Bond	4.08	4.25	3.91	2.89	3.35	2.76	2.45	2.60	2.70	2.80	3.05	3.50	4.50
Canadian Dollar (US$/C$)	**0.88**	**0.97**	**1.02**	**0.98**	**1.00**	**0.98**	**1.02**	**0.98**	**0.99**	**1.00**	**1.01**	**1.00**	**0.98**
Canadian Dollar (Euro/C$)	0.63	0.73	0.73	0.76	0.75	0.78	0.80	0.82	0.83	0.83	0.83	0.83	0.80
Euro (US$/Euro)	1.39	1.33	1.39	1.30	1.33	1.27	1.28	1.19	1.20	1.20	1.21	1.21	1.23
Yen (Yen/US$)	93.7	87.8	79.7	77.0	82.4	79.8	78	80	81	82	83	85	85

Quarter-end data and annual averages
* Septrmber 12, 2012

North American Forecasts

Canada

Period-Over-Period Annualized Per Cent Change (Unless Otherwise Indicated)

	2011Q4	2012Q1	2012Q2	2012Q3	2012Q4	2013Q1	Annual Average 2010	Annual Average 2011	Annual Average 2012	Annual Average 2013	Q4/Q4 2011	Q4/Q4 2012	Q4/Q4 2013
Real GDP (%)	**1.9**	**1.8**	**1.8**	**1.7**	**1.9**	**1.8**	**3.2**	**2.4**	**2.0**	**2.0**	**2.2**	**1.8**	**2.2**
Consumption	2.8	0.7	1.1	2.0	1.8	2.0	3.3	2.4	1.7	2.0	2.1	1.4	2.1
Business investment	2.2	5.2	8.8	7.1	6.4	6.7	8.5	12.9	5.3	6.8	7.7	6.9	6.7
Non-residential structures	13.4	7.4	11.4	9.0	7.0	7.0	2.8	13.7	10.2	7.5	11.7	8.7	7.0
Machinery and equipment	-3.7	4.0	7.2	6.0	6.0	6.5	11.8	12.5	2.7	6.4	5.4	5.8	6.5
Residential construction	3.0	11.5	1.8	-0.5	-2.0	-3.0	10.2	2.3	4.9	-1.0	5.2	2.6	-0.3
Government spending	-3.2	-2.0	-0.5	1.4	1.0	1.3	4.7	0.1	-1.3	1.2	-2.1	-0.1	1.4
Exports	7.2	4.0	0.8	4.5	4.0	3.0	6.4	4.6	4.8	3.7	5.3	3.3	4.0
Imports	2.3	5.2	6.4	3.4	3.6	3.5	13.1	7.0	3.9	3.8	5.6	4.7	3.8
Inflation (%)													
Total CPI (y/y)	2.7	2.3	1.6	1.3	1.5	1.5	1.8	2.9	1.7	1.8	2.7	1.5	2.1
Core CPI (y/y)	2.0	2.1	2.0	1.5	1.4	1.8	1.7	1.7	1.7	1.9	2.0	1.4	2.0
Unemployment rate (%)*	**7.4**	**7.4**	**7.2**	**7.3**	**7.3**	**7.2**	**8.0**	**7.5**	**7.3**	**7.2**	-	-	-
Employment	**-0.3**	**0.9**	**2.8**	**0.2**	**1.0**	**0.8**	**1.4**	**1.5**	**1.0**	**1.0**	**1.2**	**1.2**	**1.0**
Housing starts (000s)	**200**	**206**	**230**	**210**	**190**	**185**	**191**	**194**	**209**	**183**	-	-	-
Before-tax Corp. Profits (y/y)	**13.7**	**4.2**	**0.4**	**-1.8**	**-4.2**	**1.9**	**21.2**	**15.4**	**-0.4**	**5.3**	**13.7**	**-4.2**	**4.9**

*Average rate for the period.

Forecasts as of September 10, 2012

United States

Quarter-to-Quarter % Change at annual rates (Unless Otherwise Indicated)

	2011Q4	2012Q1	2012Q2	2012Q3	2012Q4	2013Q1	Annual Average 2010	Annual Average 2011	Annual Average 2012	Annual Average 2013	Q4/Q4 2011	Q4/Q4 2012	Q4/Q4 2013
Real GDP (%)	**4.1**	**2.0**	**1.7**	**1.8**	**2.0**	**1.7**	**2.4**	**1.8**	**2.2**	**2.0**	**2.0**	**1.9**	**2.3**
Consumption	2.0	2.4	1.7	1.8	1.6	1.9	1.8	2.5	1.9	1.9	1.9	1.9	2.0
Private investment	9.4	7.1	4.3	4.6	4.6	4.2	1.7	9.0	8.3	5.5	10.3	5.2	6.5
Non-residential structures	11.5	12.8	2.9	3.5	3.5	5.0	-15.6	2.8	10.9	4.1	6.9	5.6	4.5
Machinery and equipment	8.8	5.4	4.7	5.0	5.0	4.0	8.9	11.0	7.5	5.9	11.4	5.0	7.1
Residential construction	12.0	20.6	8.9	7.5	7.5	6.5	-3.7	-1.4	10.7	7.2	3.9	11.0	7.0
Government spending	-2.2	-3.0	-0.9	-0.1	-0.8	-1.8	0.6	-3.1	-1.8	-1.0	-3.3	-1.2	-1.0
Exports	1.4	4.4	6.0	3.0	4.0	4.0	11.1	6.7	4.1	4.7	4.3	4.3	5.6
Imports	4.9	3.1	2.9	4.5	5.0	4.2	12.5	4.8	3.7	4.6	3.5	3.9	4.9
Inflation													
Total CPI (y/y %)	3.3	2.8	1.9	1.7	1.8	1.6	1.6	3.1	2.1	1.6	3.3	1.8	1.6
Core CPI (y/y %)	2.2	2.2	2.3	2.1	2.0	2.0	1.0	1.7	2.1	1.9	2.2	2.0	1.9
Unemployment rate (%)*	8.7	8.3	8.2	8.3	8.3	8.3	9.6	9.0	8.3	8.3	-	-	-
Employment	1.4	2.1	1.0	1.1	1.1	0.8	-0.7	1.2	1.4	1.1	1.4	1.3	1.2
Housing Starts (in 000s)	678	715	736	765	790	770	586	612	751	786	-	-	-
Before-tax corporate profits (y/y %)	9.2	10.3	6.1	7.0	4.0	4.0	26.8	7.3	6.7	5.5	9.2	4.0	6.0

* Average rate for the period

as of September 10, 2012

Canada
Economic Forecast

*(Annual % change)**	*2009*	*2010*	*2011*	*2012*	*2013*	*Q4/Q4 2012*	*Q4/Q4 2013*
Gross domestic product (2002 $)	(2.8)	3.2	2.4	1.9	1.7	1.6	2.1
Consumption	0.4	3.3	2.4	1.8	1.9	1.6	2.3
Residential construction	(8.0)	10.2	2.3	6.1	(0.9)	3.6	(0.3)
Business investment	(20.8)	7.3	13.1	4.8	4.2	4.6	5.0
Government expenditures	4.3	4.7	0.2	(1.3)	0.5	(0.3)	0.7
Exports	(13.8)	6.4	4.6	4.5	4.0	3.0	4.5
Imports	(13.4)	13.1	7.0	3.4	3.4	3.7	3.5
Change in inventories (millions $)	(539)	8,899	12,818	10,451	8,446	9,228	4,477
Domestic demand	(2.1)	4.5	3.0	1.7	1.6	1.6	2.1
Real disposable income	0.8	3.6	1.3	1.1	1.9	1.4	2.0
Employment	(1.6)	1.4	1.5	1.1	1.1	1.3	1.2
Unemployment rate	8.3	8.0	7.5	7.4	7.4	7.5	7.3
Inflation	0.3	1.8	2.9	1.7	2.1	1.4	2.3
Before-tax profits	(32.3)	20.9	17.5	3.1	5.0	(1.4)	6.7
Federal balance (Public Acc., bil. $)	(55.6)	(33.4)	(31.7)	(20.2)	(10.4)	....	....
Current account (bil. $)	(45.2)	(50.9)	(48.0)	(43.0)	(36.0)	....	....

** or as noted*

Financial Forecast*

	Current 8/17/12	Q3	Q4	Q1 2013	Q2	*2012*	*2013*
Overnight rate	1.00	1.00	1.00	1.00	1.00	1.00	1.50
Prime rate	3.00	3.00	3.00	3.00	3.00	3.00	3.50
3 month T-Bills	1.00	0.98	0.98	0.94	1.05	0.98	1.67
Treasury yield curve							
2-Year	1.20	1.14	1.18	1.04	1.24	1.18	1.88
5-Year	1.50	1.46	1.52	1.40	1.57	1.52	2.05
10-Year	1.94	1.68	1.76	1.65	2.10	1.76	2.40
30-Year	2.48	2.25	2.31	2.20	2.58	2.31	2.86
USD per CAD*	1.01	0.97	0.95	0.98	1.01	0.99**	1.00**
Oil price (WTI), U.S.$*	96	87	86	87	89	93**	90**

National Bank Financial

** end of period*

*** annual average*

United States
Economic Forecast

(Annual % change)*	2009	2010	2011	2012	2013	Q4/Q4 2012	Q4/Q4 2013
Gross domestic product (2005 $)	(3.1)	2.4	1.8	2.2	1.7	1.7	2.2
Consumption	(1.9)	1.8	2.5	1.8	1.6	1.8	2.0
Residential construction	(22.4)	(3.7)	(1.4)	11.5	16.3	12.8	20.9
Business investment	(18.1)	0.7	8.6	8.7	5.5	5.7	5.9
Government expenditures	3.7	0.6	(3.1)	(2.0)	(1.3)	(1.6)	(1.3)
Exports	(9.1)	11.1	6.7	4.4	4.7	5.0	4.4
Imports	(13.5)	12.5	4.8	4.0	3.3	3.9	3.0
Change in inventories (bil. $)	(139.0)	50.9	31.0	59.1	38.8	55.0	35.0
Domestic demand	(3.3)	1.3	1.8	1.9	1.8	1.7	2.2
Real disposable income	(2.8)	1.8	1.3	1.7	2.5	3.0	2.5
Household employment	(3.8)	(0.6)	0.6	1.7	1.0	1.6	1.1
Unemployment rate	9.3	9.6	9.0	8.3	8.3	8.4	8.2
Inflation	(0.3)	1.6	3.1	1.8	1.5	1.1	2.0
Before-tax profits	7.5	26.8	7.3	4.9	4.1	-0.9	4.8
Federal balance (unified budget, bil. $	(1,800.0)	(1,300.0)	(1,350.0)	(1,100.0)	(900.0)	...	...
Current account (bil. $)	(410.0)	(500.0)	(480.0)	(520.0)	(510.0)	...	...

** or as noted*

Financial Forecast

	Current 8/17/12	Q3	Q4	Q1 2013	Q2	2012	2013
Fed Fund Target Rate	0.25	0.25	0.25	0.25	0.25	0.25	0.25
3 month Treasury bills	0.07	0.08	0.08	0.06	0.13	0.08	0.14
Treasury yield curve							
2-Year	0.29	0.29	0.27	0.19	0.31	0.27	0.35
5-Year	0.80	0.64	0.66	0.53	0.88	0.66	1.08
10-Year	1.81	1.52	1.58	1.43	1.89	1.58	2.18
30-Year	2.93	2.63	2.63	2.51	2.84	2.63	3.08
Exchange rates*							
U.S.$/Euro	1.23	1.23	1.18	1.20	1.20	1.26**	1.21**
YEN/U.S.$	79	78	77	80	82	79**	82**

National Bank Financial
** end of period*
*** annual average*

Global Forecast Update

Quarterly Forecasts	11Q4	12Q1	12Q2	12Q3f	12Q4f	13Q1f	13Q2f	13Q3f	13Q4f
Canada									
Real GDP (q/q, ann. % change)	1.9	1.8	1.8	1.4	1.4	1.6	1.9	2.2	2.3
Real GDP (y/y, % change)	2.2	1.8	2.5	1.7	1.6	1.6	1.6	1.8	2.0
Consumer Prices (y/y, % change)	2.7	2.3	1.6	1.3	1.6	1.7	1.8	2.3	2.3
Core CPI (y/y % change)	2.0	2.1	2.0	1.6	1.6	1.7	1.7	1.9	1.9
United States									
Real GDP (q/q, ann. % change)	4.1	2.0	1.3	1.8	1.8	1.4	2.2	2.4	2.5
Real GDP (y/y, % change)	2.0	2.4	2.1	2.3	1.7	1.6	1.8	1.9	2.1
Consumer Prices (y/y, % change)	3.3	2.8	1.9	1.6	1.9	2.0	2.3	2.4	2.3
Core CPI (y/y % change)	2.2	2.2	2.3	2.0	2.0	1.9	1.8	1.9	1.9

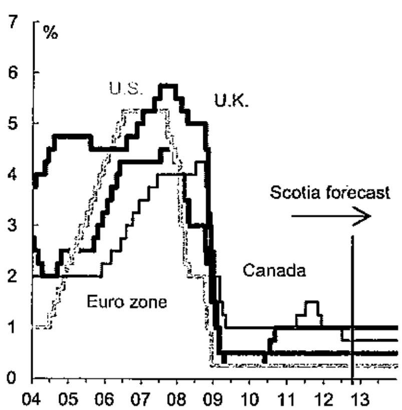
Financial Markets

Central Bank Rates				(%, end of period)					
Americas									
Bank of Canada	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
U.S. Federal Reserve	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Bank of Mexico	4.50	4.50	4.50	4.50	4.50	4.75	5.00	5.00	5.25
Central Bank of Brazil	11.00	9.75	8.50	7.50	7.25	7.25	8.00	8.50	9.00
Bank of the Republic of Colombia	4.75	5.25	5.25	4.50	4.50	4.50	4.50	5.00	5.00
Central Reserve Bank of Peru	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25
Central Bank of Chile	5.25	5.00	5.00	5.00	5.00	5.00	5.25	5.50	5.75
Europe									
European Central Bank	1.00	1.00	1.00	0.75	0.75	0.75	0.75	0.75	0.75
Bank of England	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Swiss National Bank	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Asia/Oceania									
Bank of Japan	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Reserve Bank of Australia	4.25	3.75	3.50	3.50	3.25	3.25	3.25	3.50	3.50
People's Bank of China	6.56	6.56	6.31	6.00	5.75	5.75	5.75	5.75	5.75
Reserve Bank of India	8.50	8.25	8.00	8.00	7.50	7.00	6.75	6.75	6.75
Bank of Korea	3.25	3.25	3.25	3.00	2.75	2.75	2.75	3.00	3.00
Bank Indonesia	6.00	6.00	6.00	5.75	5.75	6.00	6.00	6.25	6.25
Bank of Thailand	3.25	3.00	3.00	3.00	3.00	3.00	3.00	3.25	3.25
Canada									
3-month T-bill	0.86	0.91	0.88	0.98	1.00	1.00	1.00	1.00	1.00
2-year Canada	0.97	1.20	1.03	1.12	1.00	1.05	1.25	1.45	1.70
5-year Canada	1.27	1.57	1.25	1.36	1.30	1.45	1.60	1.75	2.10
10-year Canada	1.93	2.21	1.74	1.82	1.70	1.80	1.95	2.10	2.45
30-year Canada	2.54	2.66	2.33	2.38	2.30	2.40	2.60	2.70	3.10
United States									
3-month T-bill	0.05	0.07	0.08	0.11	0.05	0.05	0.10	0.10	0.10
2-year Treasury	0.21	0.33	0.30	0.26	0.25	0.25	0.25	0.35	0.45
5-year Treasury	0.73	1.04	0.72	0.64	0.55	0.65	1.00	1.25	1.50
10-year Treasury	1.83	2.21	1.64	1.66	1.50	1.60	1.80	2.10	2.50
30-year Treasury	2.98	3.34	2.75	2.83	2.70	2.75	2.95	3.20	3.65
Canada-U.S. Spreads									
3-month T-bill	0.81	0.85	0.80	0.87	0.95	0.95	0.90	0.90	0.90
2-year	0.76	0.87	0.73	0.86	0.75	0.80	1.00	1.10	1.25
5-year	0.54	0.53	0.53	0.72	0.75	0.80	0.60	0.50	0.60
10-year	0.10	0.00	0.10	0.16	0.20	0.20	0.15	0.00	-0.05
30-year	-0.44	-0.68	-0.42	-0.45	-0.40	-0.35	-0.35	-0.50	-0.55

Global Forecast Update

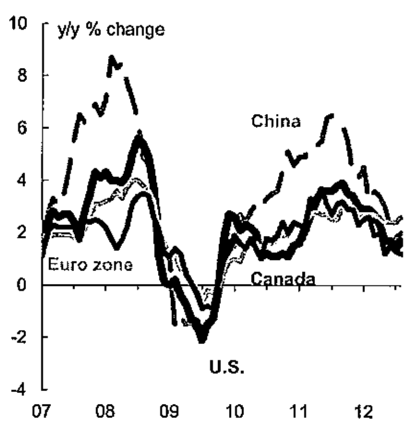
Financial Markets	11Q4	12Q1	12Q2	12Q3f	12Q4f	13Q1f	13Q2f	13Q3f	13Q4f
Exchange Rates				(end of period)					
Americas									
Canadian Dollar (USDCAD)	1.02	1.00	1.02	0.98	0.96	0.96	0.96	0.97	0.97
Canadian Dollar (CADUSD)	0.98	1.00	0.98	1.02	1.04	1.04	1.04	1.03	1.03
Mexican Peso (USDMXN)	13.94	12.81	13.36	12.92	12.81	12.92	12.83	12.94	13.17
Brazilian Real (USDBRL)	1.87	1.83	2.01	2.03	1.99	1.98	1.95	1.90	1.86
Colombian Peso (USDCOP)	1939	1789	1784	1799	1800	1810	1820	1840	1850
Peruvian Nuevo Sol (USDPEN)	2.70	2.67	2.67	2.60	2.57	2.58	2.54	2.51	2.49
Chilean Peso (USDCLP)	520	488	501	471	494	495	497	500	502
Canadian Dollar Cross Rates									
Euro (EURCAD)	1.32	1.33	1.29	1.27	1.21	1.19	1.18	1.18	1.17
U.K. Pound (GBPCAD)	1.59	1.60	1.60	1.59	1.56	1.56	1.56	1.59	1.59
Japanese Yen (CADJPY)	75	83	78	79	83	88	89	89	90
Australian Dollar (AUDCAD)	1.04	1.03	1.04	1.02	1.00	1.01	1.01	1.03	1.03
Mexican Peso (CADMXN)	13.65	12.83	13.14	13.13	13.34	13.46	13.36	13.34	13.58
Europe									
Euro (EURUSD)	1.30	1.33	1.27	1.29	1.26	1.24	1.23	1.22	1.21
U.K. Pound (GBPUSD)	1.55	1.60	1.57	1.62	1.62	1.62	1.63	1.64	1.64
Swiss Franc (USDCHF)	0.94	0.90	0.95	0.94	0.99	1.01	1.02	1.02	1.03
Swedish Krona (USDSEK)	6.88	6.61	6.92	6.62	6.71	6.81	6.83	6.89	6.86
Norwegian Krone (USDNOK)	5.98	5.69	5.96	5.76	5.75	5.60	5.50	5.40	5.30
Russian Ruble (USDRUB)	32.1	29.3	32.4	31.4	32.5	32.8	33.0	33.3	33.5
Asia/Oceania									
Japanese Yen (USDJPY)	77	83	80	78	80	84	85	86	87
Australian Dollar (AUDUSD)	1.02	1.03	1.02	1.04	1.04	1.05	1.05	1.06	1.06
Chinese Yuan (USDCNY)	6.30	6.30	6.35	6.30	6.25	6.25	6.20	6.15	6.10
Indian Rupee (USDINR)	53.1	50.9	55.6	53.5	53.5	53.5	53.0	52.5	52.0
South Korean Won (USDKRW)	1152	1133	1145	1121	1135	1120	1110	1105	1100
Indonesian Rupiah (USDIDR)	9069	9146	9433	9624	9650	9650	9600	9550	9500
Thai Baht (USDTHB)	31.6	30.8	31.6	31.0	31.3	30.8	30.5	30.3	30.2

Central Bank Rates



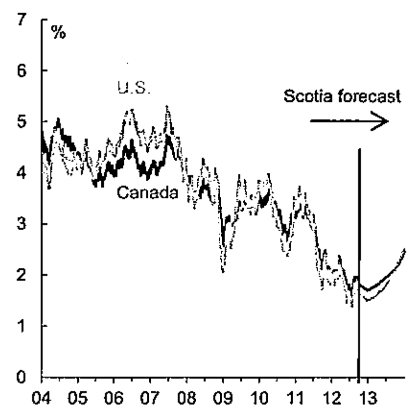
Source: Bloomberg, Scotia Economics.

Global Inflation



Source: Bloomberg, Scotia Economics.

10-Year Yields



Source: Bloomberg, Scotia Economics.

Scotia Economics

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Global Forecast Update

North America	2000-10	2011	2012f	2013f
Canada		(annual % change)		
Real GDP	2.2	2.4	1.9	1.8
Consumer Spending	3.2	2.4	1.7	1.9
Residential Investment	4.4	2.3	5.4	-0.5
Business Investment	2.5	13.1	6.4	6.5
Government	3.6	0.1	-1.6	-0.5
Exports	0.0	4.6	4.2	3.8
Imports	3.0	7.0	3.8	3.9
Nominal GDP	4.7	5.9	3.0	3.3
GDP Deflator	2.5	3.4	1.1	1.6
Consumer Price Index	2.1	2.9	1.7	2.0
Core CPI	1.8	1.7	1.8	1.8
Pre-Tax Corporate Profits	4.6	15.4	0.0	5.5
Employment	1.5	1.6	1.0	1.0
thousands of jobs	240	265	177	172
Unemployment Rate (%)	7.1	7.4	7.3	7.2
Current Account Balance (C$ bn.)	7.9	-48.4	-60.0	-62.0
Merchandise Trade Balance (C$ bn.)	46.2	2.3	-10.0	-11.0
Federal Budget Balance (C$ bn.)	-1.2	-23.5	-20.0	-12.5
per cent of GDP	0.0	-1.4	-1.1	-0.7
Housing Starts (thousands)	200	194	210	190
Motor Vehicle Sales (thousands)	1,588	1,589	1,680	1,690
Motor Vehicle Production (thousands)	2,447	2,135	2,500	2,625
Industrial Production	0.0	3.5	1.9	2.8
United States				
Real GDP	1.8	1.8	2.1	1.9
Consumer Spending	2.2	2.5	1.9	2.0
Residential Investment	-4.9	-1.4	10.9	9.3
Business Investment	0.5	8.6	7.9	4.6
Government	2.2	-3.1	-1.8	-1.2
Exports	3.9	6.7	3.7	4.1
Imports	3.4	4.8	3.1	3.7
Nominal GDP	4.1	4.0	3.9	3.7
GDP Deflator	2.3	2.1	1.7	1.8
Consumer Price Index	2.5	3.1	2.1	2.2
Core CPI	2.1	1.7	2.1	1.9
Pre-Tax Corporate Profits	6.4	7.3	4.5	6.0
Employment	0.1	1.2	1.4	1.3
millions of jobs	0.08	1.50	1.82	1.71
Unemployment Rate (%)	5.9	8.9	8.2	8.0
Current Account Balance (US$ bn.)	-561	-466	-494	-498
Merchandise Trade Balance (US$ bn.)	-633	-738	-759	-788
Federal Budget Balance (US$ bn.)	-407	-1,297	-1,150	-960
per cent of GDP	-3.0	-8.6	-7.3	-5.9
Housing Starts (millions)	1.45	0.61	0.75	0.85
Motor Vehicle Sales (millions)	15.4	12.7	14.1	14.5
Motor Vehicle Production (millions)	10.6	8.6	10.1	10.5
Industrial Production	0.1	4.1	4.1	3.0
Mexico				
Real GDP	2.1	4.2	3.9	3.6
Consumer Price Index (year-end)	4.9	3.8	4.2	4.0
Unemployment Rate (%)	3.7	5.5	4.7	4.4
Current Account Balance (US$ bn.)	-10.2	-11.1	-11.0	-22.0
Merchandise Trade Balance (US$ bn.)	-8.1	-1.5	-6.0	-13.0
Industrial Production	1.4	4.0	3.8	4.4

Forecast Changes

Canada & United States

- Our outlook for the Canadian economy in 2012-13 is little changed from last month's update. Output growth appears to be still trending below a 2% annual rate, with continuing gains in business investment and construction tempered by a more cautious consumer, a softening housing market and weak export sales.
- We have lowered our forecast for U.S. growth this year marginally to 2.1% following the downward revision to Q2 GDP. High unemployment is reinforcing consumer caution, while a weak global economic outlook and uncertainty surrounding the approaching year-end 'fiscal cliff' are restraining business confidence and spending. Our forecast for 2013 is unchanged at 1.9%.
- U.S. vehicle sales have recently strengthened to a 3-year high, prompting automakers to boost production across North America in the final months of 2012. Assemblies in Ontario will post a double-digit increase in the fourth quarter — helping to buoy manufacturing activity after some softness during the summer.
- As U.S. federal fiscal 2012 data are released in October, attention will be shifting to potential legislative compromises to mitigate some of the 'fiscal cliff' measures slated for January 2013. In Canada, alongside Provincial efforts to manage public-sector benefits and compensation, Ottawa plans significant pension plan amendments for its Members of Parliament.

Mexico

- The combination of a solid local economic outlook, the new injection of liquidity from major central banks, a still-high appetite for Mexican peso-denominated assets and the central bank's "no intervention" policy in the foreign exchange market has set an optimistic tone for the Mexican peso (MXN). As a result, we are revising our MXN year-end forecast against the U.S. dollar from 13.1 to 12.8.

CANADIAN ECONOMIC OUTLOOK

Period-Over-Period Annualized Per Cent Change Unless Otherwise Indicated

	2012				2013				2014				Annual Average				4th Qtr/4th Qtr			
	Q1	Q2	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F	11	12F	13F	14F	11	12F	13F	14F
Real GDP	1.8	1.8	1.0	1.8	2.0	2.2	2.6	2.7	2.6	2.4	2.3	2.1	2.4	1.8	2.0	2.5	2.2	1.6	2.4	2.3
Consumer Expenditure	0.7	1.1	1.8	2.3	2.2	2.1	2.3	2.1	2.0	1.9	1.8	1.6	2.4	1.7	2.1	2.0	2.1	1.5	2.1	1.8
Durable Goods	-0.2	-6.5	2.0	1.6	2.0	1.7	2.2	1.5	1.0	-0.5	-1.0	-1.2	1.8	0.9	1.3	0.6	1.9	-0.8	1.8	-0.4
Business Investment	5.8	9.4	2.9	6.5	5.0	6.0	6.8	7.4	8.9	10.0	8.5	7.0	13.1	5.9	5.8	8.2	8.7	6.1	6.3	8.6
Non-Res. Structures	7.4	11.4	9.0	6.0	5.0	5.5	5.9	6.5	8.0	9.2	7.2	7.0	13.7	10.1	6.4	7.4	11.7	8.4	5.7	7.8
Machinery & Equipment	4.0	7.2	-3.7	7.0	5.0	6.5	8.0	8.5	10.0	11.0	10.0	7.0	12.5	1.5	5.3	9.3	5.4	3.5	7.0	9.5
Residential Investment	11.5	1.8	1.2	0.5	0.2	-0.5	-4.5	-5.5	-3.5	-2.7	-1.0	-0.5	2.3	5.3	-0.6	-3.2	5.2	3.7	-2.6	-1.9
Government Expenditures	-2.0	-0.5	-0.9	-0.7	-0.7	-0.8	-0.7	-0.7	-0.7	-0.6	-0.5	-0.5	0.1	-1.7	-0.7	-0.7	0.2	-1.0	-0.7	-0.6
Final Domestic Demand	1.3	1.7	1.3	1.9	1.7	1.6	1.6	1.5	1.8	2.0	2.0	1.7	3.0	1.6	1.6	1.8	2.0	1.6	1.6	1.9
Exports	4.0	0.8	-0.5	4.3	4.1	2.9	5.1	6.4	6.6	6.2	6.1	6.0	4.6	4.2	3.4	6.0	5.3	2.1	4.6	6.2
Imports	5.2	6.4	-2.2	2.6	1.6	1.2	2.6	2.9	4.5	5.8	4.8	4.2	7.0	3.1	1.8	4.0	5.6	3.0	2.1	4.8
Change in Non-Farm Inventories ($2002 Bn)	6.2	11.7	9.0	6.0	4.0	4.1	5.5	6.2	7.0	8.5	8.2	7.5	10.0	8.2	5.0	7.8	--	--	--	--
Final Sales	0.5	-1.0	2.0	2.6	2.7	2.5	2.7	3.0	2.6	2.1	2.4	2.2	1.9	1.6	2.3	2.5	1.5	1.0	2.7	2.3
International Current Account Balance ($Bn)	-41.1	-63.6	-58.2	-49.3	-44.4	-40.3	-35.3	-29.2	-31.1	-29.4	-26.2	-22.0	-48.4	-53.1	-37.3	-27.2	--	--	--	--
% of GDP	-2.3	-3.6	-3.3	-2.7	-2.4	-2.2	-1.9	-1.5	-1.6	-1.5	-1.3	-1.1	-2.8	-3.0	-2.0	-1.4	--	--	--	--
Pre-tax Corp. Profits	-14.0	-17.5	4.3	6.0	6.1	8.8	7.9	6.9	6.5	6.2	6.1	5.9	15.4	-1.1	5.0	6.7	13.7	-5.9	7.4	6.2
% of GDP	12.0	11.5	11.5	11.5	11.6	11.7	11.8	11.8	11.9	11.9	12.0	12.0	12.1	11.6	11.7	11.9	--	--	--	--
GDP Deflator (Y/Y)	2.1	1.0	1.3	1.1	1.7	2.5	2.5	2.3	2.2	2.2	2.2	2.1	3.4	1.4	2.2	2.1	3.2	1.1	2.3	2.0
Nominal GDP	1.9	0.5	3.2	5.3	4.2	4.4	5.0	5.1	4.7	4.4	4.3	4.2	5.9	3.3	4.2	4.7	5.6	2.7	4.7	4.4
Labour Force	0.8	3.6	0.3	1.1	0.9	0.8	0.8	0.8	0.9	0.8	1.0	1.0	1.0	0.9	0.9	0.9	0.9	1.1	0.8	0.9
Employment	0.9	4.5	0.1	1.2	1.1	1.2	1.6	1.8	1.9	2.0	1.6	1.5	1.5	1.0	1.2	1.8	1.2	1.3	1.4	1.7
Employment ('000s)	41	194	4	52	48	53	70	79	84	89	72	67	262	179	214	311	203	217	250	312
Unemployment Rate (%)	7.4	7.3	7.3	7.3	7.2	7.1	7.0	6.7	6.5	6.2	6.1	6.0	7.5	7.3	7.0	6.2	--	--	--	--
Personal Disp. Income	1.5	4.2	2.8	3.6	3.5	3.8	3.8	3.7	3.8	3.6	3.5	3.5	3.3	2.9	3.6	3.7	2.9	3.1	3.7	3.6
Pers. Savings Rate (%)	3.1	3.6	3.7	3.8	3.7	3.6	3.5	3.3	3.3	3.3	3.3	3.4	3.7	3.5	3.5	3.3	--	--	--	--
Cons. Price Index (Y/Y)	2.3	1.6	1.2	1.5	2.0	2.0	2.1	2.0	2.0	2.1	2.0	2.1	2.9	1.6	2.0	2.1	2.7	1.5	2.0	2.1
Core CPI (Y/Y)	2.1	2.0	1.5	1.5	1.7	1.6	2.1	2.0	2.0	2.0	2.0	2.0	1.7	1.8	1.8	2.0	2.0	1.5	2.0	2.0
Housing Starts ('000s)	206	230	211	203	191	186	186	185	184	184	184	180	193	213	187	183	--	--	--	--
Productivity: Real GDP / worker (Y/Y)	0.9	1.3	0.7	0.3	0.3	0.8	0.8	0.9	0.9	0.7	0.7	0.6	0.9	0.8	0.7	0.7	1.0	0.3	0.9	0.6

F: Forecast by TD Economics as at September 2012

Source: Statistics Canada, Bank of Canada, Canada Mortgage and Housing Corporation, Haver Analytics

FINANCIAL INDICATOR OUTLOOK												
end-of-period level												
	2012				2013				2014			
	Q1	Q2	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F
CANADIAN FIXED INCOME												
Overnight Target Rate (%)	1.00	1.00	1.00	1.00	1.00	1.00	1.50	1.50	1.50	1.75	2.00	2.00
3-mth T-Bill Rate (%)	0.91	0.88	1.00	1.05	1.05	1.40	1.55	1.65	1.70	2.05	2.05	2.10
2-yr Govt. Bond Yield (%)	1.20	1.01	1.20	1.30	1.40	1.60	1.70	1.80	1.90	2.10	2.25	2.35
5-yr Govt. Bond Yield (%)	1.57	1.24	1.45	1.55	1.70	1.80	1.85	2.00	2.25	2.30	2.45	2.65
10-yr Govt. Bond Yield (%)	2.11	1.74	1.95	2.10	2.15	2.25	2.30	2.50	2.65	2.75	2.90	3.05
30-yr Govt. Bond Yield (%)	2.66	2.33	2.50	2.55	2.60	2.70	2.85	3.10	3.20	3.35	3.45	3.50
10-yr-2-yr Govt. Spread (%)	0.91	0.73	0.75	0.80	0.75	0.65	0.60	0.70	0.75	0.65	0.65	0.70
GLOBAL CURRENCIES												
USD per CAD	1.00	0.98	1.02	1.00	0.97	0.98	1.00	1.02	1.02	1.02	1.03	1.03
USD per EUR	1.33	1.25	1.33	1.25	1.18	1.20	1.22	1.25	1.26	1.26	1.28	1.28
JPY per USD	82	80	78	79	80	80	84	84	86	86	88	88

F: Forecast by TD Bank Group as at September 2012
Source: Statistics Canada, Bank of Canada, Bloomberg

U.S. ECONOMIC OUTLOOK

Period-Over-Period Annualized Per Cent Change Unless Otherwise Indicated

	2012				2013				2014				Annual Average			4th Qtr/4th Qtr		
	Q1	Q2	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F	12F	13F	14F	12F	13F	14F
Real GDP	2.0	1.7	1.5	1.7	1.9	2.2	2.6	3.1	3.3	3.4	3.6	3.5	2.2	2.0	3.2	1.7	2.4	3.4
Consumer Expenditure	2.4	1.7	1.8	2.2	1.6	2.0	2.4	2.6	2.6	2.7	2.8	2.7	1.9	2.0	2.6	2.0	2.1	2.7
Durable Goods	11.5	-0.1	4.5	6.7	2.2	4.5	6.5	7.5	7.7	7.5	7.0	6.6	6.8	4.5	7.1	5.6	5.1	7.2
Business Investment	7.5	4.2	2.7	5.8	5.3	6.6	6.9	8.0	8.1	7.9	7.7	7.0	8.2	5.6	7.7	5.0	6.7	7.7
Non-Res. Structures	12.8	2.9	-0.3	4.8	5.4	5.9	6.6	7.3	6.1	5.7	5.4	5.0	10.4	4.8	6.1	4.9	6.3	5.5
Equipment & Software	5.4	4.7	3.9	6.1	5.3	6.9	7.0	8.3	9.0	8.8	8.7	7.9	7.4	5.9	8.3	5.0	6.8	8.6
Residential Construction	20.6	8.9	8.5	7.9	8.7	10.9	13.8	16.1	17.7	18.4	18.0	16.9	10.9	10.1	16.6	11.4	12.4	17.8
Govt. Consumption & Gross Investment	-3.0	-0.9	-1.0	-0.7	-3.2	-3.0	-1.7	-1.1	-0.4	0.1	0.6	0.7	-1.9	-1.9	-0.6	-1.4	-2.2	0.2
Final Domestic Demand	2.2	1.6	1.5	2.1	1.2	1.7	2.4	2.8	3.0	3.2	3.3	3.2	2.0	1.8	2.9	1.9	2.0	3.2
Exports	4.4	6.0	3.0	4.5	4.9	5.2	6.5	7.5	6.9	7.6	7.2	7.7	4.2	5.1	7.1	---	---	---
Imports	3.1	2.9	1.8	3.5	2.8	4.4	4.9	5.2	5.1	5.5	5.7	5.9	3.3	3.5	5.2	2.8	4.3	5.5
Change in Non-Farm Inventories	56.9	49.9	43.5	26.3	40.3	53.5	54.5	57.5	60.4	59.8	62.8	65.7	44.2	51.4	62.2	---	---	---
Final Sales	2.4	2.0	1.7	2.2	1.4	1.7	2.5	3.0	3.1	3.4	3.5	3.4	2.0	1.9	3.1	---	---	---
International Current Account Balance ($Bn)	-553	-495	-492	-510	-499	-527	-527	-546	-539	-554	-539	-527	-512	-525	-540	---	---	---
% of GDP	-3.6	-3.2	-3.1	-3.2	-3.1	-3.3	-3.2	-3.3	-3.2	-3.3	-3.1	-3.0	-3.3	-3.2	-3.1	---	---	---
Pre-tax Corporate Profits including IVA&CCA	-10.4	2.2	-0.6	1.8	2.6	3.2	4.3	4.2	4.1	4.5	5.1	4.6	4.5	2.4	4.3	-1.9	3.6	4.6
% of GDP	12.3	12.2	12.1	12.1	12.0	12.0	12.0	12.0	11.9	11.9	11.9	11.8	12.2	12.0	11.9	---	---	---
GDP Deflator (Y/Y)	2.0	1.7	1.4	1.7	1.8	1.9	2.0	2.1	2.2	2.2	2.2	2.3	1.7	1.9	2.2	1.7	2.1	2.3
Nominal GDP	4.2	3.3	3.1	3.5	3.9	4.3	4.7	5.3	5.5	5.7	5.9	5.8	3.9	4.0	5.4	3.5	4.6	5.7
Labor Force	1.8	0.5	-0.1	0.8	0.9	0.7	0.8	1.0	1.1	1.2	1.2	1.2	0.8	0.7	1.1	0.8	0.9	1.2
Employment	2.1	1.0	0.9	1.0	1.1	1.3	1.8	1.9	2.0	2.1	2.2	2.1	1.4	1.2	2.0	---	---	---
Change in Empl. ('000s)	696	323	304	340	370	433	600	637	673	710	748	718	1,801	1,642	2,645	1,663	2,041	2,849
Unemployment Rate (%)	8.3	8.2	8.2	8.1	8.1	8.0	7.8	7.7	7.5	7.3	7.1	6.9	8.2	7.9	7.2	---	---	---
Personal Disp. Income	6.3	3.8	3.3	3.1	-0.4	4.2	4.5	5.1	5.3	5.5	5.6	5.4	3.3	2.8	5.2	---	---	---
Pers. Savings Rate (%)	3.6	4.0	4.1	3.9	2.9	2.8	2.7	2.8	2.8	2.9	3.0	3.1	3.9	2.8	3.0	---	---	---
Cons. Price Index (Y/Y)	2.8	1.9	1.6	1.9	1.7	2.1	2.3	2.2	2.3	2.3	2.3	2.3	2.0	2.1	2.3	1.9	2.2	2.3
Core CPI (Y/Y)	2.2	2.3	2.0	2.0	2.0	1.9	2.0	2.2	2.2	2.2	2.2	2.2	2.1	2.0	2.2	2.0	2.2	2.2
Housing Starts (mns)	0.72	0.74	0.75	0.77	0.80	0.84	0.90	0.97	1.04	1.11	1.18	1.24	0.74	0.88	1.14	---	---	---
Productivity: Real Output per hour (y/y)	1.0	1.2	1.3	0.9	1.3	1.1	1.2	1.4	1.5	1.6	1.7	1.6	1.1	1.3	1.6	0.9	1.4	1.6

F: Forecast by TD Economics as at September 2012

Source: U.S. Bureau of Labor Statistics, U.S. Bureau of Economic Analysis, TD Economics

INTEREST RATE OUTLOOK

	2012				2013				2014			
	Q1	Q2	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F
Fed Funds Target Rate (%)	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
3-mth T-Bill Rate (%)	0.07	0.09	0.10	0.10	0.15	0.15	0.20	0.20	0.20	0.30	0.40	0.40
2-yr Govt. Bond Yield (%)	0.33	0.33	0.25	0.30	0.30	0.30	0.30	0.40	0.40	0.45	0.45	0.50
5-yr Govt. Bond Yield (%)	1.10	0.72	0.60	0.60	0.60	0.65	0.80	1.00	1.15	1.35	1.45	1.65
10-yr Govt. Bond Yield (%)	2.30	1.63	1.75	1.95	1.95	2.00	2.25	2.60	2.65	2.70	2.80	3.00
30-yr Govt. Bond Yield (%)	3.40	2.70	2.80	3.00	3.05	3.10	3.35	3.70	3.75	3.95	4.05	4.10
10-yr-2-yr Govt. Spread (%)	1.97	1.30	1.50	1.65	1.65	1.70	1.95	2.20	2.25	2.25	2.35	2.50

f: Forecast by TD Economics as at September 2012; All forecasts are for end of period; Source: Bloomberg, TD Economics

FOREIGN EXCHANGE OUTLOOK

Currency	Exchange Rate	2012				2013				2014			
		Q1	Q2	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F
Canadian dollar	CAD per USD	1.00	1.02	0.98	1.00	1.03	1.02	1.00	0.98	0.98	0.98	0.97	0.97
Japanese yen	JPY per USD	82	80	78	79	80	80	84	84	86	86	88	88
Euro	USD per EUR	1.33	1.27	1.33	1.25	1.18	1.20	1.22	1.25	1.26	1.26	1.28	1.28
U.K. pound	USD per GBP	1.60	1.57	1.68	1.60	1.51	1.56	1.63	1.67	1.64	1.64	1.71	1.71
Swiss franc	CHF per USD	0.90	0.95	0.90	0.98	1.06	1.04	1.07	1.04	1.03	1.03	1.02	1.02
Australian dollar	USD per AUD	1.04	1.02	1.04	1.04	1.04	1.03	1.03	1.03	1.04	1.04	1.05	1.05
NZ dollar	USD per NZD	0.82	0.80	0.80	0.81	0.82	0.83	0.83	0.83	0.84	0.84	0.85	0.85

f: Forecast by TD Economics as at September 2012; All forecasts are for end of period; Source: Federal Reserve, Bloomberg, TD Economics

CANADIAN ECONOMIC OUTLOOK

Period-Over-Period Annualized Per Cent Change Unless Otherwise Indicated

	Annual Average					4th Qtr/4th Qtr				
	12F	13F	14F	15F	16F	12F	13F	14F	15F	16F
Real GDP	1.8	2.0	2.5	2.1	2.2	1.6	2.4	2.3	2.1	2.2
Consumer Expenditure	1.7	2.1	2.0	1.9	2.2	1.5	2.1	1.8	2.1	2.2
Durable Goods	0.9	1.3	0.6	0.4	2.1	-0.8	1.8	-0.4	1.6	2.2
Business Investment	5.9	5.8	8.2	6.4	4.6	6.1	6.3	8.6	5.3	4.3
Non-Res. Structures	10.1	6.4	7.4	6.3	4.7	8.4	5.7	7.8	5.5	4.3
Machinery & Equipment	1.5	5.3	9.3	6.5	4.5	3.5	7.0	9.5	5.1	4.4
Residential Investment	5.3	-0.6	-3.2	-0.3	2.5	3.7	-2.6	-1.9	0.7	3.0
Government Expenditures	-1.7	-0.7	-0.7	0.4	1.1	-1.0	-0.7	-0.6	1.0	1.0
Final Domestic Demand	1.6	1.6	1.8	2.0	2.3	1.6	1.6	1.9	2.2	2.3
Exports	4.2	3.4	6.0	5.8	5.2	2.1	4.6	6.2	5.6	4.9
Imports	3.1	1.8	4.0	4.8	5.3	3.0	2.1	4.8	5.1	5.1
Change in Non-Farm Inventories ($2002 Bn)	8.2	5.0	7.8	3.1	1.7	---	---	---	---	---
Final Sales	1.6	2.3	2.5	2.3	2.0	1.0	2.7	2.3	2.2	2.0
International Current Account Balance ($Bn)	-53.1	-37.3	-27.2	-12.1	-8.2	---	---	---	---	---
% of GDP	-3.0	-2.0	-1.4	-0.6	-0.4	---	---	---	---	---
Pre-tax Corp. Profits	-1.1	5.0	6.7	18.3	7.9	-5.9	7.4	6.2	21.6	4.3
% of GDP	11.6	11.7	11.9	13.5	14.0	---	---	---	---	---
GDP Deflator (Y/Y)	1.4	2.2	2.1	2.1	2.0	1.1	2.3	2.0	2.1	2.0
Nominal GDP	3.3	4.2	4.7	4.2	4.3	2.7	4.7	4.4	4.3	4.3
Labour Force	0.9	0.9	0.9	0.9	0.9	1.1	0.8	0.9	0.9	0.9
Employment	1.0	1.2	1.8	1.4	1.2	1.3	1.4	1.7	1.2	1.2
Employment ('000s)	179	214	311	244	219	217	250	312	217	220
Unemployment Rate (%)	7.3	7.0	6.2	5.8	5.5	---	---	---	---	---
Personal Disp. Income	2.9	3.6	3.7	4.2	4.1	3.1	3.7	3.6	4.4	4.1
Pers. Savings Rate (%)	3.5	3.5	3.3	3.7	3.6	---	---	---	---	---
Cons. Price Index (Y/Y)	1.6	2.0	2.1	2.1	2.0	1.5	2.0	2.1	2.0	0.0
Core CPI (Y/Y)	1.8	1.8	2.0	2.0	2.0	1.5	2.0	2.0	1.9	0.0
Housing Starts ('000s)	213	187	183	176	180	---	---	---	---	---
Productivity: Real GDP / worker (Y/Y)	0.8	0.7	0.7	0.8	1.0	0.3	0.9	0.6	0.9	1.0

F: Forecast by TD Economics as at September 2012

Source: Statistics Canada, Bank of Canada, Canada Mortgage and Housing Corporation, Haver Analytics

U.S. ECONOMIC OUTLOOK

Period-Over-Period Annualized Per Cent Change Unless Otherwise Indicated

	Annual Average					4th Qtr/4th Qtr				
	12F	13F	14F	15F	16F	12F	13F	14F	15F	16F
Real GDP	2.2	2.0	3.2	3.5	3.1	1.7	2.4	3.4	3.4	2.9
Consumer Expenditure	1.9	2.0	2.6	2.8	2.7	2.0	2.1	2.7	2.8	2.6
Durable Goods	6.8	4.5	7.1	6.2	4.9	5.6	5.1	7.2	5.7	4.5
Business Investment	8.2	5.6	7.7	6.6	4.7	5.0	6.7	7.7	6.0	4.0
Non-Res. Structures	10.4	4.8	6.1	4.9	4.1	4.9	6.3	5.5	4.7	3.8
Machinery & Equipment	7.4	5.9	8.3	7.4	4.9	5.0	6.8	8.6	6.5	4.1
Residential Investment	10.9	10.1	16.6	15.6	11.9	11.4	12.4	17.8	14.1	10.5
Gov't. Expenditures	-1.9	-1.9	-0.6	0.9	1.3	-1.4	-2.2	0.2	1.2	1.3
Final Domestic Demand	2.0	1.8	2.9	3.3	3.0	1.9	2.0	3.2	3.3	2.8
Exports	4.2	5.1	7.1	6.3	3.5	4.5	6.0	7.3	5.3	2.8
Imports	3.3	3.5	5.2	5.0	3.6	2.8	4.3	5.5	4.5	3.0
Change in Non-Farm Inventories	44.2	51.4	62.2	73.0	84.5	---	---	---	---	---
Final Sales	2.0	1.9	3.1	3.4	3.0	2.1	2.2	3.3	3.3	2.8
International Current Account Balance ($Bn)	-512	-525	-540	-450	-366	---	---	---	---	---
% of GDP	-3.3	-3.2	-3.1	-2.5	-1.9	---	---	---	---	---
Pre-tax Corp. Profits including IVA&CCA	4.5	2.4	4.3	4.6	4.4	-1.9	3.6	4.6	4.8	3.7
% of GDP	12.2	12.0	11.9	11.7	11.6	---	---	---	---	---
GDP Deflator (Y/Y)	1.7	1.9	2.2	2.3	2.3	1.7	2.1	2.3	2.3	2.3
Nominal GDP	3.9	4.0	5.4	5.8	5.4	3.5	4.6	5.7	5.8	5.3
Labour Force	0.8	0.7	1.1	1.1	1.0	0.7	0.8	1.2	1.1	0.9
Employment	1.4	1.2	2.0	2.1	1.7	1.3	1.5	2.1	2.1	1.4
Employment ('000s)	1,801	1,642	2,645	2,937	2,358	1,663	2,041	2,849	2,874	2,015
Unemployment Rate (%)	8.2	7.9	7.2	6.4	5.8	---	---	---	---	---
Personal Disp. Income	3.3	2.8	5.2	5.7	5.5	4.1	3.4	5.5	5.7	5.4
Pers. Savings Rate (%)	3.9	2.8	3.0	3.4	3.8	---	---	---	---	---
Cons. Price Index (Y/Y)	2.0	2.1	2.3	2.3	2.4	1.9	2.2	2.3	2.3	2.3
Core CPI (Y/Y)	2.1	2.0	2.2	2.3	2.3	2.0	2.2	2.2	2.2	2.3
Housing Starts (mns)	0.74	0.88	1.14	1.36	1.52	---	---	---	---	---
Productivity: Real GDP / worker (Y/Y)	1.1	1.3	1.6	1.6	1.3	0.9	1.4	1.6	1.6	1.3

F: Forecast by TD Economics as at September 2012

Source: U.S. Bureau of Labor Statistics, U.S. Bureau of Economic Analysis, TD Economics

INTEREST RATE OUTLOOK	Annual Average					End of Period				
	12F	13F	14F	15F	16F	12F	13F	14F	15F	16F
CANADIAN FIXED INCOME										
Overnight Target Rate (%)	1.00	1.25	1.80	2.31	3.38	1.00	1.50	2.00	2.75	3.50
3-mth T-Bill Rate (%)	0.95	1.40	2.00	2.44	3.48	1.05	1.65	2.10	2.85	3.60
2-yr Govt. Bond Yield (%)	1.20	1.65	2.15	2.70	3.63	1.30	1.80	2.35	3.05	3.70
5-yr Govt. Bond Yield (%)	1.45	1.85	2.40	3.03	3.86	1.55	2.00	2.65	3.35	3.95
10-yr Govt. Bond Yield (%)	2.00	2.30	2.85	3.49	4.33	2.10	2.50	3.05	3.80	4.50
10-yr-2-yr Govt. Spread (%)	0.80	0.65	0.70	0.79	0.70	0.80	0.70	0.70	0.75	0.80
U.S. FIXED INCOME										
Fed Funds Target Rate (%)	0.25	0.25	0.25	0.45	1.63	0.25	0.25	0.25	0.75	2.00
3-mth T-Bill Rate (%)	0.10	0.20	0.35	0.80	1.83	0.10	0.20	0.40	1.15	2.20
2-yr Govt. Bond Yield (%)	0.30	0.35	0.45	1.30	2.50	0.30	0.40	0.50	1.70	2.80
5-yr Govt. Bond Yield (%)	0.75	0.75	1.40	2.40	3.26	0.60	1.00	1.65	2.80	3.45
10-yr Govt. Bond Yield (%)	1.90	2.20	2.80	3.75	4.20	1.95	2.60	3.00	4.00	4.30
10-yr-2-yr Govt. Spread (%)	1.60	1.85	2.35	2.45	1.70	1.65	2.20	2.50	2.30	1.50
CANADA-U.S. SPREADS										
3-mth T-Bill Rate (%)	0.85	1.20	1.65	1.64	1.65	0.95	1.45	1.70	1.70	1.40
2-yr Govt. Bond Yield (%)	0.90	1.30	1.70	1.40	1.13	1.00	1.40	1.85	1.35	0.90
5-yr Govt. Bond Yield (%)	0.70	1.10	1.00	0.63	0.60	0.95	1.00	1.00	0.55	0.50
10-yr Govt. Bond Yield (%)	0.10	0.10	0.05	-0.26	0.13	0.15	-0.10	0.05	-0.20	0.20

F: Forecast by TD Bank Group as at September 2012
Source: Statistics Canada, Bank of Canada, Bloomberg

Table 1 - IHS Global Insight Selected Economic Indicators																								
Sep 11 2012	12Q1	12Q2	12Q3	12Q4	13Q1	13Q2	13Q3	13Q4	14Q1	14Q2	14Q3	14Q4	15Q1	15Q2	15Q3	15Q4	16Q1	16Q2	16Q3	16Q4	17Q1	17Q2	17Q3	17Q4
Real GDP (Bil. chained 2002 $)	1374.3	1380.6	1385.9	1392.3	1398.9	1406.6	1414.7	1423.2	1431.9	1441.5	1450.8	1460.5	1470.0	1479.4	1489.0	1498.6	1508.0	1517.6	1527.4	1536.7	1546.1	1555.6	1565.3	1574.9
Annual % Ch.	1.8	1.8	1.6	1.9	1.9	2.2	2.3	2.4	2.5	2.7	2.6	2.7	2.6	2.6	2.6	2.6	2.5	2.6	2.6	2.4	2.5	2.5	2.5	2.5
Consumer	871.2	873.6	877.9	882.0	886.2	891.1	896.1	901.0	906.2	911.3	916.5	921.7	926.7	931.8	936.9	942.0	947.3	952.8	958.2	963.9	969.4	974.9	980.5	986.1
Annual % Ch.	0.7	1.1	1.9	1.9	1.9	2.2	2.3	2.2	2.4	2.3	2.3	2.3	2.2	2.2	2.2	2.2	2.3	2.3	2.3	2.4	2.3	2.3	2.3	2.3
Government	331.9	331.5	334.3	335.8	337.7	339.6	341.5	343.3	345.2	347.0	348.7	350.6	352.4	354.3	356.1	358.1	360.0	362.0	363.9	365.9	367.9	369.9	372.0	374.0
Annual % Ch.	-2.3	-0.5	3.4	1.8	2.3	2.3	2.3	2.1	2.2	2.1	2.0	2.2	2.0	2.2	2.1	2.3	2.2	2.2	2.1	2.2	2.2	2.2	2.2	2.2
Bus. Res. Investment	84.8	85.1	86.4	87.1	87.6	88.0	88.3	88.7	89.2	89.7	90.1	90.6	91.1	91.6	92.1	92.5	93.0	93.5	94.0	94.5	95.0	95.5	96.0	96.5
Annual % Ch.	11.5	1.8	6.3	3.3	1.9	1.9	1.7	1.8	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Bus. Non-Res. Inv.	199.1	203.7	211.9	216.2	218.2	220.0	221.4	222.8	224.4	226.0	227.6	229.1	230.5	231.9	233.3	234.5	235.5	236.7	237.7	238.8	240.0	241.2	242.3	243.4
Annual % Ch.	5.8	9.4	17.2	8.4	3.7	3.3	2.6	2.6	2.9	2.9	2.8	2.7	2.4	2.5	2.3	2.2	1.7	2.0	1.7	1.9	1.9	2.1	1.9	1.8
Exports	484.3	485.2	495.2	503.2	510.2	518.5	525.5	533.4	541.9	550.3	558.6	567.0	575.3	583.9	592.8	601.8	610.4	619.3	628.3	637.1	646.0	655.2	664.3	673.6
Annual % Ch.	4.0	0.8	8.5	6.6	5.7	6.6	5.5	6.1	6.5	6.3	6.2	6.1	6.0	6.1	6.2	6.2	5.9	5.9	6.0	5.7	5.8	5.8	5.7	5.7
Imports	622.9	632.6	634.0	641.0	647.9	654.6	661.4	668.8	677.2	685.3	693.4	701.3	709.3	717.6	725.8	734.1	742.5	750.9	759.1	767.9	776.7	785.7	794.6	803.7
Annual % Ch.	5.2	6.4	0.9	4.5	4.4	4.2	4.3	4.5	5.1	4.9	4.8	4.6	4.7	4.7	4.7	4.6	4.6	4.6	4.5	4.7	4.7	4.8	4.6	4.7
Business Inventory Ch.	8.2	15.2	14.6	9.2	7.2	4.4	3.5	3.0	2.3	2.5	2.6	2.6	3.1	3.2	3.2	3.1	3.3	3.3	3.2	3.1	3.2	3.1	3.2	3.2
Statistical error	0.6	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nominal GDP (Bil. $)	1762.6	1764.6	1801.5	1817.9	1838.0	1860.3	1882.0	1904.6	1927.7	1951.3	1975.5	2000.0	2024.2	2047.9	2072.4	2096.8	2121.0	2146.1	2170.9	2195.9	2221.3	2248.9	2275.3	2302.0
Annual % Ch.	1.9	0.5	8.6	3.7	4.5	4.9	4.8	4.9	4.9	5.0	5.1	5.1	4.9	4.8	4.9	4.8	4.7	4.8	4.7	4.7	4.7	5.1	4.8	4.8
Raw Mat. Price Index	171.2	161.9	160.0	160.2	160.6	160.1	159.7	159.3	158.7	158.9	158.7	158.2	158.4	159.1	159.8	160.2	160.7	160.8	160.9	161.3	161.5	161.6	161.9	162.2
% Ch. Year Ago	-0.2	-11.9	-7.5	-7.7	-6.2	-1.1	-0.2	-0.6	-1.2	-0.7	-0.6	-0.7	-0.2	0.1	0.7	1.3	1.4	1.0	0.7	0.6	0.5	0.5	0.6	0.6
Industry Price Index	115.4	115.5	114.8	115.2	115.9	116.4	117.0	117.4	117.9	118.3	118.7	119.1	119.4	119.8	120.2	120.7	121.1	121.7	122.2	122.6	123.0	123.4	123.8	124.1
% Ch. Year Ago	1.8	0.6	-0.1	0.1	0.4	0.8	1.8	1.9	1.8	1.6	1.5	1.4	1.2	1.3	1.3	1.4	1.5	1.6	1.6	1.6	1.5	1.4	1.3	1.3
GDP Deflator	128.2	127.8	130.0	130.6	131.4	132.3	133.0	133.8	134.6	135.4	136.2	136.9	137.7	138.4	139.2	139.9	140.7	141.4	142.1	142.9	143.7	144.6	145.4	146.2
Annual % Ch.	0.0	-1.2	7.0	1.8	2.5	2.7	2.4	2.4	2.4	2.2	2.4	2.3	2.2	2.1	2.2	2.1	2.1	2.2	2.0	2.2	2.2	2.5	2.2	2.2
CPI	121.2	122.0	121.8	123.0	124.1	124.5	124.3	125.3	126.6	127.0	126.8	127.8	129.1	129.5	129.3	130.3	131.7	132.1	131.9	132.9	134.3	134.7	134.5	135.6
% Ch. Year Ago	2.3	1.6	1.3	1.9	2.4	2.1	2.0	1.9	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
3-Month T-Bill Rate (%)	0.91	0.98	1.01	1.03	1.03	1.06	1.13	1.42	1.63	1.93	2.17	2.39	2.73	3.00	3.25	3.50	3.75	4.00	4.25	4.50	4.50	4.50	4.50	4.50
US 3-Month T-Bill Rate (%)	0.07	0.09	0.10	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.17	0.46	0.95	1.43	1.93	2.43	2.92	3.35	3.66	3.74	3.74	3.74
Canada-US Differential (% pts.)	0.85	0.90	0.91	0.91	0.91	0.94	1.01	1.30	1.51	1.81	2.05	2.28	2.57	2.54	2.30	2.07	1.82	1.57	1.33	1.15	0.84	0.76	0.76	0.76
Prime Rate (%)	3.00	3.00	3.00	3.00	3.00	3.00	3.08	3.33	3.67	3.92	4.17	4.42	4.75	5.00	5.25	5.50	5.75	6.00	6.25	6.50	6.50	6.50	6.50	6.50
Overnight Rate (%)	1.00	1.00	1.00	1.00	1.00	1.00	1.08	1.33	1.67	1.92	2.17	2.42	2.75	3.00	3.25	3.50	3.75	4.00	4.25	4.50	4.50	4.50	4.50	4.50
Bank Rate (%)	1.25	1.25	1.25	1.25	1.25	1.25	1.33	1.58	1.92	2.17	2.42	2.67	3.00	3.25	3.50	3.75	4.00	4.25	4.50	4.75	4.75	4.75	4.75	4.75
GOC Bond Rate (1-3 yrs.) (%)	1.11	1.17	1.10	1.23	1.36	1.44	1.69	1.99	2.13	2.34	2.50	2.69	2.97	3.21	3.45	3.67	3.90	4.15	4.38	4.62	4.70	4.70	4.70	4.70
GOC Bond Rate (3-5 yrs.) (%)	1.35	1.35	1.31	1.49	1.59	1.72	2.08	2.39	2.48	2.63	2.73	2.90	3.14	3.35	3.59	3.79	4.00	4.26	4.47	4.71	4.84	4.85	4.85	4.85
GOC Ten-Year Bond Rate (%)	2.05	1.87	1.75	1.78	1.85	2.02	2.52	2.84	2.88	2.95	2.99	3.13	3.33	3.52	3.75	3.92	4.12	4.37	4.57	4.81	4.99	5.01	5.01	5.01
US Ten-Year T-Note Rate (%)	2.04	1.82	1.60	1.63	1.70	1.87	2.37	2.69	2.73	2.80	2.84	2.98	3.18	3.37	3.60	3.77	3.97	4.22	4.42	4.66	4.84	4.86	4.86	4.86
US Real GDP (Bil. 2005 $)	13506.4	13564.5	13616.1	13668.9	13733.3	13798.1	13864.4	13949.4	14038.6	14151.1	14275.3	14411.6	14526.1	14648.8	14766.0	14871.8	14978.8	15086.0	15195.7	15303.8	15405.1	15508.1	15608.4	15712.6
Annual % Ch.	2.0	1.7	1.5	1.6	1.9	1.9	1.9	2.5	2.6	3.2	3.6	3.9	3.2	3.4	3.2	2.9	2.9	2.9	2.9	2.9	2.7	2.7	2.6	2.7
Household Credit (Billion $)	1608.6	1629.3	1651.7	1675.8	1701.3	1728.1	1755.8	1784.2	1813.1	1842.2	1871.4	1900.5	1929.4	1958.0	1986.3	2014.1	2041.6	2068.6	2095.0	2120.8	2146.1	2170.8	2195.1	2219.2
Annual % Ch.	5.2	5.3	5.6	6.0	6.2	6.4	6.6	6.6	6.6	6.6	6.5	6.4	6.2	6.1	5.9	5.7	5.6	5.4	5.2	5.0	4.8	4.7	4.6	4.5
ExCh. Rate (Can-US)	1.00	0.99	1.00	1.00	0.98	0.97	0.97	0.96	0.95	0.94	0.94	0.94	0.93	0.92	0.92	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.90	0.90
ExCh. Rate (US-Can.)	99.9	99.0	100.1	100.3	98.3	97.3	96.6	95.9	95.3	94.4	93.7	93.5	92.7	92.4	91.7	91.3	91.0	91.1	91.2	91.4	91.0	90.8	90.5	90.4
Curr. Acct. Bal. (Billion $)	-40.6	-64.1	-46.9	-44.3	-44.8	-43.6	-43.4	-39.7	-38.5	-37.1	-35.1	-29.9	-28.2	-27.1	-25.1	-23.5	-22.1	-15.3	-13.4	-12.0	-10.3	-6.7	-4.3	-1.5

Table 24 - IHS Global Insight																								
Interest Rates																								
(Percent)																								
Overnight Money	1.00	1.00	1.00	1.00	1.00	1.00	1.08	1.33	1.67	1.92	2.17	2.42	2.75	3.00	3.25	3.50	3.75	4.00	4.25	4.50	4.50	4.50	4.50	4.50
Bank Rate	1.25	1.25	1.25	1.25	1.25	1.25	1.33	1.58	1.92	2.17	2.42	2.67	3.00	3.25	3.50	3.75	4.00	4.25	4.50	4.75	4.75	4.75	4.75	4.75
Government of Canada																								
Treasury Bills																								
3 Months	0.91	0.98	1.01	1.03	1.03	1.06	1.13	1.42	1.63	1.93	2.17	2.39	2.73	3.00	3.25	3.50	3.75	4.00	4.25	4.50	4.50	4.50	4.50	4.50
6 Months	0.98	1.05	1.09	1.14	1.14	1.17	1.24	1.53	1.74	2.04	2.28	2.50	2.84	3.11	3.36	3.61	3.86	4.11	4.36	4.61	4.61	4.61	4.61	4.61
Bonds																								
1-3 Years	1.11	1.17	1.10	1.23	1.36	1.44	1.69	1.99	2.13	2.34	2.50	2.69	2.97	3.21	3.45	3.67	3.90	4.15	4.38	4.62	4.70	4.70	4.70	4.70
3-5 Years	1.35	1.35	1.31	1.49	1.59	1.72	2.08	2.39	2.48	2.63	2.73	2.90	3.14	3.35	3.59	3.79	4.00	4.26	4.47	4.71	4.84	4.85	4.85	4.85
5 Years	1.46	1.40	1.34	1.51	1.62	1.75	2.12	2.43	2.52	2.66	2.76	2.92	3.16	3.37	3.61	3.80	4.01	4.27	4.48	4.72	4.85	4.86	4.86	4.86
5-10 Years	1.77	1.65	1.56	1.70	1.78	1.94	2.40	2.72	2.77	2.86	2.92	3.06	3.28	3.47	3.71	3.88	4.09	4.34	4.54	4.78	4.95	4.97	4.97	4.97
10 Years	2.05	1.87	1.75	1.78	1.85	2.02	2.52	2.84	2.88	2.95	2.99	3.13	3.33	3.52	3.75	3.92	4.12	4.37	4.57	4.81	4.99	5.01	5.01	5.01
10+ Years	2.53	2.33	2.18	2.19	2.26	2.41	2.90	3.21	3.24	3.30	3.34	3.47	3.66	3.84	4.07	4.24	4.43	4.69	4.88	5.12	5.30	5.31	5.31	5.31
30 Years	2.64	2.43	2.29	2.30	2.36	2.51	2.99	3.30	3.33	3.39	3.43	3.55	3.75	3.93	4.16	4.32	4.51	4.76	4.95	5.19	5.37	5.39	5.38	5.38

Table 25 - IHS Global Insight Financial Aggregates and US Interest Rates																								
Sep 11 2012	12Q1	12Q2	12Q3	12Q4	13Q1	13Q2	13Q3	13Q4	14Q1	14Q2	14Q3	14Q4	15Q1	15Q2	15Q3	15Q4	16Q1	16Q2	16Q3	16Q4	17Q1	17Q2	17Q3	17Q4
Federal Funds	0.10	0.15	0.14	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.36	0.89	1.36	1.88	2.42	2.96	3.46	3.86	4.00	4.00	4.00
3-Month T-Bills	0.07	0.09	0.10	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.17	0.46	0.95	1.43	1.93	2.43	2.92	3.35	3.66	3.74	3.74	3.74
3-Month Comm. Paper	0.16	0.20	0.21	0.23	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.27	0.55	1.06	1.54	2.06	2.59	3.12	3.58	3.95	4.04	4.04	4.04
3-Month Euro Deposit Rate	0.51	0.47	0.43	0.43	0.44	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.48	0.76	1.16	1.64	2.19	2.74	3.28	3.76	4.15	4.25	4.25	4.25
Bank Prime Rate	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.37	3.90	4.36	4.88	5.42	5.96	6.46	6.86	7.00	7.00	7.00
5-year Treasury Notes	0.90	0.79	0.65	0.68	0.82	1.02	1.22	1.37	1.40	1.47	1.52	1.55	1.67	1.91	2.31	2.73	3.21	3.64	4.04	4.35	4.45	4.46	4.46	4.46
10-Year Treasury Notes	2.04	1.82	1.60	1.63	1.70	1.87	2.37	2.69	2.73	2.80	2.84	2.98	3.18	3.37	3.60	3.77	3.97	4.22	4.42	4.66	4.84	4.86	4.86	4.86
30-year Treasury Bonds	3.14	2.94	2.69	2.74	2.81	2.93	3.39	3.76	3.81	3.90	3.95	4.01	4.05	4.10	4.24	4.39	4.59	4.82	4.98	5.19	5.39	5.40	5.40	5.40
Moody Aaa Seas Bonds	3.90	3.80	3.44	3.49	3.63	3.85	4.21	4.39	4.45	4.51	4.56	4.70	4.87	5.04	5.23	5.36	5.54	5.70	5.87	6.02	6.21	6.26	6.26	6.26
Canada-US Rate Differentials (Unadjusted)																								
3-Month T-Bills	0.85	0.90	0.91	0.91	0.91	0.94	1.01	1.30	1.51	1.81	2.05	2.28	2.57	2.54	2.30	2.07	1.82	1.57	1.33	1.15	0.84	0.76	0.76	0.76
3-Month Comm. Paper	0.99	0.96	0.93	0.92	0.91	0.94	1.02	1.30	1.51	1.82	2.05	2.28	2.59	2.58	2.31	2.09	1.82	1.53	1.26	1.05	0.68	0.59	0.59	0.59
3-Month Euro Deposit Rate	0.84	0.81	0.67	0.69	0.68	0.70	0.77	1.06	1.27	1.57	1.81	2.04	2.35	2.33	2.18	1.95	1.65	1.35	1.06	0.83	0.44	0.34	0.34	0.34
Bank Prime Rate	-0.25	-0.25	-0.25	-0.25	-0.25	-0.25	-0.17	0.08	0.42	0.67	0.92	1.17	1.50	1.63	1.35	1.14	0.87	0.58	0.29	0.04	-0.36	-0.50	-0.50	-0.50
10-Year Govt. Bond Rate	0.01	0.05	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Long-Term Corp. Bonds	-0.61	-0.66	-0.26	-0.29	-0.38	-0.44	-0.31	-0.18	-0.21	-0.21	-0.22	-0.23	-0.21	-0.19	-0.16	-0.12	-0.10	-0.01	0.00	0.10	0.09	0.05	0.05	0.05

Conference Board Sept 19 2019

	2008-Q1	2008-Q2	2008-Q3	2008-Q4	2009 Q1	2009 Q2	2009 Q3	2009 Q4	2010-Q1	2010-Q2	2010-Q3	2010-Q4	2011-Q1	2011-Q2	2011-Q3	2011-Q4	2012-Q1	2012-Q2	2012-Q3	2012-Q4
Cdn GDP Price Deflator	1.20	1.23	1.24	1.20	1.18	1.18	1.19	1.21	1.22	1.22	1.22	1.24	1.26	1.27	1.27	1.28	1.28	1.28	1.29	1.29
% chge					-1.4	-3.4	-3.6	0.9	3.3	3.0	2.6	2.8	3.0	3.7	3.7	3.3	2.1	1.0	1.3	1.0
Cdn CPI	1.12	1.15	1.16	1.14	1.14	1.15	1.15	1.15	1.15	1.16	1.17	1.17	1.18	1.20	1.20	1.21	1.21	1.22	1.22	1.23
% chge					1.2	0.1	-0.9	0.8	1.6	1.4	1.8	2.3	2.6	3.4	3.0	2.7	2.3	1.6	1.6	2.0
Cdn Long Bond rate	4.11	4.08	4.10	3.89	3.72	3.97	3.93	3.96	4.03	3.79	3.52	3.56	3.74	3.59	3.09	2.74	2.64	2.43	2.32	2.37
Cdn T-Bill Rate	2.91	2.71	2.27	1.67	0.71	0.23	0.23	0.22	0.21	0.47	0.74	0.97	0.96	0.95	0.91	0.86	0.91	0.98	1.01	1.03
Cdn$/US$	1.00	1.01	1.04	1.21	1.25	1.17	1.10	1.06	1.04	1.03	1.04	1.01	0.99	0.97	0.98	1.02	1.00	1.01	0.99	0.97
US T-Bill Rate %	2.09	1.65	1.52	0.30	0.22	0.17	0.16	0.06	0.11	0.15	0.16	0.14	0.13	0.05	0.02	0.01	0.07	0.09	0.12	0.08
US Long Bond Rate	4.41	4.58	4.45	3.68	3.45	4.17	4.32	4.33	4.62	4.37	3.85	4.16	4.56	4.34	3.70	3.04	3.14	2.94	2.87	2.78
US GDP Price Deflator	107.6	108.3	109.1	109.2	109.5	109.3	109.5	109.8	110.2	110.7	111.2	111.8	112.4	113.1	113.9	114.0	114.6	115.1	115.6	116.2
% chge					1.8	1.0	0.3	0.5	0.6	1.3	1.6	1.8	2.0	2.2	2.4	2.0	2.0	1.7	1.5	1.9
Cdn 10 Yr Bond rate	3.72	3.66	3.66	3.26	2.96	3.37	3.41	3.43	3.45	3.33	2.93	3.08	3.31	3.15	2.52	2.16	2.05	1.87	1.73	1.80

	2013-Q1	2013-Q2	2013-Q3	2013-Q4	2014-Q1	2014-Q2	2014-Q3	2014-Q4	2015-Q1	2015-Q2	2015-Q3	2015-Q4	2016-Q1	2016-Q2	2016-Q3	2016-Q4	2017-Q1	2017-Q2	2017-Q3	2017-Q4
Cdn GDP Price Deflator	1.30	1.31	1.31	1.32	1.33	1.34	1.34	1.35	1.36	1.37	1.37	1.38	1.39	1.39	1.40	1.41	1.42	1.42	1.43	1.43
% chge	1.6	2.3	2.3	2.0	2.0	2.2	2.2	2.2	2.2	2.2	2.3	2.2	2.2	2.1	2.0	2.1	2.0	1.9	1.8	1.8
Cdn CPI	1.24	1.24	1.25	1.26	1.27	1.27	1.28	1.29	1.29	1.30	1.31	1.31	1.32	1.33	1.33	1.34	1.35	1.35	1.36	1.37
% chge	2.2	2.0	2.4	2.3	2.2	2.2	2.2	2.2	2.1	2.1	2.1	2.1	2.1	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Cdn Long Bond rate	2.29	2.22	2.20	2.21	2.25	2.28	2.33	2.41	2.52	2.64	2.78	2.92	3.07	3.24	3.41	3.58	3.69	3.78	3.86	3.93
Cdn T-Bill Rate	0.99	0.97	1.03	1.18	1.37	1.48	1.64	1.83	2.08	2.32	2.56	2.81	3.05	3.30	3.55	3.80	3.84	3.84	3.84	3.85
Cdn$/US$	0.97	0.97	0.97	0.96	0.96	0.96	0.96	0.95	0.95	0.95	0.95	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98
US T-Bill Rate %	0.05	0.03	0.01	0.04	0.04	0.03	0.04	0.04	0.04	0.04	0.17	0.55	0.94	1.35	1.78	2.34	2.66	3.11	3.42	3.48
US Long Bond Rate	2.70	2.62	2.55	2.48	2.42	2.36	2.30	2.25	2.20	2.15	2.15	2.25	2.37	2.51	2.67	2.90	3.05	3.27	3.45	3.55
US GDP Price Deflator	116.8	117.3	117.9	118.5	119.2	119.8	120.5	121.1	121.8	122.5	123.1	123.8	124.5	125.2	125.8	126.5	127.3	127.9	128.6	129.2
% chge	1.9	2.0	2.0	2.0	2.1	2.1	2.1	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.1
Cdn 10 Yr Bond rate	1.77	1.75	1.76	1.82	1.90	1.96	2.05	2.16	2.30	2.45	2.61	2.78	2.96	3.14	3.33	3.53	3.63	3.72	3.80	3.87

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Canada: Major Indicators

IL Reference October 1, 2012		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
GDPMP	GDP Deflator (Chained, 1997=1)	1.38	1.41	1.44	1.46	1.49	1.52	1.56	1.59	1.62	1.65	1.68	1.71	1.75	1.78	1.82	1.85	1.89	1.92	1.96
gdpmp#p	Inflation (% change year-to-year)	1.9	2.2	2	1.7	1.7	2.2	2.4	2	2	1.8	1.8	1.9	2.1	2.1	2	1.9	1.9	1.7	1.9
CPITLI	Consumer Price Index (1992=100)	144.5	147.39	150.34	153.35	156.41	159.54	162.73	165.99	169.31	172.69	176.15	179.67	183.26	186.93	190.67	194.48	198.37	202.34	206.38
cpitli#p	Inflation (% change year-to-year)	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
TOLWAR	Wage & Salary Rate ($000 nominal per emplo	44.42	44.74	45.38	45.44	46.33	48.85	50.66	52.18	53.63	55.01	56.38	57.95	59.75	61.71	63.66	65.44	67.14	68.68	70.42
TOTULC	Unit Labour Costs (Nominal Labour Income pe	0.75	0.74	0.74	0.73	0.73	0.76	0.78	0.8	0.81	0.82	0.84	0.85	0.87	0.89	0.9	0.92	0.93	0.94	0.95
ITGSBP	Import Price Deflator (Chained, 1997=1)	1	1	1.02	1.05	1.07	1.08	1.1	1.12	1.13	1.15	1.17	1.19	1.21	1.23	1.25	1.27	1.29	1.31	1.33
termmr	Merchandise Terms of Trade (1997=1)	1.34	1.35	1.34	1.35	1.34	1.35	1.35	1.36	1.36	1.36	1.36	1.36	1.36	1.36	1.36	1.36	1.36	1.36	1.36
EOWGO6	International Crude Oil Price (WTI $U.S. per bl	79.34	81.42	83.96	86.92	90.16	93.47	96.87	100.45	104.34	108.46	112.56	116.58	120.64	124.86	129.32	133.79	138.06	142.13	146.3
REXCUR	Exchange Rate ($Can per $U.S.)	1	0.98	0.99	1	1	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
rrxcur	Real Exchange Rate [2]	0.91	0.89	0.9	0.9	0.91	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.91	0.91
rexrcr	Exchange Rate (cents U.S. per $Can)	99.6	101.8	101.1	100.5	100.2	100.7	100.7	100.7	100.7	100.7	100.7	100.7	100.7	100.7	100.7	100.7	100.7	100.7	100.7
PCP90I	Commercial Paper - 90 day (%)	1.2	1.8	2.8	3.9	4.4	3	3	3	3	3	3	3	3	3	3	3	3	3	3
INDLBI	AAA Industrial Bonds	3.8	4.3	5.1	5.7	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9
FGVLBI	Government of Canada Bonds (10+ years)	2.2	2.8	3.6	4.3	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
FGVLBR	10+ Years Canada Bonds (real [3])	0.3	1.3	1.3	2.3	2.6	2.5	2.5	2.5	2.4	2.4	2.5	2.6	2.6	2.5	2.5	2.5	2.5	2.6	2.6
INDLBR	AAA Industrial Bonds (real)	2	2.8	2.8	3.7	4	3.9	3.9	3.9	3.8	3.8	3.9	4	4	3.9	3.9	3.9	3.9	4	4

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United States: Basic Indicators

IL Reference October 1, 2012		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
IFEDRU	Federal Funds Rate	0.2	0.2	0.4	1.78	3.71	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25
ICP6RU	Commercial Paper Rate, 6 Month	0.87	0.87	1.07	2.45	4.38	4.92	4.92	4.92	4.92	4.92	4.92	4.92	4.92	4.92	4.92	4.92	4.92	4.92
IT10RU	Yield on 10-yr Treasury Notes	2.8	2.4	3.3	4.1	4.7	5.3	5.3	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
IAAARU	AAA Corporate Bond Yield	4.6	4.2	4.9	5.5	6.0	6.4	6.5	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4

PUB/CENTRA I-7

Subject: **Tab 4 Integrated Financial Forecast & Economic Outlook**

Reference: **Tab 4 Pages 5 and 6 of 7 - IFRS**

The Canadian Accounting Standards Board (AcSB) recently announced an additional deferral to implement IFRS until 2015/16 including signaling the intention to issue an Interim standard that will "grandfather" rate regulated accounting.

a) Assuming such a standard is issued as indicated, please discuss how these developments impact the current rate application and the forecast provided in CGM12.

ANSWER:

Assuming the IASB issues an interim standard that permits rate regulated entities to continue to apply their current rate-regulated accounting practices (i.e. grandfather), there would be no change to Centra's current rate application. The 2013/14 Test Year is not impacted by IFRS. As indicated in Tab 2, pages 5 to 6 of the Application, 2013/14 is projected to result in a net loss of $1 million absent the requested rate increase as a result of factors such as normal annual cost escalation, continuing conservation measures by customers, and two consecutive years (2011/12 and 2012/13) of no general rate increases.

With respect to the impact on the forecast provided in CGM12, Centra is unable to fully assess the potential impacts given that the exposure draft of the interim standard has yet to be issued. Please see the response to PUB/CENTRA I-7(c) for the scenario assuming an additional one year deferral of the transition to IFRS and the continued application of rate-regulated accounting through to the end of the forecast.

PUB/CENTRA I-7

Subject: **Tab 4 Integrated Financial Forecast & Economic Outlook**

Reference: **Tab 4 Pages 5 and 6 of 7 - IFRS**

The Canadian Accounting Standards Board (AcSB) recently announced an additional deferral to implement IFRS until 2015/16 including signaling the intention to issue an Interim standard that will "grandfather" rate regulated accounting.

b) Please file an updated CGM12 scenario including additional line items quantifying the net impact of accounting changes reflected in the IFF.

ANSWER:

Please see the following schedules:

Schedule A presents the net impacts of accounting changes by operating statement line item under CGAAP and IFRS. Schedule B presents the net impacts of the accounting changes to Retained Earnings. Please note that at the time of the preparation of CGM12, it was assumed that IFRS would be implemented during the 2014/15 fiscal year.

Narratives referencing the changes are provided following schedules A & B.

Schedules C & D reflect the impact of the accounting changes in the income statement and balance sheet of CGM12, respectively.

SCHEDULE A - CENTRA GAS ACCOUNTING CHANGES - CGM12

	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Forecast --> 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Ref
Gas only (in millions of $'s)															
OM&A															
CGAAP Changes															
Intangibles															
DSM (research & promotion)	1	1	1	1	1	1	1	1	1	1	1	1	1	1	**1**
Total	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Overhead Capitalized															
Admin & General Overhead			2	2	5	5	5	5	5	5	6	6	6	6	**2**
Total	-	-	2	2	5	5	5	5	5	5	6	6	6	6	
Change in Discount Rate on Pension & Other Benefits					1	1	1	1	1	1	1	1	1	1	**3**
Operating Expense Recoveries (Reclassification)					1	1	1	1	1	1	1	1	1	1	**4**
Total CGAAP Changes	**1**	**1**	**3**	**3**	8	8	8	8	8	8	8	9	9	9	
IFRS Changes															
DSM*							8	7	7	5	4	3	3	3	**5**
Regulatory Costs*							1	-	1	1	1	1	1	1	**5**
Admin & General Overhead							2	2	2	2	2	2	2	2	**6**
Meter Changes							(5)	(5)	(5)	(5)	(5)	(6)	(6)	(6)	**7**
Total IFRS Changes						-	6	4	5	3	2	0	0	0	
Total OM&A Accounting Changes	**1**	**1**	**3**	**3**	**8**	**8**	**14**	**12**	**13**	**11**	**10**	**9**	**9**	**9**	

*** Rate-regulated account**

SCHEDULE A - CENTRA GAS ACCOUNTING CHANGES - CGM12 cont'd	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Forecast --> 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Ref
DEPRECIATION EXPENSE															
CGAAP Changes															
Average Service Life				(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	**8**
Total CGAAP Changes	-	-	-	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	
IFRS Changes															
Reduction in Rate Regulated Assets*							(9)	(9)	(9)	(9)	(9)	(9)	(8)	(7)	**5**
Increase for Meter Changes							-	-	-	-	-	1	1	1	**7**
Change to Equal Life Group Depreciation Method							2	2	3	3	3	3	3	3	**9**
Removal of Net Salvage from depreciation rates							(5)	(5)	(5)	(6)	(6)	(6)	(6)	(6)	**10**
Total IFRS Changes	-	-	-	-	-	-	(12)	(12)	(11)	(12)	(12)	(11)	(10)	(9)	
Total Depreciation Expense Accounting Changes	-	-	-	**(1)**	**(1)**	**(1)**	**(13)**	**(13)**	**(12)**	**(13)**	**(13)**	**(12)**	**(11)**	**(10)**	
FINANCE EXPENSE															
CGAAP Changes															
IFRS Changes*							2	2	2	2	1	1	1	1	**11**
Total Finance Expense Accounting Changes	-	-	-	-	**-**	**-**	**2**	**2**	**2**	**2**	**1**	**1**	**1**	**1**	
CAPITAL & OTHER TAX EXPENSE															
CGAAP Changes															
IFRS Changes*							(4)	(4)	(4)	(3)	(3)	(3)	(3)	(3)	**11**
Total Tax Expense Accounting Changes	-	-	-	-	**-**	**-**	**(4)**	**(4)**	**(4)**	**(3)**	**(3)**	**(3)**	**(3)**	**(3)**	

*** Rate-regulated account**

SCHEDULE B - CENTRA GAS ACCOUNTING CHANGES IMPACT TO RETAINED EARNINGS - CGM12

Gas only (in millions of $'s)	Actual	Actual	Actual	Actual	Forecast -->										
IMPACT TO RETAINED EARNINGS	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	**Total**
CGAAP Changes															
Retrospective adjustment for intangible Assets		(2)													**(2)**
Annual change to OM&A	(1)	(1)	(3)	(3)	(7)	(7)	(7)	(7)	(8)	(8)	(8)	(8)	(8)	(8)	**(84)**
Annual change to Depreciation & Amortization	-	-	-	1	1	1	1	1	1	1	1	1	1	1	**11**
Total CGAAP changes	**(1)**	**(3)**	**(3)**	**(2)**	**(6)**	**(6)**	**(6)**	**(6)**	**(7)**	**(7)**	**(7)**	**(7)**	**(7)**	**(7)**	**(75)**
IFRS Changes															
Annual change to OM&A	-	-	-	-	-	-	(6)	(4)	(5)	(3)	(2)	(0)	(0)	(0)	**(20)**
Annual change to Depreciation & Amortization	-	-	-	-	-	-	12	12	11	12	12	11	10	9	**90**
Annual change to Finance & Taxes	-	-	-	-	-	-	2	2	2	1	2	2	2	2	**15**
Write Offs to:															
Power Smart Programs							(48)								**(48)**
Site Remediation							(2)								**(2)**
Regulatory Costs							(1)								**(1)**
Deferred Taxes							(27)								**(27)**
Administrative Overhead (2013/14)							(2)								**(2)**
Removal of Net Salvage Depreciation (2013/14)							5								**5**
Change to Equal Life Group Depreciation (2013/14)							(2)								**(2)**
Total IFRS changes	**-**	**-**	**-**	**-**	**-**		**(69)**	**10**	**8**	**10**	**12**	**13**	**12**	**11**	**7**
Total Annual Impact to Retained Earnings	**(1)**	**(3)**	**(3)**	**(2)**	**(6)**	**(6)**	**(76)**	**4**	**2**	**4**	**6**	**6**	**5**	**4**	**(68)**

Reference	Description	Accounting Handbook Reference
1	The OM&A adjustments for intangible assets under CGAAP reflect a change (new section 3064 Goodwill and Intangible Assets) in the Canadian accounting standards for Goodwill and Intangible assets that was effective for MH April 1, 2009. The new standard was harmonized with IFRS and required research and promotional costs to be expensed as incurred with retrospective application. Approximately $2 million was adjusted to retained earnings in fiscal 2009/10 for research and promotional costs included in opening intangible asset balances. Effective April 1, 2009 and forward, research and promotional costs associated with intangible assets are expensed as incurred	**CGAAP – Section 3064 Goodwill and Intangible Assets** .37 No intangible asset arising from research (or from the research phase of an internal project) should be recognized. Expenditure on research (or on the research phase of an internal project) should be recognized as an expense when it is incurred. [OCT. 2008] .52 In some cases, expenditure is incurred to provide future economic benefits to an entity, but no intangible asset or other asset is acquired or created that can be recognized,…,Other examples of expenditure that is recognized as an expense when it is incurred include expenditure on: (a) start-up activities (i.e., start-up costs) (b) training activities (c) advertising and promotional activities.
2	The reduction in administrative and general overhead capitalized reflects adjustments made under CGAAP to become more consistent with other Canadian utilities. The adjustments result in the following: • an annual increase in operating and administrative expense; • reductions in plant asset values for amounts no longer capitalized; and • reductions in depreciation expense as a result of reduced asset values.	**CGAAP – Section 3061 Property, plant & equipment:** .20 The cost of an item of property, plant and equipment includes direct construction or development costs (such as materials and labour), and overhead costs directly attributable to the construction or development activity.

Reference	Description	Accounting Handbook Reference
3	The increase in the pension and employee benefits cost is a result of a reduction in the 2011/12 discount rate and the corresponding increase in current service cost for employee benefits.	**CGAAP – Section 3461 Employee Future Benefits:** .50 For a defined benefit plan, the discount rate used to determine the accrued benefit obligation should be an interest rate determined by reference to: (a) market interest rates at the measurement date on high-quality debt instruments with cash flows that match the timing and amount of expected benefit payments; or (b) the interest rate inherent in the amount at which the accrued benefit obligation could be settled. [JAN. 2000] .54. The discount rate is re-evaluated at each measurement date. When long-term interest rates rise or decline, the discount rate changes in a similar manner.
4	The adjustments for operating expense recoveries are to comply with the financial reporting requirements of IFRS. Revenues that were once netted against operating costs for financial reporting will be reported as revenue in the future as IFRS generally does not permit netting of revenues and expenses.	**IFRS - IAS 1 Presentation of Financial Statements:** . 32 - An entity shall not offset assets and liabilities or income and expenses, unless required or permitted by an IFRS.
5	IFF 12 assumes rate-regulated accounting is not permitted under IFRS and thus, rate-regulated accounting will be eliminated upon transition. The impacts of this assumption are as follows • upon transition to IFRS, a one-time adjustment to retained earnings will be made for unamortized rate-regulated account balances; • future expenditures on these items will be expensed as incurred resulting in an annual increase to operating and administrative	Unlike CGAAP and US GAAP, currently, there is no specific IFRS standard that permits rate-regulated accounting. Generally, the application of the existing IFRS framework has not resulted in the recognition of regulatory assets and liabilities. Recently, the IASB has re-initiated its project on rate regulated accounting and plans to issue a draft interim standard permitting rate regulated entities, that will be adopting IFRS for the first time, to continue to apply their existing rate-

Reference	Description	Accounting Handbook Reference
	expense; and • a reduction to depreciation and amortization for previously deferred regulatory accounts.	regulated accounting practices until the IASB's project is complete. This decision by the IASB was made subsequent to the completion of IFF12.
6	The reduction in administrative and general overhead capitalized reflects adjustments to comply with IFRS upon transition. IFRS does not permit the capitalization of general administrative and overhead costs. The adjustments result in the following: • an annual increase in operating and administrative expense; • reductions in plant asset values for amounts no longer capitalized; and • reductions in depreciation expense as a result of reduced asset values.	**IFRS - IAS 16 Property, plant & equipment:** .19 Examples of costs that are not costs of an item of property, plant and equipment are:,… (d) administration and other general overhead costs.
7	CGM12 assumed that upon transition to IFRS, Centra would commence capitalization of the labour costs associated with meter exchange activities. This potential accounting treatment is being driven by the requirement under IFRS to harmonize the accounting policies of a parent company and its subsidiaries. Manitoba Hydro currently capitalizes such costs. This potential change is in the preliminary review stage and additional work is required with respect to the interpretation of the IFRS standards as well as a review of industry practices expected upon conversion to IFRS. The adjustments result in the following: • an annual decrease in operating and administrative expense;	**IFRS 10 Consolidated Financial Statements** 19 . A parent shall prepare consolidated financial statements using uniform accounting policies for like transactions and other events in similar circumstances. **Uniform accounting policies** B87. If a member of the group uses accounting policies other than those adopted in the consolidated financial statements for like transactions and events in similar circumstances, appropriate adjustments are made to that group member's financial statements in preparing the consolidated financial statements to ensure conformity with the group's accounting policies.

Reference	Description	Accounting Handbook Reference
	• increases in plant asset values for amounts capitalized; and • increases in depreciation expense as a result of the capitalization of such costs.	
8	The net result of the depreciation study under CGAAP and the average service life approach is an overall reduction in annual depreciation expense for Centra due to changes in the service lives for certain asset groups. This change is required to be implemented under Canadian GAAP.	**CGAAP – 3061 Property, plant & equipment:** .28 Amortization should be recognized in a rational and systematic manner appropriate to the nature of an item of property, plant and equipment with a limited life and its use by the enterprise. .33 The amortization method and estimates of the life and useful life of an item of property, plant and equipment should be reviewed on a regular basis. [DEC. 1990 *]
9	Upon adoption of IFRS, MH will be moving from the Average Service Life method of depreciation to the Equal Life Group method; increasing annual depreciation expense.	**IFRS - IAS 16 Property, plant & equipment:** The key IFRS reference supporting the move to the ELG method is: .43 Each part of an item of property, plant and equipment with a cost that is significant in relation to the total cost of the item shall be depreciated separately. .68 The gain or loss arising from the de-recognition of an item of property, plant and equipment shall be included in profit or loss when the item is de-recognised. Gains shall not be classified as revenue.
10	Upon adoption of IFRS, MH will be removing the impact of net salvage from depreciation rates; decreasing annual depreciation expense.	-The Inclusion of net salvage in depreciation rates is a regulatory practice applied under CGAAP by Canadian utilities. Given that IFRS does not have a standard that

Reference	Description	Accounting Handbook Reference
		permits rate-regulated accounting, it was assumed in CGM12 that the practice of including negative salvage in depreciation rates would be discontinued upon transition to IFRS. -Recently, the IASB has re-initiated its project on rate regulated accounting and plans to issue a draft interim standard permitting rate regulated entities,that will be adopting IFRS for the first time, to continue to apply their existing rate-regulated accounting practices until the IASB's project is complete. This decision by the IASB was made subsequent to the completion of IFF12.
11	The changes to finance expense and capital and other taxes reflects primarily the elimination of the annual deferral of the carrying charges on the Centra Deferred Tax balance and the elimination of the annual amortization of the Deferred Tax balance upon transition to IFRS.	Unlike CGAAP and US GAAP, currently, there is no specific IFRS standard that permits rate-regulated accounting. Generally, the application of the existing IFRS framework has not resulted in the recognition of regulatory assets and liabilities. The deferral of the carrying charges on the Centra Deferred Tax balance and the amortization of the Deferred Tax balance was a regulatory accounting practice that is currently not permitted under IFRS. Recently, the IASB has re-initiated its project on rate regulated accounting and plans to issue a draft interim standard permitting rate regulated entities, that will be adopting IFRS for the first time, to continue to apply their existing rate-regulated accounting practices until the IASB's project is complete. This decision by the IASB was made subsequent to the completion of IFF12.

SCHEDULE C - ACCOUNTING CHANGES - IMPACT ON CGM12

GAS OPERATIONS (CGM12)
PROJECTED OPERATING STATEMENT
Net Impact of Accounting Changes
(In Millions of Dollars)

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
REVENUES										
General Consumers										
at approved rates	319	312	356	351	349	348	349	349	350	350
additional*	0	7	7	7	7	9	11	13	15	18
	319	319	363	358	356	357	360	362	365	368
Cost of Gas Sold	176	168	212	203	202	201	201	201	201	201
Gross Margin	143	151	151	155	154	156	159	161	164	167
Other	1	1	1	1	1	1	1	1	1	1
CGAAP Accounting Changes - reclassifications:	1	1	1	1	1	1	1	1	1	1
	145	**153**	**153**	**156**	**156**	**158**	**161**	**163**	**166**	**169**
EXPENSES										
Operating and Administrative	59	61	63	65	65	67	69	70	72	73
CGAAP Accounting Changes:										
Changes to Intangibles - research & promotion	1	1	1	1	1	1	1	1	1	1
Reduction in Administrative and General Overhead Capitalized	5	5	5	5	5	5	6	6	6	6
Change in Discount Rate	1	1	1	1	1	1	1	1	1	1
Reclassifications	1	1	1	1	1	1	1	1	1	1
IFRS Accounting Changes:										
DSM & Regulatory Costs*			9	7	8	6	5	4	4	4
Reduction in Administrative and General Overhead Capitalized			2	2	2	2	2	2	2	2
Meter Changes			(5)	(5)	(5)	(5)	(5)	(6)	(6)	(6)
Finance Expense	18	17	19	20	21	23	24	25	26	27
IFRS Accounting Changes*			2	2	2	2	1	1	1	1
Depreciation and Amortization	29	31	33	34	34	35	36	35	35	35
CGAAP Accounting Changes - ASL:	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
IFRS Accounting Changes:										
Reduction for Regulatory Assets*			(9)	(9)	(9)	(9)	(9)	(9)	(8)	(7)
Increase for Meter Changes			-	-	-	-	-	1	1	1
Change to Equal Life Group Method			2	2	3	3	3	3	3	3
Removal of Net Salvage	-		(5)	(5)	(5)	(6)	(6)	(6)	(6)	(6)
Capital and Other Taxes	18	19	19	19	20	19	19	20	20	20
IFRS Accounting Changes*			(4)	(4)	(4)	(3)	(3)	(3)	(3)	(3)
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
	143	**147**	**144**	**147**	**151**	**153**	**155**	**158**	**161**	**165**
Net Income	**2**	**6**	**9**	**9**	**5**	**5**	**6**	**5**	**5**	**4**

*** Rate-regulated account**

SCHEDULE D - ACCOUNTING CHANGES - IMPACT ON CGM12

GAS OPERATIONS (CGM12)
PROJECTED BALANCE SHEET
Net Impact of Accounting Changes
(In Millions of Dollars)

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ASSETS										
Plant in Service	665	693	723	755	789	812	837	864	891	919
CGAAP Accounting Changes pre 2013:	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)
CGAAP Accounting changes	(5)	(10)	(15)	(20)	(25)	(31)	(36)	(42)	(48)	(54)
IFRS Accounting Changes:			1	4	7	11	14	18	21	25
Accumulated Depreciation	(234)	(243)	(255)	(266)	(277)	(290)	(303)	(316)	(330)	(345)
CGAAP Accounting Changes pre 2013:	1	1	1	1	1	1	1	1	1	1
CGAAP Accounting changes	1	2	3	4	5	6	7	8	9	10
IFRS Accounting Changes:			6	9	11	14	17	19	21	24
Net Plant in Service	**424**	**439**	**460**	**483**	**507**	**520**	**533**	**546**	**561**	**576**
Construction in Progress	2	2	2	2	2	4	6	8	8	8
Current and Other Assets	73	68	68	68	68	68	68	68	68	68
Goodwill and Intangible Assets	9	8	6	5	4	3	3	3	3	3
Regulated Assets	84	84	83	73	69	63	57	49	43	37
CGAAP Accounting Changes pre 2013:	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)
CGAAP Accounting changes	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
IFRS Accounting Changes:			(76)	(65)	(60)	(53)	(46)	(37)	(30)	(23)
Total Assets	**586**	**594**	**536**	**557**	**580**	**595**	**610**	**625**	**640**	**655**
LIABILITIES AND EQUITY										
Long-Term Debt	295	290	330	340	360	380	390	400	420	410
Current and Other Liabilities	99	96	67	69	68	56	57	57	48	69
Contributions in Aid of Construction	35	45	45	45	44	45	44	43	42	41
Share Capital	121	121	121	121	121	121	121	121	121	121
Retained Earnings	51	62	70	75	78	81	80	80	81	81
CGAAP Accounting Changes pre 2013:	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)
CGAAP Accounting Changes:	(6)	(12)	(18)	(25)	(31)	(38)	(45)	(52)	(59)	(66)
IFRS Accounting Changes:			(69)	(59)	(51)	(41)	(28)	(16)	(4)	7
Total Liabilities & Equity	**586**	**594**	**536**	**557**	**580**	**595**	**610**	**625**	**640**	**655**

PUB/CENTRA I-7

Subject: **Tab 4 Integrated Financial Forecast & Economic Outlook**

Reference: **Tab 4 Pages 5 and 6 of 7 - IFRS**

The Canadian Accounting Standards Board (AcSB) recently announced an additional deferral to implement IFRS until 2015/16 including signaling the intention to issue an Interim standard that will "grandfather" rate regulated accounting.

c) Please file an updated CGM12 scenario reflecting the proposed grandfathering of rate regulated accounting under IFRS.

ANSWER:

Please see the attached statements that assume an additional one year deferral of IFRS to fiscal 2015/16, as well as the grandfathering of rate-regulated accounting throughout the forecast.

GAS OPERATIONS
PROJECTED OPERATING STATEMENT
PUB/Centra I-7 (c): CGM12 with IFRS Deferral to 2015/16 and Rate Regulated Accounting
(In Millions of Dollars)

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
REVENUES										
General Consumers										
at approved rates	319	312	356	351	349	348	349	349	350	350
additional revenue requirement*	0	7	7	7	7	9	11	13	15	18
	319	319	363	358	356	357	360	362	365	368
Cost of Gas Sold	176	168	212	203	202	201	201	201	201	201
Gross Margin	143	151	151	155	154	156	159	161	164	167
Other	2	2	2	2	2	2	2	2	2	2
	145	153	153	156	156	158	161	163	166	169
EXPENSES										
Operating and Administrative	67	69	71	70	71	73	74	76	77	79
Finance Expense	18	17	19	20	22	23	24	25	26	27
Depreciation and Amortization	28	30	31	30	31	32	32	33	32	33
Capital and Other Taxes	18	19	19	19	19	20	20	20	20	20
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
	143	147	152	151	155	159	162	165	167	171
Net Income	2	6	1	6	1	(1)	(1)	(2)	(1)	(2)

* Additional Revenue Requirement										
Percent Increase		2.00%	0.00%	0.00%	0.00%	0.50%	0.75%	0.50%	0.50%	0.75%
Cumulative Percent Increase		2.00%	2.00%	2.00%	2.00%	2.51%	3.28%	3.80%	4.31%	5.10%

GAS OPERATIONS
PROJECTED BALANCE SHEET
PUB/Centra I-7 (c): CGM12 with IFRS Deferral to 2015/16 and Rate Regulated Accounting
(In Millions of Dollars)

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ASSETS										
Plant in Service	656	679	704	732	764	786	809	832	857	883
Accumulated Depreciation	(232)	(240)	(250)	(255)	(262)	(271)	(281)	(291)	(301)	(312)
Net Plant in Service	424	439	454	477	502	515	528	541	556	571
Construction in Progress	2	2	2	2	2	4	6	8	8	8
Current and Other Assets	73	68	68	68	68	68	68	68	68	68
Goodwill and Intangible Assets	9	8	6	5	4	3	3	3	3	3
Regulated Assets	79	78	76	73	69	63	57	49	43	37
	586	594	607	625	645	653	662	669	678	687
LIABILITIES AND EQUITY										
Long-Term Debt	295	290	330	340	360	380	390	400	410	410
Current and Other Liabilities	99	96	68	70	69	58	58	59	60	71
Contributions in Aid of Construction	35	45	45	45	44	45	44	43	42	41
Share Capital	121	121	121	121	121	121	121	121	121	121
Retained Earnings	36	42	43	49	50	49	48	46	45	43
	586	594	607	625	645	653	662	669	678	687

PUB/CENTRA I-7

Subject: **Tab 4 Integrated Financial Forecast & Economic Outlook**

Reference: **Tab 4 Pages 5 and 6 of 7 - IFRS**

The Canadian Accounting Standards Board (AcSB) recently announced an additional deferral to implement IFRS until 2015/16 including signaling the intention to issue an Interim standard that will "grandfather" rate regulated accounting.

d) Please provide a further detailed schedule on the net amount, narrative description of each of the accounting changes and cite specific handbook sections for the scenario in (b).

ANSWER:

Please see Centra's response to PUB/Centra I-7(b).

PUB/CENTRA I-8

Subject: **Tab 4 Integrated Financial Forecast & Economic Outlook**

Reference: **Tab 4 Page 6 of 7 Table 4.2.1 - Retained Earnings**

a) Please update the comparison table assuming the continuation of rate regulated accounting. Please also include a comparison of the equity ratio (gas operations) on this basis.

ANSWER:

Please see the attached tables for a comparison assuming an additional one year deferral of IFRS and the continuation of rate-regulated accounting throughout the forecast. The statements for this scenario are provided in the response to PUB/Centra I-7(c).

Table 4.2.1 - Retained Earnings
CGM12 with 1 year IFRS Deferral and Rate Regulated Accounting Allowed
vs. CGM10

	2013	2014	2015	2020	2022
CGM12 Scenario	36	42	43	46	43
CGM10	48	53	56	73	82
Increase(Decrease)	(12)	(11)	(13)	(27)	(39)

Equity Ratio (Gas Operations) (PUB Methodology)
CGM12 with 1 year IFRS Deferral and Rate Regulated Accounting Allowed
vs. CGM10

	2013	2014	2015	2020	2022
CGM12 Scenario	34%	33%	32%	29%	28%
CGM10	32%	32%	32%	33%	N/A
Increase(Decrease)	2%	1%	0%	(4%)	N/A

PUB/CENTRA I-8

Subject: **Tab 4 Integrated Financial Forecast & Economic Outlook**

Reference: **Tab 4 Page 6 of 7 Table 4.2.1 - Retained Earnings**

b) Please discuss the implications on both retained earnings and net income assuming a continuation of rate-regulated accounting.

ANSWER:

As demonstrated in the response to PUB/Centra I-7(c), the continuation of rate-regulated accounting in the forecast results in a reduction of the annual net income of Centra. The continued annual amortization and tax charges associated with the rate-regulated account balances are greater than the annual reductions in operating and finance expense associated with deferring the annual spending on these balances, which result in the overall reduction of the annual net income. Comparing the continued rate regulated accounting scenario to CGM12, the cumulative reduction to net income (retained earnings) associated with the continued use of rate regulated accounting through to 2022 is $48 million as shown in the response to PUB/Centra I-7(c) and the following table:

Annual Net Income Comparison (In millions of dollars)	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**Cumulative Total**
PUB/CENTRA I-7 (c) results vs. CGM12											
Net income - continue with rate-regulated accounting	2	6	1	6	1	(1)	(1)	(2)	(1)	(2)	
Net Income - CGM12	2	6	9	9	5	5	6	6	5	4	
Difference	**-**	**-**	**(8)**	**(3)**	**(4)**	**(6)**	**(7)**	**(8)**	**(6)**	**(6)**	**(48)**

With respect to Retained Earnings, the fiscal 2022 retained earnings balance in the continued rate-regulated accounting scenario is $43 million which is $30 million greater than the CGM12 2022 retained earnings balance of $13 million. The $30 million difference represents the difference between the CGM12, 2014/15 $78 million one-time write-off of the rate regulated account balances upon transition to IFRS and the cumulative net income reduction of $48 million in the continued rate-regulated account scenario. This difference will be eroded over time as it represents a timing difference with respect to when the expenditures for the rate-regulated accounts will be recognized in income. That is, extending the continued rate-regulated accounting scenario beyond the 2022 period will ultimately result in a reduction to retained earnings of $78 million (by way of reduced annual net income) as presented in the one-time adjustment to CGM12.

PUB/CENTRA I-9

Subject: Tab 4 Integrated Financial Forecast & Economic Outlook

Reference: Tab 4 Appendix 4.1

a) Please provide the Spring 2013 Economic Outlook when available.

ANSWER:

Centra will file the Spring 2013 Economic Outlook when available.

PUB/CENTRA I-9(Revised)

Subject: **Tab 4 Integrated Financial Forecast & Economic Outlook**

Reference: **Tab 4 Appendix 4.1**

b) **Please indicate the financial impact of utilizing the updated variables in the Spring 2013 Economic Outlook on 2013/14 revenue requirement items.**

ANSWER:

The following table shows the financial impact on 2013/14 revenue requirement items associated with updating finance expense with the Spring 2013 Economic Outlook interest rates.

Centra Gas Manitoba Inc.
2013/14 General Rate Application

PUB/Centra I-9(b) (Revised)
June 14, 2013
($000)

Summary of Total Finance Expense
Comparison of Spring 2013 Economic Outlook Interest Rates with Original Application (IFF12)

	2013/14 Update	**2013/14 IFF12**	**2013/14 Difference**
Forecasted 3 Month Canadian T-Bill Interest Rate (exc. 1% PGF)	1.05%	1.30%	-0.25%
Forecasted CDOR03 Interest Rate (exc. 1% PGF)	1.35%	1.65%	-0.30%
Forecasted 10 Year+ Interest Rate (exc. 1% PGF)	3.50%	3.30%	0.20%
Interest on Long Term Debt	12,503	12,544	(41)
Interest on Short Term Debt	230	284	(54)
Total Interest on Debt	12,733	12,828	(95)
Add:			
Provincial Guarantee Fee	2,975	2,975	-
Amortization of Debt Discounts	-	-	-
Interest on Common Assets	2,990	3,020	(30)
Interest on Inventory	151	151	-
Total Additions	6,116	6,146	(30)
Deduct:			
Capitalized Interest	(111)	(113)	2
Carrying Costs on Deferred Taxes	(2,265)	(2,265)	-
Carrying Costs on Purchased Gas Variance Account	295	332	(37)
Other	328	368	(40)
Total Deductions	(1,753)	(1,678)	(75)
			-
Total Finance Expense	**17,096**	**17,296**	**(200)**

PUB/CENTRA I-10

Subject: **Tab 4 Integrated Financial Forecast & Economic Outlook**

Reference: **Tab 4 Appendix 4.2 CGM12**

a) Please re-file CGM12 including the financial targets based on the Board-approved methodology for debt to equity.

ANSWER:

Please note that while financial targets have been calculated for gas operations only on the following schedules, as requested, Manitoba Hydro's financial targets apply to consolidated operations only.

Please see the requested schedules below.

GAS OPERATIONS (CGM12)
PROJECTED OPERATING STATEMENT
PUB/Centra I-10 (a) - CGM12 with the Board Approved Equity Ratio
(In Millions of Dollars)

For the year ended March 31	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
REVENUES										
General Consumers										
at approved rates	319	312	356	351	349	348	349	349	350	350
additional revenue requirement*	0	7	7	7	7	9	11	13	15	18
	319	319	363	358	356	357	360	362	365	368
Cost of Gas Sold	176	168	212	203	202	201	201	201	201	201
Gross Margin	143	151	151	155	154	156	159	161	164	167
Other	2	2	2	2	2	2	2	2	2	2
	145	153	153	156	156	158	161	163	166	169
EXPENSES										
Operating and Administrative	67	69	77	77	78	78	79	79	81	82
Finance Expense	18	17	21	22	23	25	25	26	27	28
Depreciation and Amortization	28	30	20	21	22	22	23	23	24	25
Capital and Other Taxes	18	19	15	15	16	16	16	17	17	17
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
	143	147	144	147	151	153	155	158	161	165
Net Income	2	6	9	9	5	5	6	6	5	4
* Additional Revenue Requirement										
Percent Increase		2.00%	0.00%	0.00%	0.00%	0.50%	0.75%	0.50%	0.50%	0.75%
Cumulative Percent Increase		2.00%	2.00%	2.00%	2.00%	2.51%	3.28%	3.80%	4.31%	5.10%
Financial Ratios										
Equity Ratio (PUB Methodology)	34%	33%	27%	22%	22%	23%	23%	23%	23%	23%
Interest Coverage	1.09	1.32	1.43	1.42	1.21	1.21	1.23	1.22	1.17	1.15
Capital Coverage	1.23	0.07	1.02	0.63	0.49	0.63	0.65	0.65	0.62	0.62

GAS OPERATIONS (CGM12)
PROJECTED BALANCE SHEET
PUB/Centra I-10 (a) - CGM12 with the Board Approved Equity Ratio
(In Millions of Dollars)

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ASSETS										
Plant in Service	656	679	705	735	767	788	811	835	860	886
Accumulated Depreciation	(232)	(240)	(245)	(252)	(260)	(269)	(278)	(288)	(299)	(310)
Net Plant in Service	424	439	460	483	507	520	533	546	561	576
Construction in Progress	2	2	2	2	2	4	6	8	8	8
Current and Other Assets	73	68	68	68	68	68	68	68	68	68
Goodwill and Intangible Assets	9	8	6	5	4	3	3	3	3	3
Regulated Assets	79	78	-	-	-	-	-	-	-	-
	586	594	536	557	580	595	610	625	640	655
LIABILITIES AND EQUITY										
Long-Term Debt	295	290	330	340	360	380	390	400	420	410
Current and Other Liabilities	99	96	67	69	68	56	57	57	48	69
Contributions in Aid of Construction	35	45	45	45	44	45	44	43	42	41
Share Capital	121	121	121	121	121	121	121	121	121	121
Retained Earnings	36	41	(27)	(18)	(13)	(7)	(2)	4	9	13
	586	594	536	557	580	595	610	625	640	655

GAS OPERATIONS (CGM12)
PROJECTED CASH FLOW STATEMENT
PUB/Centra I-10 (a) - CGM12 with the Board Approved Equity Ratio
(In Millions of Dollars)

For the year ended March 31	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
OPERATING ACTIVITIES										
Cash Receipts from Customers	355	357	401	392	390	391	394	397	399	403
Cash Paid to Suppliers and Employees	(291)	(335)	(347)	(347)	(348)	(347)	(348)	(349)	(352)	(354)
Interest Paid	(19)	(19)	(20)	(21)	(23)	(24)	(25)	(26)	(26)	(27)
	45	3	33	23	20	20	21	22	21	21
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	60	30	40	10	20	20	10	10	20	10
Retirement of Long-Term Debt	(63)	-	(35)	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-
	(3)	30	5	10	20	20	10	10	20	10
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(37)	(39)	(33)	(37)	(40)	(32)	(33)	(33)	(34)	(34)
Other	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
	(37)	(39)	(33)	(38)	(41)	(34)	(34)	(34)	(34)	(35)
Net Increase (Decrease) in Cash	5	(7)	5	(4)	(1)	7	(2)	(3)	7	(4)
Cash at Beginning of Year	(13)	(9)	(15)	(10)	(15)	(16)	(9)	(12)	(14)	(7)
Cash at End of Year	(9)	(15)	(10)	(15)	(16)	(9)	(12)	(14)	(7)	(11)

PUB/CENTRA I-10

Subject: **Tab 4 Integrated Financial Forecast & Economic Outlook**

Reference: **Tab 4 Appendix 4.2 CGM12**

b) Please provide detailed supporting calculations (CGM12) for the debt to equity ratio based on the Board's approved methodology.

ANSWER:

Please see the schedule below.

For the year ended March 31

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
PUB METHODOLOGY DEBT TO EQUITY RATIO										
Average Gas Long-Term Debt	296	310	328	335	350	370	385	395	410	425
Average Gas Due to Parent	11	12	13	13	15	12	10	13	11	9
	307	322	340	348	365	382	395	408	421	434
Average CG Capital Stock	121	121	121	121	121	121	121	121	121	121
Average Retained Earnings	35	39	7	(22)	(15)	(10)	(4)	1	7	11
	156	160	128	99	106	111	117	123	128	132
Total Debt and Equity (PUB Methodology)	464	482	469	446	471	494	512	530	549	566
Equity Ratio	**34%**	**33%**	**27%**	**22%**	**22%**	**23%**	**23%**	**23%**	**23%**	**23%**

PUB/CENTRA I-10

Subject: **Tab 4 Integrated Financial Forecast & Economic Outlook**

Reference: **Tab 4 Appendix 4.2 CGM12**

c) Please provide detailed supporting calculations for CGM12 for the interest coverage and capital coverage ratios.

ANSWER:

Please note that while financial targets have been calculated for gas operations only on the following schedule, as requested, Manitoba Hydro's financial targets apply to consolidated operations only. Please see the requested schedule below.

GAS OPERATIONS (CGM12)
PROJECTED FINANCIAL RATIOS

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
INTEREST COVERAGE										
Net Income	2	6	9	9	5	5	6	6	5	4
Finance Expense	18	17	21	22	23	25	25	26	27	28
Capitalized Interest	0	0	0	0	0	0	0	0	0	0
	20	23	30	31	29	30	32	32	32	32
Finance Expense	18	17	21	22	23	25	25	26	27	28
Capitalized Interest	0	0	0	0	0	0	0	0	0	0
	18	17	21	22	24	25	26	26	27	28
Interest Coverage	**1.09**	**1.32**	**1.43**	**1.42**	**1.21**	**1.21**	**1.23**	**1.22**	**1.17**	**1.15**
CAPITAL COVERAGE										
Internally Generated Funds	45	3	33	23	20	20	21	22	21	21
Net Capital Construction Expenditures	36	38	33	37	40	32	33	33	34	34
Capital Coverage	**1.23**	**0.07**	**1.02**	**0.63**	**0.49**	**0.63**	**0.65**	**0.65**	**0.62**	**0.62**

PUB/CENTRA I-10

Subject: **Tab 4 Integrated Financial Forecast & Economic Outlook**

Reference: **Tab 4 Appendix 4.2 CGM12**

d) Please re-file CGM12 reflecting a zero percent non-gas rate increase in the test year.

ANSWER:

Please see the schedules below.

GAS OPERATIONS
PROJECTED OPERATING STATEMENT
PUB/Centra I-10 (d) - CGM12 with No Rate Increase in 2013/14
(In Millions of Dollars)

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
REVENUES										
General Consumers										
at approved rates	319	312	356	351	349	348	349	349	350	350
additional revenue requirement*	0	0	0	0	0	2	4	6	8	10
	319	312	356	351	349	350	353	355	357	361
Cost of Gas Sold	176	168	212	203	202	201	201	201	201	201
Gross Margin	143	144	144	148	147	149	152	154	157	160
Other	2	2	2	2	2	2	2	2	2	2
	145	146	146	149	149	151	154	156	159	162
EXPENSES										
Operating and Administrative	67	69	77	77	78	78	79	79	81	82
Finance Expense	18	17	21	23	25	26	28	29	30	32
Depreciation and Amortization	28	30	20	21	22	22	23	23	24	25
Capital and Other Taxes	18	19	15	15	16	16	16	17	17	17
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
	143	147	144	148	152	154	157	160	165	169
Net Income	2	(1)	2	2	(3)	(3)	(3)	(4)	(6)	(7)
* Additional Revenue Requirement										
Percent Increase		0.00%	0.00%	0.00%	0.00%	0.50%	0.75%	0.50%	0.50%	0.75%
Cumulative Percent Increase		0.00%	0.00%	0.00%	0.00%	0.50%	1.25%	1.76%	2.27%	3.04%
Financial Ratios										
Equity (PUB Methodology)	34%	32%	25%	18%	17%	16%	14%	13%	12%	10%
Interest Coverage	1.09	0.95	1.07	1.07	0.87	0.87	0.88	0.86	0.80	0.78
Capital Coverage	1.23	(0.10)	0.79	0.42	0.29	0.36	0.37	0.35	0.31	0.30

GAS OPERATIONS
PROJECTED BALANCE SHEET
PUB/Centra I-10 (d) - CGM12 with No Rate Increase in 2013/14
(In Millions of Dollars)

For the year ended March 31	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
ASSETS										
Plant in Service	656	679	705	735	767	788	811	835	860	886
Accumulated Depreciation	(232)	(240)	(245)	(252)	(260)	(269)	(278)	(288)	(299)	(310)
Net Plant in Service	424	439	460	483	507	520	533	546	561	576
Construction in Progress	2	2	2	2	2	4	6	8	8	8
Current and Other Assets	73	68	68	68	68	68	68	68	68	68
Goodwill and Intangible Assets	9	8	6	5	4	3	3	3	3	3
Regulated Assets	79	78	-	-	-	-	-	-	-	-
	586	594	536	557	580	595	610	625	640	655
LIABILITIES AND EQUITY										
Long-Term Debt	295	300	340	370	390	420	440	460	480	490
Current and Other Liabilities	99	93	71	61	68	55	54	54	56	69
Contributions in Aid of Construction	35	45	45	45	44	45	44	43	42	41
Share Capital	121	121	121	121	121	121	121	121	121	121
Retained Earnings	36	35	(41)	(39)	(43)	(46)	(49)	(53)	(59)	(66)
	586	594	536	557	580	595	610	625	640	655

GAS OPERATIONS
PROJECTED CASH FLOW STATEMENT
PUB/Centra I-10 (d) - CGM12 with No Rate Increase in 2013/14
(In Millions of Dollars)

For the year ended March 31	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
OPERATING ACTIVITIES										
Cash Receipts from Customers	355	350	393	384	382	383	386	389	392	395
Cash Paid to Suppliers and Employees	(291)	(335)	(347)	(346)	(347)	(346)	(347)	(349)	(351)	(354)
Interest Paid	(19)	(19)	(21)	(22)	(24)	(25)	(27)	(28)	(30)	(31)
	45	(4)	26	16	11	12	12	12	10	10
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	60	40	40	30	20	30	20	20	20	30
Retirement of Long-Term Debt	(63)	-	(35)	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-
	(3)	40	5	30	20	30	20	20	20	30
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(37)	(39)	(33)	(37)	(40)	(32)	(33)	(33)	(34)	(34)
Other	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
	(37)	(39)	(33)	(38)	(41)	(34)	(34)	(34)	(34)	(35)
Net Increase (Decrease) in Cash	5	(3)	(2)	8	(9)	8	(2)	(3)	(4)	5
Cash at Beginning of Year	(13)	(9)	(12)	(14)	(6)	(16)	(8)	(9)	(12)	(16)
Cash at End of Year	(9)	(12)	(14)	(6)	(16)	(8)	(9)	(12)	(16)	(11)

PUB/CENTRA I-10

Subject: **Tab 4 Integrated Financial Forecast & Economic Outlook**

Reference: **Tab 4 Appendix 4.2 CGM12**

e) Please provide the debt to equity ratio (gas operations) based on the Board approved methodology for the years 2012/13 through 2016/17 assuming the continuation of rate regulated accounting and compare that with the debt to equity ratio assuming rate regulated accounts are not allowed.

ANSWER:

Please see the table below.

CGM12 with 1 year Deferral of IFRS and Rate Regulated Accounting Allowed

	2013	2014	2015	2016	2017
Equity (PUB Methodology)	34%	33%	32%	33%	32%

CGM12

	2013	2014	2015	2016	2017
Equity (PUB Methodology)	34%	33%	27%	22%	22%

PUB/CENTRA I-11

Subject: **Tab 4 Integrated Financial Forecast & Economic Outlook**

Reference: **Tab 4 Appendix 4.2 IFF12; 2011 & 2012 Financial Statements**
2009/10 & 2010/11 GRA Tab 3 Attachment 2

Please provide a schedule which compares the approved 2009/10, 2010/11, and 2011/12 forecasts of total cost of service with the 2009/10, 2010/11 and 2011/12 actual results and explain all material variances in a similar format to PUB/Centra I-14 from the 2009/10 & 2010/11 GRA.

ANSWER:

Please see the following tables:

Centra Gas Manitoba Inc.
2012/13 General Rate Application

PUB/Centra 11

Comparison of Approved Total Cost of Service with Actual Results **($000's)**

	2009/10 Approved [1]	2009/10 Actual [2]	Variance [3] = [2] - [1]	Explanation [4]
Cost of Gas	318 785	315 840	(2 945)	Primarily due to warmer than normal weather.
Other Income	(2 026)	(1 924)	102	
Operating & Administrative	59 160	60 951	1 791	The increase is primarily a result of a reduction in DSM costs eligible for capitalization as intangible assets and cost increases due to wage settlements and general escalation.
Depreciation & Amortization	25 047	23 697	(1 350)	Primarily due to lower capital spending including lower DSM program additions.
Capital & Other Taxes	23 703	23 351	(352)	
Finance Expense	19 725	18 921	(804)	
Furnace Replacement Program	3 800		(3 800)	FRP funding was treated as a revenue reduction item in the 2009/10 actuals.
Corporate Allocation	12 000	12 000	-	
Net Income (Loss)	2 147	(950)	(3 097)	Reduced gas sales due to warmer weather and lower usage; higher operating costs.
Total Cost of Service	462 341	451 885	(10 455)	

Centra Gas Manitoba Inc.
2012/13 General Rate Application

PUB/Centra 11

Comparison of Approved Total Cost of Service with Actual Results **($000's)**

	2010/11 Approved [1]	2010/11 Actual [2]	Variance [3] = [2] - [1]	Explanation [4]
Cost of Gas	331 442	260 835	(70 607)	Lower due to decreased gas prices.
Other Income	(2 026)	(1 394)	632	
Operating & Administrative	60 343	60 644	301	
Depreciation & Amortization	27 367	25 591	(1 776)	Primarily due to lower capital spending including lower DSM program additions.
Capital & Other Taxes	23 940	20 490	(3 450)	Reduced property taxes resulting from the 2010 provincial reassessment of property values partially offset by City of Winnipeg tax audit settlement.
Finance Expense	19 105	17 888	(1 217)	Decrease in short term debt interest expense.
Furnace Replacement Program	3 800		(3 800)	FRP funding was treated as a revenue reduction item in 2010/11 actuals.
Corporate Allocation	12 000	12 000	-	
Net Income (Loss)	2 505	6 609	4 104	Lower expenses as stated above partially offset by reduced gas sales due to conservation.
Total Cost of Service	478 476	402 663	(75 813)	

Centra Gas Manitoba Inc.
2012/13 General Rate Application

PUB/Centra 11

Comparison of Forecast with Actual Results **($000's)**

	2011/12 Forecast* [1]	2011/12 Actual [2]	Variance [3] = [2] - [1]	Explanation [4]
Cost of Gas	197 098	197 099	1	
Other Income	(896)	(991)	(95)	
Operating & Administrative	62 371	62 117	(254)	
Depreciation & Amortization	25 504	25 501	(3)	
Capital & Other Taxes	19 411	19 274	(137)	
Finance Expense	18 395	18 464	69	
Corporate Allocation	12 000	12 000	-	
Net Income (Loss)	(6 170)	(5 751)	419	
Total Cost of Service	327 713	327 713	-	

* 2011/12 forecast based on CGM11-2.

PUB/CENTRA I-12 (Revised)

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Page 2 of 30 Schedule 5.1.0**

Please update schedule 5.1.0 on a total cost of service basis, including fiscal years 2005/06 to 2013/14.

ANSWER:

Please see schedule below:

Schedule 5.1.0 on a Total Cost of Service Basis **($000's)**

	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Test Year
Cost of Gas	397,595	378,664	386,490	430,759	315,840	260,835	197,099	175,576	168,279
Other Income	(2,199)	(2,199)	(1,967)	(1,901)	(1,924)	(1,394)	(991)	(1,705)	(1,866)
Operating & Administrative	53,085	53,505	56,270	59,803	60,951	60,644	62,117	67,300	68,800
Depreciation & Amortization	18,680	18,323	23,293	24,901	23,697	25,591	25,501	27,620	30,091
Capital & Other Taxes	23,032	22,248	23,021	23,412	23,351	20,490	19,274	18,334	18,750
Finance Expense	18,364	22,095	21,711	20,158	18,921	17,888	18,464	17,901	17,296
Corporate Allocation	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000
Net Income (Loss)	(5,375)	1,075	5,899	8,596	(950)	6,609	(5,751)	1,562	4,821
Total Cost of Service	515,182	505,711	526,717	577,728	451,885	402,663	327,713	318,588	318,171
Less: Cost of Gas	397,595	378,664	386,490	430,759	315,840	260,835	197,099	175,576	168,279
Non-Gas Cost of Service	117,587	127,047	140,227	146,969	136,045	141,828	130,615	143,012	149,892

PUB/CENTRA I-13 (Revised)

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Page 2 of 30 Schedule 5.1.0; 2009/10 & 2010/11 PUB/Centra 13(f)**

a) Please file a schedule in the same format as PUB/Centra 13(f) from the 2009/10 & 2010/11 GRA comparing the actual and weather normalized results for 2006/07 to 2011/12, the actual and weather normalized preliminary results for 2012/13, and the forecasted results for 2013/14.

ANSWER:

Please see the table below.

Actual and Forecast Net Income and Retained Earnings

($000's)

	Actual 2006/07	Weather Normalized 2006/07	Actual 2007/08	Weather Normalized 2007/08	Actual 2008/09	Weather Normalized 2008/09	Actual 2009/10	Weather Normalized 2009/10	Actual 2010/11	Weather Normalized 2010/11	Actual 2011/12	Weather Normalized 2011/12	Forecast 2012/13	Forecast 2013/14
Revenue	505,711	505,711	526,717	526,717	577,728	577,728	451,885	451,885	402,663	402,663	327,713	327,713	318,588	312,426
Weather Impact on Net Income	-	1,083	-	(4,942)	-	(7,210)	-	2,851	-	(57)	-	8,232	-	
Additional Annualized Revenue Requirement	-	-	-	-	-	-	-	-	-	-	-	-	-	5,746
	505,711	506,794	526,717	521,775	577,728	570,519	451,885	454,736	402,663	402,606	327,713	335,945	318,588	318,172
Cost of Sales	378,664	378,664	386,490	386,490	430,759	430,759	315,840	315,840	260,835	260,835	197,099	197,099	175,576	168,279
Gross Margin	127,047	128,130	140,228	135,285	146,969	139,760	136,045	138,896	141,828	141,771	130,615	138,846	143,012	149,893
Other Income	2,199	2,199	1,967	1,967	1,901	1,901	1,924	1,924	1,394	1,394	991	991	1,705	1,866
	129,246	130,329	142,195	137,252	148,869	141,661	137,969	140,820	143,222	143,165	131,605	139,837	144,717	151,758
Expenses	128,172	128,172	136,296	136,296	140,273	140,273	138,919	138,919	136,612	136,612	137,357	137,357	143,155	146,937
Net Income (Loss)	1,074	2,157	5,899	957	8,596	1,388	(950)	1,901	6,609	6,553	(5,751)	2,480	1,562	4,821
Retained Earnings	21,128		27,383		34,394		33,443		40,052		34,301		35,863	40,684
Financial Results - Assuming no Rate Increase														
Net Income (Loss)														(925)
Retained Earnings														34,938

.

PUB/CENTRA I-13

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Page 2 of 30 Schedule 5.1.0; 2009/10 & 2010/11 PUB/Centra 13(f)**

b) Please explain in detail how weather normalization is achieved, update the data points, and show Centra's calculations.

ANSWER:

Weather normalization is the process of taking out the impacts of weather on net income. Each customer class has a calculated average natural gas usage of natural gas volumes per Effective Heating Degree Day (EHDD). EHDD's are forecasted based on a 25 year rolling average, for each month of the year and are compared to actual EHDD's for each month. The difference between the forecasted EHDD's and the actual EHDD's for the month are multiplied by the average usage per EHDD for each customer class. This calculates the volume variance related to weather. This is done each month.

The volume variance relating to weather for each customer class for the month is then multiplied by the blended sales rate (the aggregate of the PUB approved Primary, Supplemental, Distribution, and Transportation rates) to determine the weather impact on revenue. The same volume variance for each customer class is then multiplied by the blended weighted average cost of gas (WACOG) rate (the aggregate of the PUB approved Primary, Supplemental, Distribution, and Transportation rates) to determine the weather impact on the WACOG.

The difference between the weather impact on revenue and the weather impact on the cost of gas is the weather impact on gross margin. The gross margin impacts calculated for each month of the fiscal year are added together to determine the total weather margin impact which is what is stated as "Weather Impact on Net Income" as noted in the response to PUB/Centra I-13(a).

The above process must be completed for each customer class and for each month as each month will have different EHDD's and different sales and WACOG rates due to billing percentage changes and changes in the Primary Gas sales and WACOG rates.

If weather has an unfavourable impact on gross margin, meaning the actual EHDD's were lower than the forecast EHDD's, this is added to revenue to normalize for weather. If weather has a favourable impact on margin, then the impact is subtracted from revenue to normalize for weather.

As noted above, there are multiple data points in calculating the weather impacts for each customer class, relating to revenue and WACOG for each month in order to determine the total margin impact for the year.

PUB/CENTRA I-14

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Page 2 of 30 Schedule 5.1.0; 2009/10 & 2010/11 Schedule 4.0.0**

Please provide a schedule showing the total cost of service in a similar format to that provided in the 2009/10 & 2010/11 GRA as Schedule 4.0.0.

ANSWER:

Please see Centra's response to PUB/CENTRA I-12.

PUB/CENTRA I-15

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Page 2 of 30 Schedule 5.1.0; 2009/10 & 2010/11 PUB/Centra 16**

Please file a comparison of the actual, approved and weather normalized revenue by cost of service item from that forecasted and approved for 2008/09 through 2011/12 in a similar format to PUB/Centra 16 from the 2009/10 & 2010/11 GRA.

ANSWER:

Please see the following table for the requested information.

($000's)

	2008/09			2009/10			2010/11			2011/12		
	Approved	Actual	Weather Normal	Approved	Actual	Weather Normal	Approved	Actual	Weather Normal	IFF11-2 Forecast	Actual	Weather Normal
Cost of Gas	407,142	430,759	400,791	318,785	315,840	322,837	331,442	260,835	261,470	197,098	197,099	215,663
Other Income	(2,115)	(1,901)	(1,901)	(2,026)	(1,924)	(1,924)	(2,026)	(1,394)	(1,394)	(896)	(991)	(991)
Operating & Administrative	58,000	59,803	59,803	59,160	60,951	60,951	60,343	60,644	60,644	62,371	62,117	62,117
Depreciation & Amortization	23,072	24,901	24,901	25,047	23,697	23,697	27,367	25,591	25,591	25,504	25,501	25,501
Furnace Replacement Program (1)	3,855			3,800			3,800			3,800		
Capital & Other Taxes	23,063	23,412	23,412	23,703	23,351	23,351	23,940	20,490	20,490	19,411	19,274	19,274
Finance Expense	22,154	20,158	20,158	19,725	18,921	18,921	19,105	17,888	17,888	18,395	18,464	18,464
Corporate Allocation	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000
Net Income (Loss)	3,000	8,596	1,387	2,147	(950)	1,901	2,505	6,609	6,552	(6,170)	(5,751)	2,481
Total Cost of Service	550,171	577,728	540,551	462,341	451,885	461,734	478,476	402,663	403,241	331,513	327,713	354,509

(1) FRP funding was treated as a revenue reduction for actual results.

PUB/CENTRA I-16

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Reference Tab 5 Page 2 of 30 Schedule 5.1.0**

Order 128/09

a) **Please explain why Centra has applied for net income in excess of the $3 million previously approved by the Board in Order 128/09 as well as in previous Orders.**

ANSWER:

Centra has been regulated on the basis that it would be allowed to earn a $3 million dollar net income on an annual basis since 2003/04. However, Centra's retained earnings have essentially remained flat over that period of time and are $34 million at the end of 2011/12 versus $35 million at the end of 2002/03. The retained earnings have remained flat despite the growth in In-service Plant from $503 to $637 million during that time.

Centra's last general rate increase was 0.8% for 2010/11 flowing from Order 128/09. This is the only general rate increase that Centra obtained for the four year period between 2009/10 and 2012/13.

At the time that Centra filed the 2013/14 GRA, it was projected based on CGM12 that it would be required to write-off rate-regulated assets of approximately $77 million to retained earnings upon adoption of IFRS in 2014/15 which would result in a retained earnings deficit.

Since the filing of the 2013/14 GRA, the adoption of IFRS has been deferred by an additional year to 2015/16 and the IASB has indicated it plans to issue a draft standard to continue to permit the use of rate-regulated accounting on an interim basis for first time-adopters of IFRS. However, there is still uncertainty as to the final outcome of the IASB's project on rate-regulated activities and whether or not rate-regulated accounting will continue to be permitted over the long-term.

Even under the scenario which assumes the deferral of IFRS to 2015/16, the continuation of rate-regulated accounting until the end of the forecast period in CGM12, the 2.0% general rate increase and future indicative rate increases assumed in CGM12 (please see Centra's response to PUB/Centra I-7(c)), retained earnings are only forecast to grow marginally to $43 million by 2021/22 despite further projected growth in In-service plant to $883 million during that period of time.

There are also other financial risks facing Centra such as the need to maintain gas infrastructure in a safe and reliable manner exerting pressure on operating and maintenance costs, and lower revenues due to declining sales volumes associated with continuing conservation efforts.

Taking all of the above-noted factors into consideration, Centra is of the view that the modest general rate increase of 2.0% that is requested in the 2013/14 GRA which produces a projected net income of $5 million in 2013/14 remains reasonable. The requested rate increase is necessary to maintain an adequate financial structure and retained earnings and to promote long-term rate stability for gas customers.

PUB/CENTRA I-16

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Reference Tab 5 Page 2 of 30 Schedule 5.1.0**

Order 128/09

b) Please re-file Schedule 5.1.0 assuming $3 million in net income in 2013/14 and indicate the required rate increase on this basis.

ANSWER:

Please see schedule included below:

						($000'S)
	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
Revenues						
Revenue at Approved Rates	577,728	451,885	402,663	327,713	318,588	312,426
Additional Revenue Required*					-	3,937
	577,728	451,885	402,663	327,713	318,588	316,363
Cost of Gas	430,759	315,840	260,835	197,099	175,576	168,279
Gross Margin	146,969	136,045	141,828	130,615	143,012	148,084
Other Income	1,901	1,924	1,394	991	1,705	1,866
	148,869	137,969	143,222	131,605	144,717	149,950
Expenses						
Operating & Administrative	59,803	60,951	60,644	62,117	67,300	68,800
Finance Expense	20,158	18,921	17,888	18,464	17,901	17,309
Depreciation & Amortization	24,901	23,697	25,591	25,501	27,620	30,091
Capital & Other Taxes	23,412	23,351	20,490	19,274	18,334	18,750
Corporate Allocation	12,000	12,000	12,000	12,000	12,000	12,000
	140,273	138,919	136,612	137,356	143,155	146,950
Net Income	8,596	(950)	6,609	(5,751)	1,562	3,000

* Additional Revenue Required reflects a 1.37% rate increase effective August 1, 2013.

PUB/CENTRA I-16

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Reference Tab 5 Page 2 of 30 Schedule 5.1.0**

Order 128/09

c) Please file a schedule showing the cost of service in a similar format to that provided in the 2009/10 & 2010/11 GRA as Schedule 4.0.0 reflecting $3 million in net income.

ANSWER:

Please see schedule included below:

($000's)

	2008/09 Actual [1]	2009/10 Actual [2]	2010/11 Actual [3]	2011/12 Actual [4]	2012/13 Forecast [5]	2013/14 Forecast [6]
Cost of Gas	430,759	315,840	260,835	197,099	175,576	168,279
Other Income	(1,901)	(1,924)	(1,394)	(991)	(1,705)	(1,866)
Operating & Administrative	59,803	60,951	60,644	62,117	67,300	68,800
Depreciation & Amortization	24,901	23,697	25,591	25,501	27,620	30,091
Capital & Other Taxes	23,412	23,351	20,490	19,274	18,334	18,750
Finance Expense	20,158	18,921	17,888	18,464	17,901	17,309
Corporate Allocation	12,000	12,000	12,000	12,000	12,000	12,000
Net Income (Loss)	8,596	(950)	6,609	(5,751)	1,562	3,000
Total Cost of Service	577,728	451,885	402,663	327,713	318,588	316,363
Less: Cost of Gas	430,759	315,840	260,835	197,099	175,576	168,279
Non-Gas Cost of Service	146,969	136,045	141,828	130,615	143,012	148,084

PUB/CENTRA I-16

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Reference Tab 5 Page 2 of 30 Schedule 5.1.0**

Order 128/09

d) **Please file an IFF scenario reflecting $3 million in net income in 2013/14 and beyond, as well as the continuation of rate-regulated accounting under IFRS. Indicate the level of rate increases required to maintain the level of net income.**

ANSWER:

Please see the schedule below. Please note that the 1.19% rate increase for 2013/14 indicated in this IFF scenario assumes that the rate increase is implemented on May 1, 2013.

GAS OPERATIONS (CGM12)
PROJECTED OPERATING STATEMENT
1Yr IFRS Def, Rate Regulated Acc, $3M Net Income
(In Millions of Dollars)

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
REVENUES											
General Consumers											
at approved rates	319	312	356	351	349	348	349	349	350	350	351
additional revenue requirement*	0	4	9	4	9	13	15	17	19	21	23
	319	316	365	355	358	361	363	367	368	372	374
Cost of Gas Sold	176	168	212	203	202	201	201	201	201	201	201
Gross Margin	143	148	153	152	156	160	162	166	167	171	173
Other	2	2	2	2	2	2	2	2	2	2	2
	145	150	155	154	158	162	164	168	169	173	175
EXPENSES											
Operating and Administrative	67	69	71	70	71	73	74	76	77	79	81
Finance Expense	18	17	19	20	22	23	23	24	25	26	26
Depreciation and Amortization	28	30	31	30	31	32	32	33	32	33	32
Capital and Other Taxes	18	19	19	19	19	20	20	20	20	20	21
Corporate Allocation	12	12	12	12	12	12	12	12	12	12	12
	143	147	152	151	155	159	161	165	166	170	172
Net Income	2	3	3	3	3	3	3	3	3	3	3
* Additional Revenue Requirement											
Percent Increase		1.19%	1.48%	-1.49%	1.50%	1.03%	0.47%	0.82%	0.25%	0.82%	0.28%
Cumulative Percent Increase		1.19%	2.69%	1.16%	2.68%	3.74%	4.24%	5.09%	5.35%	6.22%	6.51%

GAS OPERATIONS (CGM12)
PROJECTED BALANCE SHEET
1Yr IFRS Def, Rate Regulated Acc, $3M Net Income
(In Millions of Dollars)

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ASSETS											
Plant in Service	656	679	704	732	764	786	809	832	857	883	909
Accumulated Depreciation	(232)	(240)	(250)	(255)	(262)	(271)	(281)	(291)	(301)	(312)	(324)
Net Plant in Service	424	439	454	477	502	515	528	541	556	571	585
Construction in Progress	2	2	2	2	2	4	6	8	8	8	9
Current and Other Assets	73	68	68	68	68	68	68	68	68	68	68
Goodwill and Intangible Assets	9	8	6	5	4	3	3	3	3	3	3
Regulated Assets	79	78	76	73	69	63	57	49	43	37	32
	586	594	607	625	645	653	662	669	678	687	697
LIABILITIES AND EQUITY											
Long-Term Debt	295	300	330	350	370	370	380	390	400	390	420
Current and Other Liabilities	99	89	68	63	61	66	62	57	54	71	49
Contributions in Aid of Construction	35	45	45	45	44	45	44	43	42	41	41
Share Capital	121	121	121	121	121	121	121	121	121	121	121
Retained Earnings	36	39	42	46	49	52	55	58	61	64	67
	586	594	607	625	645	653	662	669	678	687	697

GAS OPERATIONS (CGM12)
PROJECTED CASH FLOW STATEMENT
1Yr IFRS Def, Rate Regulated Acc, $3M Net Income
(In Millions of Dollars)

For the year ended March 31	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
OPERATING ACTIVITIES											
Cash Receipts from Customers	355	354	403	389	392	396	398	401	403	407	409
Cash Paid to Suppliers and Employees	(291)	(335)	(341)	(340)	(340)	(342)	(344)	(347)	(349)	(352)	(354)
Interest Paid	(19)	(19)	(20)	(21)	(23)	(24)	(24)	(25)	(26)	(26)	(27)
	45	0	41	28	29	29	29	30	29	29	29
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	60	40	30	20	20	-	10	10	10	10	30
Retirement of Long-Term Debt	(63)	-	(35)	-	-	-	-	-	-	-	(20)
Other	-	-	-	-	-	-	-	-	-	-	-
	(3)	40	(5)	20	20	-	10	10	10	10	10
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(37)	(39)	(39)	(45)	(48)	(37)	(37)	(37)	(37)	(37)	(39)
Other	(0)	(1)	(0)	(0)	(0)	(1)	(1)	(1)	(0)	(0)	(0)
	(37)	(39)	(39)	(45)	(48)	(38)	(38)	(37)	(38)	(38)	(39)
Net Increase (Decrease) in Cash	5	1	(3)	3	1	(9)	2	3	2	2	0
Cash at Beginning of Year	(13)	(9)	(8)	(11)	(8)	(7)	(16)	(14)	(11)	(10)	(8)
Cash at End of Year	(9)	(8)	(11)	(8)	(7)	(16)	(14)	(11)	(10)	(8)	(8)

PUB/CENTRA I-17

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Schedules 5.5.0; Appendix 5.7 Pages 2 and 4 of 23;**

a) **Please re-file the table found on page 2 of 23 including two columns for the compounded annual average increases from 2003/04 to 2011/12 and from 2011/12 to 2013/14 for top line OM&A and after accounting changes. Please include cost per customer before any adjustments.**

ANSWER:

Please see the table included below.

$ in (000's) except Cost per Customer

	2003/04 Actual	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast	Compounded Annual Increase from 2003/04 to 2011/12 %	Compounded Annual Increase from 2011/12 to 2013/14 %
Centra Gas OM&A	$ 52,786	$ 55,232	$ 53,085	$ 53,505	$ 56,270	$ 59,803	$ 60,951	$ 60,644	$ 62,117	$ 67,300	$ 68,800	2.1	5.2
Less: Accounting Changes	$ -	$ -	$ -	$ -	$ -	$ 1,000	$ 1,020	$ 3,040	$ 3,101	$ 7,491	$ 7,796		
Centra Gas OM&A after adjusting for Accounting Changes	$ 52,786	$ 55,232	$ 53,085	$ 53,505	$ 56,270	$ 58,803	$ 59,931	$ 57,604	$ 59,016	$ 59,809	$ 61,004	1.4	1.7
% Increase		4.63%	-3.89%	0.79%	5.17%	4.50%	1.92%	-3.88%	2.45%	1.34%	2.00%		
Number of Customers	253,631	255,925	257,817	259,569	261,159	263,008	264,301	265,961	267,699	270,040	273,122		
Before Adjustments for Accounting Changes:													
Cost per Customer	$ 208	$ 216	$ 206	$ 206	$ 215	$ 227	$ 231	$ 228	$ 232	$ 249	$ 252		
% Increase (Decrease)		3.70%	-4.59%	0.11%	4.53%	5.53%	1.42%	-1.12%	1.76%	7.40%	1.08%		
After Adjustments for Accounting Changes:													
Cost per Customer	$ 208	$ 216	$ 206	$ 206	$ 215	$ 224	$ 227	$ 217	$ 220	$ 221	$ 223		
% Increase (Decrease)		3.70%	-4.59%	0.11%	4.53%	3.77%	1.42%	-4.48%	1.79%	0.47%	0.85%		
Canadian CPI	1.90%	2.20%	2.30%	1.90%	2.10%	2.20%	0.40%	2.00%	2.80%	1.80%	2.10%		

PUB/CENTRA I-17

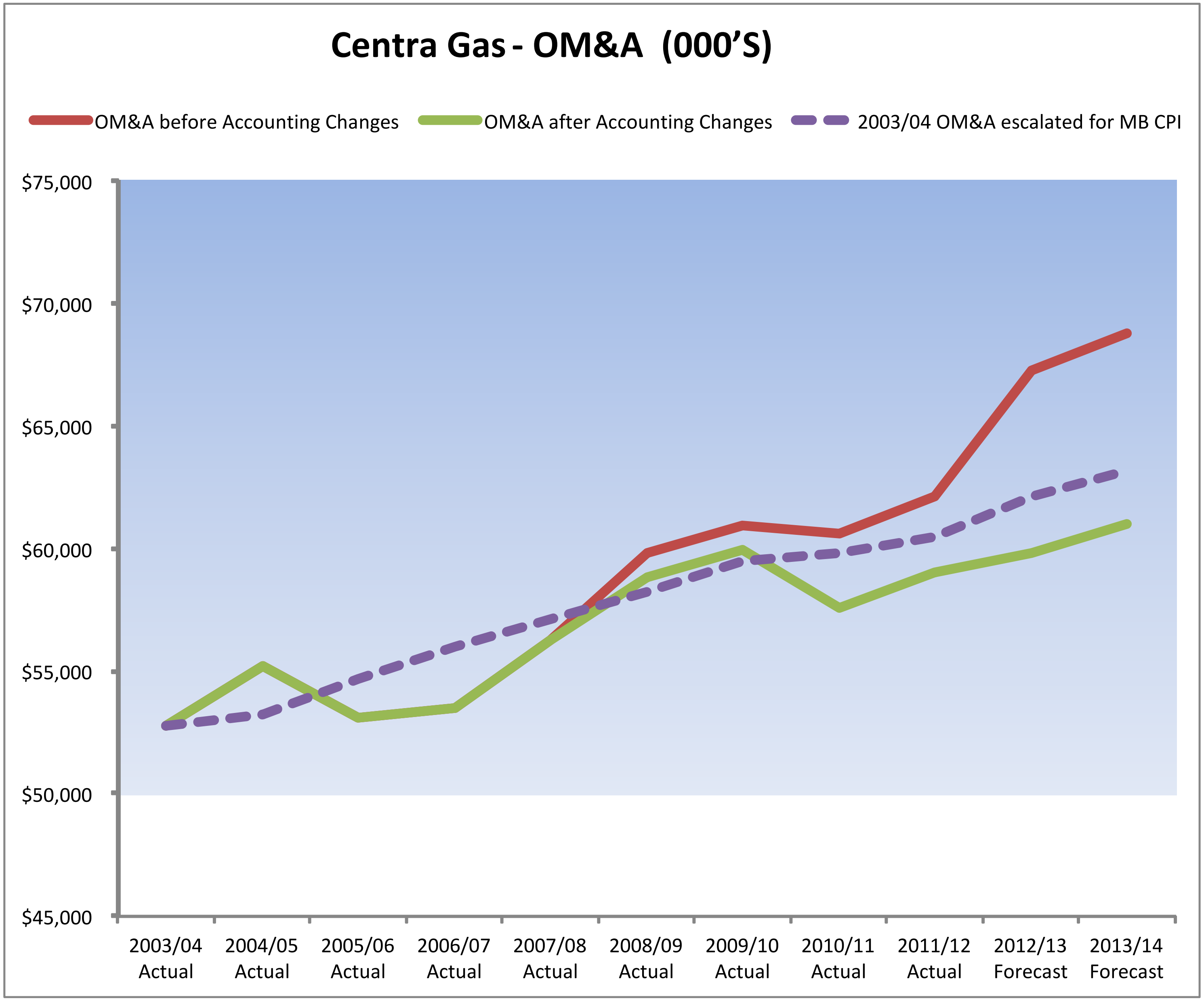
Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Schedules 5.5.0; Appendix 5.7 Pages 2 and 4 of 23;**

b) **Please provide a graph of top line OM&A growth before and after accounting changes from 2003/04 to 2013/14. Please include the 2003/04 OM&A escalated by Manitoba CPI for each year to 2013/14.**

ANSWER:

Please see graph included below.


Centra Gas - OM&A (000'S)
OM&A before Accounting Changes
OM&A after Accounting Changes
2003/04 OM&A escalated for MB CPI
$75,000
$70,000
$65,000
$60,000
$55,000
$50,000
$45,000
2003/04 Actual
2004/05 Actual
2005/06 Actual
2006/07 Actual
2007/08 Actual
2008/09 Actual
2009/10 Actual
2010/11 Actual
2011/12 Actual
2012/13 Forecast
2013/14 Forecast

PUB/CENTRA I-17

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Schedules 5.5.0; Appendix 5.7 Pages 2 and 4 of 23;**

c) Please provide a schedule indicating the amounts incurred and capitalized in each year from 2008/09 to 2013/14 on the cost items identified in the table on page 4 that Centra now indicates it has or will expense.

ANSWER:

The table on page 4 of Appendix 5.7 provides the amounts in each of the fiscal years previously capitalized either through overhead or as an intangible asset that were, or will now be, expensed.

SUMMARY OF ACCOUNTING CHANGES - CENTRA GAS IFF12
(in thousands of dollars)

	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
Reduction to Costs Capitalized						
Interest on Common Assets (Facilities & Equipment)	-	-	1,000	1,020	1,040	1,061
General & Administrative Departmental Costs	-	-	500	510	520	531
Interest on Motor Vehicles	-	-	500	510	520	531
IT Infrastructure & Related Support	-	-	-	-	1,800	1,836
Building Depreciation & Operating Costs	-	-	-	-	1,000	1,020
	-	-	2,000	2,040	4,881	4,978
Intangible Assets						
Ineligible for Capitalization	1,000	1,020	1,040	1,061	1,082	1,104
	1,000	1,020	1,040	1,061	1,082	1,104

PUB/CENTRA I-18 (Revised)

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Page 21 of 23; 2009/10 & 2010/11 GRA PUB/Centra 39 - Activity Charges by Program**

a) Please provide a table similar to PUB/Centra 39 from the 2009/10 & 2010/11 GRA for the years 2007/08 through 2012/13 showing both approved forecasts and actual amounts for each of the years. For 2012/13, show the approved forecast at the last GRA and the amount forecasted in the current application.

ANSWER:

Please see the schedule below.

Please note that forecast amounts are presented for years 2011/12 and 2012/13 as the PUB had not approved the forecasts for those respective years at the last GRA.

CENTRA GAS MANITOBA INC.
ACTIVITY CHARGES, PRIMARY COSTS AND OVERHEADS **($000's)**

	2007/08 Actual	2007/08[1] Approved	2008/09 Actual	2008/09[1] Approved	2009/10 Actual	2009/10 Approved	2010/11 Actual	2010/11 Approved	2011/12 Actual	2011/12 Forecast	2012/13 Forecast
ACTIVITY CHARGES BY PROGRAM											
PRESIDENT & CEO											
Audit	96	142	75	147	95	143	179	146	146	133	142
Liability Claims	-	-	-	-	-	-	-	-	0	-	-
Public Affairs	266	312	259	320	252	338	262	345	278	331	113
Research & Development	8	-	7	-	5	-	4	-	5	-	-
	$ 370	**$ 454**	**$ 341**	**$ 468**	**$ 353**	**$ 481**	**$ 445**	**$ 491**	**$ 429**	**$ 464**	**$ 254**
FINANCE & ADMINISTRATION											
IT - Distribution/Metering	79	212	142	220	99	124	114	123	87	162	121
IT - Banner	665	781	717	816	686	695	753	714	795	736	710
Gas Accounting	299	-	299	-	261	311	268	316	284	273	273
Gas Regulatory	847	1,434	728	1,236	1,123	1,188	1,201	1,518	869	1,095	1,176
Gas Supply	2,111	1,997	2,064	2,052	2,027	2,076	2,343	2,120	2,422	2,357	1,671
Treasury	-	-	-	-	-	-	1	-	-	-	-
Property Tax Administration	67	59	36	59	12	58	18	59	14	20	-
	$ 4,069	**$ 4,482**	**$ 3,986**	**$ 4,383**	**$ 4,208**	**$ 4,453**	**$ 4,697**	**$ 4,850**	**$ 4,471**	**$ 4,643**	**$ 3,951**
POWER SUPPLY											
Environmental Management	32	21	35	21	51	33	104	34	139	130	-
	$ 32	**$ 21**	**$ 35**	**$ 21**	**$ 51**	**$ 33**	**$ 104**	**$ 34**	**$ 139**	**$ 130**	**$ -**
TRANSMISSION											
System Support & Communication Systems	167	175	153	179	186	181	199	185	67	137	141
	$ 167	**$ 175**	**$ 153**	**$ 179**	**$ 186**	**$ 181**	**$ 199**	**$ 185**	**$ 67**	**$ 137**	**$ 141**
CUSTOMER SERVICE & DISTRIBUTION											
Billing Inquiry & Collections	1,927	2,363	1,624	2,406	2,058	1,928	2,015	1,960	1,611	2,025	1,392
Customer Inspections	7,516	7,886	7,780	8,069	8,024	7,585	8,309	7,753	8,371	8,682	7,053
Customer Relations	454	442	499	451	1,274	460	1,383	469	1,424	1,412	1,201
Dispatch	2,319	2,217	2,348	2,281	2,025	2,223	2,354	2,281	2,634	2,532	2,195
Customer Safety	1,787	1,756	1,754	1,797	1,729	1,821	1,850	1,862	1,649	1,848	1,531
Distribution Maintenance	5,426	5,502	5,785	5,630	5,961	5,969	5,754	6,103	5,655	5,911	4,906
Emergency	-	-	168	-	11	-	13	-	86	-	-
Regulating Station Maintenance	2,779	3,199	3,346	3,290	3,411	2,744	3,305	2,903	3,923	3,726	3,614
Capacity Analysis & Engineering	409	442	481	458	562	475	544	481	395	611	422
System Integrity	976	1,049	796	1,093	785	1,046	1,042	1,075	933	979	905
Meter Reading	83	111	68	114	40	85	44	86	40	47	41
Meter Changes	2,000	1,576	1,691	1,614	2,599	1,815	2,432	1,855	3,081	2,447	3,484
	$ 25,676	**$ 26,542**	**$ 26,339**	**$ 27,202**	**$ 28,480**	**$ 26,149**	**$ 29,045**	**$ 26,827**	**$ 29,800**	**$ 30,219**	**$ 26,742**
CUSTOMER CARE & MARKETING											
Billing Inquiry & Collections	5,616	6,167	5,562	6,348	4,968	6,359	4,627	6,497	4,627	4,791	4,288
Customer Relations	3,822	4,050	4,207	4,200	4,500	4,139	4,655	4,228	4,508	4,422	4,115
Customer Safety	114	85	184	88	167	166	108	170	150	202	149
Quality Assessment	-	-	203	-	371	323	543	328	574	567	440
Load Forecast	146	127	121	133	127	146	121	150	142	178	138
Meter Repair & Calibration	1,170	1,256	1,282	1,293	1,000	1,497	1,374	1,539	1,667	1,414	1,234
	$ 10,867	**$ 11,684**	**$ 11,558**	**$ 12,063**	**$ 11,132**	**$ 12,630**	**$ 11,427**	**$ 12,911**	**$ 11,669**	**$ 11,575**	**$ 10,363**
TOTAL ACTIVITY CHARGES	**$ 41,181**	**$ 43,358**	**$ 42,413**	**$ 44,316**	**$ 44,410**	**$ 43,928**	**$ 45,918**	**$ 45,297**	**$ 46,574**	**$ 47,167**	**$ 41,453**

[1] The information for 2007/08 and 2008/09 reflects the current organization and program structure.

CENTRA GAS MANITOBA INC.
ACTIVITY CHARGES, PRIMARY COSTS AND OVERHEADS **($000's)**

	2007/08 Actual	2007/08[1] Approved	2008/09 Actual	2008/09[1] Approved	2009/10 Actual	2009/10 Approved	2010/11 Actual	2010/11 Approved	2011/12 Actual	2011/12 Forecast	2012/13 Forecast
PRIMARY COSTS											
External Course, Awards	55	58	26	48	24	53	26	54	21	26	9
Material	1,326	1,261	1,476	1,286	1,294	1,301	1,184	1,327	1,170	1,343	1,337
Travel	102	174	124	177	87	170	101	173	79	101	135
Donations, Grants & Sponsorships	333	157	348	160	333	239	393	243	476	267	358
Memberships	98	117	142	119	170	121	176	123	187	116	180
Bad Debt & Collection Expense	2,148	2,730	2,135	2,784	2,086	2,803	1,613	2,859	1,435	1,655	1,559
Office Administration & Other	1,581	1,705	1,585	1,739	1,562	1,687	1,557	1,721	1,608	1,500	1,596
Computer Equipment & Maintenance	310	411	546	420	563	371	522	378	452	552	547
Meter Reading Charges (primarily MHUS)	1,765	1,932	2,288	1,971	2,425	2,296	1,949	2,342	2,130	1,922	2,126
Banking/Cash Management Services	205	221	192	226	222	220	220	224	255	273	284
Construction & Maintenance Services	1,288	1,208	1,051	1,232	1,240	1,271	947	1,297	1,823	1,183	1,138
Purchased Services	898	1,263	1,929	1,386	1,988	1,468	1,772	1,494	1,506	1,980	2,124
Promotional Items/Customer Incentives	20	14	40	14	25	22	57	22	71	21	27
Gas-PUB & Advisory Services	681	816	722	832	766	808	491	826	496	520	473
Operating Expense Recoveries	(821)	(828)	(561)	(845)	(538)	(767)	(620)	(782)	(598)	(581)	-
Other	-	-	5	-	4	5	1	5	(1)	6	(5)
TOTAL PRIMARY COSTS	**$ 9,989**	**$ 11,237**	**$ 12,047**	**$ 11,549**	**$ 12,251**	**$ 12,069**	**$ 10,390**	**$ 12,307**	**$ 11,110**	**$ 10,883**	**$ 11,887**
Corporate Allocations & Adjustments	1,455	(2,479)	1,769	(2,422)	1,460	(130)	1,660	(713)	1,718	3,160	6,559
Overhead	12,082	12,659	11,577	12,937	10,735	11,974	7,870	12,346	7,990	8,086	10,403
TOTAL PROGRAM COSTS	**$ 64,707**	**$ 64,776**	**$ 67,806**	**$ 66,380**	**$ 68,857**	**$ 67,840**	**$ 65,838**	**$ 69,237**	**$ 67,392**	**$ 69,297**	**$ 70,303**
Depreciation, Interest & Taxes	(8,437)	(8,176)	(8,003)	(8,380)	(7,906)	(8,680)	(5,194)	(8,895)	(5,275)	(5,297)	(3,003)
TOTAL OPERATING & ADMINISTRATIVE EXPENSE	**$ 56,270**	**$ 56,600**	**$ 59,803**	**$ 58,000**	**$ 60,951**	**$ 59,160**	**$ 60,644**	**$ 60,342**	**$ 62,117**	**$ 64,000**	**$ 67,300**

[1] The information for 2007/08 and 2008/09 reflects the current organization and program structure.

PUB/CENTRA I-18

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Page 21 of 23; 2009/10 & 2010/11 GRA PUB/Centra 39 - Activity Charges by Program**

b) **Please provide detailed explanations for variances between the forecasted and actual amounts for 2009/10, 2010/11, 2011/12 and 2012/13 forecast on a similar basis as that presented in response to PUB/CENTRA 39 (b) from the 2009/10 & 2010/11GRA.**

ANSWER:

Please see the following schedules:

CENTRA GAS MANITOBA INC.
ACTIVITY CHARGES, PRIMARY COSTS AND OVERHEADS **($000's)**

Activity Charges by Program - 2009/10 Actual vs 2009/10 Approved

	2009/10 Actual	2009/10 Approved	Variance	%	Variance Explanations > $100,000 & 10%
PRESIDENT & CEO					
Audit	95	143	47	33.1%	
Liability Claims	-	-	-	0.0%	
Public Affairs	252	338	86	25.5%	
Research & Development	5	-	(5)	0.0%	
	$ 353	**$ 481**	**$ 128**	**26.7%**	
FINANCE & ADMINISTRATION					
IT - Distribution/Metering	99	124	26	20.6%	
IT - Banner	686	695	9	1.3%	
Gas Accounting	261	311	50	16.0%	
Gas Regulatory	1 123	1 188	65	5.5%	
Gas Supply	2 027	2 076	49	2.4%	
Treasury	-	-	-	0.0%	
Property Tax Administration	12	58	46	79.4%	
	$ 4 208	**$ 4 453**	**$ 245**	**5.5%**	
POWER SUPPLY					
Environmental Management	51	33	(18)	(52.4%)	
	$ 51	**$ 33**	**$ (18)**	**(52.4%)**	
TRANSMISSION					
System Support & Communication Systems	186	181	(4)	(2.5%)	
	$ 186	**$ 181**	**$ (4)**	**(2.5%)**	
CUSTOMER SERVICE & DISTRIBUTION					
Billing Inquiry & Collections	2 058	1 928	(130)	(6.8%)	
Customer Inspections	8 024	7 585	(439)	(5.8%)	
Customer Relations	1 274	460	(814)	(177.1%)	Increased hours based on analysis of customer numbers across areas in the southern part of the province (not including the city of Winnipeg). Corrections were made to include areas that previously did not allocate any program costs yet have gas customers.
Dispatch	2 025	2 223	197	8.9%	
Customer Safety	1 729	1 821	92	5.1%	
Distribution Maintenance	5 961	5 969	8	0.1%	
Emergency	11	-	(11)	0.0%	
Regulating Station Maintenance	3 411	2 744	(667)	(24.3%)	Higher system monitoring activities and higher station maintenance than expected.
Capacity Analysis & Engineering	562	475	(87)	(18.3%)	
System Integrity	785	1 046	260	24.9%	Lower activities mainly due to vacancies.
Meter Reading	40	85	45	52.6%	
Meter Changes	2 599	1 815	(785)	(43.3%)	Higher metering activities in both urban and rural locations in anticipation of the new Measurement Canada standards.
	$ 28 480	**$ 26 149**	**$ (2 331)**	**(8.9%)**	
CUSTOMER CARE & MARKETING					
Billing Inquiry & Collections	4 968	6 359	1 391	21.9%	Decreased hours based on analysis of customer numbers. Corrections were made to better reflect the gas / electric customer ratio.
Customer Relations	4 500	4 139	(361)	(8.7%)	Higher than expected customer driven consultation mainly in the City of Winnipeg.
Customer Safety	167	166	(1)	(0.6%)	
Quality Assessment	371	323	(48)	(14.7%)	
Load Forecast	127	146	19	12.9%	
Meter Repair & Calibration	1 000	1 497	497	33.2%	Higher metering activities in both urban and rural locations in anticipation of the new Measurement Canada standards.
	$ 11 132	**$ 12 630**	**$ 1 498**	**11.9%**	
TOTAL ACTIVITY CHARGES	**$ 44 410**	**$ 43 928**	**$ (482)**	**(1.1%)**	

CENTRA GAS MANITOBA INC.
ACTIVITY CHARGES, PRIMARY COSTS AND OVERHEADS **($000's)**

Primary Costs - 2009/10 Actual vs 2009/10 Approved

	2009/10 Actual	2009/10 Approved	Variance	%	Variance Explanations > $100,000 & 10%
PRIMARY COSTS					
External Course, Awards	24	53	29	55.2%	
Material	1,294	1,301	8	0.6%	
Travel	87	170	83	48.9%	
Donations, Grants & Sponsorships	333	239	(94)	(39.4%)	
Memberships	170	121	(49)	(40.4%)	
Bad Debt & Collection Expense	2,086	2,803	717	25.6%	Lower uncollectible accounts than forecasted.
Office Administration & Other	1,562	1,687	125	7.4%	
Computer Equipment & Maintenance	563	371	(193)	(52.0%)	Gas Supply software maintenance forecated in Purchased Services.
Meter Reading Charges (primarily MHUS)	2,425	2,296	(129)	(5.6%)	
Banking/Cash Management Services	222	220	(3)	(1.2%)	
Construction & Maintenance Services	1,240	1,271	31	2.4%	
Purchased Services	1,988	1,468	(520)	(35.4%)	Unplanned DSM adversting costs partially offset by actual expenditures for Gas Supply software maintenance in Computer Equipment & Maintenance.
Promotional Items/Customer Incentives	25	22	(3)	(12.6%)	
Gas-PUB & Advisory Services	766	808	42	5.2%	
Operating Expense Recoveries	(538)	(767)	(229)	29.9%	Lower disconnect and reconnect fees.
Other	4	5	1	21.2%	
PRIMARY COSTS	**$ 12,251**	**$ 12,068**	**$ (183)**	**(1.5%)**	
Corporate Allocations & Adjustments	1,460	(130)	(1,590)	1223.5%	Difference due to allocation of the over/under absorption of the cost centres.
Overhead	10,735	11,974	1,238	10.3%	Mainly due to a lower actual overhead rate of 24% versus a forecasted rate of 27%.
TOTAL PROGRAM COSTS	**$ 68,857**	**$ 67,839**	**$ (1,018)**	**(1.5%)**	
Depreciation, Interest & Taxes	(7,906)	(8,680)	(774)	8.9%	
TOTAL OPERATING & ADMIN EXPENSE	**$ 60,951**	**$ 59,159**	**$ (1,792)**	**(3.0%)**	

CENTRA GAS MANITOBA INC.
ACTIVITY CHARGES, PRIMARY COSTS AND OVERHEADS **($000's)**

Activity Charges by Program - 2010/11 Actual vs 2010/11 Approved **Page 3 of 6**

	2010/11 Actual	2010/11 Approved	Variance	%	Variance Explanations > $100,000 & 10%
PRESIDENT & CEO					
Audit	179	146	(32)	(22.0%)	
Liability Claims	-	-	-	0.0%	
Public Affairs	262	345	82	23.8%	
Research & Development	4	-	(4)	0.0%	
	$ 445	**$ 491**	**$ 46**	**9.3%**	
FINANCE & ADMINISTRATION					
IT - Distribution/Metering	114	123	9	7.2%	
IT - Banner	753	714	(39)	(5.4%)	
Gas Accounting	268	316	48	15.2%	
Gas Regulatory	1 201	1 518	317	20.9%	Less General Rate Application, Cost of Gas hearing and other regulatory matter activities than forecasted.
Gas Supply	2 343	2 120	(223)	(10.5%)	More time spent on supply and transportation activities.
Treasury	1	-	(1)	0.0%	
Property Tax Administration	18	59	41	69.2%	
	$ 4 697	**$ 4 850**	**$ 152**	**3.1%**	
POWER SUPPLY					
Environmental Management	104	34	(70)	(204.5%)	
	$ 104	**$ 34**	**$ (70)**	**(204.5%)**	
TRANSMISSION					
System Support & Communication Systems	199	185	(14)	(7.7%)	
	$ 199	**$ 185**	**$ (14)**	**(7.7%)**	
CUSTOMER SERVICE & DISTRIBUTION					
Billing Inquiry & Collections	2 015	1 960	(56)	(2.9%)	
Customer Inspections	8 309	7 753	(556)	(7.2%)	
Customer Relations	1 383	469	(914)	(195.0%)	Increased hours based on analysis of customer numbers across areas in the southern part of the province (not including the city of Winnipeg). Corrections were made to include areas that previously did not allocate any program costs yet have gas customers.
Dispatch	2 354	2 281	(73)	(3.2%)	
Customer Safety	1 850	1 862	12	0.7%	
Distribution Maintenance	5 754	6 103	348	5.7%	
Emergency	13	-	(13)	0.0%	
Regulating Station Maintenance	3 305	2 903	(402)	(13.9%)	Higher system monitoring activities and higher station maintenance than expected.
Capacity Analysis & Engineering	544	481	(62)	(13.0%)	
System Integrity	1 042	1 075	32	3.0%	
Meter Reading	44	86	43	49.3%	
Meter Changes	2 432	1 855	(577)	(31.1%)	Higher metering activities in both urban and rural locations in anticipation of the new Measurement Canada standards.
	$ 29 045	**$ 26 827**	**$ (2 218)**	**(8.3%)**	
CUSTOMER CARE & MARKETING					
Billing Inquiry & Collections	4 627	6 497	1 870	28.8%	Decreased hours based on analysis of customer numbers. Corrections were made to better reflect the gas / electric customer ratio.
Customer Relations	4 655	4 228	(427)	(10.1%)	Higher than expected customer driven consultation mainly in the City of Winnipeg.
Customer Safety	108	170	62	36.4%	
Quality Assessment	543	328	(215)	(65.7%)	Higher than forecasted Natural Gas Quality Assessment work.
Load Forecast	121	150	29	19.5%	
Meter Repair & Calibration	1 374	1 539	165	10.7%	Higher metering activities in both urban and rural locations in anticipation of the new Measurement Canada standards.
	$ 11 427	**$ 12 911**	**$ 1 483**	**11.5%**	
TOTAL ACTIVITY CHARGES	**$ 45 918**	**$ 45 297**	**$ (621)**	**(1.4%)**	

CENTRA GAS MANITOBA INC.
ACTIVITY CHARGES, PRIMARY COSTS AND OVERHEADS **($000's)**

Primary Costs - 2010/11 Actual vs 2010/11 Approved **Page 4 of 6**

	2010/11 Actual	2010/11 Approved	Variance	%	Variance Explanations > $100,000 & 10%
PRIMARY COSTS					
External Course, Awards	26	54	29	52.8%	
Material	1 184	1 327	143	10.8%	Lower gas odourant required and less maintenance costs of internal regulating stations than anticipated.
Travel	101	173	72	41.5%	
Donations, Grants & Sponsorships	393	243	(149)	(61.4%)	Higher sponsorship costs including new Neighbors Helping Neighbors program.
Memberships	176	123	(53)	(42.8%)	
Bad Debt & Collection Expense	1 613	2 859	1 246	43.6%	Lower uncollectible accounts than forecasted.
Office Administration & Other	1 557	1 721	164	9.5%	
Computer Equipment & Maintenance	522	378	(144)	(38.2%)	Gas Supply software maintenance forecated in Purchased Services.
Meter Reading Charges (primarily MHUS)	1 949	2 342	392	16.8%	Repatriation of the line locate for the M3T3 locates previously performed by MHUS.
Banking/Cash Management Services	220	224	4	1.9%	
Construction & Maintenance Services	947	1 297	350	27.0%	Primarily lower System Integrity requirements and lower above and below ground maintenance work completed in Winnipeg and rural areas.
Purchased Services	1 772	1 494	(278)	(18.6%)	Unplanned DSM adversting, higher 35 Sutherland environmental monitoring and higher metering related costs partially offet by planned software maintenance charged to equipment maintenance.
Promotional Items/Customer Incentives	57	22	(35)	(155.1%)	
Gas-PUB & Advisory Services	491	826	335	40.6%	Lower Public Utilities Board Billings primarily due to engineering work that has been internalized by Centra staff.
Operating Expense Recoveries	(620)	(782)	(162)	20.8%	Lower disconnect and reconnect fees.
Other	1	5	4	80.8%	
PRIMARY COSTS	**$ 10 390**	**$ 12 307**	**$ 1 918**	**15.6%**	
Corporate Allocations & Adjustments	1 660	(713)	(2 373)	332.8%	Corporate governance and support costs previously included in overhead as well as a difference due to the allocation of the over/under absorption of the cost centres.
Overhead	7 870	12 346	4 476	36.3%	Mainly due to a lower actual overhead rate of 17% versus a forecasted rate of 27%.
TOTAL PROGRAM COSTS	**$ 65 838**	**$ 69 237**	**$ 3 399**	**4.9%**	
Depreciation, Interest & Taxes	(5 194)	(8 895)	(3 701)	41.6%	Removal of interest on common assets and motor vehicles.
TOTAL OPERATING & ADMIN EXPENSE	**$ 60 644**	**$ 60 342**	**$ (302)**	**(0.5%)**	

CENTRA GAS MANITOBA INC.
ACTIVITY CHARGES, PRIMARY COSTS AND OVERHEADS **($000's)**

Activity Charges by Program - 2011/12 Actual vs 2011/12 Forecast **Page 5 of 6**

	2011/12 Actual	2011/12 Forecast	Variance	%	Variance Explanations > $100,000 & 10%
PRESIDENT & CEO					
Audit	146	133	(13)	(9.9%)	
Liability Claims	0	-	(0)	0.0%	
Public Affairs	278	331	53	16.1%	
Research & Development	5	-	(5)	0.0%	
	$ 429	**$ 464**	**$ 35**	**7.5%**	
FINANCE & ADMINISTRATION					
IT - Distribution/Metering	87	162	75	46.2%	
IT - Banner	795	736	(59)	(8.0%)	
Gas Accounting	284	273	(11)	(3.9%)	
Gas Regulatory	869	1 095	225	20.6%	Less General Rate Application, Cost of Gas hearing and other regulatory matter activities than forecasted.
Gas Supply	2 422	2 357	(65)	(2.8%)	
Treasury	-	-	-	0.0%	
Property Tax Administration	14	20	6	32.1%	
	$ 4 471	**$ 4 643**	**$ 172**	**3.7%**	
POWER SUPPLY					
Environmental Management	139	130	(9)	(6.8%)	
	$ 139	**$ 130**	**$ (9)**	**(6.8%)**	
TRANSMISSION					
System Support & Communication Systems	67	137	70	51.0%	
	$ 67	**$ 137**	**$ 70**	**51.0%**	
CUSTOMER SERVICE & DISTRIBUTION					
Billing Inquiry & Collections	1 611	2 025	413	20.4%	Lower than expected customer billing inquiries and less time spent on collections activities.
Customer Inspections	8 371	8 682	311	3.6%	
Customer Relations	1 424	1 412	(12)	(0.9%)	
Dispatch	2 634	2 532	(102)	(4.0%)	
Customer Safety	1 649	1 848	199	10.8%	Lower safety related customer calls partially offset by higher safety watch requests than planned.
Distribution Maintenance	5 655	5 911	256	4.3%	
Emergency	86	-	(86)	0.0%	
Regulating Station Maintenance	3 923	3 726	(196)	(5.3%)	
Capacity Analysis & Engineering	395	611	216	35.4%	Shift of resources from network analysis to capital design work and lower volume of Facility Impact/3rd Party reviews.
System Integrity	933	979	46	4.7%	
Meter Reading	40	47	7	15.4%	
Meter Changes	3 081	2 447	(633)	(25.9%)	Higher number of meter changes than planned in both urban and rural locations to comply with new Measurement Canada standards.
	$ 29 800	**$ 30 219**	**$ 419**	**1.4%**	
CUSTOMER CARE & MARKETING					
Billing Inquiry & Collections	4 627	4 791	164	3.4%	
Customer Relations	4 508	4 422	(86)	(1.9%)	
Customer Safety	150	202	52	25.5%	
Quality Assessment	574	567	(7)	(1.2%)	
Load Forecast	142	178	36	20.3%	
Meter Repair & Calibration	1 667	1 414	(253)	(17.9%)	Higher number of meter changes than planned in both urban and rural locations to comply with new Measurement Canada standards.
	$ 11 669	**$ 11 575**	**$ (93)**	**(0.8%)**	
TOTAL ACTIVITY CHARGES	**$ 46 574**	**$ 47 167**	**$ 593**	**1.3%**	

CENTRA GAS MANITOBA INC.
ACTIVITY CHARGES, PRIMARY COSTS AND OVERHEADS **($000's)**

Primary Costs - 2011/12 Actual vs 2011/12 Forecast

	2011/12 Actual	2011/12 Forecast	Variance	%	Variance Explanations > $100,000 & 10%
PRIMARY COSTS					
External Course, Awards	21	26	5	19.4%	
Material	1 170	1 343	173	12.9%	Lower Burner Tip Program costs due to mild weather and less customer calls and less gas odourant costs also due to the mild winter partially offset by higher metering costs.
Travel	79	101	22	21.4%	
Donations, Grants & Sponsorships	476	267	(210)	(78.6%)	Higher sponsorship costs including new Neighbors Helping Neighbors program.
Memberships	187	116	(71)	(60.8%)	
Bad Debt & Collection Expense	1 435	1 655	219	13.3%	Lower uncollectible accounts than forecasted.
Office Administration & Other	1 608	1 500	(107)	(7.1%)	
Computer Equipment & Maintenance	452	552	100	18.1%	Reduced software maintenance for Customer Information, Treasury and Gas Supply applications.
Meter Reading Charges (primarily MHUS)	2 130	1 922	(207)	(10.8%)	Higher meter reading costs than expected and DSM standards consulting that should have been charged to Purchased Services.
Banking/Cash Management Services	255	273	18	6.6%	
Construction & Maintenance Services	1 823	1 183	(640)	(54.1%)	Unplanned meter changes performed by MHUS to comply with new Measurement Canada standards.
Purchased Services	1 506	1 980	474	23.9%	Delayed DSM advertising and postponement of environmental monitoring of Red River sediments until 2012/13 due to unsafe river ice conditions.
Promotional Items/Customer Incentives	71	21	(50)	(235.3%)	
Gas-PUB & Advisory Services	496	520	24	4.6%	
Operating Expense Recoveries	(598)	(581)	17	(2.9%)	
Other	(1)	6	7	118.2%	
PRIMARY COSTS	**$ 11 110**	**$ 10 883**	**$ (227)**	**(2.1%)**	
Corporate Allocations & Adjustments	1 718	3 160	1 442	45.6%	Mainly due to unallocated general contingency.
Overhead	7 990	8 086	97	1.2%	
TOTAL PROGRAM COSTS	**$ 67 392**	**$ 69 297**	**$ 1 905**	**2.8%**	
Depreciation, Interest & Taxes	(5 275)	(5 297)	(22)	0.4%	
TOTAL OPERATING & ADMIN EXPENSE	**$ 62 117**	**$ 64 000**	**$ 1 883**	**2.9%**	

PUB/CENTRA I-19

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Page 2 of 30; 2009/10 & 2010/11 GRA PUB/Centra 15**

Please file a summary of revenue requirement and deficiency from 2010/11 Approved for the 2012/13 forecast year and the 2013/14 test year in a similar format to that provided in response to PUB/Centra 15 from the 2009/10 & 2010/11 GRA. Please include a column showing the percentage change in addition to the net change.

ANSWER:

Please see the table included below.

($000's)

	Last Approved [1]	2012/13 Forecast Year	Net Change from Last Approved	Net Change % from Last Approved	Last Approved [1]	2013/14 Test Year	Net Change from Last Approved	Net Change % from Last Approved
Revenue Requirement:								
Cost of Gas	331,442	175,576	(155,866)	-47%	331,442	168,279	(163,163)	-49%
Other Income	(2,026)	(1,705)	321	-16%	(2,026)	(1,866)	160	-8%
Operating & Administrative	60,343	67,300	6,957	12%	60,343	68,800	8,457	14%
Depreciation & Amortization	27,367	27,620	253	1%	27,367	30,091	2,724	10%
Furnace Replacement Program	3,800	-	(3,800)	-	3,800	-	(3,800)	-
Capital and Other Taxes	23,940	18,334	(5,606)	-23%	23,940	18,750	(5,190)	-22%
Finance Expense	19,105	17,901	(1,204)	-6%	19,105	17,296	(1,809)	-9%
Corporate Allocation	12,000	12,000	-	-	12,000	12,000	-	-
Net Income	2,505	1,562	(943)	-38%	2,505	4,821	2,316	92%
Revenue Requirement from Gas Rates	478,476	318,588	(159,888)	-33%	478,476	318,171	(160,305)	-34%
Revenue on existing base rates		318,588				312,426		
Non Gas Revenue Deficiency		-				5,745		
Rate Base:								
Gas Plant in Service	634,052	658,683	24,631	4%	634,052	681,747	47,695	8%
Accumulated Depreciation	(229,807)	(232,935)	(3,128)	1%	(229,807)	(241,999)	(12,192)	5%
Net Plant	404,245	425,747	21,503	5%	404,245	439,749	35,503	9%
Contributions in Aid of Construction	(50,956)	(51,931)	(975)	2%	(50,956)	(53,062)	(2,106)	4%
Working Capital Allowance	132,576	105,031	(27,545)	-21%	132,576	102,867	(29,709)	-22%
Total Rate Base	485,864	478,847	(7,017)	-1%	485,864	489,553	3,688	1%

[1] Last approved is comprised of 2010/11 Test Year approved

PUB/CENTRA I-20

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Schedule 5.5.0 - Manitoba Hydro's OM&A**

a) Please provide a schedule that details Manitoba Hydro's overall OM&A expense by business unit, the amounts allocated or directly assigned to Centra for each of the business units and the percentage of the total allocated for each for the years 2008/09 through 2013/14.

ANSWER:

Please see the schedule below. It is noted that the schedule does not include OM&A expenses charged to Centra through Corporate Allocations and Adjustments (CAA).

The decrease in the percentage allocated to the business units between 2011/12, the 2012/13 forecast year and the 2013/14 test year is due to the reallocation of information technology support costs and administrative building costs previously included in activity or overhead rates which are now directly allocated to Centra through CAA using cost drivers.

($000's)	2008/09 Actual Total Operating Costs Consolidated	2008/09 Actual Program Costs Centra Gas	2008/09 Actual Allocated %	2009/10 Actual Total Operating Costs Consolidated	2009/10 Actual Program Costs Centra Gas	2009/10 Actual Allocated %	2010/11 Actual Total Operating Costs Consolidated	2010/11 Actual Program Costs Centra Gas	2010/11 Actual Allocated %
President & CEO	24,230	1,374	5.7%	31,578	1,222	3.9%	28,835	972	3.4%
Corporate Relations	5,520	-	0.0%	4,697	-	0.0%	4,739	-	0.0%
Finance & Administration	103,722	6,549	6.3%	108,914	6,742	6.2%	106,528	6,693	6.3%
Power Supply	142,183	47	0.0%	147,073	220	0.1%	150,120	477	0.3%
Transmission	91,088	224	0.2%	92,302	255	0.3%	90,493	250	0.3%
Customer Service & Distribution	103,762	38,078	36.7%	111,068	40,288	36.3%	106,707	37,941	35.6%
Customer Care & Marketing	38,942	19,765	50.8%	42,395	18,671	44.0%	41,446	17,845	43.1%
	509,446	66,037	13.0%	538,027	67,397	12.5%	528,867	64,178	12.1%

($000's)	2011/12 Actual			2012/13 Test Year			2013/14 Test Year		
	Total Operating Costs Consolidated	Program Costs Centra Gas	Allocated %	Total Operating Costs Consolidated	Program Costs Centra Gas	Allocated %	Total Operating Costs Consolidated	Program Costs Centra Gas	Allocated %
President & CEO	28,328	1,122	4.0%	28,692	891	3.1%	29,266	909	3.1%
Corporate Relations	3,025	-	0.0%	4,491	-	0.0%	4,581	-	0.0%
Finance & Administration	107,443	6,377	5.9%	114,343	6,187	5.4%	116,630	6,311	5.4%
Power Supply	155,084	- 317	0.2%	177,982	404	0.2%	181,541	412	0.2%
Transmission	89,261	- 99	0.1%	104,762	194	0.2%	106,857	197	0.2%
Customer Service & Distribution	110,045	- 39,564	36.0%	130,358	38,493	29.5%	132,966	39,263	29.5%
Customer Care & Marketing	43,703	- 18,195	41.6%	51,749	17,575	34.0%	52,784	17,926	34.0%
	536,889	65,674	12.2%	612,377	63,744	10.4%	624,624	65,019	10.4%

PUB/CENTRA I-20

Subject: Tab 5: Financial Results & Forecast

Reference: Tab 5 Schedule 5.5.0 - Manitoba Hydro's OM&A

b) Please indicate which expenses are directly assigned versus indirectly assigned, and the cost drivers used for the appropriate assignment.

ANSWER:

Please see the schedule below.

('000s)

($000's)	2008/09 Actual Direct	2008/09 Actual Indirect	2009/10 Actual Direct	2009/10 Actual Indirect	2010/11 Actual Direct	2010/11 Actual Indirect	2011/12 Actual Direct	2011/12 Actual Indirect	2012/13 Forecast Direct	2012/13 Forecast Indirect	2013/14 Test Year Direct	2013/14 Test Year Indirect
President & CEO	558	817	309	913	105	867	145	977	328	563	334	575
Finance & Administration	5,104	1,445	5,415	1,327	5,253	1,440	4,926	1,451	4,745	1,442	4,840	1,471
Power Supply	47	-	220	-	477	-	317	-	404	-	412	-
Transmission	206	18	240	15	233	16	84	14	181	13	184	13
Customer Service & Distribution	32,080	5,998	32,557	7,731	30,398	7,543	32,351	7,213	32,121	6,373	32,763	6,500
Customer Care & Marketing	14,538	5,227	9,445	9,226	9,553	8,292	9,802	8,393	9,237	8,337	9,422	8,504
	52,533	13,504	48,185	19,213	46,019	18,158	47,625	18,049	47,015	16,728	47,956	17,063

The following table provides common cost drivers that are used to allocate integrated activities.

Driver	Electric	Gas	Common Order Examples	Rationale
Customers	67%	33%	Bill Insertion Operations	1
Customers	67%	33%	Joint Billing Initiative	1
Total Assets	96%	4%	Donations, Grants & Sponsorships	2
Total Assets	96%	4%	Audit Costs - Common	2
Total Assets	96%	4%	Public Affairs - Common	2
Total Assets	96%	4%	Corporation Memberships - Common	2
Credit & Recovery Services Activity	60%	40%	Collection Agency	3
Activity Charges	90%	10%	Awards & Service Recognition	4
Activity Charges	90%	10%	Operating Contingency	4
Activity Charges	Various	Various	Line Locates	5
Activity & Frequency	Various	Various	Safety Watches	5

Rationale for allocations:

1. These types of costs are driven by the number customers.
2. This is a general driver that represents the relative size of the utilities.
3. This allocation is based on activity charges of the Credit & Recovery Services Department activity.
4. This is a general driver that represents the relative amount of activity charges by staff to each of the utilities.
5. Where specific departments perform gas and electric functions simultaneously (e.g. line locates) the cost driver is based upon the relative estimate of time required and the frequency of the task performed for each of the utilities. The relative percentages range from 50% electric and 50% gas to 96% electric and 4% gas.

PUB/CENTRA I-20

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Schedule 5.5.0 - Manitoba Hydro's OM&A**

c) Please indicate whether any of the cost drivers have changed since the 2009/10 & 2010/11 GRA and the rationale for the changes.

ANSWER:

The only change to the cost drivers since the 2009/10 & 2010/11 GRA is the removal of the number of bills cost driver. Common orders such as Bill Insertion Operations & Postage now use the number of customers as the driver for the allocation of costs between electric and gas operations. It was determined that the nature of the costs contained in these types of common orders was more accurately reflected in each of the utilities through this cost driver.

Where specific departments perform gas and electric functions simultaneously minor changes to common cost drivers are made as circumstances change.

PUB/CENTRA I-20 (Revised)

Subject: Tab 5: Financial Results & Forecast

Reference: Tab 5 Schedule 5.5.0 - Manitoba Hydro's OM&A

d) Please provide, by department, the wage level / average salary for the years 2003/04 to 2011/12 and forecasted for 2012/13 & 2013/14.

ANSWER:

Please see the following tables for the average salary per EFT from 2004/05 through 2013/14. This represents the average salaries of all employees of the integrated utility. For staff that support the gas operations, their wages are imbedded in the activity rates used to allocate operating costs to Centra. Information for 2003/04 was not provided in previous Information Requests and is not readily available.

MANITOBA HYDRO
AVERAGE SALARY PER EFT BY BUSINESS UNIT **(000's)**

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
President & CEO	$ 75.506	77.871	80.242	83.218	85.688	92.174	92.436	95.891	97.134	99.077
Corporate Relations	$ 55.866	58.672	62.648	63.417	62.454	63.131	63.983	68.324	68.939	70.318
Finance & Administration	$ 59.926	61.428	63.724	65.868	67.298	70.879	71.751	76.281	76.672	78.206
Power Supply	$ 59.079	60.821	62.965	64.877	66.014	68.747	69.616	73.790	75.603	77.115
Transmission	$ 58.968	60.649	62.663	64.717	66.084	68.703	70.226	74.346	76.805	78.341
Customer Services & Distribution	$ 52.705	53.622	55.011	56.094	57.220	60.088	61.135	64.733	67.261	68.606
Customer Care & Marketing	$ 52.775	53.303	55.366	57.106	58.490	61.444	61.893	66.095	67.102	68.444
Business Unit Total	**$ 57.225**	**$ 58.571**	**$ 60.550**	**$ 62.309**	**$ 63.646**	**$ 66.716**	**$ 67.736**	**$ 72.017**	**$ 73.612**	**$ 75.084**

MANITOBA HYDRO
AVERAGE SALARY PER EFT BY DIVISION **(000's)**

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
President & CEO										
General Counsel	$ 68.805	70.845	74.035	78.551	85.035	88.444	90.328	93.731	92.521	94.371
Public Affairs	$ 52.882	55.879	56.589	59.978	60.337	63.809	65.682	72.068	72.026	73.467
Research & Development	$ 77.397	78.378	75.776	77.842	83.868	90.518	56.003	55.238	55.761	56.876
Corporate Planning & Strategic Review	$ 78.297	78.706	81.679	83.763	82.711	91.139	89.433	90.875	95.403	97.311
VP Corp Planning & Strat Analysis	$ -	-	-	-	-	115.735	108.493	112.319	-	-
Administration	$ 111.497	112.009	112.815	114.786	118.753	127.271	124.135	127.592	131.531	134.161
	$ 75.506	**$ 77.871**	**$ 80.242**	**$ 83.218**	**$ 85.688**	**$ 92.174**	**$ 92.436**	**$ 95.891**	**$ 97.134**	**$ 99.077**
Corporate Relations										
Aboriginal Relations	$ 50.884	52.333	56.567	57.607	56.628	60.147	61.469	65.749	66.309	67.635
Administration	$ 96.251	101.217	105.874	110.320	110.598	104.715	108.406	123.827	135.412	138.120
	$ 55.866	**$ 58.672**	**$ 62.648**	**$ 63.417**	**$ 62.454**	**$ 63.131**	**$ 63.983**	**$ 68.324**	**$ 68.939**	**$ 70.318**
Finance & Administration										
Information Technology Services	$ 62.562	63.309	67.122	70.187	72.140	75.848	76.622	81.129	82.671	84.325
Treasury	$ 67.124	64.868	63.057	66.653	69.826	72.647	73.944	76.284	73.184	74.648
Corporate Risk Mgmt Department	$ 90.555	93.935	104.360	95.747	97.363	84.998	93.196	100.976	102.068	104.109
Gas Supply	$ 69.279	71.046	72.824	75.492	76.106	79.781	83.478	89.980	92.749	94.604
Rates & Regulatory Affairs	$ 69.353	72.330	73.072	75.235	74.565	77.711	78.675	84.017	84.975	86.675
Corporate Controller	$ 62.541	65.040	66.716	71.090	73.897	77.628	76.768	80.772	81.868	83.506
Human Resources	$ 61.916	64.335	65.940	68.068	68.024	72.487	72.858	78.396	77.234	78.779
Corporate Safety & Health	$ 68.548	69.644	70.450	72.795	74.611	78.448	79.469	83.685	81.119	82.742
Corporate Services	$ 50.174	51.635	53.201	53.644	54.775	58.386	59.822	63.481	63.784	65.060
Administration	$ 81.458	88.305	89.425	95.090	95.888	99.936	106.539	125.325	127.836	130.393
	$ 59.926	**$ 61.428**	**$ 63.724**	**$ 65.868**	**$ 67.298**	**$ 70.879**	**$ 71.751**	**$ 76.281**	**$ 76.672**	**$ 78.206**
Power Supply										
Power Planning	$ 72.753	73.136	76.619	76.909	79.466	83.089	83.629	87.892	90.856	92.673
Power Projects Development	$ 71.717	73.628	76.374	76.685	79.910	82.465	81.646	85.056	86.314	88.041
Portfolio Projects Management	$ -	78.077	73.119	69.485	66.139	67.566	70.363	70.635	81.011	82.631
HVDC	$ 56.759	61.032	62.507	64.093	66.145	68.505	69.546	73.957	76.274	77.799
Generation North	$ 55.241	58.822	61.374	63.428	64.789	67.885	68.549	72.627	73.797	75.273
Generation South	$ 55.288	58.677	60.231	62.236	64.079	67.235	68.570	72.657	74.510	76.000
Power Sales & Operations	$ 68.894	71.116	74.205	78.069	80.735	83.150	83.921	88.928	91.655	93.488
Engineering Services	$ 66.551	67.602	68.825	71.429	72.525	74.711	75.305	79.690	82.392	84.040
New Generation Construction	$ 71.192	67.757	70.906	69.967	69.180	72.064	74.845	79.731	80.757	82.372
Administration	$ 61.263	46.770	49.770	49.656	49.326	51.295	51.943	55.666	56.317	57.443
	$ 59.079	**$ 60.821**	**$ 62.965**	**$ 64.877**	**$ 66.014**	**$ 68.747**	**$ 69.616**	**$ 73.790**	**$ 75.603**	**$ 77.115**

MANITOBA HYDRO
AVERAGE SALARY PER EFT BY DIVISION (000's)

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
Transmission										
Transmission System Operations	$ 64.364	65.675	67.813	70.473	73.140	76.549	77.900	81.442	84.036	85.717
Transmission Planning & Design	$ 62.929	65.636	66.820	71.606	73.838	77.428	79.259	82.563	87.010	88.750
Transmission Construction & Line Mtce	$ 54.936	56.418	59.039	60.948	62.665	65.015	65.714	70.356	72.197	73.641
Apparatus Maintenance	$ 54.273	55.982	57.578	58.809	59.074	61.392	63.370	67.505	69.817	71.214
Administration	$ 60.859	62.434	64.955	64.445	61.098	58.692	60.561	64.333	63.237	64.502
	$ 58.968	**$ 60.649**	**$ 62.663**	**$ 64.717**	**$ 66.084**	**$ 68.703**	**$ 70.226**	**$ 74.346**	**$ 76.805**	**$ 78.341**
Customer Services & Distribution										
Customer Service Operations - Wpg&North	$ 54.277	55.634	57.114	58.109	59.137	60.840	61.821	65.207	66.834	68.170
Customer Service Operations - South	$ 51.757	52.493	53.844	54.930	56.263	59.144	60.557	63.728	66.999	68.339
Distribution E&C Rural	$ 53.097	53.731	55.687	56.464	57.105	61.055	61.198	64.806	67.221	68.566
Distribution E&C Winnipeg	$ 51.216	52.009	52.934	54.431	55.703	58.419	59.656	63.309	66.003	67.323
Administration	$ -	-	-	-	76.235	107.873	124.256	91.462	94.393	96.281
	$ 52.705	**$ 53.622**	**$ 55.011**	**$ 56.094**	**$ 57.220**	**$ 60.088**	**$ 61.135**	**$ 64.733**	**$ 67.261**	**$ 68.606**
Customer Care & Marketing										
Industrial & Commercial Solutions	$ 72.079	72.701	74.687	78.806	82.082	85.611	86.140	90.377	93.335	95.201
Consumer Marketing & Sales	$ 49.546	50.414	52.816	53.540	53.777	56.488	57.369	62.008	63.498	64.768
Business Support Services	$ 49.354	49.732	51.691	53.528	54.814	57.530	58.336	61.946	62.019	63.259
Administration	$ 65.797	66.606	67.340	69.181	71.629	72.630	70.379	75.261	76.602	78.134
	$ 52.775	**$ 53.303**	**$ 55.366**	**$ 57.106**	**$ 58.490**	**$ 61.444**	**$ 61.893**	**$ 66.095**	**$ 67.102**	**$ 68.444**
Total	**$ 57.225**	**$ 58.571**	**$ 60.550**	**$ 62.309**	**$ 63.646**	**$ 66.716**	**$ 67.736**	**$ 72.017**	**$ 73.612**	**$ 75.084**

PUB/CENTRA I-20

Subject: Tab 5: Financial Results & Forecast

Reference: Tab 5 Schedule 5.5.0 - Manitoba Hydro's OM&A

e) Please file a summary of wage settlements with Centra's unions.

ANSWER:

The following provides a summary of the contracted wage settlements since April 1, 2008.

Union	Effective Date	Wage Settlement
CEPU	December 25, 2008	2.90%
CEPU	December 22, 2010	1.00%
CEPU	December 23, 2010	2.50%
CEPU	December 22, 2011	2.50%
CEPU	December 22, 2012 (and beyond)	In Negotiations

In 2008, the 2.9% was 2.0% General Wage Increase and 0.9% special adjustment.

PUB/CENTRA I-21

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 Page 1 of 23; 2009/10 & 2010/11 GRA PUB/Centra 36 – Integrated Cost Allocation Methodology**

a) **Please file a copy of the Integrated Cost Allocation Methodology description similar to that filed as PUB/Centra 37 to the 2009/10 & 2010/11 GRA and confirm whether the schematic is applicable in the current GRA. If not, please file a revised schematic showing black lined changes with descriptions and rationale for any changes.**

ANSWER:

Please refer to the attached document, where the schematic has been updated with bold black lines to reflect the changes that have been made since the last GRA.

Historically under CGAAP, Centra utilized a full cost accounting approach to the capitalization of administrative and overhead costs. Changes in overhead capitalization practices implemented to date recognize industry trends to move away from full cost accounting and are designed to make the Corporation's practices consistent with those of other Canadian utilities. Since the last GRA, costs have been removed from overhead pools and allocated directly to the Centra income statement.

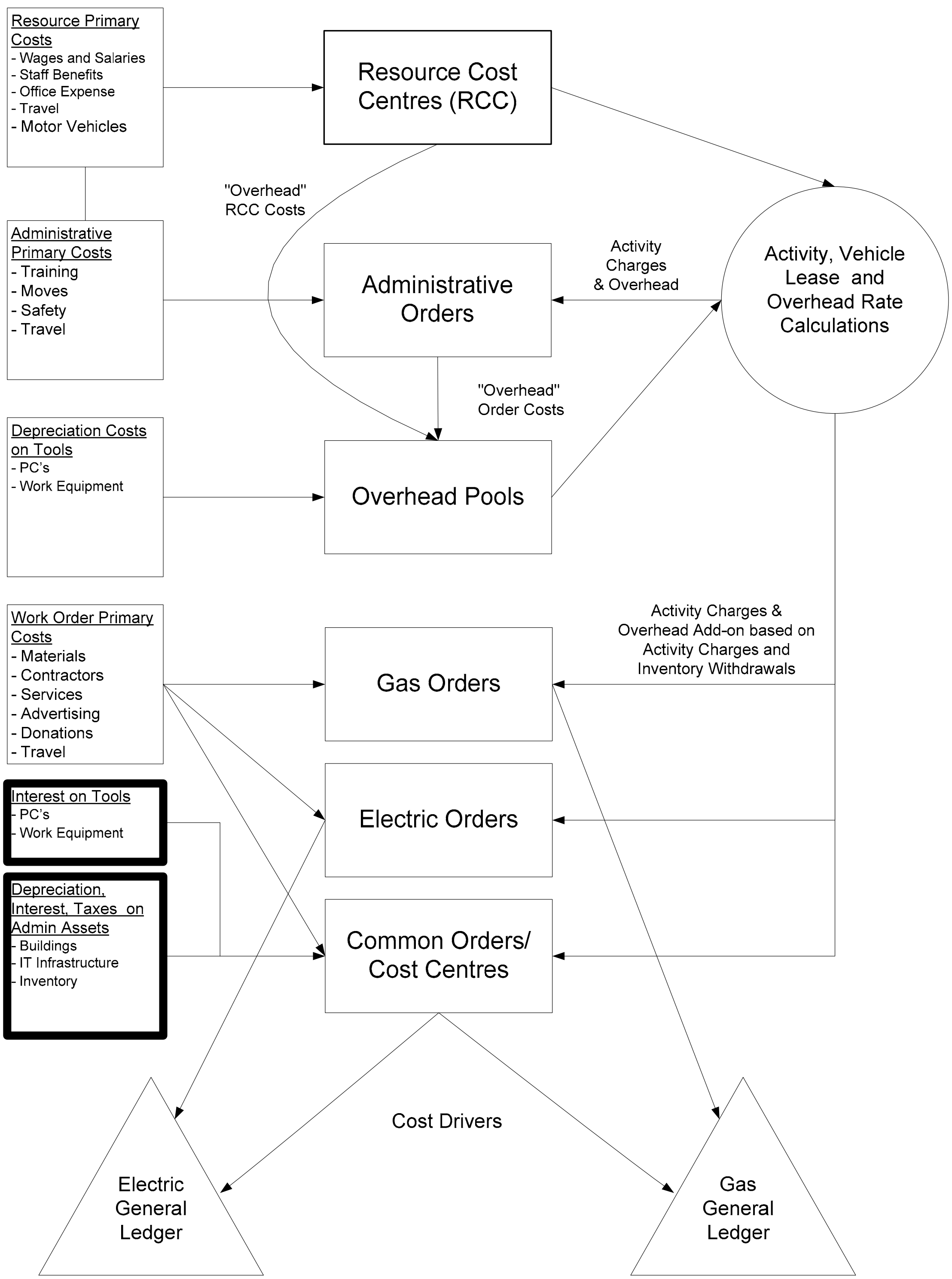
Items removed from overhead pools include interest on equipment and facilities, building depreciation and operating costs, IT infrastructure and related support, as well as various corporate department costs. These changes are compliant with CGAAP and have been fully endorsed by Manitoba Hydro's external auditors.

CENTRA GAS MANITOBA INC.
2013/14 GENERAL RATE APPLICATION

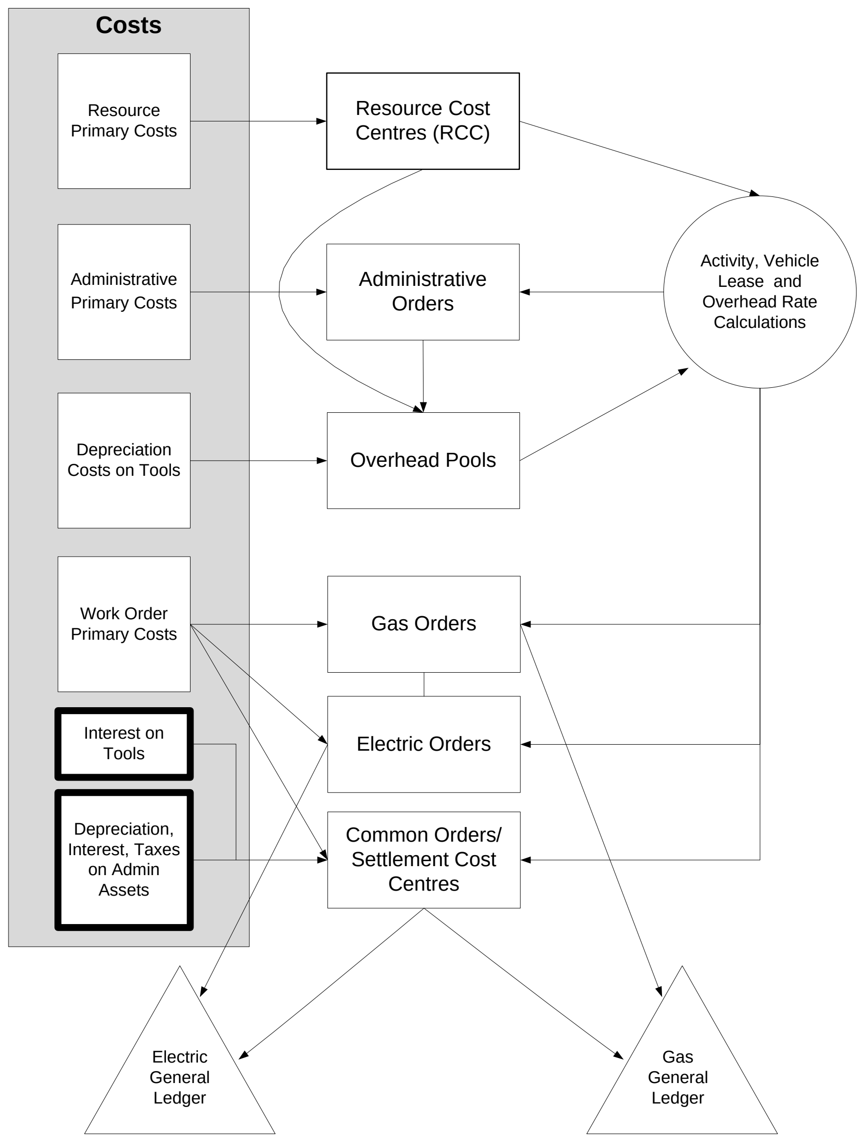
Cost Allocation Methodology

The following information provides schematics and a more detailed description of the cost allocation methodology used to allocate Cost of Operations to the gas and electric utilities.

Cost Allocation Schematic



<u>Costs</u>



Costs are broken down into two main categories – primary costs and indirect costs. *Primary costs* are incurred by the Corporation in support of its operating and capital activities and are classified according to their cost elements. Indirect costs include interest, depreciation, and taxes on administrative and general assets that are used in support and administration functions. Interest, depreciation and taxes on generation, transmission, and distribution facilities and on computer systems that directly support operating functions of either utility are charged directly to the general ledger of the utility that they pertain to.

a) Resource Primary Costs

Resource primary costs are the direct costs of operating a cost centre and include employee-related costs such as wages, salaries, staff benefits, office expenses & travel.

b) Administrative Primary Costs

Administrative primary costs are those that are incurred in the overhead and support functions of utility operations. The costs of safety programs and moves are examples of administrative primary costs.

c) Depreciation on Tools

Depreciation on tools is allocated to overhead. The tools are used to complete the work performed by employees and includes personal computers and work equipment.

d) Work Order Primary Costs

Work Order Primary Costs are those that are incurred directly in support of the operating, capital, and customer service functions of the utilities. These costs include mainly the materials and services that are purchased to support these functions, and may also include other costs such as advertising and promotion, travel & meals, computer services and software licensing for systems that support operational functions.

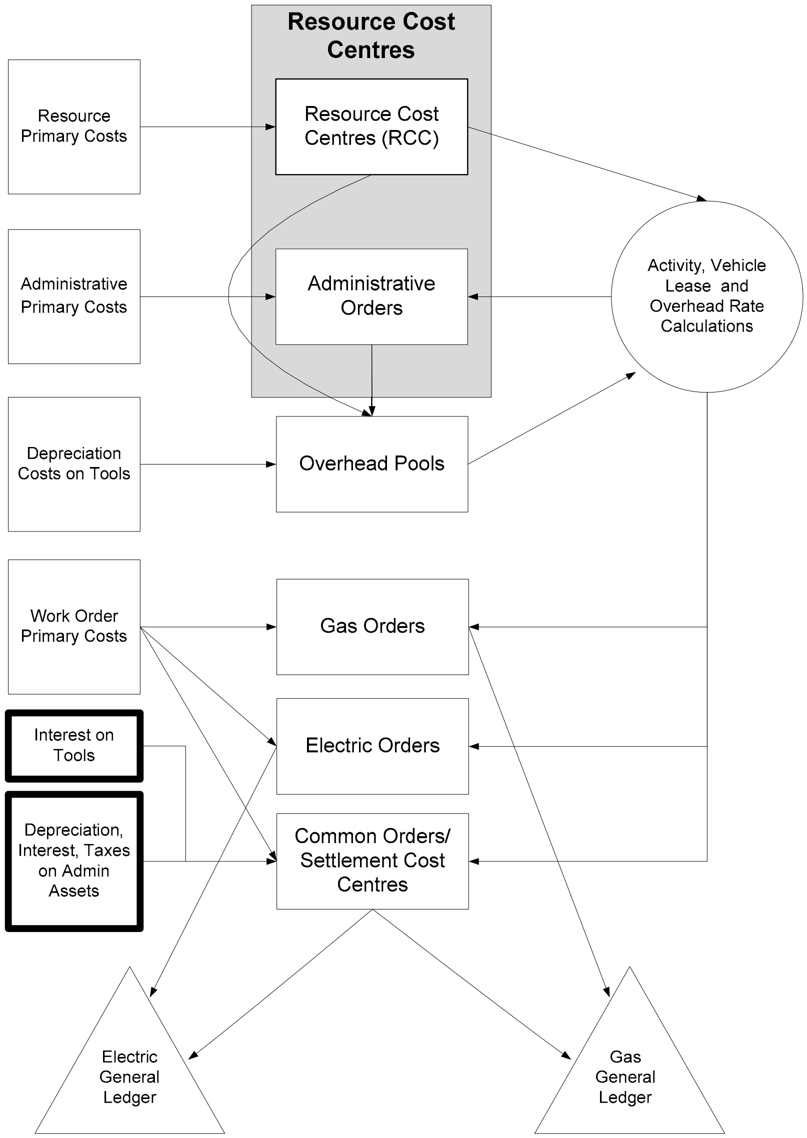
e) Interest on Tools

The interest costs on tools used to complete work performed by employees. The tools include personal computers and work equipment.

f) Interest, Depreciation and Taxes on Administrative Assets

These represent the costs associated with office buildings, communication equipment, office furniture and fixtures and IT infrastructure that have been acquired for administration and support functions. The interest associated with stores inventory is also included in this category.

Resource Cost Centres & Administrative Orders



a) Resource Cost Centres

Resource cost centres capture the people related costs associated with providing a pool of resources to operate, maintain and construct the Corporation's assets and to provide service to customers. Resource cost centres include the costs of employees that perform services for the gas, electric or both utilities.

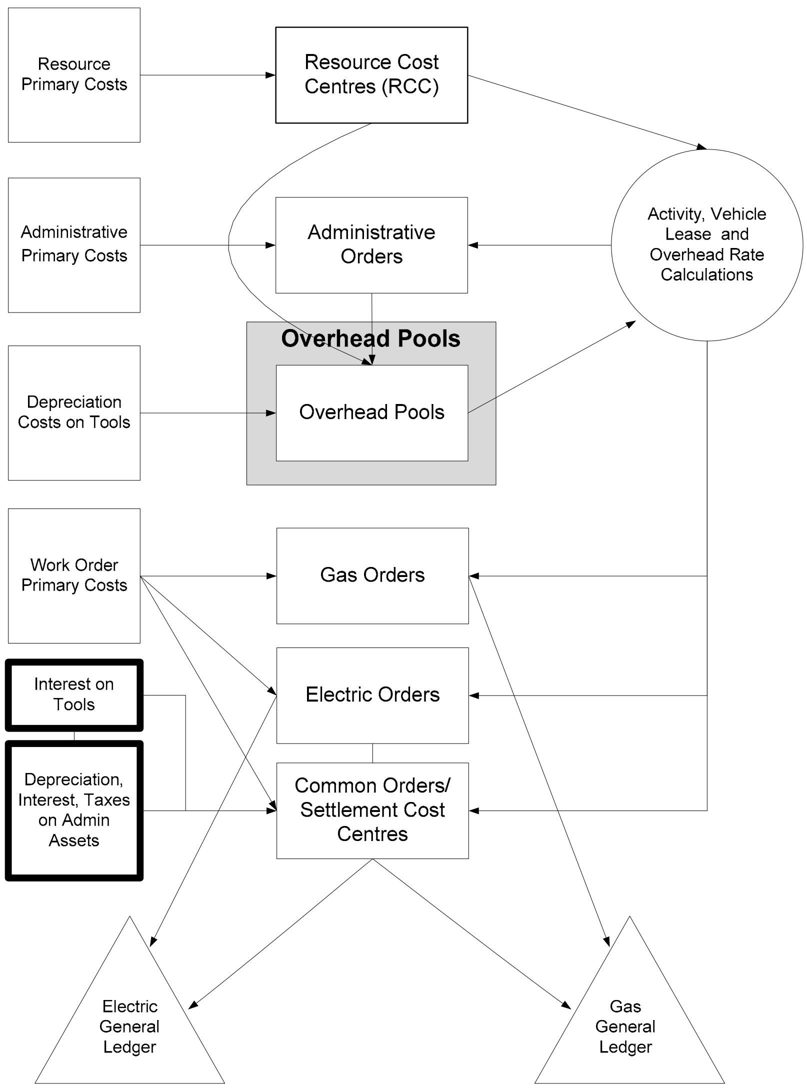
Primary costs are charged to resource cost centres, as are other allocated costs that form part of the base operating cost of a department. Allocated costs include vehicle usage cost elements.

Costs that are accumulated in resource cost centres are either used to derive activity rates or charged to overhead pools for subsequent allocation. Activity rates are used as the basis for charging resource centre costs to orders.

b) <u>Administrative Orders</u>

Administrative orders collect the costs of programs and functions that are administrative or support in nature. Examples of these types of orders include training, safety and employee moves. All program and function costs, including administrative primary costs and labour are recorded in these orders. The process for recording labour and overhead into these orders is described on page 10 of this section. Costs accumulated in administrative orders are allocated to overhead.

<u>Overhead Pools</u>

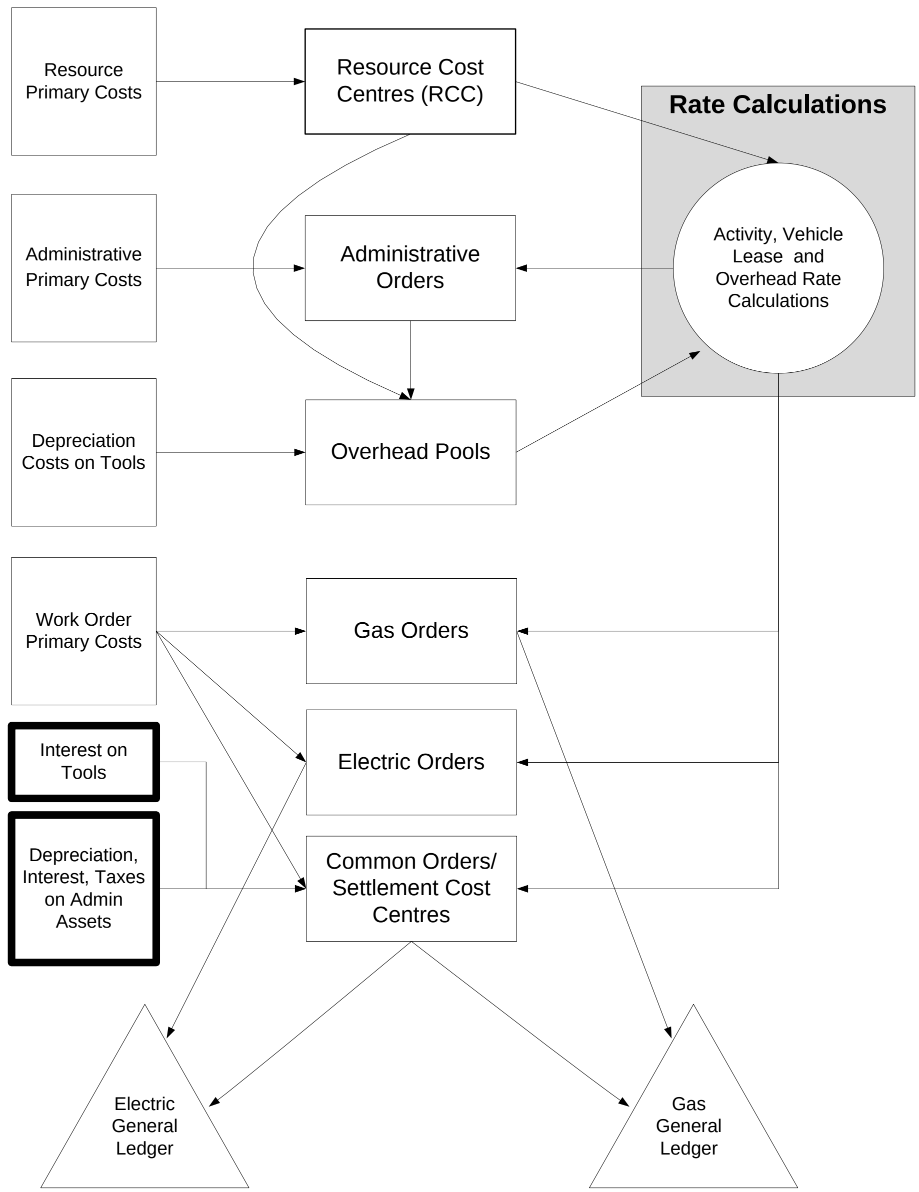


Overhead pools include the following types of costs:

- Corporate service costs such as human resources, financial services and safety that are required by the Corporation to support various activities.
- General and administrative support staff and expenditures such as office supplies and printing services.

- Division and department manager salaries and associated expenses.
- Depreciation and operating costs of employee tools such as personal computers and technical design software.
- Costs associated with accounts payables, the procurement process, training and employee moves.

Overhead costs are collected and pooled for allocation purposes.


Resource Primary Costs
Resource Cost Centres (RCC)
Rate Calculations
Administrative Primary Costs
Administrative Orders
Activity, Vehicle Lease and Overhead Rate Calculations
Depreciation Costs on Tools
Overhead Pools
Work Order Primary Costs
Gas Orders
Interest on Tools
Electric Orders
Depreciation, Interest, Taxes on Admin Assets
Common Orders/ Settlement Cost Centres
Electric General Ledger
Gas General Ledger

1. <u>Activity, Overhead and Equipment Rate Calculations</u>

Costs accumulated in resource cost centres and in overhead pools are charged to operating functions through the following methods:

- Activity charges which are based on time spent.
- Overhead allocation based upon a percentage markup on activity charges.
- Stores overhead, based upon a percentage markup on materials used.
- Vehicle and work equipment costs are charged into resource cost centres using unit rates which are calculated based upon the cost of owning and operating this equipment.

a) <u>Activity Charges</u>

Activity charges form the basis for cost allocation to the gas and electric utilities. Activity charges are based on the time spent performing capital, operating and administrative and support functions within the company, and are calculated by multiplying hours spent by activity rates. Activity rates are used to allocate internal costs from a cost centre to programs in support of gas or electric operations.

Activity rates are calculated for work groups that perform a common set of functions and for groups of staff within a cost centre that have like costs associated with them. Staff can be grouped together regardless of what they are working on, as long as the costs associated with those staff (primarily salaries) are not materially different. For example, two employees in a cost centre who earn substantially the same wages & salaries will be grouped together in determining their activity type and associated rate. If their wages & salaries are materially different, separate activity types and rates are used. A further example of where separate activity types and rates are required is where some employees in a cost centre use a vehicle and others don't. Cost centre managers have discretion in determining the number of activity rates and hence the groupings of staff within their cost centre.

Activity capacity within cost centres is estimated based on the number of available hours during the year. From this information, standard rates are developed for groups as described above. Activity charges are then applied to programs in support of gas or electric operations using these standard activity rates multiplied by the number of hours worked.

Straight time activity rates are built up from the following cost elements:

- Wages, salaries & benefits
- Meals & accommodations
- Transportation
- Vehicle charges

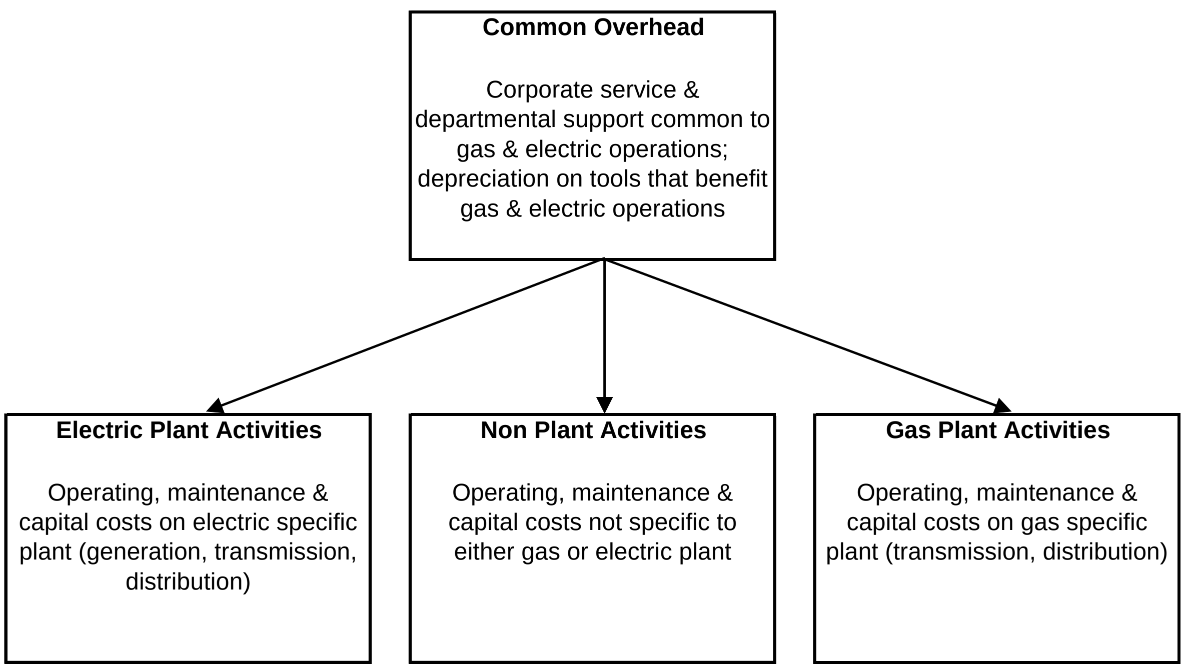
Straight time activity rates generally have a corresponding overtime activity rate. Overtime rates are calculated using the straight time rate and adding on overtime wage and benefit premiums.

b) <u>Administrative and General Overhead Allocation</u>

There are two main methods of overhead allocation used: one for common overhead and one stores overhead.

Common overhead is allocated to activities on the basis of a percentage add-on to activity dollars charged to that activity. Common overhead costs are allocated on the basis of all activities.

The following diagram provides an overview of the application of common overhead to activities:



Common Overhead

The main components of this overhead category are as follows:

- Corporate service and departmental support costs such as human resources, financial services and safety that are required by the Corporation to support various activities.
- Depreciation and operating costs of employee tools such as personal computers and technical design software.
- Costs associated with accounts payables, the procurement process and employee moves.

Allocation

Common overhead is allocated on the basis of activity charges. All activity charges, whether operating or capital, gas or electric receive the same overhead percentage add-on to their activity charges. The current add-on percentage for common overhead is 25% which consists of a 20% common overhead rate and a 5% tool and procurement rate.

Stores Overhead

Stores overhead is accumulated and then allocated on the basis of materials used. Costs accumulated in this category include resource centre costs, facilities costs, primary costs incurred in the performance of the function, vehicle and equipment charges and an apportionment of administrative costs.

Costs are allocated as a percentage mark-up on the value of the materials that are consumed. The current add-on rate for materials is 10% for all materials.

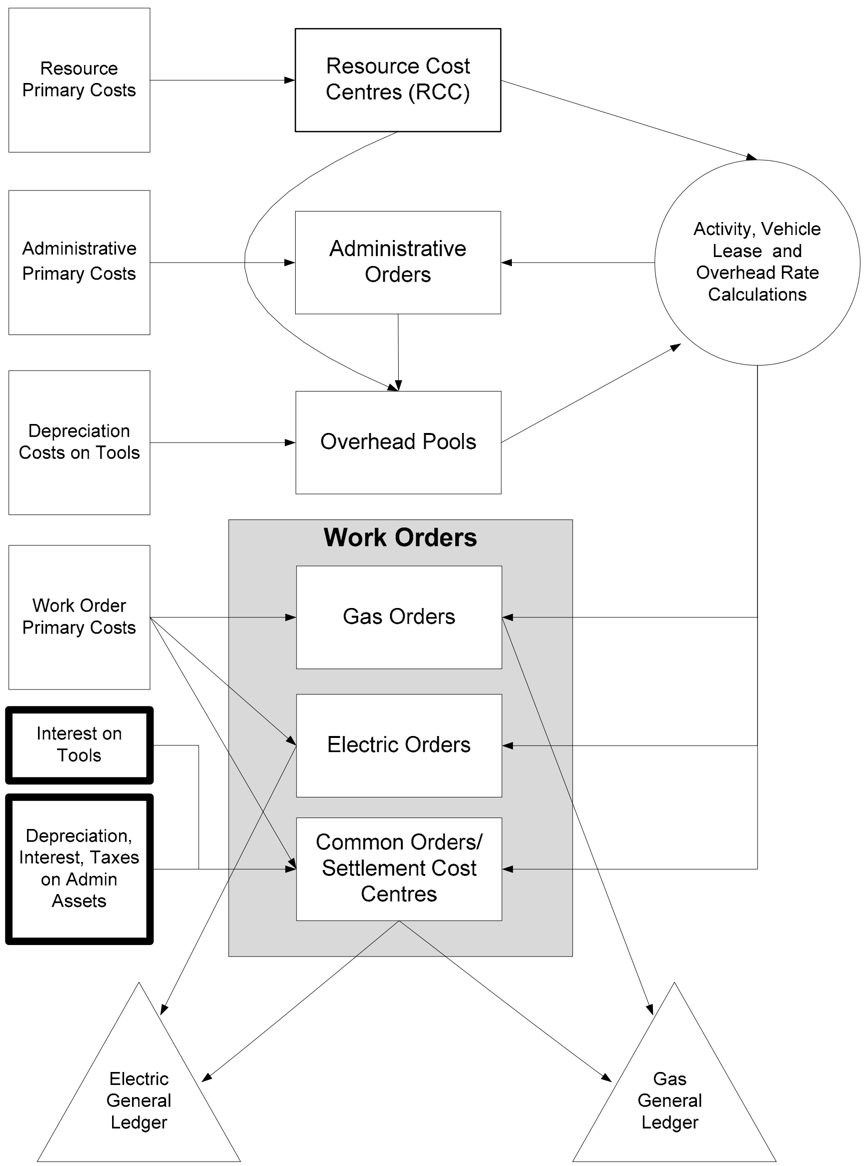
c) Vehicle and Heavy Work Equipment Unit Rates

Vehicle and heavy work equipment costs are accumulated and then charged to resource cost centres based on a derived unit rate.

Costs incorporated into the unit rate calculations include the following:

- Fleet resource centre costs
- Garage and facility costs
- Fuel & Insurance
- Parts, repairs and maintenance
- Depreciation on vehicles and equipment
- Administrative costs

Work Orders



Operations orders are used to accumulate costs for the various projects, programs, and functions of the utilities. Costs charged to orders include primary costs, activity charges and overheads.

Orders are classified as either gas, electric, or common and can be either operating or capital related.

Gas and Electric Orders

Gas and electric orders are used to accumulate the costs associated with the operational, capital, and customer service functions for each utility, where those functions pertain to one or the other utility but not to both. The costs of these orders are charged directly into the gas or electric general ledgers as appropriate.

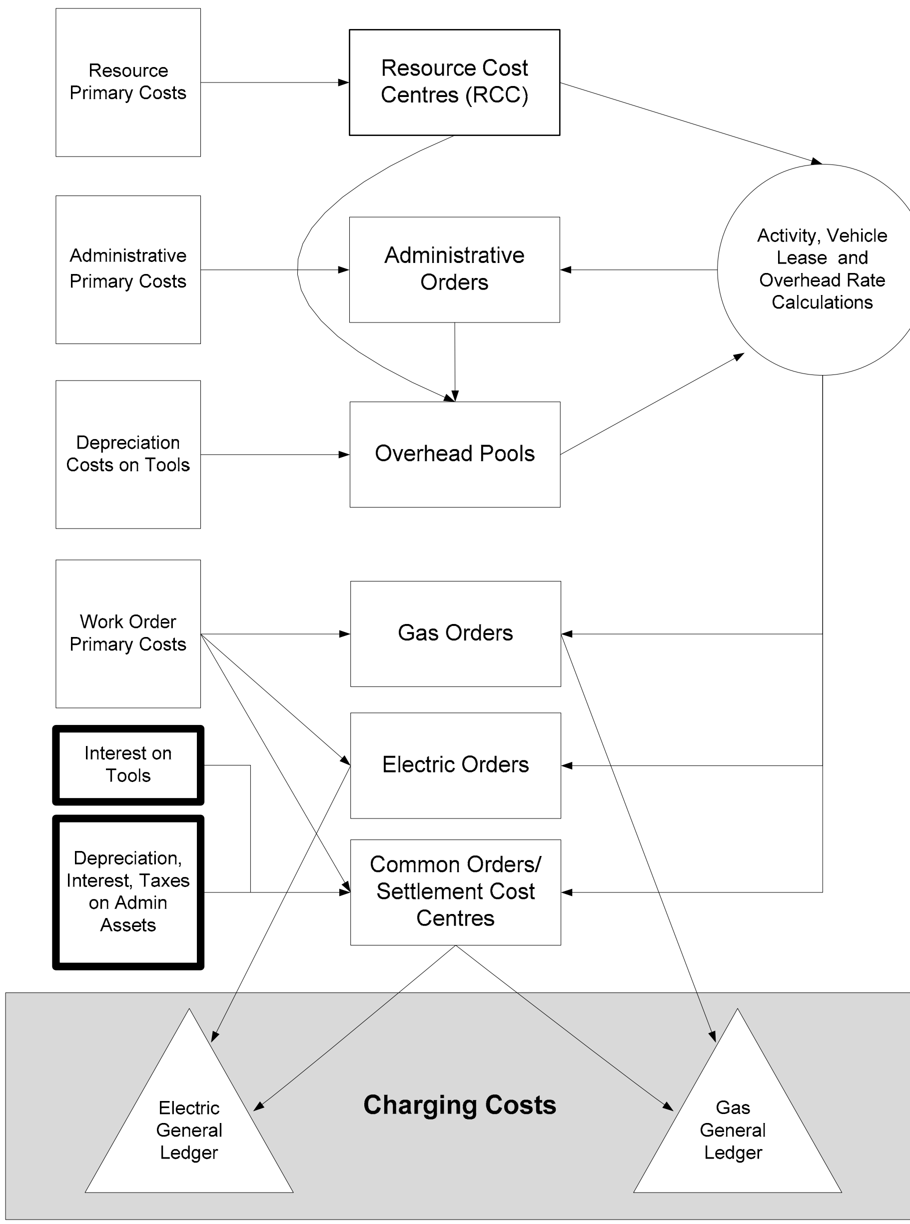
Common Orders

Common orders accumulate the costs of integrated operating activities. These costs are subsequently allocated to gas and electric operations based upon cost drivers that vary according to the nature of the costs that are being allocated.

Examples of common order classifications and the cost drivers used are:

- Common Audit & Public Affairs costs – based upon the relative size of the utilities
- Bill inserting – based upon number of customers
- Line locating – combined locates are apportioned equally to gas and electric operations

Charging of Costs to Electric and Gas General Ledgers



All costs allocated through the cost allocation system are ultimately charged to either the gas or electric general ledger as appropriate. The costs are then recorded and appropriately reported within each utility's general ledger and financial reporting system. The gas general ledger includes gas operating program costs, capital expenditures as well as depreciation, interest and taxes on common assets.

PUB/CENTRA I-21

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 Page 1 of 23; 2009/10 & 2010/11 GRA PUB/Centra 36 – Integrated Cost Allocation Methodology**

b) **Please outline any changes that have occurred in Manitoba Hydro's Integrated Cost Allocation Methodology since the last GRA, identifying on the schematic where changes have been made.**

ANSWER:

Please see Centra's response to PUB/Centra I-21(a) for a description of the changes that have occurred since the last GRA and where the changes were made.

PUB/CENTRA I-21

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 Page 1 of 23; 2009/10 & 2010/11 GRA PUB/Centra 36 – Integrated Cost Allocation Methodology**

c) For 2013/14, please provide a table showing the discrete forecasted amounts for each of the Resource Primary costs, each of the Administrative Primary Costs, each of the Interest, Depreciation & Taxes costs and each of the Work Order primary Costs in a similar format to that provided in response to PUB/Centra 36(c) at the 2009/10 & 2010/11 GRA.

ANSWER:

Please see the attachment to this response.

Centra Gas Manitoba Inc. | **PUB/Centra 21(c)**
2013/14 Gas GRA | **Attachment**
2013/14 Forecast Primary Costs - Integrated Operations | **Mar 31, '14**
($000,000's)

Resource Primary Costs		
Direct Labour	$	543
Employee Benefits		133
Material & Tools		7
Motor Vehicles		38
Office & Administration		9
Operating Expense Recoveries		(1)
Purchased Services		3
Travel		28
Payroll Tax		12
Contingency		(8)
	$	**764**
Administrative Primary Costs		
Material & Tools	$	1
Purchased Services		5
Travel		3
	$	**9**
Depreciation on Tools		
PC's	$	16
Tools & Work Equipment		7
	$	**23**
Work Order Primary Costs		
Buildings & Property	$	6
Collections		4
Customer & Public Relations		6
Materials & Tools		30
Office & Administration		7
Operating Expense Recoveries		(6)
Purchased Services		69
Travel		2
Capital Disbursements		1,247
	$	**1,365**

Interest on Tools

PC's	$	3
Work Equipment		3
Motor Vehicles		7
	$	**13**

Depreciation, Interest & Taxes on Admin Assets

Buildings	$	43
Communication Equipment		3
IT Infrastructure Hardware, Software & Systems		16
Furniture & Fixtures		3
Inventory		4
	$	**69**

PUB/CENTRA I-21

Subject: **Tab 5: Financial Results & Forecast**

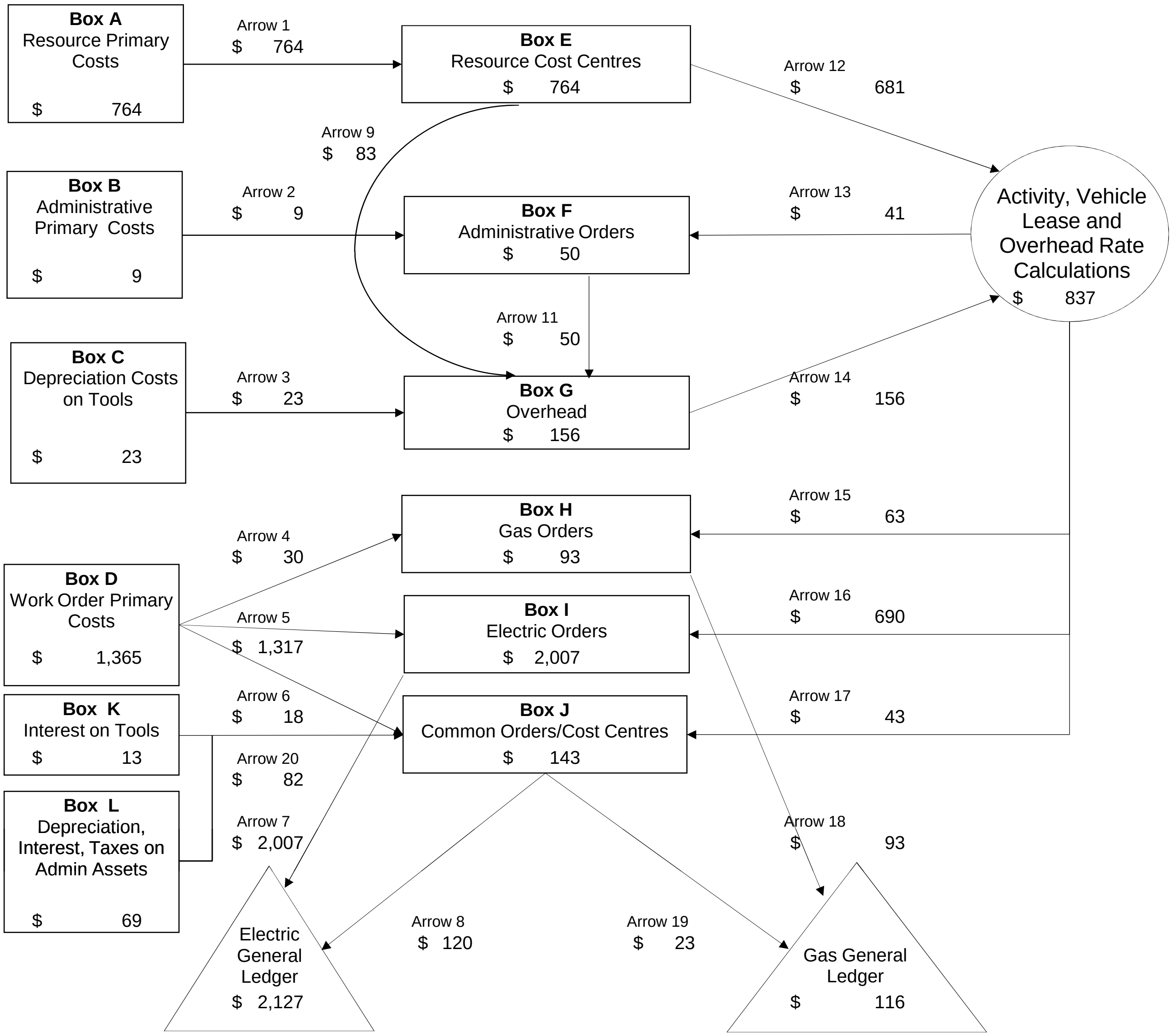
Reference: **Tab 5 Appendix 5.7 Page 1 of 23; 2009/10 & 2010/11 GRA PUB/Centra 36 – Integrated Cost Allocation Methodology**

d) For 2013/14, please provide a table showing the forecasted amounts through the cost allocation model for each of the arrow points in the schematic.

ANSWER:

Please see the attachment to this response.

Cost Allocation Flows Version 112 - 2013/14 (in millions)



Notes
-Arrow 10 which was included in the 2009/10 and 2010/11 Gas GRA (PUB/Centra 36(d)), has been removed as Motor Vehicles are now included in Box A.
-Arrow 20 which was not included in the 2009/10 and 2010/11 Gas GRA (PUB/Centra 36(d)) has been added.

PUB/CENTRA I-21 (Revised)

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 Page 1 of 23; 2009/10 & 2010/11 GRA PUB/Centra 36 – Integrated Cost Allocation Methodology**

e) Please provide the total forecasted amount of OM&A expense for each of the business units for the entire corporate entity of Manitoba Hydro for the years 2006/07 through 2013/14 in a similar format to that provided in response to PUB/Centra 36(e) at the 2009/10 & 2010/11 GRA.

ANSWER:

Please see the following table for the total forecasted amount of OM&A expense from 2006/07 through 2013/14.

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE FORECAST BY BUSINESS UNIT **(000's)**

	2006/07 Forecast	2007/08 Forecast	2008/09 Forecast	2009/10 Forecast	2010/11 Forecast	2011/12 Forecast	2012/13 Forecast	2013/14 Forecast
President & CEO								
General Counsel	4,989	5,089	5,183	5,450	5,545	5,905	6,406	6,534
Public Affairs	3,063	3,124	3,187	3,299	3,351	3,446	3,688	3,762
Research & Development	3,584	3,660	4,230	4,310	4,257	4,212	3,650	3,723
VP Corp Planning & Strat Analysis	0	0	0	123	919	594	0	0
Corporate Planning & Strategic Review	2,353	2,553	2,980	3,577	5,381	4,806	4,070	4,152
Administration	12,675	11,387	11,160	11,416	12,504	12,637	10,878	11,095
	$ 26,664	**$ 25,813**	**$ 26,739**	**$ 28,175**	**$ 31,958**	**$ 31,600**	**$ 28,692**	**$ 29,266**
Corporate Relations								
Aboriginal Relations	4,969	4,716	4,353	4,372	4,448	8,178	3,926	4,004
Administration	948	846	1,044	728	752	722	566	577
	$ 5,917	**$ 5,562**	**$ 5,398**	**$ 5,100**	**$ 5,200**	**$ 8,900**	**$ 4,491**	**$ 4,581**
Finance & Administration								
Information Technology Services	32,193	34,283	34,880	35,070	35,500	35,115	38,037	38,798
Treasury	2,307	2,353	2,390	2,090	2,100	2,022	1,981	2,021
Corporate Risk Mgmt Department	666	727	826	820	836	951	977	997
Gas Supply	2,060	2,170	2,210	2,250	2,300	2,508	2,590	2,642
Rates & Regulatory Affairs	3,577	3,649	3,720	3,700	3,741	3,391	3,273	3,339
Corporate Controller	8,371	9,847	10,710	11,480	11,626	11,376	11,173	11,397
Human Resources	11,101	11,685	12,169	11,726	11,505	11,326	12,032	12,273
Corporate Safety & Health	2,063	2,555	2,301	2,849	2,881	2,735	3,831	3,907
Corporate Services	32,727	33,822	34,400	36,250	36,936	36,742	38,263	39,028
Administration	1,603	2,448	2,506	3,085	2,938	2,019	1,818	1,854
	$ 96,669	**$ 103,538**	**$ 106,113**	**$ 109,320**	**$ 110,362**	**$ 108,184**	**$ 114,343**	**$ 116,630**
Power Supply								
Power Planning	2,700	3,551	3,780	6,422	7,574	7,100	7,205	7,349
Power Projects Development	321	504	161	339	880	660	2,304	2,350
Portfolio Projects Management	(63)	2	40	44	236	377	662	675
HVDC	18,000	18,606	19,838	22,856	22,784	23,307	27,380	27,927
Generation North	29,200	30,764	31,348	28,702	28,544	31,505	35,779	36,494
Generation South	44,624	47,413	48,390	51,841	51,821	54,851	58,670	59,843
Power Sales & Operations	10,980	11,960	12,419	13,152	13,172	13,033	14,384	14,671
Engineering Services	5,232	5,460	5,368	5,074	5,051	3,700	8,474	8,644
New Generation Construction	(546)	(319)	(652)	(249)	(249)	(900)	1,221	1,245
Administration	10,457	10,595	10,457	16,818	18,322	18,167	21,903	22,341
	$ 120,905	**$ 128,536**	**$ 131,149**	**$ 145,000**	**$ 148,135**	**$ 151,800**	**$ 177,982**	**$ 181,541**
Transmission								
Transmission System Operations	28,350	29,619	31,456	33,054	33,210	33,211	33,337	34,004
Transmission Planning & Design	5,160	5,178	4,775	4,034	4,660	4,133	8,243	8,408
Transmission Construction & Line Mtce	15,255	16,401	16,188	16,485	16,662	16,756	19,707	20,101
Apparatus Maintenance	29,726	32,528	33,447	35,070	35,579	35,587	40,625	41,438
Administration	1,505	1,587	1,740	2,457	1,955	2,114	2,849	2,906
	$ 79,995	**$ 85,314**	**$ 87,606**	**$ 91,100**	**$ 92,066**	**$ 91,800**	**$ 104,762**	**$ 106,857**
Customer Services & Distribution								
Customer Service Operations - Wpg&North	45,791	45,472	46,846	47,896	48,440	48,834	53,094	54,156
Customer Service Operations - South	41,534	44,707	46,351	48,701	48,642	50,200	56,318	57,445
Distribution E&C Rural	7,257	6,924	6,970	7,484	7,310	7,124	11,077	11,299
Distribution E&C Winnipeg	3,646	2,635	2,175	1,384	1,675	1,257	6,291	6,417
Administration	0	0	0	1,835	2,029	2,184	3,578	3,649
	$ 98,228	**$ 99,738**	**$ 102,342**	**$ 107,300**	**$ 108,095**	**$ 109,599**	**$ 130,358**	**$ 132,966**
Customer Care & Marketing								
Industrial & Commercial Solutions	3,201	3,347	3,238	3,258	3,293	2,587	4,950	5,049
Consumer Marketing & Sales	11,399	10,349	11,029	10,735	11,126	11,601	13,574	13,846
Business Support Services	26,557	24,900	25,210	23,329	23,623	23,522	27,854	28,411
Administration	4,271	4,362	4,526	4,113	4,575	5,206	5,371	5,479
	$ 45,428	**$ 42,958**	**$ 44,002**	**$ 41,435**	**$ 42,617**	**$ 42,916**	**$ 51,749**	**$ 52,784**
Corporate Allocations & Adjustments	(29,825)	(31,209)	(31,849)	(34,801)	(33,374)	(26,657)	(11,484)	(4,150)
Operating & Administrative Costs	$ 443,982	$ 460,250	$ 471,500	$ 492,628	$ 505,059	$ 518,142	$ 600,893	$ 620,474
Operating & Administrative Charged to Centra	$ (55,182)	$ (56,600)	$ (58,000)	(60,160)	(63,400)	(64,000)	(67,300)	(68,800)
Capitalized Overhead	$ (61,200)	$ (63,450)	$ (64,500)	(60,964)	(44,021)	(52,242)	(78,284)	(81,021)
OM&A Attributable to Electric Operations	**$ 327,600**	**$ 340,200**	**$ 349,000**	**$ 371,504**	**$ 397,638**	**$ 401,900**	**$ 455,309**	**$ 470,654**

PUB/CENTRA I-21

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 Page 1 of 23; 2009/10 & 2010/11 GRA PUB/Centra 36 – Integrated Cost Allocation Methodology**

f) In a similar format to PUB/Centra 36(f) of the 2009/10 & 2010/11 GRA, please file a current schedule of hours, activity rates, and activity charges used as a basis to allocate corporate costs to Centra.

ANSWER:

Attached is the current schedule of hours, activity rates, and activity charges for the 2012/13 Forecast and 2013/14 Test Year.

CENTRA GAS MANITOBA INC.
ACTIVITY CHARGES AND RATES

	2011/12 Forecast			2012/13 Forecast			2013/14 Test Year		
	Hours	Avg. Activity Rate ($)	Activity Charges ($000's)	Hours	Avg. Activity Rate ($)	Activity Charges ($000's)	Hours	Avg. Activity Rate ($)	Activity Charges ($000's)
President & CEO									
Audit	1,275	104	133	1,758	81	142	1,758	82	145
Public Affairs	4,622	72	331	1,667	68	113	1,667	69	115
	5,897	79	464	3,426	74	254	3,426	76	259
Finance & Administration									
IT - Distribution/Metering	1,930	84	162	1,666	72	121	1,666	74	123
IT - Banner	8,665	85	736	8,842	80	710	8,842	82	725
Gas Accounting	3,070	89	273	3,070	89	273	3,070	91	279
Gas Regulatory	14,609	75	1,095	15,162	78	1,176	15,162	79	1,200
Gas Supply	24,459	96	2,357	22,269	75	1,671	22,269	77	1,705
Property Tax Administration	244	83	20	-	-	-	-	-	-
	52,978	88	4,643	51,010	77	3,951	51,010	79	4,031
Power Supply									
Environmental Management	1,400	93	130	-	-	-	-	-	-
	1,400	93	130	-	-	-	-	-	-
Transmission									
Communications Systems	1,325	103	137	1,650	86	141	1,650	87	144
	1,325	103	137	1,650	86	141	1,650	87	144
Customer Service & Distribution									
Billing Inquiry & Collections	27,301	74	2,025	23,539	59	1,392	23,539	60	1,419
Customer Inspections	95,232	91	8,682	93,964	75	7,053	93,964	77	7,194
Customer Relations	15,110	93	1,412	15,525	77	1,201	15,525	79	1,225
Dispatch	28,155	90	2,532	36,832	60	2,195	36,832	61	2,239
Customer Safety	18,617	99	1,848	18,888	81	1,531	18,888	83	1,561
Distribution Maintenance	60,585	98	5,911	61,295	80	4,906	61,295	82	5,004
Regulating Station Maintenance	38,750	96	3,726	38,516	94	3,614	38,516	96	3,687
Capacity Analysis & Engineering	5,909	103	611	5,010	84	422	5,010	86	430
System Integrity	11,259	87	979	11,175	81	905	11,175	83	923
Meter Reading	460	102	47	549	75	41	549	77	42
Meter Changes	29,815	82	2,447	43,962	79	3,484	43,962	81	3,553
	331,192	91	30,219	349,255	77	26,742	349,255	78	27,277
Customer Care & Marketing									
Billing Inquiry & Collections	95,912	50	4,791	92,162	47	4,288	92,162	47	4,374
Customer Relations	58,332	76	4,422	63,783	65	4,115	63,783	66	4,197
Customer Safety	2,463	82	202	1,930	77	149	1,930	79	152
Quality Assessment	6,166	92	567	6,210	71	440	6,210	72	449
Load Forecast	2,219	80	178	1,892	73	138	1,892	75	141
Meter Repair & Calibration	18,394	77	1,414	21,520	57	1,234	21,520	58	1,259
	183,486	63	11,575	187,497	55	10,363	187,497	56	10,571
Total	**576,277**	**82**	**47,167**	**592,837**	**70**	**41,453**	**592,837**	**71**	**42,282**

CENTRA GAS MANITOBA INC.
ACTIVITY CHARGES AND RATES

	2011/12 Forecast			2012/13 Forecast				
	Hours	Avg. Activity Rate ($)	Activity Charges ($000's)	Hours	Avg. Activity Rate ($)	Activity Charges ($000's)	Inc/(Dec) in Activity Rate	%
President & CEO								
Audit	1,275	104	133	1,758	81	142	(23)	-23%
Public Affairs	4,622	72	331	1,667	68	113	(4)	-6%
	5,897	79	464	3,426	74	254	(4)	-6%
Finance & Administration								
IT - Distribution/Metering	1,930	84	162	1,666	72	121	(12)	-14%
IT - Banner	8,665	85	736	8,842	80	710	(5)	-5%
Gas Accounting	3,070	89	273	3,070	89	273	-	0%
Gas Regulatory	14,609	75	1,095	15,162	78	1,176	3	4%
Gas Supply	24,459	96	2,357	22,269	75	1,671	(21)	-22%
Property Tax Administration	244	83	20	-	-	-	(83)	-100%
	52,978	88	4,643	51,010	77	3,951	(10)	-12%
Power Supply								
Environmental Management	1,400	93	130	-	-	-	(93)	-100%
	1,400	93	130	-	-	-	(93)	-100%
Transmission								
Communications Systems	1,325	103	137	1,650	86	141	(18)	-17%
	1,325	103	137	1,650	86	141	(18)	-17%
Customer Service & Distribution								
Billing Inquiry & Collections	27,301	74	2,025	23,539	59	1,392	(15)	-20%
Customer Inspections	95,232	91	8,682	93,964	75	7,053	(16)	-18%
Customer Relations	15,110	93	1,412	15,525	77	1,201	(16)	-17%
Dispatch	28,155	90	2,532	36,832	60	2,195	(30)	-34%
Customer Safety	18,617	99	1,848	18,888	81	1,531	(18)	-18%
Distribution Maintenance	60,585	98	5,911	61,295	80	4,906	(18)	-18%
Regulating Station Maintenance	38,750	96	3,726	38,516	94	3,614	(2)	-2%
Capacity Analysis & Engineering	5,909	103	611	5,010	84	422	(19)	-19%
System Integrity	11,259	87	979	11,175	81	905	(6)	-7%
Meter Reading	460	102	47	549	75	41	(27)	-26%
Meter Changes	29,815	82	2,447	43,962	79	3,484	(3)	-3%
	331,192	91	30,219	349,255	77	26,742	(15)	-16%
Customer Care & Marketing								
Billing Inquiry & Collections	95,912	50	4,791	92,162	47	4,288	(3)	-7%
Customer Relations	58,332	76	4,422	63,783	65	4,115	(11)	-15%
Customer Safety	2,463	82	202	1,930	77	149	(5)	-6%
Quality Assessment	6,166	92	567	6,210	71	440	(21)	-23%
Load Forecast	2,219	80	178	1,892	73	138	(7)	-9%
Meter Repair & Calibration	18,394	77	1,414	21,520	57	1,234	(20)	-25%
	183,486	63	11,575	187,497	55	10,363	(8)	-12%
Total	**576,277**	**82**	**47,167**	**592,837**	**70**	**41,453**	**(12)**	**-15%**

CENTRA GAS MANITOBA INC.
ACTIVITY CHARGES AND RATES

	2012/13 Forecast			2013/14 Test Year				
	Hours	Avg. Activity Rate ($)	Activity Charges ($000's)	Hours	Avg. Activity Rate ($)	Activity Charges ($000's)	Inc/(Dec) in Activity Rate	%
President & CEO								
Audit	1,758	81	142	1,758	82	145	2	2%
Public Affairs	1,667	68	113	1,667	69	115	1	2%
	3,426	74	254	3,426	76	259	1	2%
Finance & Administration								
IT - Distribution/Metering	1,666	72	121	1,666	74	123	1	2%
IT - Banner	8,842	80	710	8,842	82	725	2	2%
Gas Accounting	3,070	89	273	3,070	91	279	2	2%
Gas Regulatory	15,162	78	1,176	15,162	79	1,200	2	2%
Gas Supply	22,269	75	1,671	22,269	77	1,705	2	2%
Property Tax Administration	-	-	-	-	-	-	-	0%
	51,010	77	3,951	51,010	79	4,031	2	2%
Power Supply								
Environmental Management	-	-	-	-	-	-	-	0%
	-	-	-	-	-	-	-	0%
Transmission								
Communications Systems	1,650	86	141	1,650	87	144	2	2%
	1,650	86	141	1,650	87	144	2	2%
Customer Service & Distribution								
Billing Inquiry & Collections	23,539	59	1,392	23,539	60	1,419	1	2%
Customer Inspections	93,964	75	7,053	93,964	77	7,194	2	2%
Customer Relations	15,525	77	1,201	15,525	79	1,225	2	2%
Dispatch	36,832	60	2,195	36,832	61	2,239	1	2%
Customer Safety	18,888	81	1,531	18,888	83	1,561	2	2%
Distribution Maintenance	61,295	80	4,906	61,295	82	5,004	2	2%
Regulating Station Maintenance	38,516	94	3,614	38,516	96	3,687	2	2%
Capacity Analysis & Engineering	5,010	84	422	5,010	86	430	2	2%
System Integrity	11,175	81	905	11,175	83	923	2	2%
Meter Reading	549	75	41	549	77	42	2	2%
Meter Changes	43,962	79	3,484	43,962	81	3,553	2	2%
	349,255	77	26,742	349,255	78	27,277	2	2%
Customer Care & Marketing								
Billing Inquiry & Collections	92,162	47	4,288	92,162	47	4,374	1	2%
Customer Relations	63,783	65	4,115	63,783	66	4,197	1	2%
Customer Safety	1,930	77	149	1,930	79	152	2	2%
Quality Assessment	6,210	71	440	6,210	72	449	1	2%
Load Forecast	1,892	73	138	1,892	75	141	1	2%
Meter Repair & Calibration	21,520	57	1,234	21,520	58	1,259	1	2%
	187,497	55	10,363	187,497	56	10,571	1	2%
Total	**592,837**	**70**	**41,453**	**592,837**	**71**	**42,282**	**1**	**2%**

PUB/CENTRA I-21

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 Page 1 of 23; 2009/10 & 2010/11 GRA PUB/Centra 36 – Integrated Cost Allocation Methodology**

g) For the ten (10) greatest increases and decreases in average activity rates as determined in (f), please provide a schedule which compares a breakdown of the cost components.

ANSWER:

The changes in activity rates are primarily due to the following factors:

1. Costing Methodology – Cost centre activity rates have declined due to changes in Manitoba Hydro's costing methodology, which was discussed in Appendix 5.7, page 21. The change in methodology reallocates support costs previously included in activity rates to either the common overhead rate or as a direct allocation to gas operations (included in Corporate Allocations and Adjustments). For example, the Dispatch program reflects the largest decrease in average activity prices per the analysis below.

CENTRA GAS MANITOBA INC.
Activity Rate Analysis - Dispatch Program - 2011-12 Forecast vs. 2012-13 Forecast

Operations Support Services Activity Rate Components	2011/12 Forecast	2012/13 Forecast	Increase/ (Decrease)	Explanation
Wages, Salaries & Benefits	1,717	1,920	203	Reflects the increase of additional technical staff, partially offset by the removal of administrative staff from the activity rate as a result of costing methodology changes
Travel	12	19	7	
Other	398	28	(370)	Reflects the removal of general & administrative costs such as divisional management, office supplies, training, and computer costs from the activity rate as a result of costing methodology changes.
Total ($000s)	2,126	1,967	(159)	
Hours	24,836	35,021	10,185	Reflects anticipated increase in hours in 2012/13 based upon actual experience and additional staff.
Activity Rate ($)	$ 87	$ 56	$ (30)	

2. Blend of Staff - The change in departmental activity rates for some programs may also be impacted by the mix of staff working in the various programs. For example, the Gas Regulatory program includes staff from several departments such as Regulatory Services, Cost of Service and Law. As demonstrated below, although the activity rate for Law has declined due to costing methodology changes, the overall average activity price for the program has increased as a result of a shift in resource requirements from areas with lower activity rates to those with higher activity rates.

CENTRA GAS MANITOBA INC.
Activity Rate Analysis - Gas Regulatory Program - 2011-12 Forecast vs. 2012-13 Forecast

Law Department Activity Rate Components	2011/12 Forecast	2012/13 Forecast	Increase/ (Decrease)	Explanation
Wages, Salaries & Benefits	2,136	982	(1,154)	Reflects the removal of administrative & senior legal staff from the activity rate as a result of costing methodology changes
Travel	19	8	(11)	Reflects the reallocation of travel costs for administrative and senior legal staff to other activity rates as a result of costing methodology changes.
Other	117	8	(109)	Reflects the removal of general & administrative costs such as office supplies, training, and computer costs from the activity rate as a result of costing methodology changes.
Total ($000s)	2,272	997	(1,274)	
Hours	19,072	10,416	(8,657)	Reflects the removal of administrative & senior legal staff from the activity rate as a result of costing methodology changes.
Activity Rate ($)	$ 119	$ 96	$ (23)	

The two largest decreases in the average activity rate are for the Property Tax Administration and Environmental Management programs in 2012/13 and 2013/14 are the result of the forecasts including primary costs only and no labour hours.

PUB/CENTRA I-21 (Revised)

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 Page 1 of 23; 2009/10 & 2010/11 GRA PUB/Centra 36 – Integrated Cost Allocation Methodology**

h) Please provide a schedule by business unit detailing the program costs by primary costs, activity charges and overhead for the years 2006/07 through 2013/14.

ANSWER:

Please see the schedule below.

CENTRA GAS MANITOBA INC.
ACTIVITY CHARGES, PRIMARY COSTS AND OVERHEADS **($000's)**

	2006/07 Actual Primary	2006/07 Actual Activity Charges	2006/07 Actual Overhead	2006/07 Actual Program Costs	2007/08 Actual Primary	2007/08 Actual Activity Charges	2007/08 Actual Overhead	2007/08 Actual Program Costs
PRESIDENT & CEO								
Audit	41	115	33	189	43	96	28	167
Liability Claims	2	-	-	2	1	-	-	1
Public Affairs	594	221	65	880	498	266	77	841
Research & Development	23	4	1	28	68	8	2	79
	$ 660	**$ 339**	**$ 99**	**$ 1,098**	**$ 610**	**$ 370**	**$ 107**	**$ 1,087**
FINANCE & ADMINISTRATION								
IT - Distribution/Metering	-	174	50	224	1	79	23	103
IT - Banner	171	728	209	1,108	121	665	192	978
Gas Accounting	-	378	109	487	(0)	299	87	386
Gas Regulatory	711	1,093	317	2,121	699	847	246	1,792
Gas Supply	237	1,850	536	2,623	240	2,111	612	2,964
Treasury	270	-	-	270	261	-	0	261
Property Tax Administration	1	67	18	86	0	67	7	74
	$ 1,389	**$ 4,289**	**$ 1,240**	**$ 6,918**	**$ 1,322**	**$ 4,069**	**$ 1,167**	**$ 6,558**
POWER SUPPLY								
Environmental Management	9	21	6	36	5	32	9	46
	$ 9	**$ 21**	**$ 6**	**$ 36**	**$ 5**	**$ 32**	**$ 9**	**$ 46**
TRANSMISSION								
System Support & Communication Systems	13	142	41	196	19	167	48	234
	$ 13	**$ 142**	**$ 41**	**$ 196**	**$ 19**	**$ 167**	**$ 48**	**$ 234**
CUSTOMER SERVICE & DISTRIBUTION								
Billing Inquiry & Collections	(143)	1,626	472	1,955	(185)	1,927	559	2,302
Customer Inspections	46	7,259	2,131	9,436	50	7,516	2,211	9,778
Customer Relations	(1)	400	116	515	(9)	454	132	576
Dispatch	45	1,934	561	2,540	4	2,319	672	2,995
Customer Safety	8	1,646	478	2,132	6	1,787	519	2,312
Distribution Maintenance	760	4,976	1,499	7,235	907	5,426	1,641	7,975
Emergency	(111)	85	25	(1)	-	-	-	-
Regulating Station Maintenance	997	2,885	843	4,724	1,134	2,779	809	4,722
Capacity Analysis & Engineering	6	343	100	448	1	409	119	529
System Integrity	194	965	280	1,438	192	976	283	1,451
Meter Reading	1,610	74	22	1,706	1,702	83	24	1,810
Meter Changes	192	875	265	1,331	255	2,000	609	2,863
	$ 3,601	**$ 23,067**	**$ 6,792**	**$ 33,460**	**$ 4,058**	**$ 25,676**	**$ 7,579**	**$ 37,313**
CUSTOMER CARE & MARKETING								
Billing Inquiry & Collections	3,692	5,645	1,654	10,991	3,425	5,616	1,646	10,687
Customer Relations	135	3,520	1,021	4,675	162	3,822	1,108	5,092
Customer Safety	3	104	30	137	58	114	33	205
Quality Assessment	-	-	-	-	-	-	-	-
Load Forecast	-	143	41	184	5	146	42	194
Meter Repair & Calibration	219	1,111	323	1,653	324	1,170	341	1,836
	$ 4,049	**$ 10,522**	**$ 3,069**	**$ 17,641**	**$ 3,974**	**$ 10,867**	**$ 3,171**	**$ 18,013**
Corporate Allocations & Adjustments				2,035				1,455
TOTAL PROGRAM COSTS	**$ 9,721**	**$ 38,380**	**$ 11,248**	**$ 61,384**	**$ 9,989**	**$ 41,181**	**$ 12,082**	**$ 64,707**
Less: Depreciation, Interest & Taxes included in above				(7,879)				(8,437)
TOTAL OPERATING & ADMINISTRATIVE EXPENSE	**$ 9,721**	**$ 38,380**	**$ 11,248**	**$ 53,505**	**$ 9,989**	**$ 41,181**	**$ 12,082**	**$ 56,270**

CENTRA GAS MANITOBA INC.
ACTIVITY CHARGES, PRIMARY COSTS AND OVERHEADS **($000's)**

	2008/09 Actual Primary	2008/09 Actual Activity Charges	2008/09 Actual Overhead	2008/09 Actual Program Costs	2009/10 Actual Primary	2009/10 Actual Activity Charges	2009/10 Actual Overhead	2009/10 Actual Program Costs
PRESIDENT & CEO								
Audit	47	75	20	143	71	95	23	189
Liability Claims	358	-	-	358	147	-	-	147
Public Affairs	485	259	70	814	502	252	60	814
Research & Development	51	7	2	60	66	5	1	72
	$ 941	**$ 341**	**$ 92**	**$ 1,374**	**$ 785**	**$ 353**	**$ 85**	**$ 1,222**
FINANCE & ADMINISTRATION								
IT - Distribution/Metering	-	142	38	181	0	99	24	123
IT - Banner	177	717	194	1,088	168	686	165	1,019
Gas Accounting	(1)	299	81	378	(0)	261	63	324
Gas Regulatory	728	728	196	1,652	806	1,123	270	2,199
Gas Supply	315	2,064	557	2,937	288	2,027	486	2,801
Treasury	260	-	0	260	258	-	-	258
Property Tax Administration	7	36	9	53	3	12	3	18
	$ 1,487	**$ 3,986**	**$ 1,076**	**$ 6,549**	**$ 1,524**	**$ 4,208**	**$ 1,010**	**$ 6,742**
POWER SUPPLY								
Environmental Management	3	35	9	47	157	51	12	220
	$ 3	**$ 35**	**$ 9**	**$ 47**	**$ 157**	**$ 51**	**$ 12**	**$ 220**
TRANSMISSION								
System Support & Communication Systems	29	153	41	224	25	186	45	255
	$ 29	**$ 153**	**$ 41**	**$ 224**	**$ 25**	**$ 186**	**$ 45**	**$ 255**
CUSTOMER SERVICE & DISTRIBUTION								
Billing Inquiry & Collections	26	1,624	439	2,088	11	2,058	494	2,563
Customer Inspections	451	7,780	2,125	10,356	550	8,024	1,944	10,518
Customer Relations	(6)	499	135	627	(8)	1,274	306	1,572
Dispatch	-	2,348	634	2,982	-	2,025	486	2,511
Customer Safety	(0)	1,754	474	2,228	8	1,729	415	2,152
Distribution Maintenance	959	5,785	1,618	8,362	985	5,961	1,461	8,407
Emergency	4	168	46	218	0	11	3	14
Regulating Station Maintenance	1,153	3,346	907	5,406	1,270	3,411	822	5,502
Capacity Analysis & Engineering	2	481	130	613	2	562	135	698
System Integrity	51	796	215	1,062	189	785	189	1,163
Meter Reading	1,743	68	18	1,829	1,811	40	10	1,861
Meter Changes	139	1,691	476	2,306	89	2,599	637	3,325
	$ 4,521	**$ 26,339**	**$ 7,217**	**$ 38,078**	**$ 4,907**	**$ 28,480**	**$ 6,900**	**$ 40,288**
CUSTOMER CARE & MARKETING								
Billing Inquiry & Collections	3,473	5,562	1,522	10,557	3,371	4,968	1,204	9,543
Customer Relations	1,143	4,207	1,136	6,485	1,063	4,500	1,080	6,643
Customer Safety	69	184	50	303	79	167	40	286
Quality Assessment	-	203	55	258	11	371	89	470
Load Forecast	2	121	33	156	9	127	30	166
Meter Repair & Calibration	378	1,282	347	2,007	322	1,000	240	1,562
	$ 5,065	**$ 11,558**	**$ 3,142**	**$ 19,765**	**$ 4,854**	**$ 11,132**	**$ 2,684**	**$ 18,670**
Corporate Allocations & Adjustments				1,769				1,460
TOTAL PROGRAM COSTS	**$ 12,047**	**$ 42,413**	**$ 11,577**	**$ 67,806**	**$ 12,251**	**$ 44,410**	**$ 10,735**	**$ 68,857**
Less: Depreciation, Interest & Taxes included in above				(8,003)				(7,906)
TOTAL OPERATING & ADMINISTRATIVE EXPENSE	**$ 12,047**	**$ 42,413**	**$ 11,577**	**$ 59,803**	**$ 12,251**	**$ 44,410**	**$ 10,735**	**$ 60,951**

CENTRA GAS MANITOBA INC.
ACTIVITY CHARGES, PRIMARY COSTS AND OVERHEADS ($000's)

	2010/11 Actual Primary	2010/11 Actual Activity Charges	2010/11 Actual Overhead	2010/11 Actual Program Costs	2011/12 Actual Primary	2011/12 Actual Activity Charges	2011/12 Actual Overhead	2011/12 Actual Program Costs
PRESIDENT & CEO								
Audit	82	179	30	291	64	146	25	235
Liability Claims	(250)	-	-	(250)	6	0	0	7
Public Affairs	584	262	45	891	550	278	47	874
Research & Development	35	4	1	40	0	5	1	6
	$ 451	**$ 445**	**$ 76**	**$ 972**	**$ 621**	**$ 429**	**$ 73**	**$ 1,122**
FINANCE & ADMINISTRATION								
IT - Distribution/Metering	0	114	19	134	-	87	15	102
IT - Banner	194	753	128	1,074	163	795	135	1,093
Gas Accounting	1	268	45	314	(0)	284	48	332
Gas Regulatory	500	1,201	204	1,905	508	869	148	1,525
Gas Supply	213	2,343	398	2,955	202	2,422	412	3,036
Treasury	281	1	0	282	280	-	-	280
Property Tax Administration	9	18	3	30	0	8	1	9
	$ 1,197	**$ 4,697**	**$ 799**	**$ 6,693**	**$ 1,153**	**$ 4,465**	**$ 759**	**$ 6,377**
POWER SUPPLY								
Environmental Management	355	104	18	477	155	139	24	317
	$ 355	**$ 104**	**$ 18**	**$ 477**	**$ 155**	**$ 139**	**$ 24**	**$ 317**
TRANSMISSION								
System Support & Communication Systems	16	199	34	250	14	73	11	99
	$ 16	**$ 199**	**$ 34**	**$ 250**	**$ 14**	**$ 73**	**$ 11**	**$ 99**
CUSTOMER SERVICE & DISTRIBUTION								
Billing Inquiry & Collections	18	2,015	343	2,376	10	1,611	274	1,895
Customer Inspections	14	8,309	1,427	9,750	(89)	8,371	1,436	9,718
Customer Relations	(4)	1,383	235	1,614	(8)	1,424	242	1,659
Dispatch	14	2,354	400	2,768	13	2,634	448	3,095
Customer Safety	1	1,850	315	2,166	6	1,649	281	1,936
Distribution Maintenance	659	5,754	1,004	7,417	737	5,655	992	7,385
Emergency	1	13	2	17	10	86	15	110
Regulating Station Maintenance	1,129	3,305	564	4,998	1,065	3,923	672	5,660
Capacity Analysis & Engineering	6	544	93	642	1	395	67	463
System Integrity	96	1,042	178	1,316	155	933	159	1,247
Meter Reading	1,877	44	7	1,928	1,924	40	7	1,970
Meter Changes	93	2,432	423	2,948	812	3,081	536	4,429
	$ 3,905	**$ 29,045**	**$ 4,991**	**$ 37,941**	**$ 4,636**	**$ 29,800**	**$ 5,128**	**$ 39,565**
CUSTOMER CARE & MARKETING								
Billing Inquiry & Collections	2,951	4,627	796	8,374	2,862	4,627	797	8,286
Customer Relations	1,026	4,655	792	6,473	1,115	4,508	767	6,390
Customer Safety	86	108	18	212	148	150	26	324
Quality Assessment	14	543	92	649	-	574	98	671
Load Forecast	17	121	21	158	7	142	24	173
Meter Repair & Calibration	370	1,374	234	1,978	401	1,667	284	2,351
	$ 4,465	**$ 11,427**	**$ 1,953**	**$ 17,845**	**$ 4,532**	**$ 11,669**	**$ 1,994**	**$ 18,195**
Corporate Allocations & Adjustments				1,660				1,718
TOTAL PROGRAM COSTS	**$ 10,390**	**$ 45,918**	**$ 7,870**	**$ 65,838**	**$ 11,110**	**$ 46,574**	**$ 7,990**	**$ 67,392**
Less: Depreciation, Interest & Taxes included in above				(5,194)				(5,275)
TOTAL OPERATING & ADMINISTRATIVE EXPENSE	**$ 10,390**	**$ 45,918**	**$ 7,870**	**$ 60,644**	**$ 11,110**	**$ 46,574**	**$ 7,990**	**$ 62,117**

CENTRA GAS MANITOBA INC.
ACTIVITY CHARGES, PRIMARY COSTS AND OVERHEADS **($000's)**

	2012/13 Forecast				2013/14 Test Year			
	Primary	Activity Charges	Overhead	Program Costs	Primary	Activity Charges	Overhead	Program Costs
PRESIDENT & CEO								
Audit	44	142	35	221	44	145	36	225
Liability Claims	80	-	-	80	82	-	-	82
Public Affairs	371	113	28	512	378	115	29	522
Research & Development	79	-	-	79	80	-	-	80
	$ 573	**$ 254**	**$ 64**	**$ 891**	**$ 584**	**$ 259**	**$ 65**	**$ 909**
FINANCE & ADMINISTRATION								
IT - Distribution/Metering	-	121	1	121	-	123	1	124
IT - Banner	207	710	178	1,095	211	725	181	1,117
Gas Accounting	-	273	68	342	-	279	70	348
Gas Regulatory	479	1,176	294	1,949	489	1,200	300	1,988
Gas Supply	279	1,671	418	2,368	285	1,705	426	2,416
Treasury	312	-	-	312	318	-	-	318
Property Tax Administration	-	-	-	-	-	-	-	-
	$ 1,277	**$ 3,951**	**$ 959**	**$ 6,187**	**$ 1,303**	**$ 4,031**	**$ 978**	**$ 6,311**
POWER SUPPLY								
Environmental Management	404	-	-	404	412	-	-	412
	$ 404	**$ -**	**$ -**	**$ 404**	**$ 412**	**$ -**	**$ -**	**$ 412**
TRANSMISSION								
System Support & Communication Systems	17	141	35	194	18	144	36	197
	$ 17	**$ 141**	**$ 35**	**$ 194**	**$ 18**	**$ 144**	**$ 36**	**$ 197**
CUSTOMER SERVICE & DISTRIBUTION								
Billing Inquiry & Collections	33	1,392	348	1,772	33	1,419	355	1,807
Customer Inspections	152	7,053	1,777	8,982	155	7,194	1,812	9,162
Customer Relations	0	1,201	300	1,501	0	1,225	306	1,531
Dispatch	50	2,195	549	2,793	51	2,239	560	2,849
Customer Safety	9	1,531	383	1,922	9	1,561	391	1,961
Distribution Maintenance	1,089	4,906	1,258	7,252	1,111	5,004	1,283	7,397
Emergency	-	-	-	-	-	-	-	-
Regulating Station Maintenance	1,239	3,614	907	5,760	1,263	3,687	925	5,875
Capacity Analysis & Engineering	108	422	106	635	110	430	108	648
System Integrity	249	905	226	1,380	254	923	231	1,407
Meter Reading	1,964	41	10	2,015	2,003	42	11	2,056
Meter Changes	115	3,484	881	4,480	117	3,553	899	4,569
	$ 5,006	**$ 26,742**	**$ 6,745**	**$ 38,493**	**$ 5,106**	**$ 27,277**	**$ 6,880**	**$ 39,263**
CUSTOMER CARE & MARKETING								
Billing Inquiry & Collections	3,004	4,288	1,082	8,374	3,064	4,374	1,104	8,542
Customer Relations	1,119	4,115	1,029	6,262	1,141	4,197	1,049	6,387
Customer Safety	122	149	37	308	124	152	38	314
Quality Assessment	15	440	110	565	15	449	112	576
Load Forecast	19	138	35	192	20	141	35	196
Meter Repair & Calibration	331	1,234	309	1,874	338	1,259	315	1,911
	$ 4,610	**$ 10,363**	**$ 2,601**	**$ 17,575**	**$ 4,703**	**$ 10,571**	**$ 2,653**	**$ 17,926**
Corporate Allocations & Adjustments				6,559				6,844
TOTAL PROGRAM COSTS	**$ 11,887**	**$ 41,453**	**$ 10,403**	**$ 70,303**	**$ 12,125**	**$ 42,282**	**$ 10,611**	**$ 71,862**
Less: Depreciation, Interest & Taxes included in above				(3,003)				(3,063)
TOTAL OPERATING & ADMINISTRATIVE EXPENSE	**$ 11,887**	**$ 41,453**	**$ 10,403**	**$ 67,300**	**$ 12,125**	**$ 42,282**	**$ 10,611**	**$ 68,800**

PUB/CENTRA I-21

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 Page 1 of 23; 2009/10 & 2010/11 GRA PUB/Centra 36 – Integrated Cost Allocation Methodology**

i) **Please confirm the last time Centra undertook an external study to assess the reasonableness of the allocation of common costs between Manitoba Hydro and Centra, and summarize the findings of this study.**

ANSWER:

At the Status Update Hearing in 2002, Centra filed a report prepared by KPMG which detailed their review of Manitoba Hydro's cost allocation methodology, including the reasonableness of the allocation of common costs between Hydro and Centra.

In this report, KPMG concluded that:

- A logical conceptual framework of cost generation within the system underlies the costing system;
- The costing system has been developed with sufficient management perspective with respect to the nature of the business;
- The system is applied consistently and rigorously over time and across the organization;
- Adequate quality assurance provisions are in place to provide a reasonable expectation of accuracy regarding the results of the system;
- The gas utility has been appropriately incorporated into the cost accounting system of an integrated utility; and
- The current cost accounting system has been designed and applied so as to avoid potential cross-subsidy between the gas ratepayers and the electric ratepayers.

PUB/CENTRA I-22

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 Page 1 of 23; 2009/10 & 2010/11 GRA PUB/Centra 37(c)**

a) Please file the response to PUB/Centra 37(c) from the 2009/10 & 2010/11 GRA.

ANSWER:

Please see the attachment to this response.

CENTRA GAS MANITOBA INC.

2009/10 & 2010/11 GENERAL RATE APPLICATION

RESPONSE TO INFORMATION REQUESTS OF THE PUBLIC UTILITIES BOARD OF MANITOBA

PUB/CENTRA 1 - 37

Reference: Tab 4 Pages 16 to 18 of 42 - Cost Allocation Methodology

(a) When was the last time Centra undertook an external study to assess the reasonableness of the allocation of common costs between Manitoba Hydro and Centra?

At the Status Update Hearing in 2002, Centra filed a report prepared by KPMG which detailed their review of Manitoba Hydro's cost allocation methodology, including the reasonableness of the allocation of common costs between Hydro and Centra.

(b) Please summarize the findings of this study.

In this report, KPMG concluded that:

- A logical conceptual framework of cost generation within the system underlies the costing system;
- The costing system has been developed with sufficient management perspective with respect to the nature of the business;
- The system is applied consistently and rigorously over time and across the organization;
- Adequate quality assurance provisions are in place to provide a reasonable expectation of accuracy regarding the results of the system;

- The gas utility has been appropriately incorporated into the cost accounting system of an integrated utility; and
- The current cost accounting system has been designed and applied so as to avoid potential cross-subsidy between the gas ratepayers and the electric ratepayers.

(c) Please file Centra's response to Order 99/07 Directive 25.

In consideration of the substantial changes to the Cost Allocation Methodology associated with IFRS and the new head office, Centra does not believe that a review of its existing Cost Allocation Methodology would be beneficial at this time. Please refer to the attachment which was submitted on April 14, 2008.

Manitoba Hydro

PO Box 815 • Winnipeg Manitoba Canada • R3C 2P4
Street Location for DELIVERY: 3rd floor – 820 Taylor Avenue
Telephone / N° de téléphone : (204) 474-3468 • Fax / N° de télécopieur : (204) 474-4947
mmurphy@hydro.mb.ca

April 14, 2008

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

ATTENTION: Mr. G. Gaudreau, Executive Director

Dear Mr. Gaudreau:

Re: Centra Gas Manitoba Inc.
Cost Allocation Review

In its Order 99/07, the Manitoba Public Utilities Board directed that Centra Gas "propose to the Board terms of reference for a review of cost development and allocation between MH and Centra". Manitoba Hydro has reviewed this directive and respectfully requests that this requirement be deferred for the following reasons:

a) Manitoba Hydro has just issued a Request for Proposal for consulting assistance in adapting its accounting processes and systems to conform with International Financial Reporting Standards (IFRS). At this time, the implications of the change to IFRS are not specifically determined but there is a high likelihood that a substantial change to the current Integrated Cost Allocation Methodology will be required.

b) Manitoba Hydro will be moving to its new head office over the next year. In relation to that move, the PUB has requested that Centra provide confirmation "that no incremental costs are to accrue to Centra's customers for Manitoba Hydro's new head office." In order to provide the PUB with this assurance, Manitoba Hydro is considering modifications to its cost allocation methodology such that space costs will be more specifically identifiable by user departments. These modifications have not yet been finalized and therefore could not be dealt with in an external review at this time.

As evidenced at the last Centra Gas General Rate Application, a comprehensive review of Manitoba Hydro's Integrated Cost Allocation Methodology was performed in 2001 at an external cost in excess of $500,000. Additionally, substantial internal time was spent on the design and implementation of the costing methodology and in managing the external review and related regulatory processes.

In consideration of the substantial changes to the Cost Allocation Methodology associated with IFRS and the new head office, Centra does not believe that a review of its existing Cost Allocation Methodology would be beneficial at this time. Centra will, of course, keep the PUB apprised of any changes to its Cost Allocation Methodology that result from the implementation of IFRS and/or the move to the new head office.

If you have any questions with respect to these matters, please contact the writer at 474-3468.

Yours truly,
MANITOBA HYDRO LAW DEPARTMENT
Per:

M Murphy

Marla D. Murphy
Barrister and Solicitor

cc: Mr. B. Peters, Fillmore & Riley
Mr. R. Cathcart, Price Waterhouse Coopers
Mr. M. Kostelnyk, Energy Consultants Inc.

PUB/CENTRA I-22

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 Page 1 of 23; 2009/10 & 2010/11 GRA PUB/Centra 37(c)**

b) Please provide an update to the April 14, 2008 letter and explain any changes made to the Integrated Cost Allocation Methodology to ensure that no incremental costs have accrued to Centra related to the new head office.

ANSWER:

The latest update to the April 14, 2008 letter was issued on September 30, 2010 (please see the attachment to this response). With the recent deferral of IFRS and the continued uncertainty with respect to regulatory accounting, Centra will be in a better position to determine the appropriate review of the Integrated Cost Allocation Methodology when the IASB concludes their review on rate regulated activities.

There has been no allocation of incremental costs of the new head office (360 Portage) to Centra. This is evidenced by the schedule included in the response to PUB/Centra I-34 (c) showing that for the seven year period from 2006/07 to 2013/14 overall building cost allocations to Centra were maintained at consistent levels with the overall cost increase of 1.7% over the period.

In regards to the changes to the Integrated Cost Allocation Methodology over the period 2006/07 to 2012/13, the response to PUB/Centra I-34 (c) identifies the timing of changes introduced to remove all building cost categories from allocation through overhead. Building costs are now allocated directly to Centra through a shared cost allocation. Shared cost allocations are charged at the company level and therefore are not charged to operating programs and capital projects. Overhead costs are allocated to operating programs and capital projects applying “activity charges” as the cost driver; the shared cost allocation for building costs also applies the “activity charges” cost driver to allocate costs.

In regards to the impact of allocations to Centra during the timeframe where Manitoba Hydro staff were relocated from previously leased administrative buildings to locations at 360 Portage and also 820 Taylor, building costs allocated to Centra were allocated through overhead allocations during this transition period. During this time, overhead rates were not changed with respect to building space costs to ensure that the overall level of costs remained the same as if the 444 St. Mary Ave and other leased administrative buildings continued to exist through the transition period. In the period post construction, a credit has been applied into the shared cost allocation to Centra to effectively maintain the building cost allocation as if the 444 St. Mary Ave and other leased administrative buildings continue to exist.

As Centra benefits proportionately in the ongoing savings from Manitoba Hydro's integrated operations it would be appropriate to have all costs associated with administrative buildings including those of 360 Portage shared fully as part of the corporation's Cost Allocation Methodology.

Manitoba Hydro

PO Box 815 • Winnipeg Manitoba Canada • R3C 2P4
Street Location for DELIVERY: 22nd floor 360 Portage Ave
Telephone / N° de téléphone : (204) 360-3468 • Fax / N° de télécopieur : (204) 360-6147
mboyd@hydro.mb.ca

September 30, 2010

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

ATTENTION: Mr. G. Gaudreau, Executive Director

Dear Mr. Gaudreau:

Re: Centra Gas Manitoba Inc. ("Centra")
Integrated Cost Allocation Methodology
Directive 11 - Order 128/09

The Public Utilities Board of Manitoba ("PUB") issued Order 128/09 with regard to Centra's 2009/10 and 2010/11 General Rate Application on September 16, 2009. In that Order, the PUB provided Directive 11 which requested:

> "Centra to file on or before March 1, 2010 a terms of reference for a study to review the Integrated Cost Allocation Methodology. The study is to be completed in sufficient time to be incorporated within the corporation's next MH or Centra GRA;

Centra is hereby providing the PUB with an update with respect to Directive 11.

The Canadian Accounting Standards Board had previously directed Canadian publicly accountable enterprises to start using International Financial Reporting Standards ("IFRS") as a replacement for Canadian Generally Accepted Accounting Principles ("GAAP") effective January 1, 2011. IFRS were thus to be implemented by Centra effective for the 2011/12 fiscal year with comparative information presented for the 2010/11 fiscal year.

Unlike Canadian GAAP, IFRS does not have a standard that allows for the recognition of rate regulated assets and liabilities. In July, 2009, the International Accounting Standards Board ("IASB") issued an exposure draft which addressed the recognition of rate regulated assets and liabilities. As a result of comment letters received by the IASB concerning that exposure draft, the IASB has determined that further research and analysis was necessary to determine whether rate regulated assets and liabilities can be recognized. In the most recent September 2010 IASB meeting, the IASB suspended the project on rate regulated accounting and indicated that they will seek feedback for future direction in the spring of 2011.

As a result of the uncertainty with regards to regulatory accounting, the Canadian Accounting Standards Board has amended its standards to revise the mandatory date for first-time adoption of International Financial Reporting Standards by entities with rate-regulated activities. This revision allows Centra to defer its implementation of IFRS by 1 year.

The delay in the ruling of this accounting decision has prevented Centra from anticipating the potential IFRS related accounting and operational changes that will be required. Centra has previously noted, and the PUB has concurred, that for efficiency purposes the accounting rules need to be known prior to undertaking a review of the Integrated Cost Allocation Methodology.

Centra will be in a better position to respond to this directive when the IASB concludes their review on rate regulated activities and provides its decision on the appropriate treatment for rate regulated entities.

Copies of this submission have also been provided to the PUB Advisors. If you have any questions with respect to this submission or require paper copies, please contact the writer at 360-3468, or Greg Barnlund at 360-5243.

Yours truly,
MANITOBA HYDRO LAW DEPARTMENT
Per:

M Boyd

Marla D. Boyd
Barrister and Solicitor

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

PUB/CENTRA I-23

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 Page 1 of 23; 2009/10 & 2010/11 GRA PUB/Centra 79; - New Corporate Head Office**

a) **Please provide the final cost for the new corporate head office at 360 Portage Avenue.**

ANSWER:

The final cost for the new corporate head office at 360 Portage Avenue was $283,028,000.

PUB/CENTRA I-23

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 Page 1 of 23; 2009/10 & 2010/11 GRA PUB/Centra 79; - New Corporate Head Office**

b) Please update PUB/Centra 79(b) from 2009/10 & 2010/11 GRA and finalize the continuity of the new head office cost.

ANSWER:

Please see the schedule below.

Please note that the information filed in PUB/Centra 79(b) (2009/10 & 2010/11 GRA) was as at March 31, 2009. The following schedule has been updated to include subsequent expenditures incurred in fiscal 2009. In addition fiscal 2010 previously reflected forecast information and has been updated to show the actual expenditures incurred.

Centra Gas Manitoba Inc.
2014 General Rate Application

PUB/Centra 23(b)
April 12, 2013
Page 1 of 3

Downtown Office Project Expenditures

($000's)

		March 31, 2003			**March 31, 2004**			**March 31, 2005**	
	Opening	**Expenditure**	**Closing**	**Opening**	**Expenditure**	**Closing**	**Opening**	**Expenditure**	**Closing**
Contract									
Excavation/Backfill/Shoring/Caissons	-	-	-	-	-	-	-	-	-
Landscaping	-	-	-	-	-	-	-	-	-
Concrete	-	-	-	-	-	-	-	-	-
Tower Crane	-	-	-	-	-	-	-	-	-
Masonry	-	-	-	-	-	-	-	-	-
Structural Steel	-	-	-	-	-	-	-	-	-
Miscellaneous Metals	-	-	-	-	-	-	-	-	-
Carpentry/Millwork	-	-	-	-	-	-	-	-	-
Roofing/Siding/Thermal/Moisture Protection	-	-	-	-	-	-	-	-	-
Doors /Frames/Hardware	-	-	-	-	-	-	-	-	-
Curtainwall	-	-	-	-	-	-	-	-	-
Interior Office Glazing	-	-	-	-	-	-	-	-	-
Finishes	-	-	-	-	-	-	-	-	-
Access Floor	-	-	-	-	-	-	-	-	-
Sun Control Devices	-	-	-	-	-	-	-	-	-
Elevators	-	-	-	-	-	-	-	-	-
Building Mechanical	-	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-	-
Building Electrical	-	-	-	-	-	-	-	-	-
Signage and Equipment	-	-	-	-	-	-	-	-	-
Total Direct Costs	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
General Expense Costs	-	-	-	-	-	-	-	62	62
Construction Manager Costs	-	-	-	-	-	-	-	546	546
Total Construction Costs	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**608**	**608**
Design Team	-	173	173	173	427	600	600	3 817	4 417
Internal Project Team	-	214	214	214	851	1 065	1 065	1 361	2 426
IT, Communications & Security	-	-		-	-	-	-	38	38
Furniture	-	-		-	-	-	-	-	-
Tenant Allowances	-	-		-	-	-	-	480	480
Insurance	-	-		-	-	-	-	-	-
Capitalized Interest	-	3	3	3	73	76	76	323	399
Total Project Cost	**-**	**390**	**390**	**390**	**1 351**	**1 741**	**1 741**	**6 627**	**8 368**

Centra Gas Manitoba Inc.
2014 General Rate Application

PUB/Centra 23(b)
April 12, 2013
Page 2 of 3

Downtown Office Project Expenditures

($000's)

	March 31, 2006			March 31, 2007			March 31, 2008		
	Opening	**Expenditure**	**Closing**	**Opening**	**Expenditure**	**Closing**	**Opening**	**Expenditure**	**Closing**
Contract									
Excavation/Backfill/Shoring/Caissons	-	11 240	11 240	11 240	364	11 604	11 604	8	11 612
Landscaping	-	-	-	-	-	-	-	-	-
Concrete	-	3 126	3 126	3 126	14 922	18 048	18 048	13 238	31 286
Tower Crane	-	545	545	545	801	1 346	1 346	1 117	2 463
Masonry	-	-	-	-	700	700	700	1 478	2 178
Structural Steel	-	-	-	-	-	-	-	2 701	2 701
Miscellaneous Metals	-	-	-	-	42	42	42	177	219
Carpentry/Millwork	-	-	-	-	-	-	-	411	411
Roofing/Siding/Thermal/Moisture Protection	-	-	-	-	75	75	75	1 125	1 200
Doors /Frames/Hardware	-	-	-	-	8	8	8	626	634
Curtainwall	-	-	-	-	3 951	3 951	3 951	18 331	22 282
Interior Office Glazing	-	-	-	-	-	-	-	257	257
Finishes	-	-	-	-	-	-	-	1 460	1 460
Access Floor	-	96	96	96	(93)	3	3	1 870	1 873
Sun Control Devices	-	-	-	-	-	-	-	320	320
Elevators	-	-	-	-	1 901	1 901	1 901	2 438	4 339
Building Mechanical	-	54	54	54	8 527	8 581	8 581	14 937	23 518
Geothermal	-	1 742	1 742	1 742	290	2 032	2 032	-	2 032
Building Electrical	-	149	149	149	5 995	6 144	6 144	13 892	20 036
Signage and Equipment	-	8	8	8	63	71	71	274	345
Total Direct Costs	**-**	**16 960**	**16 960**	**16 960**	**37 546**	**54 506**	**54 506**	**74 660**	**129 166**
General Expense Costs	62	1 080	1 142	1 142	3 224	4 366	4 366	4 824	9 190
Construction Manager Costs	546	134	680	680	2 152	2 832	2 832	3 465	6 297
Total Construction Costs	**608**	**18 174**	**18 782**	**18 782**	**42 922**	**61 704**	**61 704**	**82 949**	**144 653**
Design Team	4 417	7 427	11 844	11 844	5 449	17 293	17 293	5 135	22 428
Internal Project Team	2 426	1 624	4 050	4 050	1 737	5 787	5 787	1 250	7 037
IT, Communications & Security	38	86	124	124	588	712	712	2 785	3 497
Furniture	-	-	-	-	-	-	-	-	-
Tenant Allowances	480	-	480	480	-	480	480	(480)	-
Insurance	-	1 873	1 873	1 873	-	1 873	1 873	97	1 970
Capitalized Interest	399	1 168	1 567	1 567	3 986	5 553	5 553	8 833	14 386
Total Project Cost	**8 368**	**30 352**	**38 720**	**38 720**	**54 682**	**93 402**	**93 402**	**100 569**	**193 971**

Centra Gas Manitoba Inc.
2014 General Rate Application

PUB/Centra 23(b)
April 12, 2013
Page 3 of 3

Downtown Office Project Expenditures
($000's)

	March 31, 2009			March 31, 2010		
	Opening	**Expenditure**	**Closing**	**Opening**	**Expenditure**	**Closing**
Contract						
Excavation/Backfill/Shoring/Caissons	11 612	5	11 617	11 617	-	11 617
Landscaping	-	1 047	1 047	1 047	437	1 484
Concrete	31 286	173	31 459	31 459	10	31 469
Tower Crane	2 463	411	2 874	2 874	-	2 874
Masonry	2 178	1 791	3 969	3 969	58	4 027
Structural Steel	2 701	1 449	4 150	4 150	-	4 150
Miscellaneous Metals	219	3 823	4 042	4 042	942	4 984
Millwork	411	1 347	1 758	1 758	893	2 651
Roofing/Siding/Thermal/Moisture Protection	1 200	4 003	5 203	5 203	1 869	7 072
Doors /Frames/Hardware	634	678	1 312	1 312	240	1 552
Curtainwall	22 282	4 560	26 842	26 842	1 945	28 787
Interior Office Glazing & Drywall	257	2 839	3 096	3 096	1 173	4 269
Finishes	1 460	7 445	8 905	8 905	1 838	10 743
Access Floor	1 873	2 868	4 741	4 741	392	5 133
Sun Control Devices	320	1 183	1 503	1 503	571	2 074
Elevators	4 339	175	4 514	4 514	230	4 744
Building Mechanical	23 518	10 194	33 712	33 712	524	34 236
Geothermal	2 032	-	2 032	2 032	-	2 032
Building Electrical	20 036	6 859	26 895	26 895	92	26 987
Signage and Equipment	345	653	998	998	549	1 547
Total Direct Costs	**129 166**	**51 503**	**180 669**	**180 669**	**11 763**	**192 432**
General Expense Costs	9 190	4 835	14 025	14 025	1 550	15 575
Construction Manager Costs	6 297	2 557	8 854	8 854	552	9 406
Total Construction Costs	**144 653**	**58 895**	**203 548**	**203 548**	**13 865**	**217 413**
Design Team	22 428	3 608	26 036	26 036	1 427	27 463
Internal Project Team	7 037	1 277	8 314	8 314	677	8 991
IT, Communications & Security	3 497	2 470	5 967	5 967	147	6 114
Furniture	-	4 347	4 347	4 347	2 974	7 321
Tenant Allowances	-	-	-	-	-	-
Insurance	1 970	691	2 661	2 661	384	3 045
Artwork	-	209	209	209	257	466
Capitalized Interest	14 386	(2 171)	12 215	12 215	-	12 215
Total Project Cost	**193 971**	**69 326**	**263 297**	**263 297**	**19 731**	**283 028**

PUB/CENTRA I-23 (Revised)

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 Page 1 of 23; 2009/10 & 2010/11 GRA PUB/Centra 79; - New Corporate Head Office**

c) **Please update PUB/MH II-151 (a) from the 2010/11 & 2011/12 MH GRA providing the cost per square foot comparison for 2012/13 and 2013/14. Please provide the lease cost assumptions for 444 St. Mary for this analysis.**

ANSWER:

The 444 St Mary Avenue lease cost assumptions for 2012/13, as provided in the following table, represent current market prices as at December 2012:

444 St. Mary Ave costs	2013
Leasehold Rentals	865
Building & Property Services	668
Building & Property Taxes	252
(in '000s)	$1 785
Square footage	***78 642***
Cost per square foot	***23***

360 Portage Avenue building costs are shown as gross amounts along with the allocated costs to gas operations in the following table:

360 Portage Ave costs	2013	Centra's Allocated costs 2013	
Operating&Maintenance	3,895	390	
Property & Business Tax	4,901	490	
Depreciation	3,628	363	
Interest	18,536	1,854	
(in '000s)	$30,960	$3,096	
Offsetting credit as per PUB order #99-07, 07/08 Gas GRA and PUB order #128-09, 09/10 Gas GRA		($2,200)	(i)
Allocated to Gas (in 000's)		$896	
Square footage	***697,609***	***69,761***	
Cost per square foot	***44***	***13***	

Since 2012/13 year-end data has not yet been finalized, the 360 Portage Avenue costs are based on IFF12 forecast with the exception of property and business tax, which reflects the actual taxes paid in the year.

The second column of allocated costs to Centra reflects 10% of the gross 360 Portage Avenue building costs. The 10% allocation is based on activity charges as the cost driver.

(i) These gross costs are offset by the credit, as outlined in Order 99/07 and Order 128/09, which ultimately maintains the building cost allocation to gas operations as if the 444 St Mary Avenue and other leased administrative buildings continued to exist.

The credit is calculated based on the costs assumed by Manitoba Hydro for all leased facilities, including 444 St. Mary Ave., prior to the transition to 360 Portage Ave, as head office functions were previously located across these facilities.

Information for 2013/14 primarily reflects an escalated cost equivalent to the CPI and therefore was omitted for the purposes of this analysis.

PUB/CENTRA I-23

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 Page 1 of 23; 2009/10 & 2010/11 GRA PUB/Centra 79; - New Corporate Head Office**

d) **Please provide details on the space costs allocated to Centra through overhead allocations for the years 2007/08 through 2013/14. Compare that with the space cost of Centra continuing to reside in the offices occupied as of 2008. Please explain the methodology for determining the space costs.**

ANSWER:

Please see Centra's response to PUB/Centra I-34(c), which provides the details of the space costs allocated to Centra over the years 2006/07 through 2013/14 as well as the methodology for determining the space costs.

Please see Centra's response to PUB/Centra I-23(c), which compares the space costs allocated to Centra for 360 Portage Ave. compared to the costs of Centra continuing to reside at 444 St. Mary Ave.

PUB/CENTRA I-23

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 Page 1 of 23; 2009/10 & 2010/11 GRA PUB/Centra 79; - New Corporate Head Office**

e) **Please demonstrate that the incremental costs related to the new head office will be cost neutral or beneficial to Centra. Please provide the square footage allocated to Centra in Manitoba Hydro's head office during the test year.**

ANSWER:

There has been no allocation of incremental costs of the new head office to Centra. Please see Centra's response to PUB/Centra I-22(b) for an explanation of the cost allocation methodology related to the new head office. Square footage is not applied in the allocation of costs to Centra but rather activity charges are used as the basis for the allocation.

PUB/CENTRA I-23

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 Page 1 of 23; 2009/10 & 2010/11 GRA PUB/Centra 79; - New Corporate Head Office**

f) Please advise whether any depreciation costs in respect of Manitoba Hydro's head office are being expensed to Centra in the test year. If so, please provide:

a. The total depreciation expense in respect of Manitoba Hydro's head office during the test year.

b. The percentage of that depreciation that is being expensed to Centra.

ANSWER:

Please see the following table identifying the total depreciation cost for Manitoba Hydro's new head office and the percentage of that depreciation that is being expensed to Centra.

Depreciation Costs - 360 Portage (000's)		
	2012/13 Forecast	2013/14 Test Year
a. Total Depreciation	$ 3,628	$3,628
b. % Allocation to Centra	3%	3%

Please note that the 3% allocation to Centra is net of the credit that is outlined in the response to PUB/Centra I-23(c).

PUB/CENTRA I-23

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 Page 1 of 23; 2009/10 & 2010/11 GRA PUB/Centra 79; - New Corporate Head Office**

g) Please provide the termination date of Centra's lease of 444 St. Mary Avenue.

ANSWER:

The termination date of Centra's lease for 444 St Mary Avenue was January 31, 2009.

PUB/CENTRA I-23

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 Page 1 of 23; 2009/10 & 2010/11 GRA PUB/Centra 79; - New Corporate Head Office**

h) **Please file the 2012 Property and Business Tax Assessment from the City of Winnipeg and indicate the taxes assessed against the new head office.**

ANSWER:

For 2012, property taxes of $3,813,839.40 and business taxes of $851,440.80 were assessed against the Corporate occupied head office.

Please find a copies of the 2012 City of Winnipeg statements attached to this response.

(FRANCAIS AU VERSO)

THE CITY OF WINNIPEG 2012 GRANT-IN-LIEU OF SCHOOL AND MUNICIPAL TAXES

STATEMENT DATE: MAY 11, 2012

ROLL NUMBER: 12097557800

Property Address Information:
360 PORTAGE AVE
4985371 MANITOBA LTD

Title No.: 2071733
Mortgage No.:

Part of Lot	Lot	Block	Plan	Parish
	600-603	3	129	1 ST J
	631-633	3	129	1 ST J
	13-14		19168	1 ST J
	A		43247	1 ST J
	594-597	3	129	1 ST J

Assessment Information				
STATUS CODE	CLASS	PORTION %	ASSESSED VALUE	PORTIONED VALUE
Grant	Other Property	65.0	142,248,000	92,461,200

SCHOOL TAXES

WINNIPEG SCHOOL DIVISION(Inquires: 204-775-0231)	(92,461,200 X 0.015668)	**$1,448,682.08**
PROVINCIAL EDUCATION SUPPORT LEVY	(92,461,200 x 0.011469)	**1,060,437.50**
	TOTAL SCHOOL TAXES	**$2,509,119.58**

MUNICIPAL TAXES

MUNICIPAL TAXES(Inquiries: 311 or toll free 1-877-311-4974)	(92,461,200 x 0.014056)	**$1,299,634.63**
STREET RENEWAL - Frontage Levy		**4,593.00**
ENCROACHMENT + GST (R121682967)		**492.19**
	TOTAL MUNICIPAL TAXES	**$1,304,719.82**
	NET PROPERTY TAXES	**$3,813,839.40**
	BALANCE OWING	**N/A**

TOTAL TAXES DUE	
School Taxes	$2,509,119.58
Municipal Taxes	1,304,719.82
Total Current Taxes	$3,813,839.40
TOTAL TAXES DUE	**N/A**

Winnipeg

THE CITY OF WINNIPEG - VILLE DE WINNIPEG
STATEMENT AND DEMAND FOR 2012 GRANT-IN-LIEU BUSINESS TAXES
RELEVÉ ET DEMANDE DE SUBVENTION TENANT LIEU DE TAXES - 2012

ROLL NO. / N° DU RÔLE	STATEMENT DATE / DATE DU RELEVÉ
38290	April 19, 2012

INQUIRIES / RENSEIGNEMENTS
311 or toll free 1-877-311-4974
311 ou (sans frais) le 1-877-311-4974

NAME(S) OF TAXABLE PARTY / NOM(S) DE LA PARTIE IMPOSABLE
MANITOBA HYDRO

PREMISES ASSESSED - STREET NUMBER, ETC.
LOCAUX ÉVALUÉS - N° DE VOIRIE, ETC.
360 PORTAGE AVE

ANNUAL RENTAL VALUE / VALEUR LOCATIVE ANNUELLE	% RATE / TAUX EN %
$14,431,200	5.9

CURRENT YEAR'S TAX (ADD PENALTIES FROM JUNE 1, 2012) TAXE DE L'ANNÉE EN COURS (AJOUTEZ PÉNALITÉS À COMPTER DU 1ER JUIN 2012)	$851,440.80
SMALL BUSINESS TAX CREDIT CRÉDITS D'IMPÔT POUR PETITES ENTREPRISES	$0.00
NET BUSINESS TAX TAXE D'ENTREPRISE NETTE	$851,440.80
BUSINESS IMPROVEMENT ZONE ZONE D'AMÉLIORATION COMMERCIALE	$0.00
ARREARS (INCLUDES PENALTIES TO APRIL 1, 2012) ARRIÉRÉS (COMPREND PÉNALITÉS AU 1ER AVRIL 2012)	N/A
CREDITS CRÉDITS	N/A
TOTAL DUE MONTANT DÛ	N/A

IMPORTANT MESSAGES - Visit our website at: www.winnipegassessment.com

MESSAGES IMPORTANTS: Visitez notre site Web à : www.winnipegassessment.com

PLEASE RETAIN YOUR CANCELLED CHEQUE AS NO ADDITIONAL RECEIPT WILL BE ISSUED.

VEUILLEZ CONSERVER VOTRE CHÈQUE ENCAISSÉ, CAR AUCUN REÇU NE SERA FOURNI

DUE DATE: THURSDAY, MAY 31, 2012
PLEASE DETACH AND RETURN WITH YOUR PAYMENT

ÉCHÉANCE : JEUDI, 31 MAI 2012
VEUILLEZ DÉTACHER ET RETOURNER AVEC VOTRE PAIEMENT

ROLL NUMBER / NUMÉRO DU RÔLE	ARREARS / ARRIÉRÉS	TOTAL PAYABLE / MONTANT PAYABLE	AMOUNT PAID / MONTANT PAYÉ
38290	N/A	N/A	

B38290XXXXXX008514408038290XXXXXX

MANITOBA HYDRO
C/O PROPERTY DEPT
PO BOX 815
WINNIPEG,MB R3C 2P4

Please Pay:
The City of Winnipeg
Assessment and Taxation Department
Administration Building
510 Main Street
Winnipeg (MB) R3B 3M2

FAIRE PARVENIR À:
Ville de Winnipeg
Service de l'évaluation et des taxes
Immeuble de l'administrationn
510, rue Main
Winnipeg (MB) R3B 3M2

PUB/CENTRA I-24

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 Pages 3 and 4 of 23 – Accounting Changes**

a) **Please explain how the split between electric and gas operations was determined for the five cost items now proposed to be expensed for 2012/13 and 2013/14.**

ANSWER:

The split of these costs between electric and gas operations is as follows:

- Interest on Common Assets, Interest on Motor Vehicles, IT Infrastructure and Related Support & Building Depreciation & Operation Costs - 90% to Electric operations and 10% to Gas operations using activity charges as the driver for the allocation. These cost items are incurred in support the staff of the utilities, therefore activity charges is an appropriate cost driver as it aligns with the time spent by the staff between electric and gas operations.
- General & Administrative Department Costs – 96% to Electric operations and 4% to Gas operations using Total Assets as the driver for the allocation. The areas included in this category provide a corporate governance function. The value of the assets was viewed as an appropriate cost allocation driver as it represents the relative size of the utilities.

PUB/CENTRA I-24

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 Pages 3 and 4 of 23 – Accounting Changes**

b) Please provide the supporting calculations for the pension expense change resulting from discount rate changes to be recorded in 2012/13 and 2013/14.

ANSWER:

Below are the supporting calculations for the change in pension expense resulting from lowering the discount rate for fiscal 2012/13 and 2013/14.

	2012/13	**2013/14**
	(millions of dollars)	
IFF11 - Discount Rate 6.5%		
Manitoba Hydro/Wpg Hydro	44.1	49.1
Centra Gas	0.8	0.2
Total	44.9	49.3
IFF12 - Discount Rate 5.25%		
Manitoba Hydro/Wpg Hydro	59.1	66.2
Centra Gas	1.7	1.8
Total	60.8	68.0
Change	15.9	18.7
Allocation to operating - 58%	9.2	10.8
Allocation to Gas Operations - 10%	**0.9**	**1.1**

PUB/CENTRA I-24

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 Pages 3 and 4 of 23 – Accounting Changes**

c) **Please explain the offset in depreciation cost previously included in gas programs referred to on page 3 line 23.**

ANSWER:

Overhead and activity rates charged to gas programs previously included depreciation & operating costs associated with buildings and IT infrastructure. Effective for the 2012/13 fiscal year, these costs were removed from overhead and activity charges and are no longer captured in the gas programs. Operating and maintenance costs of buildings and IT infrastructure are direct charged to Centra's OM&A through Corporate Allocations and Adjustments.

PUB/CENTRA I-25 (Revised)

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Schedule 5.5.0; Appendix 5.7 Page 17 of 23 – Cost Per Customer**

a) **Please provide a schedule of the OM&A expenses (program view and business unit) from 2003/04 to 2013/14. On the schedule please include the total number of customers and the OM&A cost per customer (including and excluding accounting changes) for each of the years. Also include two columns which indicate the Compounded annual Growth, one for 2003/04 to 2011/12 and one for 2011/12 to 2013/14.**

ANSWER:

Please see the attached schedules.

SCHEDULE 1 - 2003/04 to 2005/06 **($000's)**

	2003/04 Actual	2004/05 Actual	2005/06 Actual
President & CEO			
Audit	217	241	152
Liability Claims	8	(12)	8
Policy & Procedure	198		
Public Affairs	1,062	1,067	776
Total President & CEO	**$ 1,485**	**$ 1,296**	**$ 936**
Finance & Administration			
Customer Billing	2,479	2,807	3,156
IT - Banner System	1,551	1,356	828
IT - Distribution/ Metering Systems	238	415	242
Gas Accounting	439	399	508
Gas Regulatory	1,773	2,064	1,864
Gas Supply	2,610	2,466	2,663
Treasury	334	255	97
Total Finance & Administration	**$ 9,423**	**$ 9,762**	**$ 9,358**
Power Supply			
Environmental Management	163	171	29
Total Power Supply	**$ 163**	**$ 171**	**$ 29**
Transmission & Distribution			
Property Tax Administration	157	96	56
Research & Development	51	(25)	10
Station Maintenance	4,496	4,295	4,219
System Integrity	1,285	1,111	1,265
System Maintenance & Support	909	692	563
System Support & Communication Systems	214	209	217
Total Transmission & Distribution	**$ 7,112**	**$ 6,378**	**$ 6,330**
Customer Service & Marketing			
Billing Inquiries & Collections	7,032	10,935	11,457
Emergency	317	56	98
Customer Inspections	8,267	9,057	9,431
Customer Relations	9,532	5,749	4,493
Customer Safety	2,093	2,079	2,115
Dispatch	2,815	2,557	2,692
Distribution Maintenance	8,199	8,504	7,998
Load Forecast	68	136	185
Meter Reading	2,108	1,892	1,767
Metering	3,797	3,830	3,687
Total Customer Service & Marketing	**$ 44,226**	**$ 44,795**	**$ 43,923**
Corporate Allocations & Adjustments	(1,858)	804	221
Program View	**$ 60,551**	**$ 63,206**	**$ 60,797**
Less: Depreciation, Interest & Taxes included in above	(7,765)	(7,974)	(7,712)
Operating & Administrative Expense	**$ 52,786**	**$ 55,232**	**$ 53,085**
Less: Accounting Changes	-	-	-
OM&A after adjusting for Accounting Changes	**$ 52,786**	**$ 55,232**	**$ 53,085**
Number of Customers	253,631	255,925	257,817
OM&A Cost per Customer:			
Before Adjustments for Accounting Changes	$ 208	$ 216	$ 206
After Adjustments for Accounting Changes	$ 208	$ 216	$ 206

Note: Information presented for years 2003/04 to 2005/06 (Schedule 1) is not directly comparable to years 2006/07 to 2013/14 (Schedule 2) as a result of changes to the Corporate organizational structure.

SCHEDULE 1 - 2003/04 to 2005/06 **($000's)**

	2003/04 Actual	2004/05 Actual	2005/06 Actual
President & CEO	1,485	1,296	936
Finance & Administration	9,423	9,762	9,358
Power Supply	163	171	29
Transmission & Distribution	7,112	6,378	6,330
Customer Service & Marketing	44,226	44,795	43,923
Corporate Allocations & Adjustments	(1,858)	804	221
Program View - Operating & Administrative Expense	**$ 60,551**	**$ 63,206**	**$ 60,797**
Less: Depreciation, Interest & Taxes included in above	(7,765)	(7,974)	(7,712)
Operating & Administrative Expense	**$ 52,786**	**$ 55,232**	**$ 53,085**
Less: Accounting Changes	-	-	-
OM&A after adjusting for Accounting Changes	**$ 52,786**	**$ 55,232**	**$ 53,085**
Number of Customers	253,631	255,925	257,817
OM&A Cost per Customer:			
Before Adjustments for Accounting Changes	$ 208	$ 216	$ 206
After Adjustments for Accounting Changes	$ 208	$ 216	$ 206

Note: Information presented for years 2003/04 to 2005/06 (Schedule 1) is not directly comparable to years 2006/07 to 2013/14 (Schedule 2) as a result of changes to the Corporate organizational structure.

CENTRA GAS MANITOBA INC.
OPERATING & ADMINISTRATIVE EXPENSES - BY BUSINESS UNIT

($000's)

	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Test Year	2013/14 Test Year	Compounded Annual Growth 2006/07 to 2011/12 % Inc/(Dec)	Compounded Annual Growth 2011/12 to 2013/14 % Inc/(Dec)
President & CEO	1,098	1,088	1,374	1,222	972	1,122	891	909	0.4	(10.0)
Finance & Administration	6,918	6,558	6,549	6,742	6,693	6,377	6,187	6,311	(1.6)	(0.5)
Power Supply	36	46	47	220	477	317	404	412	54.7	14.0
Transmission	200	236	224	255	250	99	194	197	(13.1)	41.3
Customer Service & Distribution	33,460	37,313	38,078	40,288	37,941	39,565	38,493	39,263	3.4	(0.4)
Customer Care & Marketing	17,637	18,011	19,765	18,670	17,845	18,195	17,575	17,926	0.6	(0.7)
Corporate Allocations & Adjustments	2,035	1,455	1,769	1,460	1,660	1,718	6,559	6,844	(3.3)	99.6
Program View - Operating & Administrative Expense	**$ 61,384**	**$ 64,707**	**$ 67,806**	**$ 68,857**	**$ 65,838**	**$ 67,393**	**$ 70,303**	**$ 71,862**	**1.9**	**3.3**
Less: Depreciation, Interest & Taxes included in above	(7,879)	(8,437)	(8,003)	(7,906)	(5,194)	(5,275)	(3,003)	(3,063)	(7.7)	(23.8)
Operating & Administrative Expense	**$ 53,505**	**$ 56,270**	**$ 59,803**	**$ 60,951**	**$ 60,644**	**$ 62,117**	**$ 67,300**	**$ 68,800**	**3.0**	**5.2**
Less: Accounting Changes	-	-	1,000	1 020	3 040	3 101	7 491	7 796		
OM&A after adjusting for Accounting Changes	**$ 53,505**	**$ 56,270**	**$ 58,803**	**$ 59,931**	**$ 57,604**	**$ 59,016**	**$ 59,809**	**$ 61,004**	**2.0**	**1.7**
Number of Customers	259,569	261,159	263,008	264,301	265,961	267,699	270,040	273,122		
OM&A Cost per Customer:										
Before Adjustments for Accounting Changes	$ 206	$ 215	$ 227	$ 231	$ 228	$ 232	$ 249	$ 252	2.4	4.2
After Adjustments for Accounting Changes	$ 206	$ 215	$ 224	$ 227	$ 217	$ 220	$ 221	$ 223	1.4	0.7

CENTRA GAS MANITOBA INC.
OPERATING & ADMINISTRATIVE EXPENSES - BY PROGRAM (

($000's)

	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Test Year	2013/14 Test Year	Compounded Annual Growth 2006/07 to 2011/12 % Inc/(Dec)	Compounded Annual Growth 2011/12 to 2013/14 % Inc/(Dec)
President & CEO										
Audit	189	167	143	189	291	235	221	225	4.4	(2.1)
Liability Claims	2	1	358	147	(250)	7	80	82	35.3	246.1
Public Affairs	880	841	814	814	891	874	512	522	(0.1)	(22.7)
Research & Development	28	79	60	72	40	6	79	80	(26.2)	264.0
Total President & CEO	**$ 1,098**	**$ 1,088**	**$ 1,374**	**$ 1,222**	**$ 972**	**$ 1,122**	**$ 891**	**$ 909**	**0.4**	**(10.0)**
Finance & Administration										
IT - Distribution/Metering	224	103	181	123	134	102	121	124	(14.5)	10.1
IT - Banner	1,108	978	1,088	1,019	1,074	1,093	1,095	1,117	(0.3)	1.1
Gas Accounting	487	386	378	324	314	332	342	348	(7.4)	2.4
Gas Regulatory	2,121	1,792	1,652	2,199	1,905	1,525	1,949	1,988	(6.4)	14.2
Gas Supply	2,623	2,964	2,937	2,801	2,955	3,036	2,368	2,416	3.0	(10.8)
Treasury	270	261	260	258	282	280	312	318	0.7	6.6
Property Tax Administration	86	74	53	18	30	9	0	0	(36.2)	(100.0)
Total Finance & Administration	**$ 6,918**	**$ 6,558**	**$ 6,549**	**$ 6,742**	**$ 6,693**	**$ 6,377**	**$ 6,187**	**$ 6,311**	**(1.6)**	**(0.5)**
Power Supply										
Environmental Management	36	46	47	220	477	317	404	412	54.7	14.0
Total Power Supply	**$ 36**	**$ 46**	**$ 47**	**$ 220**	**$ 477**	**$ 317**	**$ 404**	**$ 412**	**54.7**	**14.0**
Transmission										
System Support & Communications Systems	200	236	224	255	250	99	194	197	(13.1)	41.3
Total Transmission	**$ 200**	**$ 236**	**$ 224**	**$ 255**	**$ 250**	**$ 99**	**$ 194**	**$ 197**	**(13.1)**	**41.3**
Customer Service & Distribution										
Billing Inquiry & Collections	1,955	2,302	2,088	2,563	2,376	1,895	1,772	1,807	(0.6)	(2.3)
Customer Inspections	9,436	9,778	10,356	10,518	9,750	9,718	8,982	9,162	0.6	(2.9)
Customer Relations	515	576	627	1,572	1,614	1,659	1,501	1,531	26.4	(3.9)
Dispatch	2,540	2,995	2,982	2,511	2,768	3,095	2,793	2,849	4.0	(4.0)
Customer Safety	2,132	2,312	2,228	2,152	2,166	1,936	1,922	1,961	(1.9)	0.6
Distribution Maintenance	7,235	7,975	8,362	8,407	7,417	7,385	7,252	7,397	0.4	0.1
Emergency	(1)	0	218	14	17	110	0	0	(339.9)	(100.0)
Regulating Station Maintenance	4,724	4,722	5,406	5,502	4,998	5,660	5,760	5,875	3.7	1.9
Capacity Analysis & Engineering	448	529	613	698	642	463	635	648	0.6	18.3
System Integrity	1,438	1,451	1,062	1,163	1,316	1,247	1,380	1,407	(2.8)	6.2
Meter Reading	1,706	1,810	1,829	1,861	1,928	1,970	2,015	2,056	2.9	2.1
Meter Changes	1,331	2,863	2,306	3,325	2,948	4,429	4,480	4,569	27.2	1.6
Total Customer Service & Distribution	**$ 33,460**	**$ 37,313**	**$ 38,078**	**$ 40,288**	**$ 37,941**	**$ 39,565**	**$ 38,493**	**$ 39,263**	**3.4**	**(0.4)**
Customer Care & Marketing										
Billing Inquiry & Collections	10,987	10,684	10,557	9,543	8,374	8,286	8,374	8,542	(5.5)	1.5
Customer Relations	4,675	5,092	6,485	6,643	6,473	6,390	6,262	6,387	6.4	0.0
Customer Safety	137	205	303	286	212	324	308	314	18.9	(1.6)
Quality Assessment	0	0	258	470	649	671	565	576		(7.4)
Load Forecast	184	194	156	166	158	173	192	196	(1.2)	6.4
Meter Repair & Calibration	1,653	1,837	2,007	1,562	1,978	2,351	1,874	1,911	7.3	(9.8)
Total Customer Care & Marketing	**$ 17,637**	**$ 18,011**	**$ 19,765**	**$ 18,670**	**$ 17,845**	**$ 18,195**	**$ 17,575**	**$ 17,926**	**0.6**	**(0.7)**
Corporate Allocations & Adjustments	2,035	1,455	1,769	1,460	1,660	1,718	6,559	6,844	(3.3)	99.6
Program View	**$ 61,384**	**$ 64,707**	**$ 67,806**	**$ 68,857**	**$ 65,838**	**$ 67,393**	**$ 70,303**	**$ 71,862**	**1.9**	**3.3**
Less: Depreciation, Interest & Taxes included in above	(7,879)	(8,437)	(8,003)	(7,906)	(5,194)	(5,275)	(3,003)	(3,063)	(7.7)	(23.8)
Operating & Administrative Expense	**$ 53,505**	**$ 56,270**	**$ 59,803**	**$ 60,951**	**$ 60,644**	**$ 62,117**	**$ 67,300**	**$ 68,800**	**3.0**	**5.2**
Less: Accounting Changes	-	-	1,000	1,020	3,040	3,101	7,491	7,796		
OM&A after adjusting for Accounting Changes	**$ 53,505**	**$ 56,270**	**$ 58,803**	**$ 59,931**	**$ 57,604**	**$ 59,016**	**$ 59,809**	**$ 61,004**	**2.0**	**1.7**
Number of Customers	259,569	261,159	263,008	264,301	265,961	267,699	270,040	273,122		
OM&A Cost per Customer:										
Before Adjustments for Accounting Changes	$ 206	$ 215	$ 227	$ 231	$ 228	$ 232	$ 249	$ 252	2.4	4.2
After Adjustments for Accounting Changes	$ 206	$ 215	$ 224	$ 227	$ 217	$ 220	$ 221	$ 223	1.4	0.7

PUB/CENTRA I-25

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Schedule 5.5.0; Appendix 5.7 Page 17 of 23 – Cost Per Customer**

b) **Provide a schedule that compares the OM&A expenses by business unit and program forecasted for 2009/10, 2010/11, and 2011/12 at the 2009/10 & 2010/11 GRA with actual for those respective years in this GRA, and explain any major variances.**

ANSWER:

Please see the schedules below.

CENTRA GAS MANITOBA INC.
OPERATING & ADMINISTRATIVE EXPENSES

Program View - 2009/10 Actual vs 2009/10 Approved **($000's)**

	2009/10 Actual	2009/10 Approved	Variance	%	Variance Explanations > $100,000 & 10%
President & CEO					
Audit	189	228	39	17.1%	
Liability Claims	147	61	(86)	(140.2%)	
Public Affairs	814	785	(29)	(3.7%)	
Research & Development	72	59	(13)	(22.1%)	
Total President & CEO	**$ 1 222**	**$ 1 134**	**$ (88)**	**(7.8%)**	
Finance & Administration					
IT - Distribution/Metering	123	158	35	22.3%	
IT - Banner	1 019	1 080	62	5.7%	
Gas Accounting	324	400	76	18.9%	
Gas Regulatory	2 199	2 324	126	5.4%	
Gas Supply	2 801	2 923	122	4.2%	
Treasury	258	329	71	21.6%	
Property Tax Administration	18	66	48	73.0%	
Total Finance & Administration	**$ 6 742**	**$ 7 281**	**$ 540**	**7.4%**	
Power Supply					
Environmental Management	220	231	11	4.8%	
Total Power Supply	**$ 220**	**$ 231**	**$ 11**	**4.8%**	
Transmission					
System Support & Communications Systems	255	252	(3)	(1.1%)	
Total Transmission	**$ 255**	**$ 252**	**$ (3)**	**(1.1%)**	
Customer Service & Distribution					
Billing Inquiry & Collections	2 563	2 222	(341)	(15.3%)	Increased hours based on analysis of customer numbers across areas in the southern part of the province (not including the city of Winnipeg). Corrections were made to include areas that previously did not allocate any program costs yet have gas customers. Lower disconnect and reconnect fees.
Customer Inspections	10 518	10 159	(359)	(3.5%)	
Customer Relations	1 572	583	(989)	(169.6%)	Increased hours based on analysis of customer numbers across areas in the southern part of the province (not including the city of Winnipeg). Corrections were made to include areas that previously did not allocate any program costs yet have gas customers.
Dispatch	2 511	2 840	329	11.6%	Lower work coordination activities and lower overhead.
Customer Safety	2 152	2 318	166	7.2%	
Distribution Maintenance	8 407	8 554	148	1.7%	
Emergency	14	-	(14)	0.0%	
Regulating Station Maintenance	5 502	4 741	(762)	(16.1%)	Higher system monitoring activities and higher station maintenance than expected.
Capacity Analysis & Engineering	698	607	(91)	(14.9%)	
System Integrity	1 163	1 623	459	28.3%	Lower activities mainly due to vacancies and lower contracted services for river crossing inspections, depth of cover inspections, close interval surveys and corrosion assessments.
Meter Reading	1 861	1 837	(24)	(1.3%)	
Meter Changes	3 325	2 497	(827)	(33.1%)	Higher metering activities in both urban and rural locations in anticipation of the new Measurement Canada standards.
Total Customer Service & Distribution	**$ 40 288**	**$ 37 982**	**$ (2 306)**	**(6.1%)**	
Customer Care & Marketing					
Billing Inquiry & Collections	9 543	12 281	2 738	22.3%	Decreased hours based on analysis of customer numbers. Corrections were made to better reflect the gas / electric customer ratio. Lower bad debt expense and lower overhead.
Customer Relations	6 642	5 809	(834)	(14.4%)	Unplanned DSM program costs.
Customer Safety	286	283	(3)	(0.9%)	
Quality Assessment	470	411	(60)	(14.6%)	
Load Forecast	166	219	53	24.3%	
Meter Repair & Calibration	1 562	2 086	524	25.1%	Higher metering activities in both urban and rural locations in anticipation of the new Measurement Canada standards.
Total Customer Care & Marketing	**$ 18 670**	**$ 21 090**	**$ 2 420**	**11.5%**	
Corporate Allocations & Adjustments	1 460	(130)	(1 590)	1223.8%	Difference due to allocation of the over/under absorption of the cost centres.
Program View	**$ 68 857**	**$ 67 839**	**$ (1 018)**	**-1.5%**	
Less: Depreciation, Interest & Taxes included in above	(7 906)	(8 680)	(774)	8.9%	
Operating & Administrative Expense	**$ 60 951**	**$ 59 160**	**$ (1 791)**	**-3.0%**	

CENTRA GAS MANITOBA INC.
OPERATING & ADMINISTRATIVE EXPENSES

Program View - 2010/11 Actual vs 2010/11 Approved **($000's)**

	2010/11 Actual	2010/11 Approved	Variance	%	Variance Explanations > $100,000 & 10%
President & CEO					
Audit	291	234	(57)	(24.4%)	
Liability Claims	(250)	62	312	501.0%	Write down of existing liability claims not forecasted.
Public Affairs	891	800	(91)	(11.4%)	
Research & Development	40	60	21	34.0%	
Total President & CEO	**$ 972**	**$ 1 157**	**$ 185**	**16.0%**	
Finance & Administration					
IT - Distribution/Metering	134	156	23	14.4%	
IT - Banner	1 074	1 108	34	3.1%	
Gas Accounting	314	405	92	22.6%	
Gas Regulatory	1 905	2 761	856	31.0%	Less General Rate Application, Cost of Gas hearing and other regulatory matter activities and related costs.
Gas Supply	2 955	2 985	30	1.0%	
Treasury	282	336	54	16.2%	
Property Tax Administration	30	67	37	55.2%	
Total Finance & Administration	**$ 6 693**	**$ 7 819**	**$ 1 126**	**14.4%**	
Power Supply					
Environmental Management	476	232	(244)	(105.3%)	Higher environmental monitoring than forecasted.
Total Power Supply	**$ 476**	**$ 232**	**$ (244)**	**(105.3%)**	
Transmission					
System Support & Communications Systems	250	258	8	3.1%	
Total Transmission	**$ 250**	**$ 258**	**$ 8**	**3.1%**	
Customer Service & Distribution					
Billing Inquiry & Collections	2 376	2 258	(118)	(5.2%)	
Customer Inspections	9 750	10 383	633	6.1%	
Customer Relations	1 614	594	(1 020)	(171.6%)	Increased hours based on analysis of customer numbers across areas in the southern part of the province (not including the city of Winnipeg). Corrections were made to include areas that previously did not allocate any program costs yet have gas customers.
Dispatch	2 768	2 914	146	5.0%	
Customer Safety	2 166	2 370	204	8.6%	
Distribution Maintenance	7 417	8 744	1 327	15.2%	Lower above and below grade maintenance activities.
Emergency	17	-	(17)	0.0%	
Regulating Station Maintenance	4 998	4 967	(31)	(0.6%)	
Capacity Analysis & Engineering	642	616	(26)	(4.3%)	
System Integrity	1 316	1 665	349	21.0%	Lower contracted services for river crossing inspections, depth of cover inspections, close interval surveys and corrosion assessments and lower activities mainly due to vacancies.
Meter Reading	1 928	1 873	(55)	(2.9%)	
Meter Changes	2 948	2 552	(396)	(15.5%)	Higher metering activities in both urban and rural locations in anticipation of the new Measurement Canada standards.
Total Customer Service & Distribution	**$ 37 941**	**$ 38 938**	**$ 997**	**2.6%**	
Customer Care & Marketing					
Billing Inquiry & Collections	8 375	12 540	4 166	33.2%	Decreased hours based on analysis of customer numbers. Corrections were made to better reflect the gas / electric customer ratio. Lower bad debt expense.
Customer Relations	6 473	5 932	(541)	(9.1%)	
Customer Safety	212	290	77	26.7%	
Quality Assessment	649	416	(233)	(55.9%)	Higher than anticipated Natural Gas Quality Assessment work requirements.
Load Forecast	158	225	67	29.7%	
Meter Repair & Calibration	1 978	2 144	165	7.7%	
Total Customer Care & Marketing	**$ 17 845**	**$ 21 547**	**$ 3 702**	**17.2%**	
Corporate Allocations & Adjustments	1 660	(713)	(2 373)	332.9%	Corporate governance and support costs previously included in overhead as well as a difference due to the allocation of the over/under absorption of the cost centres.
Program View	**$ 65 838**	**$ 69 238**	**$ 3 400**	**4.9%**	
Less: Depreciation, Interest & Taxes included in above	(5 194)	(8 895)	(3 701)	41.6%	Removal of interest on common assets and motor vehicles.
Operating & Administrative Expense	**$ 60 644**	**$ 60 343**	**$ (301)**	**-0.5%**	

CENTRA GAS MANITOBA INC.
OPERATING & ADMINISTRATIVE EXPENSES

Program View - 2011/12 Actual vs 2011/12 Forecast **($000's)**

	2011/12 Actual	2011/12 Forecast	Variance	%	Variance Explanations > $100,000 & 10%
President & CEO					
Audit	235	241	6	2.5%	
Liability Claims	7	80	73	91.5%	
Public Affairs	874	755	(119)	(15.8%)	Higher industry membership fees and higher sponsorships.
Research & Development	6	61	55	90.1%	
Total President & CEO	**$ 1 122**	**$ 1 137**	**$ 15**	**1.3%**	
Finance & Administration					
IT - Distribution/Metering	102	190	88	46.2%	
IT - Banner	1 093	1 070	(24)	(2.2%)	
Gas Accounting	332	324	(8)	(2.5%)	
Gas Regulatory	1 525	1 808	283	15.6%	Less General Rate Application, Cost of Gas hearing and other regulatory matter activities and related costs.
Gas Supply	3 036	2 985	(50)	(1.7%)	
Treasury	280	297	17	5.6%	
Property Tax Administration	9	24	15	61.7%	
Total Finance & Administration	**$ 6 377**	**$ 6 696**	**$ 319**	**4.8%**	
Power Supply					
Environmental Management	317	435	118	27.1%	Higher environmental monitoring than forecasted.
Total Power Supply	**$ 317**	**$ 435**	**$ 118**	**27.1%**	
Transmission					
System Support & Communications Systems	99	174	76	43.4%	
Total Transmission	**$ 99**	**$ 174**	**$ 76**	**43.4%**	
Customer Service & Distribution					
Billing Inquiry & Collections	1 895	2 381	486	20.4%	Lower than expected customer billing inquiries and less time spent on collection activities.
Customer Inspections	9 718	10 220	502	4.9%	
Customer Relations	1 659	1 635	(23)	(1.4%)	
Dispatch	3 095	2 978	(117)	(3.9%)	
Customer Safety	1 936	2 172	236	10.9%	Lower safety related customer calls partially offset by higher safety watch requests than planned.
Distribution Maintenance	7 385	7 755	370	4.8%	
Emergency	110	-	(110)	0.0%	
Regulating Station Maintenance	5 660	5 593	(66)	(1.2%)	
Capacity Analysis & Engineering	463	723	260	36.0%	Shift of resources from network analysis to capital design work and lower volume of Facility Impact/3rd Party reviews.
System Integrity	1 247	1 406	160	11.4%	Lower contracted services for river crossing inspections, depth of cover inspections and corrosion assessments.
Meter Reading	1 970	1 923	(47)	(2.4%)	
Meter Changes	4 429	2 974	(1 455)	(48.9%)	Higher metering activities in both urban and rural locations in anticipation of the new Measurement Canada standards.
Total Customer Service & Distribution	**$ 39 565**	**$ 39 760**	**$ 195**	**0.5%**	
Customer Care & Marketing					
Billing Inquiry & Collections	8 286	8 524	238	2.8%	
Customer Relations	6 390	6 224	(166)	(2.7%)	
Customer Safety	324	306	(18)	(5.9%)	
Quality Assessment	671	679	7	1.1%	
Load Forecast	173	226	53	23.4%	
Meter Repair & Calibration	2 351	1 976	(375)	(19.0%)	Higher metering activities in both urban and rural locations in anticipation of the new Measurement Canada standards.
Total Customer Care & Marketing	**$ 18 195**	**$ 17 935**	**$ (260)**	**(1.5%)**	
Corporate Allocations & Adjustments	1 718	3 160	1 442	45.6%	Mainly due to unallocated general contingency.
Program View	**$ 67 393**	**$ 69 297**	**$ 1 904**	**2.8%**	
Less: Depreciation, Interest & Taxes included in above	(5 275)	(5 297)	(22)	0.4%	
Operating & Administrative Expense	**$ 62 117**	**$ 64 000**	**$ 1 883**	**2.9%**	

PUB/CENTRA I-25

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Schedule 5.5.0; Appendix 5.7 Page 17 of 23 – Cost Per Customer**

c) Please provide a list of other gas utilities in Canada and their respective OM&A cost per customer for each of the years 2005 through 2012 and show the cumulative annual growth rate of cost per customer. Please include Canada's CPI in this table.

ANSWER:

Centra notes that there are inherent limitations in any comparison of OM&A information across utilities. As a result of accounting changes related to the adoption of IFRS or U.S. GAAP by a number of Canadian utilities, and the associated restatement of financial information from previous years, it is not possible to provide meaningful and comparable OM&A per customer comparisons based on utilities' reported financial results. A very detailed understanding of other utilities' accounting practices would be required to produce results that are near to comparable. This would not only be a difficult undertaking but a very time consuming exercise.

In light of these limitations, and for information purposes only, Centra is providing below data on the average O&A per customer for Canadian Gas Association ("CGA") member LDCs, which is compiled by the CGA. This information is collected by the CGA through its corporate profile surveys. Centra understands that the details underlying the data are provided by member utilities to the CGA on a confidential basis and cannot be disclosed to Centra and/or in the public domain.

	2005	2006	2007	2008	2009	2010	2011	2012	Cumulative Annual Growth Rate 2005 - 2011 (%)
CGA Average O&A Cost per Customer *	$ 213	$ 214	$ 222	$ 230	$ 237	$ 246	$ 252	N/A	2.84
Centra O&A Cost per Customer**	$ 216	$ 206	$ 206	$ 215	$ 227	$ 231	$ 228	$ 232	0.91
Canadian CPI	2.20%	2.30%	1.90%	2.10%	2.20%	0.40%	2.00%	2.80%	1.58

** average O&A per customer for Canadian Gas Association member utilities*
*** O&A per customer before adjustments for accounting changes*

PUB/CENTRA I-25

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Schedule 5.5.0; Appendix 5.7 Page 17 of 23 – Cost Per Customer**

d) Please provide a schedule comparing the OM&A cost per customer since fiscal 2003/04 through 2011/12 to the respective cost per customer targets in the Corporate Strategic Plans for the respective years.

ANSWER:

Please see the attachment to this response.

Centra - Cost per Customer

	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Actual	$ 208	$ 216	$ 206	$ 206	$ 215	$ 227	$ 231	$ 228	$ 232
Target	$ 200	$ 200	$ 211	$ 213	$ 213	$ 220	$ 223	$ 230	$ 238

PUB/CENTRA I-26

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Schedule 5.5.0, Appendix 5.7 Pages 17 to 21 of 23; 2009/10 & 2010/11 GRA PUB/Centra 26(b)**

a) Please provide a comparison of the OM&A by Cost Element for the years 2009/10, 2010/11 and 2011/12 forecasted at the last GRA with actual results indicated at this GRA and explain the differences.

ANSWER:

Please see Centra's response to PUB/Centra I-18(b).

PUB/CENTRA I-26

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Schedule 5.5.0, Appendix 5.7 Pages 17 to 21 of 23; 2009/10 & 2010/11 GRA PUB/Centra 26(b)**

b) Please provide a similar analysis to (a) based on the detailed program view.

ANSWER:

Please see Centra's response to PUB/Centra I-25(b).

PUB/CENTRA I-26 (Revised)

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Schedule 5.5.0, Appendix 5.7 Pages 17 to 21 of 23; 2009/10 & 2010/11 GRA PUB/Centra 26(b)**

c) Please provide an update to the schedule in Appendix 5.7 page 21 on a similar basis to PUB/Centra 26(b) from the 2009/10 & 2010/11 GRA to include the years 2003/04 to 2013/14. Provide additional columns for the compound annual growth for 2003/04 to 2011/12 and for the years 2011/12 to 2013/14.

ANSWER:

Please see the schedule below.

($000's)

	2003/04 Actual	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Test Year	Compounded Annual Growth 2003/04 to 2011/12 % Inc/(Dec)	Compounded Annual Growth 2011/12 to 2013/14 % Inc/(Dec)
Activity Charges	39,609	39,680	37,924	38,380	41,181	42,413	44,410	45,918	46,574	41,453	42,282	2.0	(4.7)
Primary Costs:													
External Course, Awards	55	54	44	41	55	26	24	26	21	9	9	(11.2)	(33.2)
Material	1,486	1,460	1,256	1,107	1,326	1,476	1,294	1,184	1,170	1,337	1,364	(2.9)	8.0
Travel	82	131	125	96	102	124	87	102	79	135	137	(0.4)	31.6
Donations, Grants & Sponsorships	464	514	389	309	333	348	333	393	476	358	365	0.3	(12.4)
Memberships	115	113	95	138	98	142	170	176	188	180	184	6.3	(1.1)
Bad Debt & Collection Expense	2,850	2,771	4,128	2,427	2,148	2,135	2,086	1,613	1,435	1,559	1,590	(8.2)	5.2
Office Administration & Other	1,355	1,601	1,565	1,566	1,581	1,585	1,562	1,557	1,608	1,596	1,628	2.2	0.6
Computer Equipment & Maintenance	467	381	450	265	310	546	563	522	452	547	557	(0.4)	11.1
Meter Reading Charges (primarily MHUS)	1,694	1,698	1,738	1,677	1,765	2,288	2,425	1,949	2,130	2,126	2,169	2.9	0.9
Banking/Cash Management Services	324	299	90	207	205	192	222	220	255	284	290	(3.0)	6.6
Construction & Maintenance Services	1,050	1,204	1,214	1,116	1,288	1,051	1,240	947	1,823	1,138	1,160	7.1	(20.2)
Purchased Services	1,920	721	753	835	898	1,929	1,988	1,772	1,506	2,124	2,166	(3.0)	19.9
Promotional Items/Customer Incentives	31	19	38	54	20	40	25	57	71	27	28	10.8	(37.2)
Gas-PUB & Advisory Services	739	652	637	706	681	722	766	491	496	473	482	(4.9)	(1.4)
Operating Expense Recoveries	(2,050)	(1,109)	(1,013)	(823)	(821)	(561)	(537)	(620)	(598)	0	0	(14.3)	(100.0)
Other	558	522	24	0	0	5	4	1	(1)	(5)	(5)	0.0	110.6
Total Primary Costs	11,140	11,031	11,533	9,721	9,989	12,047	12,251	10,390	11,110	11,887	12,125	0.0	4.5
Corporate Allocations & Adjustments	(1,858)	804	222	2,035	1,455	1,769	1,460	1,660	1,718	6,559	6,844	0.0	99.6
Overhead	11,660	11,691	11,118	11,248	12,082	11,577	10,735	7,870	7,990	10,403	10,611	(4.6)	15.2
Total Program Costs	**$ 60,551**	**$ 63,206**	**$ 60,797**	**$ 61,384**	**$ 64,707**	**$ 67,806**	**$ 68,857**	**$ 65,838**	**$ 67,392**	**$ 70,302**	**$ 71,862**	**1.3**	**3.3**
Depreciation, Interest & Taxes	(7,765)	(7,974)	(7,712)	(7,879)	(8,437)	(8,003)	(7,906)	(5,194)	(5,275)	(3,003)	(3,063)	(4.7)	(23.8)
Operating and Administrative Expense	**$ 52,786**	**$ 55,232**	**$ 53,085**	**$ 53,505**	**$ 56,270**	**$ 59,803**	**$ 60,951**	**$ 60,644**	**$ 62,117**	**$ 67,300**	**$ 68,800**	**2.1**	**5.2**
Less: Accounting Changes	-	-	-	-	-	1,000	1,020	3,040	3,101	7,491	7,796		
OM&A after adjusting for Accounting Changes	**$ 52,786**	**$ 55,232**	**$ 53,085**	**$ 53,505**	**$ 56,270**	**$ 58,803**	**$ 59,931**	**$ 57,604**	**$ 59,016**	**$ 59,809**	**$ 61,004**	**1.4**	**1.7**

PUB/CENTRA I-27

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 Page 17 of 23; 2009/10 & 2010/11 GRA PUB/Centra 32 – EFT**

a) Please explain how Equivalent Full Time ("EFT") positions have been determined and detail any changes, if any, in the determination of EFTs since the last GRA.

ANSWER:

EFTs are calculated on the basis of activity hours charged to gas programs. 1,916 activity hours equals 1 EFT for one year. There have been no changes in the determination of EFTs since the last GRA.

PUB/CENTRA I-27 (Revised)

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 Page 17 of 23; 2009/10 & 2010/11 GRA PUB/Centra 32 – EFT**

b) Please file a schedule of EFTs from 2003/04 through 20013/14 for Centra operations on a similar basis as that provided in response to PUB/Centra 32(b) from the 2009/10 & 2010/11 GRA.

ANSWER:

Please see the following schedule.

CENTRA GAS MANITOBA INC.
SCHEDULE OF EFTS

	2003/04 Actual			2004/05 Actual			2005/06 Actual		
	Activity Charges ($000's)	Activity Hours	EFT's	Activity Charges ($000's)	Activity Hours	EFT's	Activity Charges ($000's)	Activity Hours	EFT's
President & CEO	295	4,208	2.2	171	254	0.1	232	3,861	2.0
Finance & Administration	5,323	92,513	48.3	5,441	89,499	46.7	5,427	90,768	47.4
Power Supply	117	1,761	0.9	125	1,714	0.9	18	234	0.1
Transmission & Distribution	4,289	63,780	33.3	3,863	56,826	29.7	3,731	53,712	28.0
Customer Service & Marketing	29,585	515,158	268.9	30,080	483,703	252.5	28,516	455,859	237.9
Total	**39,609**	**677,420**	**353.6**	**39,680**	**631,996**	**329.9**	**37,924**	**604,434**	**315.4**

	2006/07 Actual			2007/08 Actual			2008/09 Actual			2009/10 Actual		
	Activity Charges ($000's)	Activity Hours	EFT's	Activity Charges ($000's)	Activity Hours	EFT's	Activity Charges ($000's)	Activity Hours	EFT's	Activity Charges ($000's)	Activity Hours	EFT's
President & CEO	339	6,064	3.2	370	5,874	3.1	341	5,542	2.9	353	5,358	2.8
Finance & Administration	4,289	59,588	31.1	4,069	50,833	26.5	3,986	50,690	26.5	4,208	52,510	27.4
Power Supply	21	279	0.1	32	382	0.2	35	394	0.2	51	562	0.3
Transmission	142	1,929	1.0	167	2,141	1.1	153	1,951	1.0	186	2,192	1.1
Customer Service & Distribution	23,067	295,471	154.2	25,676	316,174	165.0	26,339	314,656	164.2	28,480	334,072	174.4
Customer Care & Marketing	10,522	206,119	107.6	10,867	193,253	100.9	11,558	200,762	104.8	11,132	181,858	94.9
Total	**38,381**	**569,451**	**297.2**	**41,181**	**568,657**	**296.8**	**42,413**	**573,996**	**299.6**	**44,410**	**576,551**	**300.9**

	2010/11 Actual			2011/12 Actual			2012/13 Test Year			2013/14 Test Year		
	Activity Charges ($000's)	Activity Hours	EFT's	Activity Charges ($000's)	Activity Hours	EFT's	Activity Charges ($000's)	Activity Hours	EFT's	Activity Charges ($000's)	Activity Hours	EFT's
President & CEO	445	6,262	3.3	429	5,779	3.0	254	3,426	1.8	259	3,426	1.8
Finance & Administration	4,697	52,385	27.3	4,465	50,977	26.6	3,951	51,010	26.6	4,031	51,010	26.6
Power Supply	104	1,177	0.6	139	1,508	0.8	-	-	-	-	-	-
Transmission	199	2,134	1.1	73	710	0.4	141	1,650	0.9	144	1,650	0.9
Customer Service & Distribution	29,045	334,303	174.5	29,800	323,583	168.9	26,742	349,255	182.3	27,277	349,255	182.3
Customer Care & Marketing	11,427	179,012	93.4	11,669	183,293	95.7	10,363	187,497	97.9	10,571	187,497	97.9
Total	**45,918**	**575,273**	**300.2**	**46,574**	**565,850**	**295.3**	**41,453**	**592,837**	**309.4**	**42,282**	**592,837**	**309.4**

Note: Information presented for years 2003/04 to 2005/06 is not directly comparable to years 2006/07 to 2013/14 as a result of changes to the Corporate organizational structure.

PUB/CENTRA I-27 (Revised)

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 Page 17 of 23; 2009/10 & 2010/11 GRA PUB/Centra 32 – EFT**

c) Please file a schedule of EFTs from 2003/04 through 2013/14 for Manitoba Hydro integrated operations on a similar format as that provided in response PUB/Centra 32(c) from the 2009/10 & 2010/11 GRA.

ANSWER:

Please see the following table for the schedule of EFTs for Manitoba Hydro integrated operations from 2003/04 through 2013/14.

Manitoba Hydro
EFT's by Division

Manitoba Hydro EFTs

	2003/04 [1] Actual
PRESIDENT & CEO	
Public Affairs	33
General Counsel	24
Administration	25
	81
CORPORATE RELATIONS	
Corporate Planning	12
Aboriginal Relations	44
Purchasing Department	-
Administration	-
	56
FINANCE & ADMINISTRATION	
Information Technology Services	352
Treasury	34
Financial Planning & Corporate Risk Mgmt	-
Human Resources	128
Gas Supply	20
Rates & Regulatory Affairs	22
Corporate Controller	194
Corporate Facilities	45
Corporate Safety & Health	-
Administration	8
	803
POWER SUPPLY	
Power Planning	60
Power Projects Development	-
HVDC	255
Generation North	227
Generations South	484
Engineering Services	173
Power Sales & Operations	70
New Generation Construction	-
Administration	52
	1,320
TRANSMISSION & DISTRIBUTION	
Research & Development	5
Transmission System Operations	337
Transmission Planning & Design	212
Transmission Construction & Line Mtce	302
Distribution Planning & Design	249
Distribution Construction	405
Apparatus Maintenance	392
Administration	107
	2,007
CUSTOMER SERVICE & MARKETING	
Industrial & Commercial Solutions	51
Customer Service Operations	1,031
Consumer Marketing & Sales	189
Business Support Services	170
Administration	81
	1,522
TOTAL EFT EMPLOYEES	5,790

[1] Information presented for 2003/04 is not directly comparable to years 2004/05 to 2013/14 as a result of changes to the Corporate organizational structure.

MANITOBA HYDRO
EFTs BY DIVISION

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Test Year	2013/14 Test Year
President & CEO										
General Counsel	24.5	24.9	25.8	27.2	26.3	29.3	30.5	32.2	32.8	32.8
Public Affairs	32.5	30.1	29.8	30.8	31.7	33.8	33.1	33.3	33.7	33.7
Research & Development	5.0	3.1	2.0	2.0	2.0	1.7	0.7	0.8	1.0	1.0
Corporate Planning & Strategic Review	18.6	18.8	20.3	19.2	20.0	19.3	24.5	27.9	27.1	27.1
VP Corp Planning & Strat Analysis	-	-	-	-	-	2.7	2.5	0.9	-	-
Administration	23.2	23.9	25.8	26.6	26.5	29.1	31.8	32.1	31.5	31.5
	103.7	**100.8**	**103.7**	**105.8**	**106.5**	**116.0**	**123.0**	**127.1**	**126.1**	**126.1**
Corporate Relations										
Aboriginal Relations	43.8	53.8	58.9	61.1	67.4	68.4	65.2	65.7	72.2	72.2
Administration	5.3	7.9	8.1	7.4	7.9	4.7	3.6	2.9	2.8	2.8
	49.0	**61.7**	**67.0**	**68.5**	**75.3**	**73.1**	**68.8**	**68.6**	**75.0**	**75.0**
Finance & Administration										
Information Technology Services	350.0	363.9	336.0	313.0	312.6	313.1	313.8	311.6	309.6	309.6
Treasury	16.6	15.6	14.7	15.2	15.5	14.2	13.1	12.7	13.2	13.2
Corporate Risk Mgmt Department	1.0	1.6	3.3	4.1	5.0	4.9	5.5	6.3	6.4	6.4
Gas Supply	20.2	19.8	18.8	18.6	19.8	20.0	20.6	20.0	19.5	19.5
Rates & Regulatory Affairs	22.4	18.6	18.9	18.7	18.7	19.5	21.6	20.6	20.6	20.6
Corporate Controller	116.1	112.5	105.8	107.6	107.4	112.6	110.2	103.9	105.1	105.1
Human Resources	145.8	140.6	138.5	134.7	137.9	129.1	126.8	126.5	130.9	130.9
Corporate Safety & Health	53.6	53.5	54.2	58.8	60.8	57.1	56.8	54.8	60.7	60.7
Corporate Services	298.1	294.4	298.4	304.4	310.6	320.6	324.7	313.1	322.7	322.7
Administration	14.2	14.4	17.8	17.4	17.9	18.4	16.3	13.4	14.0	14.0
	1,038.0	**1,035.0**	**1,006.5**	**992.6**	**1,006.2**	**1,009.6**	**1,009.5**	**982.9**	**1,002.8**	**1,002.8**
Power Supply										
Power Planning	32.4	35.1	42.0	54.9	57.7	66.0	74.9	77.5	77.4	77.4
Power Projects Development	38.4	37.3	38.6	42.3	43.9	46.8	47.8	52.5	58.1	58.1
Portfolio Projects Management	-	0.4	2.8	4.1	4.9	4.5	6.1	8.6	12.9	12.9
HVDC	266.3	228.1	231.7	235.2	249.7	253.8	259.9	257.8	273.0	273.0
Generation North	233.5	213.1	210.8	214.9	219.4	223.6	234.5	249.3	267.7	267.7
Generation South	496.1	461.6	458.9	454.6	458.6	471.3	487.7	488.8	491.8	491.8
Power Sales & Operations	78.7	83.6	82.3	84.4	84.1	82.5	85.9	87.7	88.7	88.7
Engineering Services	163.1	161.8	175.7	174.5	183.4	213.6	232.7	239.1	247.7	247.7
New Generation Construction	13.5	14.2	25.2	55.5	83.4	108.2	124.1	137.0	181.4	181.4
Administration	22.6	131.1	136.7	149.7	190.8	208.3	242.7	255.1	273.3	273.3
	1,344.6	**1,366.2**	**1,404.8**	**1,470.1**	**1,575.9**	**1,678.6**	**1,796.2**	**1,853.4**	**1,971.9**	**1,971.9**
Transmission										
Transmission System Operations	341.1	345.8	362.9	361.8	362.3	363.9	365.4	355.9	357.9	357.9
Transmission Planning & Design	202.3	194.5	193.3	178.1	191.1	205.6	214.3	233.1	234.8	234.8
Transmission Construction & Line Mtce	270.6	276.2	274.0	273.4	275.5	291.9	303.1	300.9	319.8	319.8
Apparatus Maintenance	357.5	362.1	364.8	396.6	420.5	431.2	434.5	428.0	428.6	428.6
Administration	37.0	41.8	38.3	45.6	48.7	49.9	47.5	35.7	44.1	44.1
	1,208.5	**1,220.5**	**1,233.3**	**1,255.5**	**1,298.1**	**1,342.5**	**1,364.8**	**1,353.5**	**1,385.3**	**1,385.3**
Customer Services & Distribution										
Customer Service Operations - Wpg&North	535.0	536.8	514.7	520.4	530.0	528.1	531.5	507.8	528.3	528.3
Customer Service Operations - South	546.6	568.8	559.2	560.9	565.9	576.9	580.2	561.5	561.0	561.0
Distribution E&C Rural	252.8	254.7	260.8	276.2	283.8	277.4	287.9	308.7	306.5	306.5
Distribution E&C Winnipeg	270.6	287.0	281.6	282.5	291.0	288.0	298.1	296.5	308.0	308.0
Administration	-	-	-	-	0.7	7.4	6.1	27.0	27.3	27.3
	1,604.9	**1,647.3**	**1,616.4**	**1,640.0**	**1,671.3**	**1,677.8**	**1,703.9**	**1,701.5**	**1,731.2**	**1,731.2**
Customer Care & Marketing										
Industrial & Commercial Solutions	48.1	49.3	50.7	51.5	54.2	56.8	54.3	52.4	56.6	56.6
Consumer Marketing & Sales	203.7	221.3	227.9	218.0	216.3	206.9	210.3	199.4	206.5	206.5
Business Support Services	230.0	237.4	238.6	229.3	228.5	222.0	216.8	220.3	234.7	234.7
Administration	39.2	38.8	38.8	39.5	43.6	46.1	46.9	48.7	46.6	46.6
	521.0	**546.8**	**556.1**	**538.3**	**542.7**	**531.8**	**528.3**	**520.8**	**544.3**	**544.3**
Total	**5,869.7**	**5,978.2**	**5,987.7**	**6,071.0**	**6,276.0**	**6,429.2**	**6,594.4**	**6,607.8**	**6,836.6**	**6,836.6**

PUB/CENTRA I-27 (Revised)

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 Page 17 of 23; 2009/10 & 2010/11 GRA PUB/Centra 32 – EFT**

d) **Please provide an extension of the table contained on PUB/Centra 32(d) from the 2009/10 & 2010/11 GRA showing actual amounts for each of the years 2003/04 through 2011/12 and forecasted for the years 2012/13 and 2013/14. Include on this table the activity hours, average hourly activity charge, and the percentage change in average hourly activity charge.**

ANSWER:

Please see the table below for the Activity Cost per EFT from 2003/04 through 2013/14.

CENTRA GAS MANITOBA INC.
ACTIVITY COST PER EFT

	2003/04 Actual	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Test Year	2013/14 Test Year
Activity Charges ($000's)	39,609	39,680	37,924	38,381	41,181	42,413	44,410	45,918	46,574	41,453	42,282
EFT's	354	330	315	297.2	296.8	299.6	300.9	300.2	295.3	309.4	309.4
Activity Charges / EFT	112,016	120,242	120,395	129,137	138,753	141,574	147,582	152,935	157,703	133,971	136,651
Activity Hours	677,420	631,996	604,435	569,451	568,657	573,996	576,551	575,273	565,850	592,837	592,837
Average Hourly Activity Charge	58	63	63	67	72	74	77	80	82	70	71
Percentage Change		7.4%	(0.1%)	7.4%	7.4%	2.0%	4.2%	3.6%	3.1%	(15.0%)	2.0%

The decline in activity charges and average hourly activity rates in 2012/13 is reflective of costing methodology changes. Please refer to PUB/Centra I-21(g) for further information.

PUB/CENTRA I-27

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 Page 17 of 23; 2009/10 & 2010/11 GRA PUB/Centra 32 – EFT**

e) **Similar to the response to PUB/Centra 158 from the 2009/10 & 2010/11 GRA, for each of the fiscal years 2010/11 through 2013/14 please provide an estimate for the percentage of activity charges recovering salaries, wages & benefits (including overtime).**

ANSWER:

The following schedule provides the requested information for the most significant natural gas programs:

Program	*2010/2011 Actuals* Actual Activity Rate	Wages, Salaries & Benefits ($000's)	Activity Charges ($000's)	Average	*2011/2012 Actuals* Actual Activity Rate	Wages, Salaries & Benefits ($000's)	Activity Charges ($000's)	Average	*2012/2013 Forecast* Forecast Activity Rate	Wages, Salaries & Benefits ($000's)	Activity Charges ($000's)	Average	*2013/2014 Forecast* Forecast Activity Rate	Wages, Salaries & Benefits ($000's)	Activity Charges ($000's)	Average
Customer Inspections	$ 87	5,400	8,309	65%	$ 92	5,592	8,371	67%	$ 75	5,702	7,053	81%	$ 77	5,816	7,194	81%
Billing Inquiry & Collections	$ 56	5,215	6,642	79%	$ 55	4,959	6,238	79%	$ 49	5,297	5,680	93%	$ 50	5,403	5,793	93%
Customer Relations	$ 81	4,439	6,038	74%	$ 78	4,551	5,932	77%	$ 67	4,838	5,315	91%	$ 68	4,935	5,422	91%
Distribution Maintenance	$ 95	3,734	5,754	65%	$ 97	3,698	5,655	65%	$ 80	3,959	4,906	81%	$ 82	4,038	5,004	81%
Regulating Station Maintenance	$ 86	2,428	3,305	73%	$ 95	2,916	3,923	74%	$ 94	2,946	3,614	81%	$ 96	3,005	3,687	81%
		21,216	30,048	71%		21,716	30,119	72%		22,742	26,568	* 86%		23,197	27,100	* 86%

*As discussed in Appendix 5.7, page 21, the increase in the average percentage between 2011/12 and 2012/13 is due to the change in costing methodology which reallocates support costs previously included in activity rates to either the common overhead rate or a direct allocation to gas operations. As a result the proportion of wages as a component of total costs in the activity rate is higher.

PUB/CENTRA I-28

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 - Staff Compensation**

a) **Please confirm whether Centra or Manitoba Hydro has undertaken an internal or external compensation review study.**

ANSWER:

Manitoba Hydro has not undertaken a formal compensation study or review either internally or externally. However, Manitoba Hydro does monitor compensation paid to workers in other jurisdictions and compares this to matching positions at Manitoba Hydro.

Manitoba Hydro is in the planning stages of conducting a joint benchmarking study with one of its electric based bargaining units. The study will likely be completed by the end of 2013.

PUB/CENTRA I-28

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 - Staff Compensation**

b) Please confirm whether Centra has undertaken a compensation review or comparison to other utilities, or participated in a review for another utility. If so, please provide the details of these studies and the findings.

ANSWER:

Manitoba Hydro has not undertaken a compensation review but does periodically participate in select salary surveys or conducts ad hoc comparisons of salaries of matching jobs of other utilities.

These comparisons are normally conducted for electric based classifications however one such comparison was done with SaskEnergy utility in January 2013. The following table is the comparison of three matching jobs and the hourly rates paid at both organizations.

SaskEnergy Classification	SaskEnergy Rate	Manitoba Hydro Classification	Manitoba Hydro Rate
Maintenance Technician	$ 32.90	Maintenance Person	$ 33.18
Instrument Technician	$ 35.55 (*TMA top up to $38.75)	Measurement Tech	$ 36.87
Pipeline Welder	$ 35.55 (*TMA top up to $39.25)	Welder	$ 36.87

*TMA is a temporary market adjustment.

Manitoba Hydro does periodically participate in select salary surveys. In November 2011, Manitoba Hydro participated in a compensation benchmarking study conducted by Mercer on Hydro One's behalf. The study provided a Total Remuneration comparison for 25 Manitoba Hydro positions. The following is a summary of the results relating to the 25 positions:

- 13 positions placed below the 25th percentile of surveyed participants
- 10 positions placed between the 25th and 50th percentile of surveyed participants
- 2 positions placed between the 50th and 75th percentile of surveyed participants

The results of this comparison shows that Manitoba Hydro's Total Remuneration is below the market average for 23 out of 25 positions.

PUB/CENTRA I-28

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 - Staff Compensation**

c) Please provide any compensation analysis of salary levels at Centra or Manitoba Hydro with other utilities.

ANSWER:

Please see Centra's response to PUB/Centra I-28(b).

PUB/CENTRA I-29

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Appendix 5.7 Page 17 of 23; 2009/10 &2010/11 GRA PUB/Centra I-38 – Overhead Rates**

a) Please provide a calculation of the gas and electric overhead rate for each of the years 2006/07 to 2011/12.

ANSWER:

Separate gas and electric overhead rates are no longer calculated. Starting in 2006/07 a common overhead rate was calculated and applied to gas and electric.

See the schedule in PUB/CENTRA I-29(b) for common overheard rates for 2006/07 to 2011/12.

PUB/CENTRA I-29

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Appendix 5.7 Page 17 of 23; 2009/10 &2010/11 GRA PUB/Centra I-38 – Overhead Rates**

b) **Please provide the common overhead rate for each of the years 2009/10 through 2013/14 in a similar format to that provided in response to PUB/Centra I-38 at the 2009/10 & 2010/11GRA.**

ANSWER:

Please see the schedule below.

Common Overhead Rates **($000's)**

	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Test Year	2013/14 Test Year
Common Overhead Pool	134,509	99,593	106,083	140,000	
Activity	566,062	597,731	622,379	564,000	
Common Overhead Rate Calculation	24%	17%	17%	25%	
Common Overhead Rate Approved	24%	17%	17%	25%	25%

The overhead rate for 2013/14 is based on the 2012/13 forecast therefore the calculations are not repeated.

PUB/CENTRA I-30

Subject: Tab 5: Financial Results & Forecast

Reference: Tab 5 Appendix 5.7 Pages 17 to 19 of 23

a) Please elaborate on what changes were made to the allocation of Customer Relations program costs "…to better reflect the number of gas customers."

ANSWER:

The changes made to the allocation of the Customer Relations program costs are based on an analysis of customer numbers across areas in the southern part of the province (not including the city of Winnipeg). Corrections have been made to include areas that previously did not allocate any Customer Relation program costs, yet have gas customers.

PUB/CENTRA I-30

Subject: Tab 5: Financial Results & Forecast

Reference: Tab 5 Appendix 5.7 Pages 17 to 19 of 23

b) Please describe the nature of the costs incurred related to the Meter Change program and why such costs are being expensed versus capitalized.

ANSWER:

The Meter Compliance Program involves the annual determination of the sample of meters to be tested per Measurement Canada specifications, the exchange of new meters for existing ones, the testing of existing meters, and the subsequent repair, recalibration and accreditation activities for those meters that fail the testing process. Units that are repaired, recalibrated and accredited are placed in inventory for future installation.

The original purchase and installation cost of the new meters is capitalized as an item of property, plant and equipment. The internal labour costs associated with sample determination, testing, exchange activities and repair, calibration and accreditation activities have historically been expensed as incurred. This accounting practice has been reflected in previous rate applications and incorporated in the revenue requirement forecasts.

CGM12 assumes that upon transition to IFRS, Centra would commence capitalization of the labour costs associated with the exchange activities. This potential accounting treatment is being driven by the requirement under IFRS to harmonize the accounting policies of a parent company and its subsidiaries. Manitoba Hydro currently capitalizes such costs. This potential change is in the preliminary review stage and additional work is required with respect to the interpretation of the IFRS standards as well as a review of industry practices expected upon conversion to IFRS.

PUB/CENTRA I-31

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Appendix 5.7 Page 21 of 23 Capitalized OM&A**

a) **Please provide Manitoba Hydro's corporate accounting policy on capitalizing OM&A and other expenses and comment on any changes, if any, in the policy since the 2009/10 & 2010/11 GRA.**

ANSWER:

Manitoba Hydro's Corporate accounting policy with respect to the capitalization of OM&A and other costs is as follows:

Property, plant & equipment is stated at cost which includes direct labour, materials, contracted services, a proportionate share of overhead costs and interest applied at the average cost of debt. Interest is allocated to construction until a capital project becomes operational or a decision is made to abandon, cancel or indefinitely defer construction. Once the transfer to in-service property, plant and equipment is made, interest allocated to construction ceases, and depreciation and interest charged to operations commences.

In general, this policy has not changed since the 2009/10 and 2010/11 GRA, but the types of overhead costs included for capitalization has. Historically under CGAAP, the Corporation has utilized a "full cost" accounting approach to the capitalization of administrative and overhead costs. This approach recognized that approximately 40% of the Corporation's activities are directed towards the construction of capital assets and thus, capital activities should receive a proportionate share of overhead costs.

Over the past several years, the Corporation has made changes to its overhead capitalization practices as a result of industry trends to move away from the capitalization of costs that do not vary with the level of capital activity in an organization and as a result, cannot be directly linked to capital projects. As presented on page 4 of Appendix 5.7 of the Application, Centra implemented changes to overheads included for capitalization in 2010/11 and forward so as to ensure that Centra's capitalization practices were consistent with those of other utilities. Under CGAAP, the Corporation removed from overhead capitalized, costs that would exist regardless of the level of capital activity in the Corporation. The following provides further information as to the costs that are no longer capitalized by Centra as presented in Appendix 5.7:

Interest on Common Assets and Motor vehicles

Examples of common assets include shared buildings such as 360 Portage Ave and 820 Taylor Ave., shared communication equipment and infrastructure, and shared computer systems such as the Banner and Web Trader systems. The category of motor vehicles represents the vehicles and equipment used for the gas operations and capital activities. Per discussions with other utilities, no utilities were including in overhead capitalized interest on common assets or motor vehicles. Given that the interest on the costs to construct and acquire such assets is already capitalized in their book value cost, the inclusion of additional interest on these assets in overhead eligible for capitalization was considered an aggressive capitalization practice.

General & Administrative Departmental Costs

General & administrative departmental costs include the costs associated with certain Corporate departments such as General Counsel, Corporate Document Services, Cash Management and Corporate Accounting. These departments provide support services that are shared across the organization would exist regardless of the level of construction activities of the Corporation. The Corporation has thus removed such costs from overhead capitalized.

IT Infrastructure & Related Support

This category includes general IT & system support (including staff) charges that would exist regardless of whether or not Centra incurred capital spending. The primary IT system included in this category is the SAP system and its fully integrated modules including financial accounting, human resource management, materials management, and the distribution planning maintenance system. While such systems vary in size relative to the activities of the Corporation, such systems would be required regardless of the level of capital activity. Similar to general and administrative department costs, such charges are no longer included in overhead capitalized.

Building Depreciation and Operating Costs

Included in this category are depreciation, maintenance, and operating costs of common building facilities such as 360 Portage, and 820 Taylor Ave. and the various operating centers. As described above with respect to other charges removed from overhead capitalized, such buildings would be required regardless of the level of capital activity within the Corporation and thus, depreciation and operating costs associated with common buildings are no longer included in overhead capitalized.

PUB/CENTRA I-31 (Revised)

Subject: Tab 5: Financial Results & Forecast

Reference: Appendix 5.7 Page 21 of 23 Capitalized OM&A

b) Please provide a schedule showing total annual capital spending and capitalized OM&A expenses by business unit for each of the years 2004/05 to 2013/14 including amount of OM&A capitalized and the capitalized OM&A as percentage of OM&A expensed in each of the years.

ANSWER:

Please refer to the attached schedules.

Please note that in this schedule, total capital spending includes only expenditures related to utility plant and therefore excludes DSM and other deferred amounts. Due to organizational changes, fiscal years 2004/05 to 2007/08 has been filed in Schedule 1 and 2008/09 to 2013/14 have been filed in Schedule 2.

Total Spending by Business Unit - Schedule #1 **($000's)**

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual
Total Capital Spending	22,695	26,985	28,901	27,928
Capitalized Operating & Administrative				
Overhead				
Transmission & Distribution	2,233	2,794	2,611	2,167
Customer Service & Marketing	208	536	641	627
Overhead	2,441	3,330	3,252	2,794
Capitalized Activity Charges				
Transmission & Distribution	5,076	6,239	6,623	6,207
Customer Service & Marketing	581	1,383	2,059	2,033
Capitalized Activity Charges	5,657	7,622	8,682	8,239
Total Capitalized Operating & Administrative	8,098	10,952	11,934	11,033
Operating Expenses				
President & CEO	1,296	936	1,071	1,009
Finance & Administration	9,762	9,358	9,841	9,724
Transmission & Distribution	6,378	6,330	6,924	7,092
Power Supply	171	29	36	46
Customer Service & Marketing	44,795	43,923	41,477	45,381
Corporate Allocations & Adjustments	804	221	2,035	1,455
Program View	63,206	60,797	61,384	64,707
Less: Depreciation, Interest & Taxes	(7,974)	(7,712)	(7,879)	(8,437)
Operating & Administrative Expense	55,232	53,085	53,505	56,270
Capitalized O&A as a percentage of O&A expensed	15%	21%	22%	20%

Total Spending by Business Unit - Schedule #2 **($000's)**

	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Test Year
Total Capital Spending	31,705	26,776	29,942	30,866	27,000	27,400
Capitalized Operating & Administrative						
Overhead						
Customer Service & Distribution	2,362	2,015	1,400	1,476	1,646	1,679
Finance & Administration	56	37	40	27	4	4
Transmission	26	9	38	46	1	1
Customer Care & Marketing	10	2	9	20	11	11
Overhead	2,453	2,063	1,488	1,569	1,662	1,696
Capitalized Activity Charges						
Customer Service & Distribution	8,747	8,394	8,238	8,684	6,583	6,715
Finance & Administration	207	155	234	158	15	16
Transmission	95	38	225	272	4	4
Customer Care & Marketing	36	10	53	118	45	46
Capitalized Activity Charges	9,086	8,597	8,750	9,232	6,648	6,781
Total Capitalized Operating & Administrative	11,539	10,660	10,238	10,801	8,310	8,476
Operating Expenses						
President & CEO	1,374	1,222	972	1,122	891	909
Finance & Administration	6,549	6,742	6,693	6,377	6,187	6,310
Power Supply	47	220	477	317	404	412
Transmission	224	255	250	99	194	197
Customer Service & Distribution	38,078	40,288	37,941	39,565	38,493	39,263
Customer Care & Marketing	19,765	18,671	17,845	18,195	17,575	17,926
Corporate Allocations & Adjustments	1,769	1,460	1,660	1,718	6,559	6,844
Total Program Costs	67,806	68,857	65,838	67,392	70,302	71,862
Less: Depreciation, Interest & Taxes	(8,003)	(7,906)	(5,194)	(5,275)	(3,003)	(3,063)
Operating & Administrative Expense	59,803	60,951	60,644	62,117	67,299	68,799
Capitalized O&A as a percentage of O&A expensed	19%	17%	17%	17%	12%	12%

PUB/CENTRA I-32

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 Page 21 of 23 - Productivity**

a) Please elaborate on any initiatives undertaken by Centra to improve productivity, improve the efficient delivery of its services, and limit, control, or reduce its expenditures.

ANSWER:

Please see Centra's responses to PUB/Centra I-4(a) and PUB/Centra I-32(c).

PUB/CENTRA I-32

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 Page 21 of 23 - Productivity**

b) Please identify the costs savings that each of these initiatives is forecasted to achieve.

ANSWER:

Centra engages in a number of activities to gain both operational efficiencies and improve productivity in managing its resources and controlling expenditures. The measurement of achievement is in the attainment of necessary business requirements within budget levels. Employment of these initiatives has enabled Centra to limit increases in OM&A costs to a 1.39% average annual increase which is below the level of inflation, as described in page 2 of Appendix 5.7, throughout the period reflected in this Application.

PUB/CENTRA I-32

Subject: Tab 5: Financial Results & Forecast

Reference: Tab 5 Appendix 5.7 Page 21 of 23 - Productivity

c) Please explain whether Centra has considered and to what extent Centra has implemented the following productivity and cost control measures:

a. Jointly locating of utility plant with other owners of underground utility plant;

b. Changes to the levels of supervision of field employees to increase the scope of supervision and reduce the number of supervisors;

c. Implementation of mobile workforce management systems to improve the scheduling of field employees;

d. Changes to corporate procurement activities;

e. Changes to human resources activities including improvements to hiring and training processes;

f. Optimization and extension of the maintenance intervals of utility plant and general equipment;

g. Vehicle acquisition and operating costs, including conversion to natural gas fuel; and

h. Implementation of a one-call number (Call before you dig) for the public to use to request locations of utility plant.

ANSWER:

Please see a discussion for each of these measures below:

a) Centra has realized productivity improvements in line locating dating back to the inception of joint natural gas / electric line locating. Following the purchase of Centra by Manitoba Hydro, line locating services were integrated resulting in one field person locating both natural gas and electric underground facilities. Regarding integration of line locating services with external companies, Manitoba Hydro has had discussions with communications utilities about line locating. A legislated One Call System that requires facility owners to participate would allow for eventual joint locating services.

b) Centra does consider productivity and cost control measures as part of the overall determination of optimal levels of supervision of field employees. Over the past six years organization reviews have resulted in increased scope of supervision and a reduction in the numbers of traditional field supervisors. In Customer Service Operations, there has been a reduction of two traditional field employee supervisor positions during this period.

c) In January 2012, the Corporation implemented its new mobile workforce management system for the scheduling of field employees. This standardized integrated system will improve workload and workplace distribution, enhance customer safety and satisfaction, advance forecasting and planning and increase productivity.

d) There has been an evolving process for access to and distribution of tender documents. Manitoba Hydro is now able to post tenders on an internet portal which allows Manitoba Hydro to address both administrative and purchase costs while being more environmentally friendly. This has resulted in reductions in costs as well as providing greater access to a larger supplier/contractor audience which has enhanced the number of bids received. This practice is used for all tenders with a value greater than $50,000.

More specific to Gas Distribution business, Centra, as part of ongoing process improvement, has been pursuing multiyear supply and service agreements including supply/contractor callout lists. Through these agreements, Centra is enabling savings based on economies of scale, enhanced quality and safety through standardization, improved scheduling of services and improved administration.

e) Manitoba Hydro recently upgraded its recruitment/applicant management system with enhanced candidate search and short listing tools. Training programs have been enhanced with the addition of more hands-on exposure in the classroom. Field training has been enhanced with increased mentorship from qualified journeypersons, resulting in higher retention of learned material and more qualified staff.

f) Centra does give consideration for optimization and extension of the maintenance intervals of utility plant and general equipment. Through the development and adoption of best industry practices Centra has moved to reliability centered maintenance which extends the period for major overhauls of station pressure regulators. This change has reduced the time and material traditionally applied to such maintenance programs without impacting safety or reliability. These changes have allowed Centra to absorb new and expanded infrastructure along with associated maintenance without increasing staffing levels.

g) Centra has considered and implemented a number of measures as more particularly described in Centra's response to PUB/Centra I-5(f).

h) Centra is evaluating the feasibility of participating in a "Call Before You Dig" service. Due to requirements of s. 6(2)(e) of the Gas Pipeline Act (Regulation 140/92), Centra must obtain the signature of the excavator. The most cost effective way to meet this requirement is to schedule an appointment with the customer/excavator at the time of the request (inbound call). This requirement limits Centra's ability to participate in any "one Call" service provided by any third party without incurring substantial additional costs.

PUB/CENTRA I-33

Subject: Tab 5: Financial Results & Forecast

Reference: Tab 5 Appendix 5.7 Pages 21 and 22 of 23

Please provide details of the balance of corporate allocation & adjustments for 2010/11 through 2013/14 identifying the components that were previously included in activity rates or common overhead rates.

ANSWER:

Please see below:

				($000's)
	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
Buildings & Facility OM&A[1]			2,281	2,327
Head Office Credit	(274)	(240)	(240)	(240)
IT Infrastructure Support[1]	-	-	2,937	2,996
Corporate Governance	1,934	2,081	1,638	1,670
Other Corporate Adjustments		(123)	(57)	91
Total	1,660	1,718	6,559	6,844

[1]In 2010/11 and 2011/12 building and facility OM&A & IT infrastructure support costs were recovered through overhead and activity rates and embedded in operating programs. In 2012/13 these costs were removed from overhead and activity rates and allocated directly to Centra through Corporate Allocations and Adjustments.

PUB/CENTRA I-34

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 - Building Depreciation & Operating Costs**

a) **Please indicate to what extent the change in accounting, which has resulted in the expensing of building depreciation and operating costs, relates to the new head office.**

ANSWER:

The change in the accounting does not change the amount of costs that are allocated to Centra. Please see Centra's response PUB/Centra I-22(b) and PUB/Centra I-34(c) for additional details.

PUB/CENTRA I-34

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 - Building Depreciation & Operating Costs**

b) **Please demonstrate that this change in accounting policy has not resulted in an increase in costs to Centra compared to the costs Centra would have incurred had it renewed its lease at 444 St. Mary.**

ANSWER:

Please see Centra's response to PUB/Centra I-34(c) which demonstrates that the change in accounting policy has not resulted in an increase in costs to Centra. Overall space cost allocations to Centra were maintained at consistent levels with an overall annual compounded growth rate of 1.7%.

PUB/CENTRA I-34

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 - Building Depreciation & Operating Costs**

c) Please provide the allocations to Centra for building and space costs for each year from 2006/07 to 2013/14.

ANSWER:

Included in the building (space) costs charged to Centra are all costs of common facilities. This includes lease costs, depreciation expense, finance expense, property and business taxes, as well as facility operating and maintenance costs. Space costs were allocated to Centra by way of overhead allocation and a shared cost allocation over the period 2006/07 to 2013/14. Both methods apply the same cost driver of "activity charges" to allocate costs.

Property and business taxes were allocated by way of overhead until the end of 2008/09 after which they were allocated through a shared cost allocation. Finance expenses were allocated through overhead until the end of 2009/10 after which they were allocated by a shared cost allocation. Depreciation expenses, lease costs and operating and maintenance costs were allocated by way of overhead until the end of 2011/12 after which they were allocated by a shared cost allocation.

As illustrated in the table on the next page, overall space cost allocations to Centra were maintained at consistent levels with an overall annual compound growth rate of 1.7% over the seven year period.

During 2010, Manitoba Hydro completed the movement of staff into both 360 Portage and 820 Taylor. In fiscal 2010/11, Manitoba Hydro began allocating a portion of the costs associated with the new head office to Centra, the details of this allocation are presented as part of the response to PUB/Centra I-23(c).

Please see the schedule below identifying the allocations to Centra for space costs from 2006/07 to 2013/14.

Allocations to Centra for Administrative Buildings (Space Costs) - 2006/07 to 2013/14 **($ million's)**

	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
Space Cost Allocation [1]	$ 3.4	$ 3.4	$ 3.3	$ 3.3	$ 3.6	$ 3.5	$ 3.7	$ 3.8

[1] Annualized Compounded Growth Rate 1.7%

PUB/CENTRA I-35

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.8 Page 2 of 5**

a) Please confirm that the removal of asset retirement costs from depreciation would be compatible with current GAAP accounting standards and is not contingent on the adoption of IFRS or a switch to the equal life group methodology of determining depreciation.

ANSWER:

Centra confirms that the removal of asset retirement costs from depreciation would be acceptable under existing CGAAP and is not contingent on the adoption of IFRS or a switch to the Equal Life Group method of depreciation. However, it is important to note that including asset retirement costs in depreciation rates has been a long standing regulatory accounting practice under CGAAP as a means to promote intergenerational equity by gas distribution utilities across Canada. IFRS does not currently have a standard that permits the recognition of rate-regulated accounts and thus, Centra will be required to change its practices upon transition to IFRS. Centra's reasoning for removing asset retirement costs from depreciation upon transition to IFRS is as follows:

Retrospective application: The removal of asset retirement costs from depreciation under CGAAP would be considered a change in accounting policy which would require retrospective application. Applying such a change on a retrospective basis would be administratively costly and complex and would require the development of arbitrary assumptions. Removing asset retirement costs from depreciation rates upon transition to IFRS is preferable as IFRS permits rate-regulated entities that are first-time adopters of IFRS to carry forward the net book value of their property, plant & equipment assets upon transition; eliminating the requirement for retrospective application.

Accounting policies of the parent: Upon transition to IFRS, Centra will be required to report in accordance with the accounting policies of its parent Manitoba Hydro. IFRS 10 Consolidated Financial Statements paragraph B87 stipulates that, " If a member of the group uses accounting policies other than those adopted in the consolidated financial statements for like transactions and events for similar circumstances, appropriate adjustments are made to that group member's financial statements in preparing the consolidated financial statements to ensure conformity with the group's accounting policies." Manitoba Hydro will be removing asset retirement costs from its depreciation rates upon transition to IFRS and thus, Centra will be required to do the same.

Mitigate customer rate impacts of IFRS transition: While on its own Centra would not favour the removal of net salvage from depreciation rates upon transition to IFRS, the reduction in depreciation expense from this change does provide an offset to some of the other cost increases associated with the transition to IFRS such as the additional operating costs for overhead ineligible for capitalization and the additional depreciation expense related to the move to the Equal Life Group method. Implementing the change upon transition to IFRS allows Manitoba Hydro and its subsidiary Centra to appropriately manage the overall accounting policy changes in a way that will minimize the rate impacts to customers resulting from the transition to IFRS.

Centra's intention to remove asset retirement costs from depreciation rates upon transition to IFRS is consistent with the recent decision of the PUB with respect to Manitoba Hydro's electric operations. PUB Order 43/13 p.18 reads as follows, *"The Board also accepts Manitoba Hydro's position that net salvage should be removed from depreciation rates when International Financial Reporting Standards are implemented rather than during the test years."*

PUB/CENTRA I-35

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.8 Page 2 of 5**

b) Please outline Centra's reasoning for not removing asset retirement costs from depreciation prior to the planned switch to the equal life group methodology.

ANSWER:

Please see Centra's response to PUB/Centra I-35(a)

PUB/CENTRA I-36

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.8 Pages 1 through 5 of 55**

Please confirm whether Centra will request approval of depreciation rates based on the ELG methodology and the removal of asset retirement costs prior to the implementation of these rates.

ANSWER:

As indicated in Centra's response to PUB/Centra I-37(a), Centra intends to implement IFRS compliant depreciation rates effective April 1, 2015. In light of the uncertainty that exists with respect to the requirements of a potential interim standard on rate-regulated accounting under IFRS, Centra will apprise the PUB of its plans respecting an application for approval to implement new depreciation rates involving a change in methodology, such as a change to the ELG procedure for group depreciation or the removal of net salvage from depreciation rates, at the appropriate time.

PUB/CENTRA I-37

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Page 24 of 30 Schedule 5.7.0**

a) Please confirm the proposed depreciation rates for April 1, 2014 will now not be implemented until April 1, 2015.

ANSWER:

Confirmed. As indicated in the letter from Centra to The Public Utilities Board dated February 22, 2013, which accompanied Volume II of the General Rate Application filing, Centra advised on a preliminary basis that it intends to adopt the further deferral and would, as a result, transition to IFRS during its 2015/16 fiscal year.

As described in Appendix 5.8 to the filing, the implementation of depreciation rates resulting from the 2010 Depreciation Study will be accomplished in two phases. In the first phase, Centra updated services lives effective April 1, 2011. In the second phase, Centra intends to implement IFRS compliant depreciation rates effective April 1, 2015, which will include a change in the depreciation methodology to the Equal Life Group (ELG) and the removal of asset retirement costs from depreciation rates.

PUB/CENTRA I-37

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Page 24 of 30 Schedule 5.7.0**

b) **Please provide schedules detailing the net plant in service by component, the depreciation rate, and the total depreciation expense for the years 2008/09 through 2013/14 similar to those provided in 2009/10 & 2010/11 GRA Schedules 4.9.0 to 4.9.4 (with the additional column of net plant in service).**

ANSWER:

The following schedules provide Cost, Accumulated Depreciation, Net Book Value, Depreciation Rate, and Depreciation Expense for each depreciable component, for the years 2008/09 through 2013/14.

CENTRA GAS MANITOBA INC. **PUB/CENTRA I-37(b)**
Utility Net Plant and Depreciation
2008/09 Actual **($000'S)**

	Cost Mar 31/09	Accumulated Depreciation Mar 31/09	Net Book Value Mar 31/09	Depreciation Rate %	Depreciation Expense 2008/09
Intangible Plant					
Franchises & Consents	38	20	18	5.56 %	2
Land Rights					
Transmission	3,065	503	2,562	1.23 %	32
Distribution	670	102	568	1.28 %	8
Computer System Development	12,493	7,291	5,202	10.00 %	1,582
Transmission Plant					
Land	958	-	958	0.00 %	-
Structures & Improvements - M&R	972	512	460	1.64 %	15
Structures & Improvements	77	41	36	3.51 %	3
Mains - Transmission	83,514	20,791	62,724	1.73 %	1,384
Measuring & Regulating Equipment	6,621	2,000	4,621	2.62 %	160
Other Transmission Equipment	5	5	-	2.50 %	-
Distribution Plant					
Land	767	-	767	0.00 %	-
Structures & Improvements	1,342	646	696	3.19 %	43
Structures & Improvements - M&R	3,618	1,144	2,474	1.56 %	56
Services	197,023	71,178	125,845	3.27 %	6,298
Regulators	43,121	15,659	27,463	2.62 %	1,103
Mains - Distribution	152,621	51,483	101,138	1.80 %	2,689
Measuring & Reg. Equipment	32,719	13,632	19,087	4.04 %	1,306
Telemetry Equipment	3,991	2,730	1,262	5.59 %	202
Meters	37,693	11,732	25,961	3.76 %	1,467
AMR/ERT Modules	89	96	(7)	10.00 %	9
General Plant					
Land	136	-	136	0.00 %	-
Structures & Improvements	9,119	5,325	3,793	1.95 %	179
Leasehold Improvements	668	668	-	10.70 %	125
Office Furniture & Equipment	1,099	819	280	6.67 %	73
Computer Equipment - Hardware	3	4	(1)	20.00 %	1
Transportation Equipment	2,041	1,719	322	6.14 %	-
Heavy Work Equipment	650	598	52	5.34 %	6
Tools & Work Equipment	2,928	1,921	1,007	6.67 %	195
Communication Struct.& Equip.	913	964	(51)	10.50 %	96
Other General Equipment	412	121	291	10.00 %	8
Total Gross Plant	599,366	211,702	387,664		17,040

CENTRA GAS MANITOBA INC. **PUB/CENTRA I-37(b)**
Utility Net Plant and Depreciation
2009/10 Actual **($000'S)**

	Cost Mar 31/10	Accumulated Depreciation Mar 31/10	Net Book Value Mar 31/10	Depreciation Rate %	Depreciation Expense 2009/10
Intangible Plant					
Franchises & Consents	38	23	15	5.56 %	2
Land Rights					
Transmission	3,493	542	2,951	1.23 %	41
Distribution	731	111	620	1.28 %	9
Computer System Development	9,889	6,081	3,808	10.00 %	1,395
Transmission Plant					
Land	777	-	777	0.00 %	-
Structures & Improvements - M&R	1,003	527	476	1.64 %	16
Structures & Improvements	76	51	25	3.51 %	3
Mains - Transmission	87,830	22,219	65,610	1.73 %	1,475
Measuring & Regulating Equipment	7,312	2,153	5,159	2.62 %	181
Other Transmission Equipment	-	-	-	2.50 %	-
Distribution Plant					
Land	966	-	966	0.00 %	-
Structures & Improvements	1,342	669	673	3.19 %	43
Structures & Improvements - M&R	3,757	1,181	2,576	1.56 %	56
Services	204,217	73,871	130,346	3.27 %	6,555
Regulators	44,900	16,809	28,091	2.62 %	1,150
Mains - Distribution	156,954	53,826	103,129	1.80 %	2,771
Measuring & Reg. Equipment	33,131	13,885	19,246	4.04 %	1,330
Telemetry Equipment	4,086	2,936	1,150	5.59 %	208
Meters	38,120	10,874	27,246	3.76 %	1,469
AMR/ERT Modules	89	87	2	10.00 %	1
General Plant					
Land	136	-	136	0.00 %	-
Structures & Improvements	9,147	5,606	3,541	1.95 %	178
Office Furniture & Equipment	1,073	865	207	6.67 %	73
Computer Equipment - Hardware	-	-	-	20.00 %	-
Transportation Equipment	1,391	1,074	317	6.14 %	-
Heavy Work Equipment	595	576	19	5.34 %	6
Tools & Work Equipment	2,928	2,117	811	6.67 %	195
Communication Struct.& Equip.	194	272	(78)	10.50 %	27
Other General Equipment	142	-	142	0.00 %	-
Total Gross Plant	614,317	216,356	397,961		17,184

CENTRA GAS MANITOBA INC. **PUB/CENTRA I-37(b)**

Utility Net Plant and Depreciation

2010/11 Actual **($000'S)**

	Cost Mar 31/11	Accumulated Depreciation Mar 31/11	Net Book Value Mar 31/11	Depreciation Rate %	Depreciation Expense 2010/11
Intangible Plant					
Franchises & Consents	38	25	13	5.56 %	2
Land Rights					
Transmission	3,565	585	2,980	1.23 %	44
Distribution	904	122	782	1.28 %	10
Computer System Development	9,889	7,229	2,660	10.00 %	1,348
Transmission Plant					
Land	779	-	779	0.00 %	-
Structures & Improvements - M&R	1,015	500	515	1.64 %	17
Structures & Improvements	76	54	22	3.51 %	3
Mains - Transmission	91,145	23,108	68,037	1.73 %	1,520
Measuring & Regulating Equipment	7,523	2,312	5,211	2.62 %	192
Other Transmission Equipment	-	-	-	2.50 %	-
Distribution Plant					
Land	1,017	-	1,017	0.00 %	-
Structures & Improvements	1,342	715	627	3.19 %	43
Structures & Improvements - M&R	4,060	1,225	2,835	1.56 %	59
Services	210,656	76,635	134,021	3.27 %	6,781
Regulators	46,691	17,985	28,706	2.62 %	1,197
Mains - Distribution	160,547	56,490	104,057	1.80 %	2,842
Measuring & Reg. Equipment	33,466	15,127	18,340	4.04 %	1,339
Telemetry Equipment	3,978	2,938	1,039	5.59 %	168
Meters	39,386	10,552	28,834	3.76 %	1,499
AMR/ERT Modules	-	-	-	10.00 %	-
Computer Equipment - Hardware (SCADA)	103	8	95	20.00 %	8
General Plant					
Land	138	-	138	0.00 %	-
Structures & Improvements	9,145	5,674	3,471	1.95 %	161
Office Furniture & Equipment	1,073	907	165	6.67 %	42
Transportation Equipment	1,141	844	298	6.14 %	-
Heavy Work Equipment	544	550	(7)	5.34 %	6
Tools & Work Equipment	2,928	2,310	618	6.67 %	195
Communication Struct.& Equip.	-	-	-	10.50 %	2
Other General Equipment	190	-	190	10.00 %	-
Total Gross Plant	631,338	225,896	405,442		17,475

CENTRA GAS MANITOBA INC. **PUB/CENTRA I-37(b)**

Utility Net Plant and Depreciation

2011/12 Actual **($000'S)**

	Cost Mar 31/12	Accumulated Depreciation Mar 31/12	Net Book Value Mar 31/12	Depreciation Rate %	Depreciation Expense 2011/12
Intangible Plant					
Franchises & Consents	22	10	12	5.56 %	1
Land Rights					
Transmission	3,584	631	2,953	1.29 %	46
Distribution	1,015	134	881	1.29 %	12
Computer System Development	5,304	3,271	2,033	10.00 %	626
Dist. Computer System Development (SCADA)	-	-	-	20.00 %	-
Transmission Plant					
Land	779	-	779	0.00 %	-
Structures & Improvements - M&R	1,040	518	523	1.96 %	20
Structures & Improvements	76	56	20	2.32 %	2
Mains - Transmission	94,885	24,496	70,389	1.74 %	1,599
Measuring & Regulating Equipment	7,508	2,441	5,067	1.93 %	145
Other Transmission Equipment	-	-	-	2.50 %	-
Distribution Plant					
Land	1,026	-	1,026	0.00 %	-
Structures & Improvements	1,335	742	594	2.10 %	28
Structures & Improvements - M&R	4,036	1,263	2,772	1.58 %	64
Services	216,865	79,095	137,770	2.89 %	6,167
Regulators	48,566	18,999	29,568	2.13 %	1,014
Mains - Distribution	167,605	59,140	108,465	1.84 %	2,999
Measuring & Reg. Equipment	34,336	16,171	18,165	3.27 %	1,101
Telemetry Equipment	3,978	3,129	849	5.00 %	199
Meters	40,805	9,053	31,753	4.15 %	1,708
AMR/ERT Modules	-	-	-	10.00 %	-
Computer Equipment - Hardware (SCADA)	361	46	315	20.00 %	37
General Plant					
Land	137	-	137	0.00 %	-
Structures & Improvements	9,145	5,811	3,334	1.50 %	137
Office Furniture & Equipment	465	353	112	6.67 %	53
Transportation Equipment	1,023	867	156	13.94 %	138
Heavy Work Equipment	530	541	(12)	0.00 %	-
Tools & Work Equipment	2,439	2,004	435	6.67 %	183
Other General Equipment	393	-	393	0.00 %	-
Total Gross Plant	647,259	228,773	418,486		16,280

CENTRA GAS MANITOBA INC. **PUB/CENTRA I-37(b)**

Utility Net Plant and Depreciation

2012/13 Forecast **($000'S)**

	Cost Mar 31/13	Accumulated Depreciation Mar 31/13	Net Book Value Mar 31/13	Depreciation Rate %	Depreciation Expense 2012/13
Intangible Plant					
Franchises & Consents	22	12	11	5.56 %	1
Land Rights					
Transmission	3,584	677	2,906	1.29 %	46
Distribution	1,015	147	868	1.29 %	13
Computer System Development	5,304	3,801	1,503	10.00 %	530
Dist. Computer System Development (SCADA)	3,461	330	3,130	20.00 %	330
Transmission Plant					
Land	791	-	791	0.00 %	-
Structures & Improvements - M&R	1,040	538	502	1.96 %	20
Structures & Improvements	76	58	18	2.32 %	2
Mains - Transmission	96,004	25,640	70,364	1.74 %	1,654
Measuring & Regulating Equipment	7,625	2,557	5,068	1.93 %	146
Other Transmission Equipment	-	-	-	2.50 %	-
Distribution Plant					
Land	1,091	-	1,091	0.00 %	-
Structures & Improvements	1,544	771	773	2.10 %	30
Structures & Improvements - M&R	4,295	1,318	2,977	1.58 %	66
Services	222,094	82,129	139,965	2.89 %	6,347
Regulators	50,058	20,048	30,010	2.13 %	1,049
Mains - Distribution	177,385	61,877	115,509	1.84 %	3,146
Measuring & Reg. Equipment	35,086	17,235	17,852	3.27 %	1,134
Telemetry Equipment	4,018	3,311	708	5.00 %	200
Meters	41,882	7,706	34,175	4.15 %	1,794
AMR/ERT Modules	-	-	-	10.00 %	-
Computer Equipment - Hardware (SCADA)	469	132	337	20.00 %	87
General Plant					
Land	137	-	137	0.00 %	-
Structures & Improvements	9,145	5,948	3,196	1.50 %	137
Office Furniture & Equipment	382	300	82	6.67 %	30
Transportation Equipment	556	543	13	13.94 %	143
Heavy Work Equipment	362	373	(12)	0.00 %	-
Tools & Work Equipment	1,943	1,644	299	6.67 %	136
Other General Equipment	393	-	393	0.00 %	-
Total Gross Plant	669,763	237,097	432,666		17,042

CENTRA GAS MANITOBA INC. **PUB/CENTRA I-37(b)**

Utility Net Plant and Depreciation

2013/14 Forecast **($000'S)**

	Cost Mar 31/14	Accumulated Depreciation Mar 31/14	Net Book Value Mar 31/14	Depreciation Rate %	Depreciation Expense 2013/14
Intangible Plant					
Franchises & Consents	22	13	9	5.56 %	1
Land Rights					
Transmission	3,584	724	2,860	1.29 %	46
Distribution	1,015	160	855	1.29 %	13
Computer System Development	5,304	4,331	974	10.00 %	530
Dist. Computer System Development (SCADA)	3,461	1,123	2,338	20.00 %	793
Transmission Plant					
Land	791	-	791	0.00 %	-
Structures & Improvements - M&R	1,040	559	482	1.96 %	20
Structures & Improvements	76	59	17	2.32 %	2
Mains - Transmission	96,527	27,308	69,218	1.74 %	1,668
Measuring & Regulating Equipment	7,780	2,676	5,103	1.93 %	149
Other Transmission Equipment	-	-	-	2.50 %	-
Distribution Plant					
Land	1,091	-	1,091	0.00 %	-
Structures & Improvements	1,544	804	740	2.10 %	32
Structures & Improvements - M&R	4,558	1,376	3,181	1.58 %	70
Services	228,317	85,306	143,011	2.89 %	6,555
Regulators	55,445	21,170	34,274	2.13 %	1,123
Mains - Distribution	186,692	64,718	121,974	1.84 %	3,259
Measuring & Reg. Equipment	36,175	18,334	17,841	3.27 %	1,171
Telemetry Equipment	4,059	3,495	564	5.00 %	203
Meters	43,609	6,505	37,103	4.15 %	1,999
AMR/ERT Modules	-	-	-	10.00 %	-
Computer Equipment - Hardware (SCADA)	469	226	243	20.00 %	94
General Plant					
Land	137	-	137	0.00 %	-
Structures & Improvements	9,145	6,086	3,059	1.50 %	137
Office Furniture & Equipment	266	208	58	6.67 %	24
Transportation Equipment	-	13	(13)	13.94 %	26
Heavy Work Equipment	362	373	(12)	0.00 %	-
Tools & Work Equipment	1,513	1,332	180	6.67 %	119
Other General Equipment	393	-	393	0.00 %	-
Total Gross Plant	693,372	246,900	446,472		18,036

PUB/CENTRA I-37

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Page 24 of 30 Schedule 5.7.0**

c) **Please provide a comparison, by component, of the depreciation expense and depreciation rates between the rates implemented in 2007 and the rates implemented April 1, 2011 for 2011/12, 2012/13, and 2013/14.**

ANSWER:

The following schedules provide a calculation of the impact, by component, of the change in depreciation rates for the 2011/12, 2012/13 and 2013/14 fiscal years.

CENTRA GAS MANITOBA INC. **PUB/CENTRA I-37(c)**
Utility Plant Depreciation Expense
2011/12 Actual **($000'S)**

	Depreciation Rates Implemented April 1, 2007		Depreciation Rates Implemented April 1, 2011		Difference Resulting From Change in Depreciation Rates	
	Rate %	Expense 2011/12	Rate %	Expense 2011/12	Rate %	Expense 2011/12
Intangible Plant						
Franchises & Consents	5.56 %	1	5.56 %	1	-	-
Land Rights					-	
Transmission	1.23 %	44	1.29 %	46	0.06 %	2
Distribution	1.28 %	12	1.29 %	12	0.01 %	-
Computer System Development	10.00 %	626	10.00 %	626	-	-
Dist. Computer System Development (SCADA)	20.00 %	-	20.00 %	-	-	-
Transmission Plant						
Land	0.00 %	-	0.00 %	-	-	-
Structures & Improvements - M&R	1.64 %	17	1.96 %	20	0.32 %	3
Structures & Improvements	3.51 %	3	2.32 %	2	-1.19 %	(1)
Mains - Transmission	1.73 %	1,590	1.74 %	1,599	0.01 %	9
Measuring & Regulating Equipment	2.62 %	197	1.93 %	145	-0.69 %	(52)
Other Transmission Equipment	2.50 %	-	2.50 %	-	-	-
Distribution Plant						
Land	0.00 %	-	0.00 %	-	-	-
Structures & Improvements	3.19 %	43	2.10 %	28	-1.09 %	(15)
Structures & Improvements - M&R	1.56 %	63	1.58 %	64	0.02 %	1
Services	3.27 %	6,978	2.89 %	6,167	-0.38 %	(811)
Regulators	2.62 %	1,247	2.13 %	1,014	-0.49 %	(233)
Mains - Distribution	1.80 %	2,934	1.84 %	2,999	0.04 %	65
Measuring & Reg. Equipment	4.04 %	1,360	3.27 %	1,101	-0.77 %	(259)
Telemetry Equipment	5.59 %	222	5.00 %	199	-0.59 %	(23)
Meters	3.76 %	1,548	4.15 %	1,708	0.39 %	160
AMR/ERT Modules	10.00 %	-	10.00 %	-	-	-
Computer Equipment - Hardware (SCADA)	20.00 %	37	20.00 %	37	-	-
General Plant						
Land	0.00 %	-	0.00 %	-	-	-
Structures & Improvements	1.95 %	178	1.50 %	137	-0.45 %	(41)
Office Furniture & Equipment	6.67 %	53	6.67 %	53	-	-
Transportation Equipment	6.14 %	61	13.94 %	138	7.80 %	77
Heavy Work Equipment	5.34 %	-	0.00 %	-	-5.34 %	-
Tools & Work Equipment	6.67 %	183	6.67 %	183	-	-
Other General Equipment	0.00 %	-	0.00 %	-	-	-
Total Gross Plant		17,397		16,280		(1,117)

CENTRA GAS MANITOBA INC. **PUB/CENTRA I-37(c)**
Utility Plant Depreciation Expense
2012/13 Forecast **($000'S)**

	Depreciation Rates Implemented April 1, 2007		Depreciation Rates Implemented April 1, 2011		Difference Resulting From Change in Depreciation Rates	
	Rate %	Expense 2012/13	Rate %	Expense 2012/13	Rate %	Expense 2012/13
Intangible Plant						
Franchises & Consents	5.56 %	1	5.56 %	1	-	-
Land Rights						
Transmission	1.23 %	44	1.29 %	46	0.06 %	2
Distribution	1.28 %	13	1.29 %	13	0.01 %	-
Computer System Development	10.00 %	530	10.00 %	530	-	-
Dist. Computer System Development (SCADA)	20.00 %	330	20.00 %	330	-	-
Transmission Plant						
Land	0.00 %	-	0.00 %	-	-	-
Structures & Improvements - M&R	1.64 %	17	1.96 %	20	0.32 %	3
Structures & Improvements	3.51 %	3	2.32 %	2	-1.19 %	(1)
Mains - Transmission	1.73 %	1,644	1.74 %	1,654	0.01 %	10
Measuring & Regulating Equipment	2.62 %	198	1.93 %	146	-0.69 %	(52)
Other Transmission Equipment	2.50 %	-	2.50 %	-	-	-
Distribution Plant						
Land	0.00 %	-	0.00 %	-	-	-
Structures & Improvements	3.19 %	45	2.10 %	30	-1.09 %	(15)
Structures & Improvements - M&R	1.56 %	65	1.58 %	66	0.02 %	1
Services	3.27 %	7,182	2.89 %	6,347	-0.38 %	(835)
Regulators	2.62 %	1,290	2.13 %	1,049	-0.49 %	(241)
Mains - Distribution	1.80 %	3,078	1.84 %	3,146	0.04 %	68
Measuring & Reg. Equipment	4.04 %	1,401	3.27 %	1,134	-0.77 %	(267)
Telemetry Equipment	5.59 %	224	5.00 %	200	-0.59 %	(24)
Meters	3.76 %	1,626	4.15 %	1,794	0.39 %	168
AMR/ERT Modules	10.00 %	-	10.00 %	-	-	-
Computer Equipment - Hardware (SCADA)	20.00 %	87	20.00 %	87	-	-
General Plant						
Land	0.00 %	-	0.00 %	-	-	-
Structures & Improvements	1.95 %	178	1.50 %	137	-0.45 %	(41)
Office Furniture & Equipment	6.67 %	30	6.67 %	30	-	-
Transportation Equipment	6.14 %	63	13.94 %	143	7.80 %	80
Heavy Work Equipment	5.34 %	-	0.00 %	-	-5.34 %	-
Tools & Work Equipment	6.67 %	136	6.67 %	136	-	-
Other General Equipment	0.00 %	-	0.00 %	-	-	-
Total Gross Plant		18,185		17,042		(1,143)

CENTRA GAS MANITOBA INC. **PUB/CENTRA I-37(c)**
Utility Plant Depreciation Expense
2013/14 Forecast **($000'S)**

	Depreciation Rates Implemented April 1, 2007		Depreciation Rates Implemented April 1, 2011		Difference Resulting From Change in Depreciation Rates	
	Rate %	Expense 2013/14	Rate %	Expense 2013/14	Rate %	Expense 2013/14
Intangible Plant						
Franchises & Consents	5.56 %	1	5.56 %	1	-	-
Land Rights					-	
Transmission	1.23 %	44	1.29 %	46	0.06 %	2
Distribution	1.28 %	13	1.29 %	13	0.01 %	-
Computer System Development	10.00 %	530	10.00 %	530	-	-
Dist. Computer System Development (SCADA)	20.00 %	793	20.00 %	793	-	-
Transmission Plant						
Land	0.00 %	-	0.00 %	-	-	-
Structures & Improvements - M&R	1.64 %	17	1.96 %	20	0.32 %	3
Structures & Improvements	3.51 %	3	2.32 %	2	-1.19 %	(1)
Mains - Transmission	1.73 %	1,659	1.74 %	1,668	0.01 %	9
Measuring & Regulating Equipment	2.62 %	203	1.93 %	149	-0.69 %	(54)
Other Transmission Equipment	2.50 %	-	2.50 %	-	-	-
Distribution Plant						
Land	0.00 %	-	0.00 %	-	-	-
Structures & Improvements	3.19 %	48	2.10 %	32	-1.09 %	(16)
Structures & Improvements - M&R	1.56 %	68	1.58 %	70	0.02 %	2
Services	3.27 %	7,416	2.89 %	6,555	-0.38 %	(861)
Regulators	2.62 %	1,380	2.13 %	1,123	-0.49 %	(257)
Mains - Distribution	1.80 %	3,187	1.84 %	3,259	0.04 %	72
Measuring & Reg. Equipment	4.04 %	1,446	3.27 %	1,171	-0.77 %	(275)
Telemetry Equipment	5.59 %	225	5.00 %	203	-0.59 %	(22)
Meters	3.76 %	1,811	4.15 %	1,999	0.39 %	188
AMR/ERT Modules	10.00 %	-	10.00 %	-	-	-
Computer Equipment - Hardware (SCADA)	20.00 %	94	20.00 %	94	-	-
General Plant						
Land	0.00 %	-	0.00 %	-	-	-
Structures & Improvements	1.95 %	178	1.50 %	137	-0.45 %	(41)
Office Furniture & Equipment	6.67 %	24	6.67 %	24	-	-
Transportation Equipment	6.14 %	10	13.94 %	26	7.80 %	16
Heavy Work Equipment	5.34 %	-	0.00 %	-	-5.34 %	-
Tools & Work Equipment	6.67 %	119	6.67 %	119	-	-
Other General Equipment	0.00 %	-	0.00 %	-	-	-
Total Gross Plant		19,269		18,036		(1,233)

PUB/CENTRA I-37

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Page 24 of 30 Schedule 5.7.0**

d) Please identify all the changes made to component accounts since the last depreciation study and explain why these changes were made.

ANSWER:

For the 2010 Depreciation Study, the following four new accounts were added in response to changing business requirements, which will be used on a go forward basis. The regulating station electronic equipment accounts were established in recognition of the increasing use of electronic equipment in regulating stations. Electronic equipment has a significantly shorter life and will require earlier replacement than mechanical equipment. The computer hardware and system development accounts were established for the new gas SCADA system.

Transmission:

467.20 Regulating Station Electronic Equipment

Distribution:

477.20 Regulating Station Electronic Equipment

479.10 Computer Hardware Equipment – EMS/SCADA

479.30 Computer System Development – EMS/SCADA

The following amortization method accounts were removed as all assets existing as at the 2005 Depreciation Study became fully depreciated and were retired prior to the 2010 Depreciation Study. These accounts are no longer required by Centra, as all General Plant assets are now acquired by Manitoba Hydro.

General Plant:

482.10 Leasehold Improvements

483.10 Computer Hardware Equipment

483.20 Computer Software

488.00 Communication Structures & Equipment

489.00 Other General Equipment

PUB/CENTRA I-38

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.8 Page 8 of 55 - Changes to Service Lives**

In supporting changes to service lives of plant assets, Gannett Fleming has cited retirement trends, views of operational staff and a closer (fit) to the range of average service life estimates of the relevant peer group of Utilities.

Please provide supporting data and other information including relevant peer group information that demonstrates the need to change the Iowa curves for the following plant accounts: 473.0 Services - Distribution, 475.00 Mains- Distribution, 477.00 Measuring and Regulatory Equipment- Distribution, and 482. Structure and Improvements – General Plant.

ANSWER:

The following response was prepared by Gannett Fleming.

In the circumstances of each of the accounts identified in this question, a retirement rate analysis was prepared. The results of the analysis are discussed below. Please refer to the attached charts and schedules for a copy of the retirement rate analysis for the specified accounts.

Account 473 – Services – Distribution

As indicated at page II-25 and II-26 of the Gannett Fleming depreciation study report, given the absence of any early generation uncertified plastic pipe in the Centra Gas system, it is not expected that there will be any large programs for the removal of uncertified plastic pipe as is being witnessed by a number of Western Canadian gas distribution utilities. As such, it is felt that the historic retirement experience provides for a meaningful indication of the future retirement trends in this account.

The retirement rate analysis completed by Gannett Fleming indicated that an Iowa curve estimate ranging from the 55-R2.5 to the 57-R2.5 curves would fit to the historic retirement trends. This analysis indicated to Gannett Fleming that the historic data provided indication that an increase in the average service life estimate from the currently approved Iowa 50-R2.5 was warranted.

Gannett Fleming reviewed the approved average service life estimates of a group of peer gas distribution utilities. The results of the review indicated the followed live estimates:

- FortisBC Energy Inc. (BCUC Application 3698562) – Iowa 55-R2.5
- ATCO Gas (AUC Application 1606822) – Iowa 57-R2.5
- AltaGas Utilities Inc. (AUC Application 1606694) – Iowa 50-R4
- SaskEnergy – Iowa 50-R3
- Enbridge Gas Distribution (OEB Application EB-2007-0615) –Iowa 40-R2

This peer review indicated that two of the five peers companies that were considered as a relevant group were using life estimates longer than the currently approved Centra Gas life estimate (but similar to the life estimate as indicated by the statistical analysis), two were using a life estimate that is similar the currently approved Centra Gas estimate, and one utility was using a significantly shorter life estimate than is currently used by Centra Gas. Based on the peer analysis Gannett Fleming viewed that a small life extension could also be appropriate, in particular in view of the fact that two of the peer utilities had approved life estimates consistent with the statistical analysis of the historic retirement trends.

Based on this analysis, Gannett Fleming made a preliminary recommendation to Centra Gas that an average service life extension to the Iowa 55-R2.5 would be reasonable. The 55 year average service life was reviewed by the company's operating and management staff and was confirmed as being reasonable.

Account 475- Mains – Distribution

As indicated at page II-26 of the Gannett Fleming depreciation study report, this account has historically retired only a small percentage of plant installed. The retirement rate analysis indicated that over 90% of even the oldest plant installations are still in service. Therefore the retirement rate analysis could not provide a meaningful indication of the future retirement trends in this account, other than the need to use a high mode curve in order to recognize the absence of retirement experience for many years after the initial installation of the mains.

Gannett Fleming reviewed the approved average service life estimates of a group of peer gas distribution utilities to determine if the currently used Iowa 65-R3 would be reasonable in light of the approved estimates of the appropriate peer group. The results of the review indicated the followed live estimates:

- FortisBC Energy Inc. (BCUC Application 3698562) – Iowa 60-R3
- ATCO Gas (AUC Application 1606822) – Iowa 66-R2.5
- AltaGas Utilities Inc. (AUC Application 1606694) – Iowa 62.5-R2
- SaskEnergy – Iowa 60-R3
- Enbridge Gas Distribution (OEB Application EB-2007-0615) –Iowa 65-R3 (Plastic)

- Enbridge Gas Distribution (OEB Application EB-2007-0615) –Iowa 61-R3 (Steel)

The above analysis indicated that the continued use of the 65 year average service life estimate would be consistent with the approved estimates used by the peer group. It was specifically noted that no peer had a life estimate of longer than the currently used 65 years. Based on this analysis and lack of historic retirement experience, Gannett Fleming made a preliminary recommendation to Centra Gas to continue use of the average service life of 65 years combined with an increase in the mode of the Iowa curve to a R4. The recommended Iowa 65-R4 was reviewed by the company's operating and management staff and was confirmed as being reasonable.

Account 477.00 Measuring and Regulating Equipment – Distribution

This account has a significant amount of historic retirement experience which was analyzed using the retirement rate method of analysis. The analysis of historic experience resulted in a best fit Iowa curve selection of an Iowa 35-R2, which represents an increase of 4 years from the currently used Iowa 31-R2.

Gannett Fleming reviewed the approved average service life estimates of a group of peer gas distribution utilities. The results of the review indicated the followed live estimates:

- FortisBC Energy Inc. (BCUC Application 3698562) – Iowa 15-R2.5
- ATCO Gas (AUC Application 1606822) – Iowa 40-R2.5
- AltaGas Utilities Inc. (AUC Application 1606694) – Iowa 50-R3
- SaskEnergy – Iowa 35-R4
- Enbridge Gas Distribution (OEB Application EB-2007-0615) –Iowa 25-L2

This peer review indicated that three of the five peers companies that were considered as a relevant group were using life estimates longer than the currently approved Centra Gas life estimate, and two were using a significantly shorter life estimate than is currently used by Centra Gas. Based on the peer analysis Gannett Fleming viewed that a small life extension could also be justified, given the statistical analysis of the historic retirement trends

Based on this analysis, Gannett Fleming made a preliminary recommendation to Centra Gas that an average service life extension to the Iowa 35-R2 would be reasonable. The 35 year average service life was reviewed by the company's operating and management staff and was confirmed as being reasonable.

Account 482.00 Structure and Improvements - General Plant

This account has a significant amount of historic retirement experience which was analyzed using the retirement rate method of analysis. The retirement rate analysis revealed that a large amount of retirement experience occurred in the first 20 years of the assets lives. The majority of the early life retirements stemmed from the disposal of redundant buildings following the acquisition of Centra Gas by Manitoba Hydro. After discussions with Centra Gas, it was determined that this early retirement experience should be considered as outlier retirement activity, and excluded from the analysis. As such, the retirement transactions occuring at an age of 18 year and younger were removed from the analysis of historic retirement transactions. The resultant analysis produced a life estimate of Iowa 45-R3.

While, the retirement activity within this account is often largely impacted by company specific policy, Gannett Fleming did review the approved average service life estimates of a group of peer gas distribution utilities to determine the reasonableness of the retirement rate analysis results. The results of the review indicated the followed live estimates:

- FortisBC Energy Inc. (BCUC Application 3698562) – Iowa 25-R2

- ATCO Gas (AUC Application 1606822) – Iowa 40-R2
- AltaGas Utilities Inc. (AUC Application 1606694) – A life span for each building is used
- SaskEnergy – Iowa 25-R3
- Enbridge Gas Distribution (OEB Application EB-2007-0615) –A life span for each building is used

Based largely on the results of the retirement rate analysis, and in part on the professional judgment and experience of Gannett Fleming, a preliminary recommendation to Centra Gas that an average service life extension to the Iowa 45-R3 would be reasonable. The 45 year average service life was reviewed by company management staff and was confirmed as being reasonable.

PUB/CENTRA I-39

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.8 Page 28 of 55**

Please confirm whether Centra has installation year data for all of its plant. If Centra does not have installation year data, please explain the process used to derive survivor curves for its plant.

ANSWER:

The following response has been prepared by Gannett Fleming.

Gannett Fleming confirms that vintaged plant accounting information was available for all accounting transaction years since 1989. Gannett Fleming has had a long standing relationship with Centra Gas, and has prepared depreciation studies for Centra Gas since 1998. Prior to 1998, Centra Gas retained the consulting firm Stone and Webster Management Consulting Inc. (Stone and Webster) for the completion of depreciation studies. Stone and Webster completed all of the Centra Gas studies through 1992 using a Simulated Plant Record method, in which the vintage year for retirement transactions is estimated through a simulation process. This method was widely used by regulated utilities throughout North America though the late 1980's. Starting in the 1990's computerized plant accounting systems provided an ability to track the installation years within the plant accounting sub-ledgers. With this ability to track installation years, the use of the retirement rate method of analysis became more prevalent.

During the first study completed by Gannett Fleming for Centra Gas Manitoba in 1999, the availability of aged data was reviewed. It was determined that for accounting years prior to the merger of the Greater Winnipeg Gas Company and ICG Utilities (Manitoba) Ltd. in 1989, aged data was not collected and could not be re-constructed. However, for the periods after 1989, sufficient aged transaction detail was available and aged accounting data could be developed. As part of the 1999 depreciation study, Gannett Fleming was provided the data bases as developed by Stone and Webster through the end of 1989, which included the statistically developed plant balances through 1989. Centra Gas was able to provide the installation year aging for most retirement transactions for the period of 1989 through 1998. Gannett Fleming merged the statistically developed data from prior to 1989 with the actual aged data from 1989 to develop an aged database as at December 31, 1998. The databases were reconciled to ensure accuracy and reasonableness. This process of combining statistically aged databases with actual aged transactions (once they became available) was widely used in the preparation of depreciation studies in the 1990's. In each subsequent study since 1998, the depreciation databases have been updated with the aged accounting transactions (which include the installation year detail) since the last study. The aged data was analyzed using the retirement rate analysis method as described at pages II-10 through II-18 of the Gannett Fleming depreciation study report.

PUB/CENTRA I-40

Subject: Tab 5: Financial Results & Forecast

Reference: Tab 5 Appendix 5.8 Page 44 of 55 - Residual Values

Please provide an example of how residual values were incorporated in the depreciation rates.

ANSWER:

Consistent with past depreciation studies, the ASL based depreciation rates implemented on April 1, 2011, and applicable through to March 31, 2015, include a provision for net salvage for a number of plant accounts. For accounts where Centra expects to receive salvage proceeds in excess of future removal costs, a positive net salvage provision is included in the calculation of the depreciation rates. With this provision, annual depreciation accruals are reduced over the lifetime of the asset, leaving a residual net book value at retirement, which is expected to be recouped by proceeds on disposition. Where the company expects to incur future removal costs in excess of any proceeds on disposition of the assets, a negative salvage provision is included in the depreciation rates to pre-collect the expected salvage costs over the lifetime of the asset. The net salvage percentages used in the 2010 Depreciation Study (ASL rates) are shown in Tab 5, Appendix 5.8, Page 8 of 55, Column (3) Net Salvage.

The following example shows the impact of the inclusion of a net salvage factor in the calculation of a depreciation rate. Account 484.00 Transportation Equipment has a net salvage percent of +10, indicating that the company expects to be able to recover 10% of the original cost when the assets are sold at the end of their 10 year useful life.

CENTRA GAS MANITOBA INC.

ACCOUNT 484.00 TRANSPORTATION EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO GAS PLANT IN SERVICE AS OF MARCH 31, 2010

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	--ACCRUED DEPREC.-- FACTOR (7)	AMOUNT (8)
SURVIVOR CURVE.. IOWA 10-R5							
NET SALVAGE PERCENT.. +10							
1989	23,446.53	10.00				1.0000	21,102
1993	166,780.85	10.00				1.0000	150,103
1995	147,283.04	10.00				1.0000	132,555
1996	85,501.92	10.00				1.0000	76,952
1997	223,153.03	10.00	10.00	20,083.77	0.06	0.9940	199,633
1998	101,540.73	10.00	10.00	9,138.67	0.29	0.9710	88,736
2000	355,399.01	10.00	10.00	31,985.91	0.79	0.9210	294,590
2001	287,828.94	10.00	10.00	25,904.60	1.24	0.8760	226,924
	1,390,934.05			87,112.95			1,190,595

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 6.26

For each vintage year, the annual depreciation accrual amount and the total calculated accrued depreciation amount have been reduced by 10%.

- Annual Accrual = Original Cost (column 2) x Rate (column 4) x [1 – Net Salvage Percent]
- Accrued Depreciation Amount = Original Cost (column 2) x Accrued Depreciation Factor (column 7) x [1 – Net Salvage Percent]

For this account, assets acquired in 1996 and earlier are considered to be fully depreciated. The accrued depreciation amount is 10% less than the original cost for each of these years, reflecting the positive salvage percentage.

For assets acquired in 1998:

- Annual Depreciation Accrual = 101,540.73 x 10% x [1 - 10%] = 9,138.67
- Accrued Depreciation Amount = 101,540.73 x 0.9710 x [1 - 10%] = 88,736

PUB/CENTRA I-41

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Page 19 of 30 - Common Assets**

a) **Please provide the policy for the classification of Common Assets and indicate whether it has changed since the last GRA.**

ANSWER:

Manitoba Hydro classifies assets that are used in the operation and administration of both the electricity and gas segments as common assets. The costs of ownership of common assets (depreciation, interest and taxes) are allocated to electricity and gas operations based on related cost drivers or through overhead rates.

This policy has not changed since the last GRA.

PUB/CENTRA I-41

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Page 19 of 30 - Common Assets**

b) Please provide a schedule listing common assets held by Centra and Manitoba Hydro by major category for 2011/12.

ANSWER:

The following table provides a summary of common assets by major category held by Centra and Manitoba Hydro at March 31, 2012, which result in depreciation charges to Centra:

CENTRA GAS MANITOBA INC. **PUB/CENTRA I-41(b)**
2013/14 General Rate Application

Schedule of Common Assets - 2011/12 Actual **($000's)**

	Centra Gas	Manitoba Hydro	Total
Facilities			
Operations & Administrative - Rural	-	83,853	83,853
Operations & Administrative - City	9,145	43,670	52,815
820 Taylor	-	16,582	16,582
360 Portage	-	278,981	278,981
	9,145	423,086	432,231
Communication	-	23,030	23,030
Office and Work Equipment			
Office Furniture & Equipment	465	26,226	26,691
Tools & Work Equipment	2,439	85,494	87,933
	2,904	111,720	114,624
Computer System Development			
Enterprise Resource Planning (SAP)	-	32,587	32,587
Geographic Information Systems	-	29,039	29,039
Banner	5,304	16,744	22,048
Other IT	-	55,259	55,259
	5,304	133,629	138,933
Computer Hardware	-	71,482	71,482
Transportation & Hvy. Work Equipment	1,553	182,472	184,025
Total	18,906	945,419	964,325

PUB/CENTRA I-41 (Revised)

Subject: Tab 5: Financial Results & Forecast

Reference: Tab 5 Page 19 of 30 - Common Assets

c) Please provide a continuity schedule of common assets for the years 2006/07 to 2013/14 (in a similar format as PUB/Centra 50(c) at the 2009/10 & 2010/11 GRA) included on Manitoba Hydro's accounting records that attract depreciation charges to Centra.

ANSWER:

The following tables provide a continuity schedule of common assets which result in depreciation charges to Centra for the years 2006/07 to 2013/14.

CENTRA GAS MANITOBA INC. **PUB/CENTRA I-41(c)**
2013/14 General Rate Application

Continuity Schedule of Common Assets - 2006/07 Actual **($ 000's)**

	Actual Balance Mar 31, 2006	Previously Reported [1] Addition	Retirement	Adjustments Remove Land [2]	Transfer	Reclass	Actual Balance Mar 31, 2007
Facilities							
Operations & Administrative - Rural	65,108	2,042	-	(1,337)	-	(1,701)	64,112
Operations & Administrative - City	47,872	1,557	-	(4,064)	137	1,701	47,203
820 Taylor	13,287	150	-	(71)	-	-	13,366
360 Portage	19,299	-	-	(19,299)	-	-	-
	145,567	3,748	-	(24,772)	137	-	124,681
Communication	42,150	2,061	-	(15)	-	-	44,196
Office and Work Equipment							
Office Furniture & Equipment	21,187	1,056	(7,839)	-	-	-	14,404
Tools & Work Equipment	67,057	5,041	(9,091)	-	-	-	63,008
	88,244	6,097	(16,929)	-	-	-	77,412
Computer System Development							
Enterprise Resource Planning (SAP)	54,296	-	-	-	-	-	54,296
Geographic Information Systems	50,399	4,362	(3,763)	-	-	-	50,998
Banner	21,160	1,454	-	-	-	-	22,614
Other IT	25,016	1,785	(1,702)	-	-	-	25,099
	150,871	7,600	(5,465)	-	-	-	153,007
Computer Hardware	77,405	20,228	(9,097)	-	-	-	88,536
Transportation & Hvy. Work Equipment	133,774	14,227	(7,290)	-	-	-	140,711
Total	638,012	53,962	(38,781)	(24,787)	137	-	628,543

[1] Figures provided in response to PUB/CENTRA I-50(c), for the 2008/09 & 2009/10 General Rate Application

[2] Land has been removed from the schedules as it does not result in depreciation charges to Centra.

CENTRA GAS MANITOBA INC. **PUB/CENTRA I-41(c)**
2013/14 General Rate Application

Continuity Schedule of Common Assets - 2007/08 Actual **($ 000's)**

	Actual Balance Mar 31, 2007	Previously Reported [1] Addition	Retirement	Adjustments Remove Land [2]	Transfer [3]	Reclass	Actual Balance Mar 31, 2008
Facilities							
Operations & Administrative - Rural	64,112	2,067	-	-	-	(28)	66,151
Operations & Administrative - City	47,203	611	(667)	9	1,699	28	48,883
820 Taylor	13,366	116	-	-	-	-	13,482
360 Portage	-	576	-	(463)	-	(113)	-
	124,681	3,370	(667)	(454)	1,699	(113)	128,516
Communication	44,196	3,125	-	-	-	-	47,321
Office and Work Equipment							
Office Furniture & Equipment	14,404	768	(1,590)	-	-	70	13,652
Tools & Work Equipment	63,008	5,598	(640)	-	-	-	67,966
	77,412	6,366	(2,230)	-	-	70	81,618
Computer System Development							
Enterprise Resource Planning (SAP)	54,296	466	(22,807)	-	-	-	31,955
Geographic Information Systems	50,998	684	(5,517)	-	-	-	46,165
Banner	22,614	7	-	-	-	-	22,621
Other IT	25,099	6,166	(347)	-	-	-	30,917
	153,007	7,323	(28,672)	-	-	-	131,658
Computer Hardware	88,536	16,276	(13,806)	-	-	43	91,049
Transportation & Hvy. Work Equipment	140,711	15,913	(5,981)	-	-	-	150,643
Total	628,543	52,372	(51,356)	(454)	1,699	-	630,805

[1] Figures provided in response to PUB/CENTRA I-50(c), for the 2008/09 & 2009/10 General Rate Application

[2] Land has been removed from the schedules as it does not result in depreciation charges to Centra.

[3] Inclusion of the Selkirk Laboratory

CENTRA GAS MANITOBA INC.
2013/14 General Rate Application

PUB/CENTRA I-41(c)

Continuity Schedule of Common Assets - 2008/09 Actual **($ 000's)**

	Actual Balance Mar 31, 2008	Addition	Retirement	Adjustments Transfer	Adjustments Reclass	Actual Balance Mar 31, 2009
Facilities						
Operations & Administrative - Rural	66,151	3,781	-	-	3	69,935
Operations & Administrative - City	48,883	1,829	(594)	-	(3)	50,115
820 Taylor	13,482	65	-	-	(8)	13,539
360 Portage	-	252,787	-	-	-	252,787
	128,516	258,462	(594)	-	(8)	386,376
Communication	47,321	1,403	-	38	-	48,762
Office and Work Equipment						
Office Furniture & Equipment	13,652	6,636	-	-	-	20,288
Tools & Work Equipment	67,966	4,487	(415)	(54)	-	71,984
	81,618	11,123	(415)	(54)	-	92,272
Computer System Development						
Enterprise Resource Planning (SAP)	31,955	785	-	-	11,103	43,843
Geographic Information Systems	46,165	6,332	(9,305)	-	850	44,042
Banner	22,621	-	-	-	480	23,101
Other IT	30,917	6,550	-	(1,899)	9,070	44,638
	131,658	13,667	(9,305)	(1,899) [1]	21,503 [1]	155,624
Computer Hardware	91,049	17,303	(31,117)	(3,844) [1]	(21,495) [1]	51,896
Transportation & Hvy. Work Equipment	150,643	14,971	(4,958)	-	-	160,656
Total	630,805 [2]	316,929 [2]	(46,389)	(5,759)	-	895,586

[1] Reclassification of computer system development.

[2] The opening balance and addition totals shown in the original response included typographical errors which have been corrected for this revised response.

CENTRA GAS MANITOBA INC. **PUB/CENTRA I-41(c)**
2013/14 General Rate Application

Continuity Schedule of Common Assets - 2009/10 Actual **($ 000's)**

	Actual Balance Mar 31, 2009	Addition	Retirement	Adjustments Transfer [1]	Reclass [1]	Write-down [2]	Actual Balance Mar 31, 2010
Facilities							
Operations & Administrative - Rural	69,935	7,750	-	-	-	-	77,685
Operations & Administrative - City	50,115	1,137	(1,731)	-	-	-	49,521
820 Taylor	13,539	1,358	-	-	-	-	14,897
360 Portage	252,787	19,414	-	-	-	-	272,201
	386,376	29,659	(1,731)	-	-	-	414,304
Communication	48,762	2,341	-	-	-	-	51,103
Office and Work Equipment							
Office Furniture & Equipment	20,288	8,081	-	-	-	-	28,369
Tools & Work Equipment	71,984	7,686	(437)	-	-	-	79,233
	92,272	15,767	(437)	-	-	-	107,602
Computer System Development							
Enterprise Resource Planning (SAP)	43,843	385	(955)	-	(1,412)	(2,337)	39,524
Geographic Information Systems	44,042	884	(5,485)	-	139	(1,542)	38,038
Banner	23,101	10	-	-	-	(342)	22,769
Other IT	44,638	5,136	(8,847)	(1,836)	1,273	(3,307)	37,057
	155,624	6,417	(15,287)	(1,836)	-	(7,528)	137,388
Computer Hardware	51,896	11,800	(14,004)	-	-	-	49,692
Transportation & Hvy. Work Equipment	160,656	14,513	(8,151)	-	-	-	167,018
Total	895,586	80,497	(39,610)	(1,836)	-	(7,528)	927,107

[1] Reclassification of computer system development.

[2] Write-down required to retrospectively apply changes to CGAAP accounting standard for Intangible Assets (Section 3064) which does not permit the capitalization of research and end-user training.

CENTRA GAS MANITOBA INC. **PUB/CENTRA I-41(c)**
2013/14 General Rate Application

Continuity Schedule of Common Assets - 2010/11 Actual **($ 000's)**

	Actual Balance Mar 31, 2010	Addition	Retirement	Adjustments Transfer [1]	Reclass [1]	Actual Balance Mar 31, 2011
Facilities						
Operations & Administrative - Rural	77,685	2,312	(534)	3,095	(67)	82,491
Operations & Administrative - City	49,521	3,519	(908)	48	(187)	51,993
820 Taylor	14,897	1,071	-	-	-	15,968
360 Portage	272,201	2,882	-	-	1,401	276,484
	414,304	9,784	(1,442)	3,143	1,147	426,936
Communication	51,103	1,146	(18,114)	(13,938)	2,572	22,769
Office and Work Equipment						
Office Furniture & Equipment	28,369	2,549	-	673	(1,322)	30,269
Tools & Work Equipment	79,233	5,906	-	(1,069)	202	84,272
	107,602	8,455	-	(396)	(1,120)	114,541
Computer System Development						
Enterprise Resource Planning (SAP)	39,524	-	-	-	-	39,524
Geographic Information Systems	38,038	34	-	-	-	38,072
Banner	22,769	1,184	-	-	-	23,953
Other IT	37,057	7,773	-	-	-	44,830
	137,388	8,991	-	-	-	146,379
Computer Hardware	49,692	11,627	(4,259)	(1,987)	(2,619)	52,454
Transportation & Hvy. Work Equipment	167,018	13,322	(7,326)	-	20	173,034
Total	927,107	53,325	(31,141)	(13,178)	-	936,113

[1] Reclassification of assets identified during the asset componentization review.

CENTRA GAS MANITOBA INC. **PUB/CENTRA I-41(c)**
2013/14 General Rate Application

Continuity Schedule of Common Assets - 2011/12 Actual **($ 000's)**

	Actual Balance Mar 31, 2011	Addition	Retirement	Adjustments Transfer	Adjustments Reclass [1]	Actual Balance Mar 31, 2012
Facilities						
Operations & Administrative - Rural	82,491	3,210	(658)	(1,190)	-	83,853
Operations & Administrative - City	51,993	1,486	(664)	-	-	52,815
820 Taylor	15,968	659	(45)	-	-	16,582
360 Portage	276,484	2,427	-	-	70	278,981
	426,936	7,782	(1,367)	(1,190)	70	432,231
Communication	22,769	496	(235)	-	-	23,030
Office and Work Equipment						
Office Furniture & Equipment	30,269	2,723	(607)	-	(5,694)	26,691
Tools & Work Equipment	84,272	4,150	(489)	-	-	87,933
	114,541	6,873	(1,096)	-	(5,694)	114,624
Computer System Development						
Enterprise Resource Planning (SAP)	39,524	2,139	(9,076)	-	-	32,587
Geographic Information Systems	38,072	2,881	(11,914)	-	-	29,039
Banner	23,953	-	(1,905)	-	-	22,048
Other IT	44,830	5,229	(424)	-	5,624	55,259
	146,379	10,249	(23,319)	-	5,624	138,933
Computer Hardware	52,454	24,311	(5,354)	71	-	71,482
Transportation & Hvy. Work Equipment	173,034	14,819	(3,828)	-	-	184,025
Total	936,113	64,530	(35,199)	(1,119)	-	964,325

[1] Reclassification of assets identified during the asset componentization review.

CENTRA GAS MANITOBA INC. **PUB/CENTRA I-41(c)**
2013/14 General Rate Application

Continuity Schedule of Common Assets - 2012/13 Forecast **($ 000's)**

	Actual Balance Mar 31, 2012	Addition	Retirement	Forecast Balance Mar 31, 2013
Facilities				
Operations & Administrative - Rural	83,853	2,748	(2)	86,599
Operations & Administrative - City	52,815	1,830	-	54,645
820 Taylor	16,582	1,101	-	17,683
360 Portage	278,981	639	-	279,620
	432,231	6,318	(2)	438,547
Communication	23,030	2,571	-	25,601
Office and Work Equipment				
Office Furniture & Equipment	26,691	2,858	(83)	29,466
Tools & Work Equipment	87,933	5,853	(1,421)	92,365
	114,624	8,711	(1,504)	121,831
Computer System Development				
Enterprise Resource Planning (SAP)	32,587	101	(2,932)	29,756
Geographic Information Systems	29,039	2,120	-	31,159
Banner	22,048	-	-	22,048
Other IT	55,259	3,349	(5,298)	53,310
	138,933	5,570	(8,230)	136,273
Computer Hardware	71,482	10,014	(10,864)	70,632
Transportation & Hvy. Work Equipment	184,025	13,241	(7,877)	189,389
Total	964,325	46,425	(28,477)	982,273

CENTRA GAS MANITOBA INC. **PUB/CENTRA I-41(c)**
2013/14 General Rate Application

Continuity Schedule of Common Assets - 2013/14 Test Year **($ 000's)**

	Forecast Balance Mar 31, 2013	Addition	Retirement	Test Year Balance Mar 31, 2014
Facilities				
Operations & Administrative - Rural	86,599	3,165	-	89,764
Operations & Administrative - City	54,645	1,028	-	55,673
820 Taylor	17,683	645	-	18,328
360 Portage	279,620	226	-	279,846
	438,547	5,064	-	443,611
Communication	25,601	1,879	-	27,480
Office and Work Equipment				
Office Furniture & Equipment	29,466	3,072	(132)	32,406
Tools & Work Equipment	92,365	5,912	(1,620)	96,657
	121,831	8,984	(1,752)	129,063
Computer System Development				
Enterprise Resource Planning (SAP)	29,756	17,369	(2,801)	44,324
Geographic Information Systems	31,159	250	(254)	31,155
Banner	22,048	-	-	22,048
Other IT	53,310	7,786	(4,679)	56,417
	136,273	25,405	(7,734)	153,944
Computer Hardware	70,632	10,073	(17,712)	62,993
Transportation & Hvy. Work Equipment	189,389	14,342	(9,713)	194,018
Total	982,273	65,747	(36,911)	1,011,109

PUB/CENTRA I-41

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Page 19 of 30 - Common Assets**

d) With respect to the schedule in (c), for the years 2011/12, 2012/13, and 2013/14, please provide the details in support of the determination of the interest on common assets and inventory as it relates to Centra.

ANSWER:

Centra program costs consist of activity charges, primary costs and overhead. Prior to 2010/11, activity charges and overhead amounts included depreciation, interest and taxes on common assets. For reporting purposes, these amounts are removed from the Centra Operating & Administrative Expenses and reclassified into their respective categories on the Centra income statement. In 2010/11 interest on common assets and motor vehicles was removed from Centra programs and allocated directly to the Centra income statement.

The attached schedule details the interest on common assets and interest on inventory as it relates to Centra. Please refer to PUB/Centra I-22(b) for further information on the Head Office Credit.

Interest on Common Assets

	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
Operations & Administrative Buildings - Rural			
Interest Costs ($000's)	$ 4,120	$ 4,360	$ 4,486
Gas Split	10%	10%	10%
Interest ($000's)	$ 412	$ 436	$ 449
Operations & Administrative Buildings - City			
Interest Costs ($000's)	$ 2,506	$ 2,343	$ 2,411
Gas Split	10%	10%	10%
Interest ($000's)	$ 251	$ 234	$ 241
820 Taylor			
Interest Costs ($000's)	$ 608	$ 614	$ 632
Gas Split	10%	10%	10%
Interest ($000's)	$ 61	$ 61	$ 63
New Head Office			
Interest Costs ($000's)	$ 18,663	$ 18,535	$ 19,073
Gas Split	10%	10%	10%
Interest ($000's)	$ 1,866	$ 1,854	$ 1,907
Communications			
Interest Costs ($000's)	$ 346	$ 352	$ 363
Gas Split	10%	10%	10%
Interest ($000's)	$ 35	$ 35	$ 36
Office Furniture & Equipment			
Interest Costs ($000's)	$ 1,136	$ 1,265	$ 1,301
Gas Split	10%	10%	10%
Interest ($000's)	$ 114	$ 126	$ 130
Tools & Work Equipment			
Interest Costs ($000's)	$ 3,163	$ 3,116	$ 3,207
Gas Split	10%	10%	10%
Interest ($000's)	$ 316	$ 312	$ 321
PC's & IT Infastructure			
Interest Costs ($000's)	$ 5,225	$ 5,966	$ 6,139
Gas Split	10%	10%	10%
Interest ($000's)	$ 523	$ 597	$ 614
Transportation & Heavy Work Equipment			
Interest Costs ($000's)	$ 6,530	$ 7,584	$ 7,804
Gas Split	10%	10%	10%
Interest ($000's)	$ 653	$ 758	$ 780

	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
Computer Development			
Interest Costs ($000's)	$ 34	$ 26	$ 18
Gas Split	100.00%	100%	100%
Interest ($000's)	$ 34	$ 26	$ 18
Customer Telephone Integration			
Interest Costs ($000's)	$ 1	$ 7	$ 7
Gas Split	100.00%	100%	100%
Interest ($000's)	$ 1	$ 7	$ 7
Banner			
Interest Costs ($000's)	$ 664	$ 527	$ 377
Gas Split	33%	33%	33%
Interest ($000's)	$ 219	$ 174	$ 124
WebTrader			
Interest Costs ($000's)	$ 45	$ 32	$ 19
Gas Split	32.00%	32.00%	32.00%
Interest ($000's)	$ 14	$ 10	$ 6
DSM Tracking			
Interest Costs ($000's)	$ 31	$ 27	$ 22
Gas Split	20.00%	20.00%	20.00%
Interest ($000's)	$ 6	$ 5	$ 4
Total Interest on Common Assets ($000's)	$ 4,505	$ 4,636	$ 4,701
Less amount transferred from Centra to Manitoba Hydro	(433)	(372)	(313)
Less amount for Head Office Credit	(1,368)	(1,368)	(1,368)
Net Finance Expense	2,703	2,896	3,020

Interest on Inventory

	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
Interest on Inventory			
Gas Material Inventory	$ 18,826	$ 27,450	$ 27,971
Monthly WACD	0.55%	0.54%	0.54%
Interest ($000's)	$ 104	$ 148	$ 151
Total Interest on Inventory ($000's)	104	148	151

PUB/CENTRA I-42

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Pages 20 to 22 of 30; 2009/10 & 2010/11 GRA PUB/Centra 149**

a) Please file the detail of finance expense for the years 2006/07 to 2013/14 in a similar format to PUB/Centra 149 from the 2009/10 & 2010/11 GRA.

ANSWER:

Please see the schedule below.

CENTRA GAS MANITOBA INC.
Finance Expense

($000's)

	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Test Year
Interest on Long Term Debt	13,762	13,547	13,753	14,305	14,142	14,390	13,336	12,544
Interest on Short Term Debt	3,349	4,665	2,758	342	131	102	22	284
Total Interest on Debt	17,111	18,212	16,511	14,647	14,274	14,492	13,358	12,828
Add:								
Provincial Guarantee Fee	3,079	3,217	3,282	3,382	3,142	3,103	3,048	2,975
Amortization of Debt Discounts	1,692	1,253	1,256	1,262	298	318	167	-
Interest on Common Assets	2,139	2,244	2,384	2,398	2,805	2,703	2,896	3,020
Interest on Inventory	25	32	25	104	93	104	148	151
Total Additions	6,933	6,747	6,947	7,146	6,337	6,228	6,259	6,146
Deduct:								
Capitalized Interest	(145)	(206)	(193)	(134)	(142)	(210)	(174)	(113)
Carrying Costs on Deferred Taxes	(3,352)	(3,156)	(2,996)	(2,850)	(2,704)	(2,565)	(2,412)	(2,266)
Carrying Costs on Purchased Gas Variance Account	1,539	66	(158)	(43)	(15)	262	584	332
Other	9	49	48	154	138	257	286	369
Total Deductions	(1,949)	(3,248)	(3,299)	(2,873)	(2,723)	(2,255)	(1,716)	(1,678)
Total Finance Expense	**22,095**	**21,711**	**20,158**	**18,921**	**17,888**	**18,464**	**17,901**	**17,296**

PUB/CENTRA I-42

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Pages 20 to 22 of 30; 2009/10 & 2010/11 GRA PUB/Centra 149**

b) Please file a comparison schedule prepared on the basis of (a) between actual and that forecasted (CGM08-1) at the 2009/10 & 2010/11 GRA for the years 2008/09, 2009/10, 2010/11 and 2011/12.

ANSWER:

Please see the schedule below.

CENTRA GAS MANITOBA INC.
Finance Expense (000's)

	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual
Interest on Long Term Debt	13,753	14,305	14,142	14,390
Interest on Short Term Debt	2,758	342	131	102
Total Interest on Debt	16,511	14,647	14,274	14,492
Add:				
Provincial Guarantee Fee	3,282	3,382	3,142	3,103
Amortization of Debt Discounts	1,256	1,262	298	318
Interest on Common Assets	2,384	2,398	2,805	2,703
Interest on Inventory	25	104	93	104
Total Additions	6,947	7,146	6,337	6,228
Deduct:				
Capitalized Interest	(193)	(134)	(142)	(210)
Carrying Costs on Deferred Taxes	(2,996)	(2,850)	(2,704)	(2,565)
Carrying Costs on Purchased Gas Variance Account	(158)	(43)	(15)	262
Other	48	154	138	257
Total Deductions	(3,299)	(2,873)	(2,723)	(2,255)
Total Finance Expense	**20,158**	**18,921**	**17,888**	**18,464**

	2008/09 **Forecast** (CGM08-1)	2009/10 **Forecast** (CGM08-1)	2010/11 **Forecast** (CGM08-1)	2011/12 **Forecast** (CGM08-1)
Interest on Long Term Debt	13,760	14,987	15,342	15,342
Interest on Short Term Debt	4,384	912	1,719	3,530
Total Interest on Debt	18,144	15,899	17,061	18,872
Add:				
Provincial Guarantee Fee	3,282	3,285	3,633	3,674
Amortization of Debt Discounts	1,256	1,262	298	318
Interest on Common Assets	2,562	2,677	2,839	3,244
Interest on Inventory	24	25	27	29
Total Additions	7,124	7,249	6,797	7,265
Deduct:				
Capitalized Interest	(214)	(212)	(127)	(127)
Carrying Costs on Deferred Taxes	(2,996)	(2,850)	(2,704)	(2,557)
Carrying Costs on Purchased Gas Variance Account	109	809	(31)	-
Other	58	97	21	(77)
Total Deductions	(3,043)	(2,156)	(2,841)	(2,762)
Total Finance Expense	**22,225**	**20,992**	**21,017**	**23,375**

	2008/09 Difference	2009/10 Difference	2010/11 Difference	2011/12 Difference
Interest on Long Term Debt	(7)	(682)	(1,200)	(952)
Interest on Short Term Debt	(1,626)	(570)	(1,588)	(3,428)
Total Interest on Debt	(1,633)	(1,252)	(2,787)	(4,380)
Add:				
Provincial Guarantee Fee	-	97	(491)	(571)
Amortization of Debt Discounts	-	-	-	-
Interest on Common Assets	(178)	(279)	(34)	(541)
Interest on Inventory	1	79	66	75
Total Additions	(177)	(103)	(460)	(1,037)
Deduct:				
Capitalized Interest	21	78	(15)	(83)
Carrying Costs on Deferred Taxes	-	-	-	-
Carrying Costs on Purchased Gas Variance Account	(267)	(852)	16	262
Other	(10)	57	117	334
Total Deductions	(256)	(717)	118	514
Total Finance Expense	**(2,067)**	**(2,071)**	**(3,129)**	**(4,904)**

PUB/CENTRA I-42

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Pages 20 to 22 of 30; 2009/10 & 2010/11 GRA PUB/Centra 149**

c) File the summary as in (a) of Total Finance Expense for the 20 year IFF CGM12.

ANSWER:

Please see the schedule on the following pages.

Summary of Total Finance Expense (CGM12) - Forecast to March 31, 2022

In Thousands for the Years Ending

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Interest on Long Term Debt	13,336	12,544	13,527	14,412	15,176	16,179	17,190	17,720	18,250	19,310
Interest on Short Term Debt	22	284	250	301	639	569	323	426	546	310
Total Interest on Debt	13,358	12,828	13,777	14,713	15,815	16,748	17,513	18,146	18,796	19,620
Add:										
Provincial Guarantee Fee	3,048	2,975	3,341	3,341	3,485	3,695	3,828	3,952	4,079	4,212
Amortization of Debt Discounts	167	-	-	-	-	-	-	-	-	-
Interest on Common Assets	2,896	3,020	3,139	3,196	3,253	3,315	3,378	3,442	3,508	3,574
Interest on Inventory	148	151	154	157	160	163	166	169	172	175
Total Additions	6,259	6,146	6,634	6,694	6,898	7,173	7,372	7,563	7,759	7,961
Deduct:										
Capitalized Interest	(174)	(113)	(137)	(135)	(129)	(128)	(127)	(131)	(140)	(133)
Carrying Costs on Deferred Taxes	(2,412)	(2,265)	-	-	-	-	-	-	-	-
Carrying Costs on Purchased Gas Variance Account	584	332	(153)	-	-	-	-	-	-	-
Other	286	368	556	747	803	745	671	589	500	409
Total Deductions	(1,716)	(1,678)	266	612	674	617	544	458	360	276
Total Finance Expense	**17,901**	**17,296**	**20,677**	**22,019**	**23,387**	**24,538**	**25,429**	**26,167**	**26,915**	**27,857**

PUB/CENTRA I-43

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Pages 20 and 21 of 30 - Debt Issues**

a) Please provide the interest rates applicable to Centra on a stand-alone basis, given its current capital structure, for short term and long-term debt.

ANSWER:

On a stand-alone basis, Centra's capital structure may not be sufficient to support an investment grade credit rating. As such, it is unclear what liquidity, interest rates and financing terms would be available to Centra as a stand-alone entity.

PUB/CENTRA I-43

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Pages 20 and 21 of 30 - Debt Issues**

b) Please file copies of the term sheets for all existing debt issues.

ANSWER:

Please find copies of the term sheets below.

TERM SHEET

Series CG7
Intercompany Advance from the Manitoba Hydro-Electric Board (MHEB)

Principal	**$50,000,000 CAD**
Issue Date	November 22, 2006
Maturity Date	March 5, 2037
Term to Maturity	30.5 Years
Coupon Rate	4.505%
Yield Rate	4.505%
Interest Payable	March 5 & September 5

NOTE: Long term inter-company advance Series CG7 was issued to Centra Gas Manitoba by the MHEB in order to refinance long term inter-company advance Series CG3 that had a November 22, 2006 maturity of $48,525,300. The interest rate was assigned based on MHEB Series FA-4. Interest will accrue from the date of issuance November 22, 2006 with the first interest payment occurring March 5, 2007.

TERM SHEET

Series CG8
Intercompany Advance from the Manitoba Hydro-Electric Board (MHEB)

Principal	**$30,000,000 CAD**
Issue Date	October 29, 2002
Maturity Date	October 29, 2032
Term to Maturity	30 Years
Coupon Rate	6.30%
Yield Rate	6.30%
Interest Payable	April 29 & October 29

NOTE: Long term inter-company advance Series CG6 was issued to Centra Gas Manitoba by the MHEB in order to finance $30 million of cumulative new capital cash requirements at October 29, 2002. The interest was assigned based on MHEB Series CO52. In October 2007, the bondholder exercised the option to extend the term to maturity to October 29, 2032 at a 6.30% coupon rate. As the debt terms had been modified, the debt issue was renamed Series CG8. Interest on CG8 will accrue from October 29, 2007 with the first interest payment occurring April 29, 2008.

TERM SHEET

Series CG9
Intercompany Advance from the Manitoba Hydro-Electric Board (MHEB)

Principal	**$30,000,000 CAD**
Issue Date	September 1, 2009
Maturity Date	March 5, 2040
Term to Maturity	30.5 Years
Coupon Rate	5.1754%
Yield Rate	5.1754%
Interest Payable	March 5 & September 5

NOTE: Long term inter-company advance Series CG9 was issued to Centra Gas Manitoba by the MHEB in order to finance $30 million of cumulative new capital cash requirements at September 1, 2009. The coupon rate was assigned based on the MHEB Series FK-2 which was issued on June 5, 2009. Interest will accrue from the date of issuance September 1, 2009 with the first interest payment occurring March 5, 2010.

TERM SHEET

Series CG10
Intercompany Advance from the Manitoba Hydro-Electric Board (MHEB)

Principal	**$35,000,000 CAD**
Issue Date	February 22, 2010
Maturity Date	February 22, 2015
Term to Maturity	5 Years
Coupon Rate	3 Month BAs + 0.484%
Yield Rate	3 Month BAs + 0.484%
Interest Payable	March 1 & September 1

NOTE: Long term inter-company advance Series CG10 was issued to Centra Gas Manitoba by the MHEB in order to partially refinance long term inter-company advance Series CG5 that had a February 22, 2010 maturity of $75,000,000. The interest rate was assigned based on MHEB Series FM-4. Interest will accrue from the date of issuance February 22, 2010 with the first interest payment occurring September 1, 2010. The last interest payment will be a short stub payable February 22, 2015.

TERM SHEET

Series CG11
Intercompany Advance from the Manitoba Hydro-Electric Board (MHEB)

Principal	**$30,000,000 CAD**
Issue Date	February 22, 2010
Maturity Date	February 22, 2030
Term to Maturity	20 Years
Coupon Rate	4.726%
Yield Rate	4.726%
Interest Payable	March 5 & September 5

NOTE: Long term inter-company advance Series CG11 was issued to Centra Gas Manitoba by the MHEB in order to partially refinance long term inter-company advance Series CG5 that had a February 22, 2010 maturity of $75,000,000. The interest rate was assigned based on MHEB Series FN. Interest will accrue from the date of issuance February 22, 2010 with the first interest payment occurring September 5, 2010. The last interest payment will be a short stub payable February 22, 2030.

TERM SHEET

Series CG12
Intercompany Advance from the Manitoba Hydro-Electric Board (MHEB)

Principal	**$10,000,000 CAD**
Issue Date	February 22, 2010
Maturity Date	August 22, 2037
Term to Maturity	27.5 Years
Coupon Rate	4.638%
Yield Rate	4.638%
Interest Payable	March 5 & September 5

NOTE: Long term inter-company advance Series CG12 was issued to Centra Gas Manitoba by the MHEB in order to partially refinance long term inter-company advance Series CG5 that had a February 22, 2010 maturity of $75,000,000. The interest rate was assigned based on MHEB Series C109. Interest will accrue from the date of issuance February 22, 2010 with the first interest payment occurring September 5, 2010. The last interest payment will be a short stub payable August 22, 2037.

TERM SHEET

Series CG13
Intercompany Advance from the Manitoba Hydro-Electric Board (MHEB)

Principal	**$20,000,000 CAD**
Issue Date	March 31, 2010
Maturity Date	September 30, 2037
Term to Maturity	27.5 Years
Coupon Rate	4.638%
Yield Rate	4.638%
Interest Payable	March 5 & September 5

NOTE: Long term inter-company advance Series CG13 was issued to Centra Gas Manitoba by the MHEB in order to refinance long term inter-company advance Series CG4 that had a March 31, 2010 maturity of $18,077,200. The interest rate was assigned based on MHEB Series C109. Interest will accrue from the date of issuance March 31, 2010 with the first interest payment occurring September 5, 2010. The last interest payment will be a short stub payable September 30, 2037.

TERM SHEET

Series CG14
Intercompany Advance from the Manitoba Hydro-Electric Board (MHEB)

Principal	**$30,000,000 CAD**
Issue Date	March 31, 2010
Maturity Date	March 31, 2035
Term to Maturity	25 Years
Coupon Rate	4.629%
Yield Rate	4.629%
Interest Payable	March 5 & September 5

NOTE: Long term inter-company advance Series CG14 was issued to Centra Gas Manitoba by the MHEB in order to finance $30 million of cumulative new capital cash requirements to March 31, 2010. The interest rate was assigned based on MHEB Series C110. Interest will accrue from the date of issuance March 31, 2010 with the first interest payment occurring September 5, 2010. The last interest payment will be a short stub payable March 31, 2035.

TERM SHEET

Series CG15
Intercompany Advance from the Manitoba Hydro-Electric Board (MHEB)

Principal	**$20,000,000 CAD**
Issue Date	September 18, 2012
Maturity Date	September 18, 2022
Term to Maturity	10 Years
Coupon Rate	3.178%
Yield Rate	3.178%
Interest Payable	March 18 & September 18

NOTE: Long term inter-company advance Series CG15 was issued to Centra Gas Manitoba by the MHEB in order to partially refinance long term inter-company advance Series CG1 that had a September 18, 2012 maturity of $62,670,600. The interest rate was assigned based on MHEB Series C129. Interest will accrue from the date of issuance September 18, 2012 with the first interest payment occurring March 18, 2013.

TERM SHEET

Series CG16
Intercompany Advance from the Manitoba Hydro-Electric Board (MHEB)

Principal	**$20,000,000 CAD**
Issue Date	September 18, 2012
Maturity Date	September 18, 2033
Term to Maturity	21 Years
Coupon Rate	3.281%
Yield Rate	3.281%
Interest Payable	March 18 & September 18

NOTE: Long term inter-company advance Series CG16 was issued to Centra Gas Manitoba by the MHEB in order to partially refinance long term inter-company advance Series CG1 that had a September 18, 2012 maturity of $62,670,600. The interest rate was assigned based on MHEB Series FN-3. Interest will accrue from the date of issuance September 18, 2012 with the first interest payment occurring March 18, 2013.

TERM SHEET

Series CG17
Intercompany Advance from the Manitoba Hydro-Electric Board (MHEB)

Principal	**$20,000,000 CAD**
Issue Date	September 18, 2012
Maturity Date	September 18, 2042
Term to Maturity	30 Years
Coupon Rate	3.413%
Yield Rate	3.413%
Interest Payable	March 18 & September 18

NOTE: Long term inter-company advance Series CG17 was issued to Centra Gas Manitoba by the MHEB in order to partially refinance long term inter-company advance Series CG1 that had a September 18, 2012 maturity of $62,670,600. The interest rate was assigned based on MHEB Series GA. Interest will accrue from the date of issuance September 18, 2012 with the first interest payment occurring March 18, 2013.

PUB/CENTRA I-43

Subject: Tab 5: Financial Results & Forecast

Reference: Tab 5 Pages 20 and 21 of 30 - Debt Issues

c) Please provide a schedule of the long term debt from 2006/07 through 20013/14.

ANSWER:

Please find attached a continuity schedule of long term debt from 2006/07 through 2013/14.

CENTRA GAS MANITOBA INC.
2012/13 General Rate Application

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Long Term Debt Continuity Schedule

($000's)

	2006	2006/07				2007/08			2008/09			2009/10		
	Ending Balance	Serial Redemption	Maturities	New Advances	Ending Balance	Serial Redemption	Maturities	Ending Balance	Serial Redemption	Maturities	Ending Balance	Maturities	New Advances	Ending Balance
MH Advances														
CG1	62,671				62,671			62,671			62,671			62,671
CG2	6,520		(6,520)		-			-			-			-
CG3	48,525		(48,525)		-			-			-			-
CG4	24,856	(2,260)			22,597	(2,260)		20,337	(2,260)		18,077	(18,077)		-
CG5	75,000				75,000			75,000			75,000	(75,000)		-
CG7				50,000	50,000			50,000			50,000			50,000
CG8	30,000				30,000			30,000			30,000			30,000
CG9													30,000	30,000
CG10													35,000	35,000
CG11													30,000	30,000
CG12													10,000	10,000
CG13													20,000	20,000
CG14													30,000	30,000
CG15														
CG16														
CG17														
Total	**247,572**	**(2,260)**	**(55,045)**	**50,000**	**240,267**	**(2,260)**	**-**	**238,007**	**(2,260)**		**235,748**	**(93,077)**		**297,671**

CENTRA GAS MANITOBA INC.
2012/13 General Rate Application

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Long Term Debt Continuity Schedule

($000's)

	2010	**2010/11**			**2011/12**			**2012/13**			**2013/14**		
	Ending Balance	Maturities	New Advances	Ending Balance	Maturities	New Advances	Ending Balance	Maturities	New Advances	Ending Balance	Maturities	New Advances	Ending Balance
MH Advances													
CG1	62,671			62,671			62,671	(62,671)		-			-
CG2	-			-			-			-			-
CG3	-			-			-			-			-
CG4	-			-			-			-			-
CG5	-			-			-			-			-
CG7	50,000			50,000			50,000			50,000			50,000
CG8	30,000			30,000			30,000			30,000			30,000
CG9	30,000			30,000			30,000			30,000			30,000
CG10	35,000			35,000			35,000			35,000			35,000
CG11	30,000			30,000			30,000			30,000			30,000
CG12	10,000			10,000			10,000			10,000			10,000
CG13	20,000			20,000			20,000			20,000			20,000
CG14	30,000			30,000			30,000			30,000			30,000
CG15									20,000	20,000			20,000
CG16									20,000	20,000			20,000
CG17									20,000	20,000			20,000
New Debt - March 2014												30,000	30,000
Total	**297,671**	**-**		**297,671**	**-**	**-**	**297,671**	**(62,671)**		**295,000**	**-**	**30,000**	**325,000**

PUB/CENTRA I-44 (Revised)

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Page 27 of 30 Schedule 5.8.0; Appendix 5.9 - Capital & Other Taxes**

a) Please provide the schedule by year of Capital and Other Taxes showing actual amounts since 2003/04 through forecasted amounts for 2013/14.

ANSWER:

	2003/04 Actual	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual
Corporation Capital Tax	2,226	2,175	2,317	2,414	2,477	2,452
Municipal Taxes	13,833	14,805	14,889	14,223	15,024	15,436
Payroll Tax	795	820	639	616	653	700
Taxes on Common Assets	(169)	(143)	(52)	(97)	(79)	24
Deferred Income Taxes	5,531	5,385	5,239	5,092	4,946	4,800
City of Winnipeg Audit Settlement						
Total Taxes	22,216	23,042	23,032	22,248	23,021	23,412

	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Test Year	2013/14 Test Year
Corporation Capital Tax	2,377	2,398	2,323	2,304	2,516
Municipal Taxes	14,836	10,844	11,561	10,861	11,187
Payroll Tax	788	802	800	793	807
Taxes on Common Assets	380	421	221	160	170
Deferred Income Taxes	4,654	4,508	4,369	4,216	4,070
City of Winnipeg Audit Settlement	316	1,517			
Total Taxes	23,351	20,490	19,274	18,334	18,750

PUB/CENTRA I-44

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Page 27 of 30 Schedule 5.8.0; Appendix 5.9 - Capital & Other Taxes**

b) Please provide the full amortization schedule for the one time income tax liability including the total financing cost to be incurred over the term of the amortization.

ANSWER:

Please see the schedule below.

Amortization Schedule for One Time Tax Payment ($000's)

	1999/2000 Actual	2000/01 Actual	2001/02 Actual	2002/03 Actual	2003/04 Actual	2004/05 Actual	2005/06 Actual	2006/07 Actual
Beginning Balance	58,249	52,322	50,518	48,714	46,910	45,105	43,301	41,497
Amortization of Beginning Balance and Additions	(5,927)	(1,804)	(1,804)	(1,804)	(1,804)	(1,804)	(1,804)	(1,804)
Carrying Costs	1,553	4,165	4,019	3,873	3,727	3,580	3,435	3,288
Amortization - Carrying Costs	(1,553)	(4,165)	(4,019)	(3,873)	(3,727)	(3,580)	(3,435)	(3,288)
Ending Balance	52,322	50,518	48,714	46,910	45,105	43,301	41,497	39,693

	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Test Year	2014/15 Plan
Beginning Balance	39,693	37,889	36,084	34,280	32,476	30,672	28,867	27,063
Amortization of Beginning Balance and Additions	(1,804)	(1,804)	(1,804)	(1,804)	(1,804)	(1,804)	(1,804)	(1,804)
Carrying Costs	3,142	2,996	2,850	2,704	2,565	2,412	2,266	2,119
Amortization - Carrying Costs	(3,142)	(2,996)	(2,850)	(2,704)	(2,565)	(2,412)	(2,266)	(2,119)
Ending Balance	37,889	36,084	34,280	32,476	30,672	28,867	27,063	25,259

	2015/16 Plan	2016/17 Plan	2017/18 Plan	2018/19 Plan	2019/20 Plan	2020/21 Plan	2021/22 Plan	2022/23 Plan
Beginning Balance	25,259	23,455	21,651	19,846	18,042	16,238	14,434	12,630
Amortization of Beginning Balance and Additions	(1,804)	(1,804)	(1,804)	(1,804)	(1,804)	(1,804)	(1,804)	(1,804)
Carrying Costs	1,973	1,827	1,681	1,534	1,388	1,242	1,096	950
Amortization - Carrying Costs	(1,973)	(1,827)	(1,681)	(1,534)	(1,388)	(1,242)	(1,096)	(950)
Ending Balance	23,455	21,651	19,846	18,042	16,238	14,434	12,630	10,825

	2023/24 Plan	2024/25 Plan	2025/26 Plan	2026/27 Plan	2027/28 Plan	2028/29 Plan	Total
Beginning Balance	10,825	9,021	7,217	5,413	3,608	1,804	
Amortization of Beginning Balance and Additions	(1,804)	(1,804)	(1,804)	(1,804)	(1,804)	(1,804)	
Carrying Costs	804	658	511	365	219	73	63,015
Amortization - Carrying Costs	(804)	(658)	(511)	(365)	(219)	(73)	
Ending Balance	9,021	7,217	5,413	3,608	1,804	0	

PUB/CENTRA I-44

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Page 27 of 30 Schedule 5.8.0; Appendix 5.9 - Capital & Other Taxes**

c) Please provide a schedule detailing the Municipal Taxes and payments in lieu of municipal tax by municipality for each of the years 2009/10 through 2013/14.

ANSWER:

Please see the following schedule showing the actual municipal taxes paid for the calendar years 2009 through to 2012.

Municipal tax payments are made on a calendar year basis and appropriate accruals are then made to record fiscal year expenses. Tax bills for 2013, which will be paid in the 2013/14 fiscal year, have not yet been received. Municipal tax payments are not forecasted on a municipality by municipality basis. Therefore a detailed comparison by municipality cannot be provided for 2013/14.

($000's)	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual
RM of Alexander	$ 1	$ 1	$ 1	$ 1
Town of Altona	48	36	36	31
Town of Arborg	9	7	8	7
Rm of Archie	12	14	14	15
RM of Arthur	10	12	13	13
Town of Beausejour	41	26	28	24
RM of Bifrost	40	46	47	48
Rm of Binscarth	9	7	7	6
RM of Blanshard	10	10	10	10
Town of Boissevain	17	14	15	12
City of Brandon	641	476	499	467
RM of Brenda	17	13	13	13
RM of Brokenhead	52	46	48	56
RM of Cameron	24	35	35	36
Town of Carberry	22	15	16	13
Town of Carmen	43	33	33	29
RM of Cartier	25	35	29	32
RM of Cornwallis	96	93	95	96
Rm of Daly	14	15	15	16
Town of Dauphin	174	134	135	118
RM of DeSalaberry	56	54	55	51
Town of Deloraine	20	16	16	15
Rm of Dufferin	58	67	66	67
Rm of Dunnottar	23	16	16	15
RM of East St. Paul	157	111	114	108
Village of Elkhorn	12	10	10	8
RM of Ellice	39	42	46	53
RM of Elton	169	216	224	226
Town of Emerson	19	19	21	19
RM of Franklin	54	58	60	61
RM of Gilbert Plains	54	62	61	59
RM of Gimli	112	97	98	96
Town of Gladstone	13	12	12	9
RM of Glenwood	35	38	38	40
RM of Grandview	71	75	78	77
Town of Gretna	9	7	7	6
RM of Grey	72	84	87	86
Town of Hamiota	43	40	42	38
RM of Hanover	300	267	321	294
Town of Hartney	12	9	9	8

($000's)	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual
RM of Headingly	46	35	36	31
Town of Killarney	49	48	50	60
RM of La Broquerie	151	143	144	131
RM of Langford	16	17	18	17
RM of Macdonald	175	163	169	169
Town of MacGregor	13	9	9	8
Town of Melita	21	20	20	16
RM of Miniota	23	26	26	27
Town of Minnedosa	66	54	55	51
RM of Minto	0	0	0	0
RM of Montcalm	66	72	75	69
RM of Mossomin	3	3	3	3
Town of Morden	95	63	68	62
RM of Morris	39	42	40	34
Town of Morris	43	32	33	28
RM of Morton	49	60	61	59
Town of Neepawa	68	50	50	45
Town of Niverville	32	23	23	22
RM of North Cypress	43	49	52	50
RM of North Norfolk	61	64	67	62
RM of Oakland	19	21	22	24
RM of Odanah	55	61	64	66
RM of Pipestone	17	19	19	19
Town of Plum Coulee	14	10	10	9
RM of Portage	123	126	129	129
Town of Portage la Prairie	220	175	181	175
RM of Reynolds	4	4	4	3
RM of Rhineland	49	53	55	56
RM of Richot	139	126	130	122
Town of Rivers	21	15	14	11
Village of Riverton	8	7	7	7
Town of Roblin	34	26	26	22
RM of Rockwood	82	76	78	75
RM of Roland	38	52	54	53
RM of Rosser	26	27	27	27
RM of Russell	91	97	97	105
City of Selkirk	155	116	117	107
RM of Shell River	16	17	18	17
RM of Shellmouth-Boulton	59	69	68	72
RM of Shoal Lake	23	25	24	21

($000's)	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual
Town of Souris	31	23	24	21
RM of South Cypress	1	1	1	0
RM of St Andrews	223	186	193	186
Village of St. Claude	14	12	13	11
RM of St. Clements	206	178	182	176
Village of St Lazare	9	8	8	8
Village of St Pierre	12	8	8	7
Town of Ste Anne	46	52	53	51
RM of Springfield	215	192	207	195
RM of Stanley	65	74	72	71
City of Steinbach	144	104	108	96
Town of Stonewall	47	29	30	27
RM of Tache	149	126	130	123
Town of Teulon	11	9	9	8
Town of Virden	51	36	37	34
RM of Wallace	74	80	85	85
RM of West St. Paul	75	51	54	51
RM of Westbourne	64	72	71	67
RM of Whitewater	21	27	27	28
RM of Winchester	12	14	14	15
City of Winkler	104	80	82	72
City of Winnipeg	8,809	5,597	5,497	5,137
Town of Winnipeg Beach	29	21	21	19
RM of Woodlands	20	20	21	20
	$ 15,320	$ 11,463	$ 11,562	$ 10,950

PUB/CENTRA I-45

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Pages 27 to 30 of 30 - Payments to Governments**

a) **Please provide a schedule demonstrating Centra's payments to governments (federal, provincial and municipal) by type for 2009/10 to 2013/14 on a similar basis to that presented in response to PUB/CENTRA 47 at the 2009/10 & 2010/11 GRA.**

ANSWER:

Centra was no longer subject to provincial income taxes and federal income taxes subsequent to the acquisition of the company by Manitoba Hydro. Centra's deferred income taxes represent the one-time tax liability that was triggered by the acquisition of the company by Manitoba Hydro. In accordance with Order 118/03, Centra deferred the resulting liability and is amortizing the amount over a 30-year period.

As of April 1, 2001 all Centra employees were transferred to the payroll of Manitoba Hydro. Therefore, Centra no longer makes payments directly to the provincial and federal governments for payroll related taxes.

Of the payments included in the table below, only corporation capital taxes and property and business taxes are calculated and paid directly by Centra. The debt guarantee fee is initially paid by Manitoba Hydro and allocated to Centra based on the company's portion of total outstanding corporate group debt. Similarly, payroll taxes are paid by Manitoba Hydro and allocated to Centra in line with total labour charges allocated.

Summary of Payments to Government **($000's)**

	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Test Year	2013/14 Test Year
Provincial Payments:					
Income Tax	n/a	n/a	n/a	n/a	n/a
Corporation Capital Taxes	2,377	2,398	2,323	2,304	2,516
Debt Guarantee Fee	3,382	3,142	3,103	3,048	2,975
Payroll Taxes	788	802	800	793	807
Total Provincial Payments	6,547	6,342	6,226	6,145	6,298
Federal Payments:					
Income Tax	n/a	n/a	n/a	n/a	n/a
Employment Insurance	n/a	n/a	n/a	n/a	n/a
Canadian Pension Plan	n/a	n/a	n/a	n/a	n/a
Total Federal Payments	-	-	-	-	-
Municipal Payments:					
Property & Business Taxes	14,836	10,844	11,561	10,861	11,187
Total Corporate Payments	21,383	17,186	17,787	17,006	17,485

PUB/CENTRA I-45

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Pages 27 to 30 of 30 - Payments to Governments**

b) Please provide the calculation for the determination of the Corporation Capital Tax for the years 2009/10 through 2013/14.

ANSWER:

Capital Tax Calculations **($000'S)**

	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Test Year
Paid-up Capital Stock	121,250	121,250	121,250	121,250	121,250
Retained Earnings	33,443	40,052	34,301	35,863	41,470
Loans, Debentures & Other	321,826	316,715	311,074	303,767	340,437
	476,519	478,017	466,625	460,880	503,157
Total Paid up Capital					
Investment Allowance					
Taxable Paid Up Capital	476,519	478,017	466,625	460,880	503,157
Post-2007 Basic Tax @ .5%	2,383	2,390	2,333	2,304	2,516
Total Corporation Capital Tax	2,383	2,390	2,333	2,304	2,516
Rounding	(6)	8	(10)		
Capital Tax Expense	2,377	2,398	2,323	2,304	2,516

PUB/CENTRA I-45

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Pages 27 to 30 of 30 - Payments to Governments**

c) Please provide a schedule showing the supporting calculations for the Debt Guarantee Fee for the years 2009/10 through 2013/14.

ANSWER:

Please see the table below:

PUB-CENTRA I - 45

Provincial Debt Guarantee Fee (PGF) Calculations
($ thousands CAD)

	Actual 2009/10	Actual 2010/11	Actual 2011/12	Forecast 2012/13	Forecast 2013/14
Long Term Debt Balance for PGF	235,748	297,676	297,671	297,671	295,000
Short Term Debt Balance for PGF	102,458	16,502	12,631	7,116	2,480
Debt Balance for PGF Purposes	338,206	314,178	310,302	304,786	297,480
PGF Rate	1.00%	1.00%	1.00%	1.00%	1.00%
Amount PGF Paid to Manitoba Hydro	3,382	3,142	3,103	3,048	2,975

Note: The fee calculation is based on ending debt balances at March 31 of the prior fiscal year. The fiscal year debt balances presented in PUB/CENTRA I - 45 represent the amount of debt upon which the PGF was paid or is payable for that fiscal year.

PUB/CENTRA I-46

Subject: Tab 5: Financial Results & Forecast

Reference: Tab 5 Appendix 5.4 Note 9 Long Term Debt

Please indicate the weighted average yield rate that 2013 debt repayments were rolled over at.

ANSWER:

Centra debt issue CG1 for $62.67 million with a weighted average yield rate of 5.98% matured on September 18, 2012 and was refinanced with the following long term debt issues:

CG15	$20 million	3.178%
CG16	$20 million	3.281%
CG17	$20 million	3.413%

The weighted average yield rate for CG15-17 is 3.291%.

PUB/CENTRA I-47

Subject: Tab 5: Financial Results & Forecast

Reference: Tab 5 Appendix 5.4 Note 12 Employee Future Benefits

a) Please file the actuarial valuation at December 31, 2012.

ANSWER:

The actuarial valuation report at December 31, 2012 will be provided when it is finalized.

PUB/CENTRA I-47

Subject: Tab 5: Financial Results & Forecast

Reference: Tab 5 Appendix 5.4 Note 12 Employee Future Benefits

b) Please provide an update on the pension assets value given the changes in interest rate assumptions.

ANSWER:

Please see Centra's response to PUB/Centra I-47(a).

PUB/CENTRA I-47

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.4 Note 12 Employee Future Benefits**

c) Please provide a table that details the significant actuarial assumptions in the December 31, 2012 actuarial report with the stated assumptions in note 12.

ANSWER:

Please see Centra's response to PUB/Centra I-47(a).

PUB/CENTRA I-48 (Revised)

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.4 Page 15 - Credit Risk**

a) Please provide a schedule detailing the aging of A/R for fiscal 2007 through 2012.

ANSWER:

Fiscal Year Ending March 31	*Total*	*Current*	*30 day*	*60+ day*	*Allowance for Doubtful Accounts*
2012	$ 47,131	$ 42,072	$ 3,356	$ 3,957	$ (2,254)
2011	$ 89,907	$ 82,492	$ 4,429	$ 5,282	$ (2,296)
2010	$ 78,564	$ 68,626	$ 5,893	$ 6,471	$ (2,426)
2009	$ 138,475	$ 126,949	$ 7,153	$ 7,299	$ (2,926)
2008	$ 142,482	$ 130,909	$ 7,716	$ 6,625	$ (2,768)
2007	$ 128,503	$ 116,316	$ 7,637	$ 7,452	$ (2,902)

PUB/CENTRA I-48

Subject: Tab 5: Financial Results & Forecast

Reference: Tab 5 Appendix 5.4 Page 15 - Credit Risk

b) Please explain what factors have led to the reduction in the under-30 days A/R balance in 2012 versus the prior year.

ANSWER:

The general reduction in the price of natural gas combined with a warmer than normal heating season, resulting in decreased general consumer revenue, is the primary factor leading to the under-30 day A/R balance reduction in 2011/12 versus the previous year.

PUB/CENTRA I-48

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.4 Page 15 - Credit Risk**

c) Please explain the changes to procedures that have resulted in a reduction in bad debt and collection costs.

ANSWER:

Changes to operational procedures resulting in a reduction in bad debt and collection costs include:

- The treatment of combined natural gas and electric accounts as one receivable, flowing from Order 14/08. As one receivable, more flexible payment arrangements can be offered, avoiding further collection action. Failure to bring an entire account to good standing results in disconnection or load restriction of service(s) regardless of which product or service is in arrears.
- Expanded communication options for customers wishing to make payment arrangements (e.g. MyBill payment arrangements, email communications).
- Implementation of the Bad Debt Improvement information technology project which sends accounts to third party collection agencies more quickly once deemed uncollectable and assigns volume of accounts to individual third party agencies based on past performance.
- Expanded quality call monitoring that provides enhanced staff training and coaching.
- Special monitoring of higher risk commercial accounts including previously bankrupt customers, restaurants, bars and nightclubs.

PUB/CENTRA I-48

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.4 Page 15 - Credit Risk**

d) For each of the last 5 years, please provide the bad debt expense by customer class, the number of bad debt accounts, and the average debt per account.

ANSWER:

Note: data prior to 2009/10 is not available by rental and owner occupied units by customer class.

The following table provides the bad debt expense translated into write-offs by customer class.

Write-offs – Total Dollars				
	Residential		*Commercial*	
Year	*Tenant*	*Owner*	*Tenant*	*Owner*
2012/13	$1,335,860	$40,899	$245,570	$11,185
2011/12	$1,224,188	$21,024	$239,532	$7,251
2010/11	$1,664,484	$47,323	$239,532	$2,601
2009/10	$1,740,294	$28,106	$530,315	$11,852

The following table provides the number of write-off accounts by customer class translated from bad debt expense.

Write-offs – # of Accounts				
	Residential		*Commercial*	
Year	*Tenant*	*Owner*	*Tenant*	*Owner*
2012/13	3,404	181	197	12
2011/12	3,392	137	153	7
2010/11	3,508	193	225	11
2009/10	3,425	245	223	18

The following table provides the average debt per write-off account by customer class translated from bad debt expense.

Write-offs – Average Debt per Account				
	Residential		*Commercial*	
Year	*Tenant*	*Owner*	*Tenant*	*Owner*
2012/13	$392.44	$225.96	$1,246.55	$932.10
2011/12	$360.90	$153.46	$1,033.48	$1,035.84
2010/11	$474.48	$245.19	$1,064.58	$236.47
2009/10	$508.11	$114.72	$2,378.09	$658.42

PUB/CENTRA I-48

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.4 Page 15 - Credit Risk**

e) For SGS Residential customers, please provide the number of accounts written off for rental units and for owner occupied units.

ANSWER:

Please see Centra's response to PUB/Centra I-48(d).

PUB/CENTRA I-48

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.4 Page 15 - Credit Risk**

f) Please detail the costs incurred by Centra administering the collection of past due accounts for each of the past five years.

ANSWER:

The following table presents the costs incurred by the Corporation for administering the collection of past due natural gas accounts over the past five years ($000's).

	2007/08	2008/09	2009/10	2010/11	2011/12
Labour	$2,210	$2,065	$1,870	$1,725	$1,719
Overhead	$641	$557	$449	$293	$292
Expenses	$2,182	$2,179	$2,138	$1,639	$1,478
Expense Recoveries	($20)	($26)	($28)	($37)	($21)
Collection Total	$5,014	$4,775	$4,429	$3,620	$3,468

PUB/CENTRA I-49

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.9; 2009/10 & 2010/11 GRA PUB/Centra 48 - Deferred Costs**

a) Please provide details of interest capitalized for each of the years from 2008/09 through 2013/14.

ANSWER:

Please see below:

CENTRA GAS MANITOBA INC.
2013/14 General Rate Application

PUB/Centra 49(a)

Interest Capitalized **($000's)**

	Actual 2008/09	Actual 2009/10	Actual 2010/11	Actual 2011/12	Forecast 2012/13	Forecast 2013/14
Deferred Gas Costs	(158)	(43)	(15)	262	584	332
One Time Tax Payment	(2 996)	(2 850)	(2 704)	(2 565)	(2 412)	(2 266)
Interest During Construction	(193)	(134)	(142)	(210)	(174)	(113)
Total Interest Capitalized	(3 347)	(3 027)	(2 861)	(2 512)	(2 002)	(2 047)

PUB/CENTRA I-49

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.9; 2009/10 & 2010/11 GRA PUB/Centra 48 - Deferred Costs**

b) For 2009/10, please provide a schedule which compares the interest capitalized as forecasted in the 2009/10 & 2010/11 GRA with actual amounts. Please compare using the same level of detail shown in the answer to part (a).

ANSWER:

The following table provides a comparison of forecasted vs. actual interest capitalized. The significant variance is related to interest on deferred gas costs. Actual interest for 2009/10 was lower than forecast which accounted for $587 thousand of the variance. The remainder of the variance on interest on deferred gas costs is due the total gas deferral being in a net receivable position for the majority of the year, whereas the forecast was in a net payable position for the year. This means Centra's actual cost of gas was higher than forecast and higher than that included in rates (WACOG).

Interest Capitalized (000's)

	Forecast 2009/10	Actual 2009/10	Variance
Deferred Gas Costs	809	(43)	(851)
One Time Tax Payment	(2 850)	(2 850)	0
Interest During Construction	(212)	(134)	78
Total Interest Capitalized	(2 253)	(3 027)	(774)

PUB/CENTRA I-49 (Revised)

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.9; 2009/10 & 2010/11 GRA PUB/Centra 48 - Deferred Costs**

c) Please provide details of the additions to site clean-up deferred charges, by site, in each of the years 2006/07 through 2011/12.

ANSWER:

Please see the table below:

CENTRA GAS MANITOBA INC. **PUB/Centra 49(c)**
2013/14 General Rate Application

Gas Deferred Site Clean-up Additions **($000's)**

	Actual 2006/07	Actual 2007/08	Actual 2008/09	Actual 2009/10	Actual 2010/11	Actual 2011/12
Site Investigation 121-123 Annabella	503	-	-	-	419	-
35 Sutherland - General Site Clean-up	686	400	293	-	-	-
12th Street Portage La Prairie	441					
Site Clean-up 1284 Wilkes	56	1	-	-	-	-
Centra Farm Tap & Regulator Station	-	-	-	56	-	-
Stead Radio Tower General Site Clean-up	-	-	-	5	-	-
Neepawa RS 102 General Site Clean-up	-	-	-	-	33	5
Other	88					
Total Additions	1 774	401	293	61	453	5

PUB/CENTRA I-50

Subject: Tab 6 Capital Expenditures

Reference: Tab 6 Page 2 of 2 Table 6.1.1

Please explain how the target adjustment amounts for customer service and distribution were determined for 2013 and 2014.

ANSWER:

In the course of preparing CEF12, Centra decided that the overall capital spending should not vary substantially from the previously approved amount in CEF11. An analysis of previous years' capital expenditure performance indicated that due to various circumstances, including resource capabilities, project constraints, and active project prioritization, the achieved levels of capital expenditures on an annual aggregate basis had historically been lower than the sum of all individual projects.

By considering historical capital performance factors, capital expenditure trends, and current capital demands, annual capital targets were proposed that met the corporate direction for capital spending levels and were deemed to be realistic given prevailing resourcing, capabilities and project constraints. The annual targets were reviewed and accepted for CEF12.

Subsequent to the establishment of the targets and the approval of the specific projects included in CEF12, the target adjustment was calculated as the difference between the capital targets as determined above and the total of all approved individual project spending.

PUB/CENTRA I-51

Subject: **Tab 6 Capital Expenditures**

Reference: **Tab 6 Page 2 of 2 Table 6.1.1; 2009/10 & 2010/11 GRA PUB/Centra 12(b)**

Please file a schedule in a similar format to PUB/Centra 12(b) from the 2009/10 & 2010/11 GRA detailing the five year Information Technology capital expenditures forecasted by major program and indicate in each year the amount of common asset charges allocated to Centra.

ANSWER:

The following table details the five year Information Technology capital expenditures forecasted by major program. The column entitled Centra represents the amount of those expenditures which are used to determine the common asset charges (depreciation and interest) allocated to Centra. This schedule represents the project totals that have gone into service in each of the years, whereas the CEF amounts represent the capital costs that have been incurred in each of the years. The on-going difference between this schedule and the capital expenditures is maintained within CWIP.

Centra Gas Manitoba Inc.

Information Technology Capital Expenditure Plan

($000's)

Description	Manitoba Hydro In-Service Amounts 2013	2014	2015	2016	2017	Centra * 2013	2014	2015	2016	2017
Workforce Management (Phase 1 to 4)	1,362	-	-	-	-	136	-	-	-	-
EAM Project - Phase 2	101	15,850	2,601	-	-	10	1,427	234	-	-
Major Projects	1,463	15,850	2,601	-	-	146	1,427	234	-	-
Engineering Application Software Blanket	150	150	153	156	159	15	14	14	14	14
Engineering Applications Hardware Blanket	200	200	204	208	212	20	18	18	19	19
Data Communication Network Blanket	2,300	2,300	2,346	2,393	2,441	230	207	211	215	220
Application Related Servers	900	900	918	936	955	90	81	83	84	86
PC & Upgrades Blanket	3,600	3,600	3,672	3,745	3,820	360	324	330	337	344
Desktop Software Blanket	550	550	561	572	584	55	50	50	51	53
GIS/Autodesk Product Suite Blanket	250	250	255	260	265	25	23	23	23	24
Multi-Functional Device Equipment Blanket	350	350	357	364	371	35	32	32	33	33
Storage Area Network (SAN) Blanket	2,300	2,000	2,040	2,081	2,122	230	180	184	187	191
R&D H/W & S/W Blanket (Application Blanket)	1,000	1,000	1,020	1,040	1,061	100	90	92	94	96
PS&O Domestic Capital Plan	35	126	121	124	126	3	11	11	11	11
Gas AMD - Current Plan	8	9	9	9	9	1	1	1	1	1
Blankets	11,643	11,434	11,656	11,889	12,127	1,164	1,029	1,049	1,070	1,091
Customer Email Project	511	-	-	-	-	51	-	-	-	-
Condition AssessDataMgmtSys(CADAMS)	4	-	-	-	-	-	-	-	-	-
Enterprse Archit(EA) Mgmt System-Phase1	935	-	-	-	-	-	-	-	-	-
CSI Phase III	1,531	-	-	-	-	-	-	-	-	-
Distribution Maint Plan Sys(DPMS)-Phase2	-	-	1,326	-	-	-	-	-	-	-
GE Smallworld eGIS Technical Upgrade Ph2	1,870	-	-	-	-	187	-	-	-	-
Sharepoint 2010 Upgrade Project	589	675	-	-	-	59	61	-	-	-
Remedy Upgrade Project	36	1,110	-	-	-	4	100	-	-	-
Travel and Expense Management	-	1,519	-	-	-	-	137	-	-	-
Gen Performance & Reporting Software	-	1,241	-	-	-	-	-	-	-	-
Bad Debt Enhancement Project	140	-	-	-	-	14	-	-	-	-
Windows 7 Des&Plan Phase 1	644	-	-	-	-	64	-	-	-	-
Call Before You Dig Manitoba	482	-	-	-	-	159	-	-	-	-
Joint Use Tracking Application	-	524	-	-	-	-	173	-	-	-
Mobile Infrastructure Setup Project	-	-	-	-	221	-	-	-	-	-
Reliability Centered Maint/Failure M&A	-	350	-	-	-	-	-	-	-	-
Predictive Analytics Project	940	9	-	-	-	-	-	-	-	-
Energy Trading Risk Management	1,402	-	-	-	-	-	-	-	-	-
RMS Technology Upgrade Project	383	-	-	-	-	-	-	-	-	-
Corporate LIMS Phase 1	16	926	-	-	-	-	-	-	-	-
Primavera P6 - SAP PS Integration	-	636	-	-	-	-	-	-	-	-
Generation Attribution Tracking System	-	537	-	-	-	-	-	-	-	-
Powersmart Paradox Replacement	213	-	-	-	-	21	-	-	-	-
Projects Pending Approval / Unallocated	(2,007)	4,366	10,803	12,372	12,399	(201)	393	972	1,114	1,116
Non-Blankets	7,689	11,892	12,130	12,372	12,620	359	863	972	1,114	1,116
Total Domestic Capital	19,332	23,326	23,786	24,262	24,747	1,523	1,892	2,021	2,184	2,207
Total Capital	20,795	39,177	26,387	24,262	24,747	1,669	3,319	2,255	2,184	2,207

* Represents the amount of in-service capital expenditures which are used to determine the interest and depreciation charges allocated to Centra.

PUB/CENTRA I-52

Subject: **Tab 6 Capital Expenditures**

Reference: **Tab 6 Appendix 6.1**

a) Please file the Centra portions of CEF09, CEF10 and CEF11.

ANSWER:

Please see the attachment to this response.

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF11-2)
For the Years 2011/12 – 2021/22

CAPITAL EXPENDITURE FORECAST (CEF11-2)
(in millions of dollars)

	Total Project Cost	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	11 Year Total
Customer Care & Marketing													
Advanced Metering Infrastructure	30.9	-	4.0	5.3	5.4	5.6	4.3	4.2	-	-	-	-	28.8
Customer Care & Marketing Domestic	91.2	3.0	3.0	3.1	3.8	3.9	4.0	4.1	4.1	4.2	4.3	4.4	42.0
Target Adjustment	(22.3)	3.6	1.0	(0.3)	(0.9)	(2.3)	(1.2)	(5.4)	(1.1)	(1.2)	(1.2)	(1.2)	(10.2)
		6.6	8.0	8.1	8.4	7.2	7.1	2.9	3.0	3.1	3.1	3.2	60.7
Finance & Administration													
Corporate Buildings	NA	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	88.0
EAM Phase 2	19.3	6.1	8.9	2.3	-	-	-	-	-	-	-	-	17.3
Workforce Management (Phase 1 to 4)	15.7	2.3	-	-	-	-	-	-	-	-	-	-	2.3
Fleet	NA	13.8	14.1	14.3	14.6	14.9	15.2	15.5	15.8	16.2	16.5	16.8	167.7
Finance & Administration Domestic	643.1	24.9	25.4	25.9	26.5	27.0	27.5	28.1	28.7	29.2	29.8	30.4	303.5
Target Adjustment	(20.2)	(8.4)	(8.9)	(2.3)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(19.8)
		46.7	47.5	48.3	49.1	49.9	50.7	51.6	52.5	53.3	54.3	55.2	559.0
ELECTRIC CAPITAL SUBTOTAL		**1 107.1**	**1 201.1**	**1 518.2**	**1 675.9**	**1 966.2**	**1 962.9**	**2 268.9**	**1 480.0**	**1 703.3**	**1 832.6**	**1 767.1**	**18 483.4**
GAS													
Customer Service & Distribution													
Ile Des Chenes NG Transmission Network Upgrade	1.2	0.3	0.9	-	-	-	-	-	-	-	-	-	1.2
Gas SCADA Replacement	4.6	3.6	-	-	-	-	-	-	-	-	-	-	3.6
Bunclouday Natural Gas Crossing at Souris River	1.6	1.6	-	-	-	-	-	-	-	-	-	-	1.6
Customer Service & Distribution Domestic	649.4	25.2	25.7	26.2	26.7	27.3	27.8	28.4	28.9	29.5	30.1	30.7	306.5
Target Adjustment	(94.4)	(6.2)	(4.5)	(3.7)	(3.7)	(3.8)	(3.9)	(4.0)	(4.0)	(4.1)	(4.2)	(4.3)	(46.4)
		24.6	22.1	22.5	23.0	23.4	23.9	24.4	24.9	25.4	25.9	26.4	266.5
Customer Care & Marketing													
Advanced Metering Infrastructure	15.0	-	1.0	5.4	8.4	-	-	-	-	-	-	-	14.7
Demand Side Management	NA	12.6	13.4	-	-	-	-	-	-	-	-	-	26.1
Customer Care & Marketing Domestic	122.1	4.8	4.8	4.9	5.0	5.1	5.2	5.3	5.4	5.5	5.7	5.8	57.7
Target Adjustment	(52.5)	(1.5)	1.4	(1.2)	(11.9)	(2.9)	(2.9)	(2.1)	(2.7)	(2.8)	(2.3)	(2.3)	(31.1)
		15.9	20.7	9.1	1.5	2.3	2.4	3.3	2.7	2.7	3.4	3.5	67.3
GAS CAPITAL SUBTOTAL		**40.5**	**42.8**	**31.6**	**24.5**	**25.7**	**26.3**	**27.7**	**27.6**	**28.1**	**29.3**	**29.9**	**333.9**
CONSOLIDATED CAPITAL		**1 147.6**	**1 243.9**	**1 549.8**	**1 700.4**	**1 991.9**	**1 989.1**	**2 296.6**	**1 507.6**	**1 731.5**	**1 861.9**	**1 797.0**	**18 817.3**
Target Adjustment	NA	(33.6)	(0.0)	0.0	0.0	31.1	87.9	135.9	160.3	182.2	51.8	5.2	620.8
CEF11-2 TOTAL		**1 114.1**	**1 243.9**	**1 549.8**	**1 700.4**	**2 022.9**	**2 077.0**	**2 432.5**	**1 667.9**	**1 913.6**	**1 913.7**	**1 802.1**	**19 438.1**

NOTE: THE CEF11-2 TABLES BELOW REFLECT CEF11 VALUES. THE DIFFERENCE BETWEEN CEF11 AND CEF11-2 IS DEFERRAL OF IFRS BY AN ADDITIONAL YEAR IN CEF11-2.

CUSTOMER SERVICE & DISTRIBUTION:

Ile Des Chenes NG Transmission Network Upgrade

Description:
Upgrade the Ile Des Chenes natural gas transmission network by installing 220 meters of NPS 12 steel natural gas transmission pipeline, two 16" isolation valve assemblies, and abandoning approximately 10 meters of NPS 16 steel natural gas transmission pipeline and one NPS 12 plug valve.

Justification:
The upgrades will increase the reliability of gas supply to the city of Winnipeg and communities north and east of Winnipeg. The current configuration of the Ile Des Chenes transmission system at the Red River Floodway crossing does not allow for isolation of the NPS 16 pipeline in the event of damage, which could negatively impact approximately 203,000 natural gas customers.

In-Service Date:
October 2012.

Revision:
The project schedule has been revised for summer 2012 construction to avoid system risks with fall 2011 construction, and in-service deferred twelve months from October 2011.

	Total	2012	2013	2014	2015	2016	2017-21
Previously Approved	$ 1.2	$ 0.4	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	-	(0.1)	0.9	-	-	-	-
Revised Forecast	$ 1.2	$ 0.3	$ 0.9	$ -	$ -	$ -	$ -

Gas SCADA Replacement

Description:
Replace the current Gas Supervisory Control and Data Acquisition (SCADA) system with a vendor-supported SCADA system.

Justification:
Replacement of the current gas SCADA system is required as product support is being discontinued by the vendor, and vendor alternative product does not meet the complete system requirements for Manitoba Hydro.

In-Service Date:
February 2012.

Revision:
Cost flow revision, and in-service date deferred five months from September 2011.

	Total	2012	2013	2014	2015	2016	2017-21
Previously Approved	$ 4.6	$ 2.6	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	-	1.1	-	-	-	-	-
Revised Forecast	$ 4.6	$ 3.6	$ -	$ -	$ -	$ -	$ -

Bunclody Natural Gas Crossing at Souris River

Description:
Install approximately 400m of 6" steel transmission pressure pipeline to replace the existing crossing exposed by a failed riverbank.

Justification:
The existing temporary bypass must be replaced on an emergency basis to provide a continued reliable source of natural gas to 1025 customers as the higher loads of colder temperatures approach. Leaving the temporary bypass in place is not acceptable for several reasons. The bypass currently runs over Bunclody Bridge which is a temporary, emergency route and was never intended as a permanent solution, and because of time constraints and material availability. The installed temporary line has a pressure restriction due to the materials that were used, which limits the system capacity to a gas load corresponding with a temperature of 0°C. This means the pipe will not be rated for pressures corresponding to gas loading during winter temperatures.

In-Service Date:
October 2011.

Revision:
New item.

	Total	2012	2013	2014	2015	2016	2017-21
Previously Approved	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	1.6	1.6	-	-	-	-	-
Revised Forecast	$ 1.6	$ 1.6	$ -	$ -	$ -	$ -	$ -

Customer Service & Distribution Domestic

Description:
This program consists of projects whose individual costs are of a relatively small amount. These projects are required to extend, rebuild or upgrade: transmission pipelines, distribution pipelines, regulating stations, and customer service lines.

Justification:
Required to provide ongoing safe and reliable supply of natural gas to customers.

In-Service Date:
Ongoing.

Revision:
Increased domestic budget for the supply of gas meters to comply with Measurement Canada's recently completed new compliance sampling specification, *S-S-06 - Sampling Plans for the Inspection of Isolated Lots of In-service Meters*.

	Total	2012	2013	2014	2015	2016	2017-21
Previously Approved	NA	$ 21.7	$ 22.1	$ 22.5	$ 23.0	$ 23.4	$ 124.5
Increase (Decrease)		3.8	4.0	4.0	4.0	4.0	20.0
Revised Forecast		$ 25.4	$ 25.7	$ 26.2	$ 26.7	$ 27.3	$ 144.7

CUSTOMER CARE & MARKETING:

Advanced Metering Infrastructure

Description:
Purchase and install an automated metering infrastructure (AMI) communication network to remotely read and electronically disseminate gas meter readings and other relevant customer information to appropriate departments and divisions.

Justification:
Satisfies the ongoing need for routine, periodic meter readings in customer billing as well as provides 'on demand' readings to respond to customer inquiries. Other benefits include: increased customer satisfaction due to greater billing accuracy; better detection of theft of service, meter tampering, defective meters and leaks; and greater flexibility in the timing and consolidation of billings.

In-Service Date:
March 2019.

Revision:
Cost flow revision and in-service date deferred three years from March 2016.

	Total	2012	2013	2014	2015	2016	2017-21
Previously Approved	$ 15.0	$ 1.0	$ 5.4	$ 8.4	$ -	$ -	$ -
Increase (Decrease)	-	(1.0)	(4.4)	(3.0)	8.4	-	-
Revised Forecast	$ 15.0	$ -	$ 1.0	$ 5.4	$ 8.4	$ -	$ -

Demand Side Management

Description:
Design, implement and deliver incentive based PowerSmart conservation programs to reduce gas consumption and greenhouse gas emissions in Manitoba. When combined with savings realized to-date, total natural gas savings of 149 million cubic meters are expected to be achieved by 2025.

Justification:
The natural gas Demand Side Management plan provides customers with exceptional value through the implementation of cost-effective energy conservation programs that are designed to minimize the total cost of energy services to customers, position the Corporation as a national leader in implementing cost-effective energy conservation and alternative energy programs, protect the environment and promote sustainable energy supply and service.

In-Service Date:
Ongoing.

Revision:
The change in expenditures in 2011/12 is due to revisions to energy saving and expenditures for a number of programs based on current and updated market information. Upon adoption of IFRS in 2012/13, the demand side management programs will no longer be capitalized.

	Total	2012	2013	2014	2015	2016	2017-21
Previously Approved	NA	$ 12.0	$ 12.4	$ 10.4	$ 10.4	$ 10.0	$ 32.4
Increase (Decrease)		0.6	(12.4)	(10.4)	(10.4)	(10.0)	(32.4)
Revised Forecast		$ 12.6	$ -	$ -	$ -	$ -	$ -

Customer Care & Marketing Domestic

Description:
This program covers the additions and replacements of gas meters.

Justification:
As required for the connection of new customers to the system, as well as replacement of existing time expired or faulty meters.

In-Service Date:
Ongoing.

Revision:
Increased domestic budget for the supply of gas meters to comply with Measurement Canada's recently completed new compliance sampling specification, *S-S-06 - Sampling Plans for the Inspection of Isolated Lots of In-service Meters*.

	Total	2012	2013	2014	2015	2016	2017-21
Previously Approved	NA	$ 2.9	$ 2.9	$ 3.0	$ 3.0	$ 3.1	$ 16.5
Increase (Decrease)		2.1	1.9	1.9	2.0	2.0	10.8
Revised Forecast		$ 5.0	$ 4.8	$ 4.9	$ 5.0	$ 5.1	$ 27.2

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF10)
For the Years 2010/11 – 2019/20

CAPITAL EXPENDITURE FORECAST (CEF10)
(in millions of dollars)

	Total Project Cost	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	10 Year Total
Finance & Administration												
Corporate Buildings Program	NA	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	80.0
Workforce Management	11.3	0.8	-	-	-	-	-	-	-	-	-	0.8
Fleet Acqusitions	NA	13.5	13.8	14.1	14.3	14.6	14.9	15.2	15.5	15.8	16.2	148.0
Finance & Administration Domestic	NA	24.4	24.9	25.4	25.9	26.4	27.0	27.5	28.1	28.6	29.2	267.5
		46.7	46.7	47.5	48.3	49.1	49.9	50.7	51.6	52.5	53.3	496.2
Capital Increase Provision		-	-	-	-	-	31.1	87.9	133.7	155.4	177.2	585.2
ELECTRIC CAPITAL SUBTOTAL		**1 179.3**	**1 139.6**	**1 178.2**	**1 424.5**	**1 562.7**	**1 903.0**	**1 808.2**	**2 193.5**	**2 272.1**	**2 174.9**	**16 836.0**
GAS												
Customer Service & Distribution												
Ile Des Chenes NG Transmission Network Upgrade	1.2	0.8	0.4	-	-	-	-	-	-	-	-	1.2
Centerport NPS 16 Natural Gas Transmission Main	1.7	1.7	-	-	-	-	-	-	-	-	-	1.7
Gas SCADA Replacement	4.6	1.8	2.6	-	-	-	-	-	-	-	-	4.4
Customer Service & Distribution Domestic	NA	21.2	21.7	22.1	22.5	23.0	23.4	23.9	24.4	24.9	25.4	232.5
		25.6	24.6	22.1	22.5	23.0	23.4	23.9	24.4	24.9	25.4	239.8
Customer Care & Marketing												
Advanced Metering Infrastructure	15.0	-	1.0	5.4	8.4	-	-	-	-	-	-	14.7
Demand Side Management	NA	11.2	12.0	12.4	10.4	10.4	10.0	9.4	7.2	5.6	5.1	93.7
Customer Care & Marketing Domestic	NA	2.8	2.9	2.9	3.0	3.0	3.1	3.2	3.2	3.3	3.4	30.7
		14.0	15.9	20.7	21.8	13.4	13.1	12.5	10.5	8.9	8.5	139.2
Capital Increase Provision		-	-	-	-	-	-	-	2.3	4.9	5.0	12.1
GAS CAPITAL SUBTOTAL		**39.6**	**40.5**	**42.8**	**44.3**	**36.4**	**36.6**	**36.4**	**37.1**	**38.7**	**38.8**	**391.1**
CONSOLIDATED CAPITAL		**1 218.9**	**1 180.1**	**1 220.9**	**1 468.8**	**1 599.1**	**1 939.6**	**1 844.7**	**2 230.6**	**2 310.7**	**2 213.7**	**17 227.1**
Target Adjustment		(97.0)	(111.0)	(88.0)	-	-	-	-	-	-	-	(296.0)
CEF10 TOTAL		**1 121.9**	**1 069.1**	**1 132.9**	**1 468.8**	**1 599.1**	**1 939.6**	**1 844.7**	**2 230.6**	**2 310.7**	**2 213.7**	**16 931.1**

CUSTOMER SERVICE & DISTRIBUTION:

Ile Des Chenes NG Transmission Network Upgrade

Description:
Upgrade the Ile Des Chenes natural gas transmission network by installing 220 meters of NPS 12 steel natural gas transmission pipeline, two 16" isolation valve assemblies, and abandoning approximately 10 meters of NPS 16 steel natural gas transmission pipeline and one NPS 12 plug valve.

Justification:
The upgrades will increase the reliability of gas supply to the city of Winnipeg and communities north and east of Winnipeg. The current configuration of the Ile Des Chenes transmission system at the Red River Floodway crossing does not allow for isolation of the NPS 16 pipeline in the event of damage, which could negatively impact approximately 203,000 natural gas customers.

In-Service Date:
October 2011.

Revision:
New item.

	Total	2011	2012	2013	2014	2015	2016-20
Previously Approved	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	1.2	0.8	0.4	-	-	-	-
Revised Forecast	$ 1.2	$ 0.8	$ 0.4	$ -	$ -	$ -	$ -

Centerport NPS 16 Natural Gas Transmission Main

Description:
Relocate 2.2 kms of existing NPS 16 natural gas transmission pipeline, which requires the installation of 3.1 kms of NPS 16 to permit the construction of an above grade highway interchange at PTH 101 and Saskatchewan Avenue.

Justification:
The existing location of the NPS 16 Oakbluff natural gas transmission pipeline is at risk of damage and poses a safety risk to the public if it is not relocated prior to the commencement of the interchange construction. In addition, the existing configuration of the Oakbluff Transmission Pressure Network could leave some natural gas regulation stations within the City of Winnipeg vulnerable in the event of damage to the NPS 16 natural gas transmission pipeline. The relocation of the main will assist in preventing damage during construction or the loss of service to Manitoba Hydro's natural gas customers. The costs for this project will be jointly shared by Manitoba Hydro and Manitoba Infrastructure and Transportation as per the Treasury Board Policy for Utility Relocations within highway right of ways. This will result in a 50/50 cost split for all capital costs related to the relocation.

In-Service Date:
December 2010.

Revision:
New item.

	Total	2011	2012	2013	2014	2015	2016-20
Previously Approved	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	1.7	1.7	-	-	-	-	-
Revised Forecast	$ 1.7	$ 1.7	$ -	$ -	$ -	$ -	$ -

Gas SCADA Replacement

Description:
Replace the current Gas Supervisory Control and Data Acquisition (SCADA) system with a vendor-supported SCADA system.

Justification:
Replacement of the current gas SCADA system is required as product support is being discontinued by the vendor, and vendor alternative product does not meet the complete system requirements for Manitoba Hydro.

In-Service Date:
September 2011.

Revision:
Cost flow revision, and in-service date deferred three months from June 2011.

	Total	2011	2012	2013	2014	2015	2016-20
Previously Approved	$ 4.6	$ 3.0	$ 0.6	$ -	$ -	$ -	$ -
Increase (Decrease)	-	(1.2)	2.0	-	-	-	-
Revised Forecast	$ 4.6	$ 1.8	$ 2.6	$ -	$ -	$ -	$ -

Customer Service & Distribution Domestic

Description:
This program consists of projects whose individual costs are of a relatively small amount. These projects are required to extend, rebuild or upgrade: transmission pipelines, distribution pipelines, regulating stations, and customer service lines.

Justification:
Required to provide ongoing safe and reliable supply of natural gas to customers.

In-Service Date:
Ongoing.

Revision:
No change.

	Total	2011	2012	2013	2014	2015	2016-20
Previously Approved	NA	$ 21.2	$ 21.7	$ 22.1	$ 22.5	$ 23.0	$ 122.0
Increase (Decrease)		-	-	-	-	-	-
Revised Forecast		$ 21.2	$ 21.7	$ 22.1	$ 22.5	$ 23.0	$ 122.0

CUSTOMER CARE & MARKETING:

Advanced Metering Infrastructure

Description:
Purchase and install an automated metering infrastructure (AMI) communication network to remotely read and electronically disseminate gas meter readings and other relevant customer information to appropriate departments and divisions.

Justification:
Satisfies the ongoing need for routine, periodic meter readings in customer billing as well as provides ‘on demand’ readings to respond to customer inquiries. Other benefits include: increased customer satisfaction due to greater billing accuracy; better detection of theft of service, meter tampering, defective meters and leaks; and greater flexibility in the timing and consolidation of billings.

In-Service Date:
March 2016.

Revision:
Cost flow revision, and in-service date deferred one year from March 2015.

	Total	2011	2012	2013	2014	2015	2016-20
Previously Approved	$ 15.0	$ 1.0	$ 5.4	$ 8.3	$ -	$ -	$ -
Increase (Decrease)	-	(1.0)	(4.4)	(2.9)	8.4	-	-
Revised Forecast	$ 15.0	$ -	$ 1.0	$ 5.4	$ 8.4	$ -	$ -

Demand Side Management

Description:
Design, implement and deliver incentive based PowerSmart conservation programs to reduce gas consumption and greenhouse gas emissions in Manitoba. When combined with savings realized to-date, total natural gas savings of 149 million cubic meters are expected to be achieved by 2025.

Justification:
The natural gas Demand Side Management plan provides customers with exceptional value through the implementation of cost-effective energy conservation programs that are designed to minimize the total cost of energy services to customers, position the Corporation as a national leader in implementing cost-effective energy conservation and alternative energy programs, protect the environment and promote sustainable energy supply and service.

In-Service Date:
Ongoing.

Revision:
The change in expenditures is due to revisions to energy saving and expenditures for a number of programs based on current and updated market information.

	Total	2011	2012	2013	2014	2015	2016-20
Previously Approved	NA	$ 13.1	$ 11.6	$ 11.7	$ 11.1	$ 10.2	$ 39.2
Increase (Decrease)		(1.9)	0.5	0.7	(0.7)	0.2	(1.9)
Revised Forecast		$ 11.2	$ 12.0	$ 12.4	$ 10.4	$ 10.4	$ 37.3

Customer Care & Marketing Domestic

Description:
This program covers the additions and replacements of gas meters.

Justification:
As required for the connection of new customers to the system, as well as replacement of existing time expired or faulty meters.

In-Service Date:
Ongoing.

Revision:
No change.

	Total	2011	2012	2013	2014	2015	2016-20
Previously Approved	NA	$ 2.8	$ 2.9	$ 2.9	$ 3.0	$ 3.0	$ 16.1
Increase (Decrease)		-	-	-	-	-	-
Revised Forecast		$ 2.8	$ 2.9	$ 2.9	$ 3.0	$ 3.0	$ 16.1

CAPITAL EXPENDITURE FORECAST SUMMARY TABLE (CEF09)
(in millions of dollars)

	Total Project Cost	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	11 Year Total
Finance & Administration													
Corporate Buildings	NA	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	88.0
Workforce Management (Phase 1 to 4)	11.3	3.9	1.0	-	-	-	-	-	-	-	-	-	4.9
Fleet	NA	13.3	13.5	13.8	14.1	14.3	14.6	14.9	15.2	15.5	15.8	16.2	161.2
Finance & Administration Domestic	NA	24.1	24.4	24.9	25.4	25.9	26.4	27.0	27.5	28.1	28.6	29.2	291.6
		49.2	46.9	46.7	47.5	48.3	49.1	49.9	50.7	51.6	52.5	53.3	545.7
Capital Increase Provision		-	-	-	-	-	-	63.1	90.4	82.8	97.3	99.2	432.8
ELECTRIC CAPITAL SUBTOTAL		**1 255.0**	**1 165.5**	**1 074.5**	**1 038.6**	**1 228.0**	**1 691.7**	**2 247.6**	**2 160.5**	**1 653.3**	**1 800.3**	**1 557.9**	**16 872.9**
GAS													
Customer Service & Distribution													
Customer Service & Distribution Domestic	NA	20.7	21.2	21.7	22.1	22.5	23.0	23.4	23.9	24.4	24.9	25.4	253.3
		20.7	21.2	21.7	22.1	22.5	23.0	23.4	23.9	24.4	24.9	25.4	253.3
Customer Care & Marketing													
Advanced Metering Infrastructure	15.0	-	1.0	5.4	8.3	-	-	-	-	-	-	-	14.6
Demand Side Management	NA	13.5	13.1	11.6	11.7	11.1	10.2	10.6	10.3	7.7	5.5	5.1	110.3
Customer Care & Marketing Domestic	NA	2.8	2.8	2.9	2.9	3.0	3.0	3.1	3.2	3.2	3.3	3.4	33.5
		16.2	16.9	19.8	22.9	14.1	13.2	13.7	13.5	11.0	8.8	8.4	158.5
Capital Increase Provision		-	-	-	-	-	-	-	-	2.3	4.9	5.0	12.1
GAS CAPITAL SUBTOTAL		**37.0**	**38.2**	**41.5**	**45.0**	**36.6**	**36.2**	**37.2**	**37.4**	**37.6**	**38.5**	**38.8**	**423.9**
CONSOLIDATED CAPITAL		**1 292.0**	**1 203.6**	**1 116.0**	**1 083.6**	**1 264.6**	**1 727.9**	**2 284.8**	**2 197.9**	**1 690.9**	**1 838.8**	**1 596.6**	**17 296.7**
TARGET ADJUSTMENT		(188.0)	(118.6)	(80.0)	(59.1)	221.4	37.1	(128.8)	(32.7)	25.4	(187.8)	(305.6)	(816.7)
		1 104.0	**1 085.0**	**1 036.0**	**1 024.5**	**1 486.0**	**1 765.0**	**2 156.0**	**2 165.2**	**1 716.3**	**1 651.0**	**1 291.0**	**16 480.0**

CUSTOMER SERVICE & DISTRIBUTION:

Customer Service & Distribution Domestic

Description:
This program consists of projects whose individual costs are of a relatively small amount. These projects are required to extend, rebuild or upgrade: transmission pipelines, distribution pipelines, regulating stations, and customer service lines.

Justification:
Required to provide ongoing safe and reliable supply of natural gas to customers.

In-Service Date:
Ongoing.

Revision:
Revised escalation rates.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	NA	$ 21.4	$ 21.8	$ 22.2	$ 22.7	$ 23.1	$ 148.8
Increase (Decrease)		(0.7)	(0.6)	(0.5)	(0.6)	(0.6)	(3.8)
Revised Forecast		$ 20.7	$ 21.2	$ 21.7	$ 22.1	$ 22.5	$ 145.0

CUSTOMER CARE & MARKETING:

Advanced Metering Infrastructure

Description:
Purchase and install an automated metering infrastructure (AMI) communication network to remotely read and electronically disseminate gas meter readings and other relevant customer information to appropriate departments and divisions.

Justification:
Satisfies the ongoing need for routine, periodic meter readings in customer billing as well as provides 'on demand' readings to respond to customer inquiries. Other benefits include: increased customer satisfaction due to greater billing accuracy; better detection of theft of service, meter tampering, defective meters and leaks; and greater flexibility in the timing and consolidation of billings.

In-Service Date:
March 2015.

Revision:
Cost flow revision, and in-service date deferred two years from March 2013.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	$ 15.0	$ 3.7	$ 3.7	$ 3.5	$ 3.8	$ -	$ -
Increase (Decrease)	-	(3.7)	(2.7)	1.9	4.5	-	-
Revised Forecast	$ 15.0	$ -	$ 1.0	$ 5.4	$ 8.3	$ -	$ -

Demand Side Management

Description:
Design, implement and deliver incentive based PowerSmart conservation programs to reduce gas consumption and greenhouse gas emissions in Manitoba. When combined with savings realized to-date, total natural gas savings of 172 million cubic meters are expected to be achieved by 2025.

Justification:
Provides customers with exceptional value through the implementation of cost-effective energy conservation programs that are designed to minimize the total cost of energy services to customers, position the Corporation as a national leader implementing cost-effective energy conservation and alternative energy programs, protects the environment, and promotes sustainable energy supply and service.

In-Service Date:
Ongoing.

Revision:
Refinements to existing programs to reflect current information.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	NA	$ 14.2	$ 13.3	$ 12.4	$ 11.5	$ 10.7	$ 40.2
Increase (Decrease)		(0.7)	(0.2)	(0.8)	0.2	0.4	9.2
Revised Forecast		$ 13.5	$ 13.1	$ 11.6	$ 11.7	$ 11.1	$ 49.4

Customer Care & Marketing Domestic

Description:
This program covers the additions and replacements of gas meters.

Justification:
As required for the connection of new customers to the system, as well as replacement of existing time expired or faulty meters.

In-Service Date:
Ongoing.

Revision:
Revised escalation rates.

	Total	2010	2011	2012	2013	2014	2015-20
Previously Approved	NA	$ 2.8	$ 2.9	$ 2.9	$ 3.0	$ 3.1	$ 19.7
Increase (Decrease)		(0.0)	(0.1)	(0.0)	(0.1)	(0.1)	(0.5)
Revised Forecast		$ 2.8	$ 2.8	$ 2.9	$ 2.9	$ 3.0	$ 19.2

PUB/CENTRA I-52

Subject: **Tab 6 Capital Expenditures**

Reference: **Tab 6 Appendix 6.1**

b) Please explain why the in-service dates for the Ile des Chenes and SCADA projects were delayed by one year from the dates shown in CEF10.

ANSWER:

Ile des Chenes Natural Gas Transmission Network Upgrade

Delays in material procurement affected the initial start date. The decision to delay the project from 2011 to 2012 was made to avoid the risk associated with working on a major supply to Winnipeg and areas north during the heating season. Therefore, performing the project in 2012 allowed the project to be constructed during summer months with lower system pressure and reduced gas flow rates.

SCADA

SCADA was delayed due to vendor technology upgrades. Significant development and improvement to the product were necessary for Centra to properly implement the software in a single phase.

PUB/CENTRA I-52

Subject: **Tab 6 Capital Expenditures**

Reference: **Tab 6 Appendix 6.1**

c) Please explain why the Customer Care and Marketing Domestic expenditures are forecasted to decrease $2 million compared to the amounts in CEF08 (2009/10 GRA PUB/Centra 12(a) attachment Jun 1/09 update).

ANSWER:

Customer Care and Marketing Domestic expenditures are forecasted to decrease by $2 million in CEF12 compared to CEF08 as a result of organizational changes. Responsibility for gas system improvement capital expenditures was transferred to the Customer Service & Distribution Business Units' domestic forecast.

PUB/CENTRA I-52

Subject: **Tab 6 Capital Expenditures**

Reference: **Tab 6 Appendix 6.1**

d) Please explain why the Customer Service and Distribution Domestic expenditure forecasts for the test year and beyond have increased to the $26 million to $27 million range, compared to the $22 million to $23 million range shown in CEF10.

ANSWER:

The increase is mainly due to a forecast assumption to include the capitalization of meter exchange activities. This assumption is currently under review. Please see PUB/Centra I-30(b) for further discussion. Appendix 6.1, page 3, Customer Service and Distribution's domestic expenditures for fiscal 2014 should include the target adjustment of $3.7 million which reflects the deferral of the capitalization of the Meter Compliance Program to 2015 upon transition to IFRS.

PUB/CENTRA I-53

Subject: **Tab 7 DSM**

Reference: **Tab 7 Pages 2 and 3 of 4; Appendix 7.1 2011 Power Smart Plan**

a) **Please provide an update on the amount of budgeted DSM spending on natural gas programs forecasted for 2012/13 and 2013/14 by program and compare with the DSM spending included in the 2011 Power Smart Plan. Please explain any differences.**

ANSWER:

The following table compares the budget from the 2011 Power Smart Plan to the updated budget, including funding from natural gas Power Smart, the Affordable Energy Fund and the Furnace Replacement Budget.

Included as an attachment to this response is the 2013-16 Power Smart Plan.

	(in $1000's)			
	2012/13		**2013/14**	
	2011 PS Plan (2011$)	Updated (2012$)	2011 PS Plan (2011$)	Updated (2012$)
RESIDENTIAL				
New Home Program	96	0	107	0
Lower Income:				
Power Smart	*692*	*760*	*686*	*744*
Furnace Replacement Program	*2,330*	*2,378*	*2,330*	*3,054*
Apportioned Affordable Energy Fund	*3,219*	*3,075*	*3,207*	*2,378*
Lower Income Total	6,242	6,213	6,223	6,177
Home Insulation Program	2,600	1,697	2,538	1,688
Water and Energy Saver Program	644	804	637	804
RESIDENTIAL TOTAL	9,582	8,714	9,504	8,669
COMMERCIAL				
Commercial Custom Measures Program	92	141	99	141
Commercial Windows Program	503	438	503	422
Commercial Insulation Program	3,373	1,613	3,373	1,435
Commercial New Construction Program	248	569	239	440
Commercial Building Optimization Program	314	255	335	193
Internal Retrofit Program	0	53	0	0
Commercial Kitchen Appliance Program	79	38	91	88
CO2 Sensors	64	58	66	56
Commercial Rinse & Save Program	2	0	0	0
Commercial Water Heater Program	91	0	97	0
Commercial Boiler Program	804	1,025	816	543
COMMERCIAL TOTAL	5,573	4,192	5,619	3,317
INDUSTRIAL				
Industrial Natural Gas Optimization Program	923	770	763	770
INDUSTRIAL TOTAL	923	770	763	770
EFFICIENCY PROGRAMS SUBTOTAL	16,077	13,676	15,885	12,756
CUSTOMER SELF-GENERATION				
BioEnergy Optimization Program	572	139	30	221
	572	139	30	221
PROGRAMS SUBTOTAL	16,649	13,815	15,915	12,977
CUSTOMER SERVICE INITIATIVES, SUPPORT AND CONTINGENCY	3,551	2,128	3,410	2,354
GRAND TOTAL	20,200	15,943	19,325	15,332

2013 - 2016
Power Smart Plan

An overview of Manitoba Hydro's energy efficiency initiatives for the next three years.

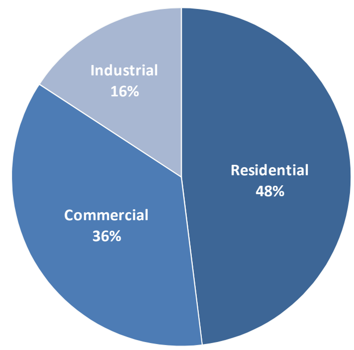
Highlights

Manitoba Hydro has been successfully delivering demand side management (DSM) for over twenty years in an effort to meet the energy needs of Manitoba in a more sustainable manner while assisting customers to use energy more efficiently and to reduce their energy bills. Manitoba Hydro has a strong commitment to DSM with a focus on pursuing all cost effective energy efficiency opportunities and continually monitoring the market for emerging trends and opportunities which may become economically viable. Manitoba Hydro's efforts on energy efficiency have been recognized by the Canadian Energy Efficiency Alliance (CEEA) in its Report Card on Energy Efficiency. Manitoba received an A+ in the last Report Card issued in August 2010, which was Manitoba's fourth consecutive first place rating. This document outlines the Power Smart Plan for the next three years: April 2013 through to March 31, 2016.

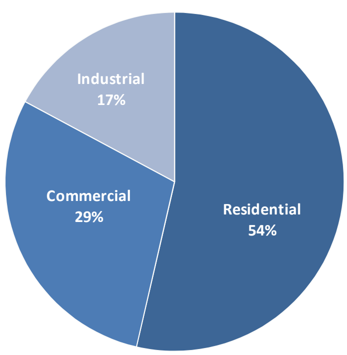
Electric DSM

- Targeted electric savings of 280 MW and 510 GW.h over the next 3 years.
- This activity represents 2.0% of the estimated load forecast by 2015/16.
- Combined with savings achieved to date, total electrical savings of 685 MW and 2,407 GW.h are expected to be achieved to 2015/16.
- These energy savings are equivalent to approximately 80% of the firm generation capability of Keeyask Generation Station or 1/3rd of the electrical energy needs of Winnipeg (excluding industrial customers).

Electric Energy Savings
(cumulative to 2015/16)



Natural Gas Energy Savings
(cumulative to 2015/16)



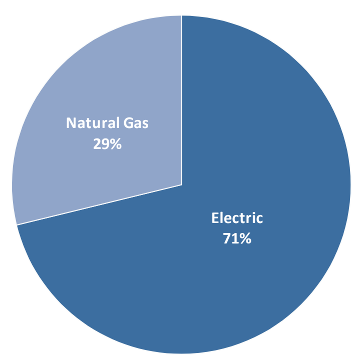
Natural Gas DSM

- Targeted natural gas savings of 30 million cubic meters over the next 3 years.
- This activity represents 1.5% of the estimated load forecast by 2015/16.
- Combined with savings achieved to date, total natural gas savings of 112 million cubic meters are expected to be achieved to 2015/16.
- These energy savings are equivalent to about 2.5 times the natural gas needs of Brandon (excluding industrial customers) or enough natural gas to serve over 46 000 homes.

Codes & Standards

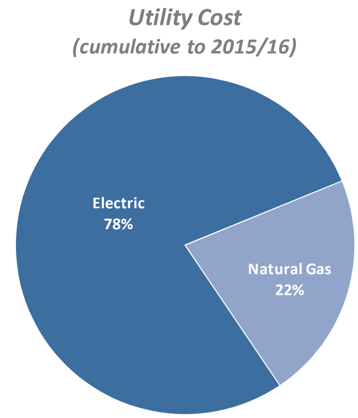
- Included in the DSM targets are electric savings of 52 MW and 222 GW.h and natural gas savings of 8 million cubic meters over the next 3 years.
- These energy savings result from codes and standards currently in place along with new codes and standards in the areas of residential lighting and appliances which will come into effect over the next 3 years.
- Combined with past efforts, electric savings of 184 MW and 797 GW.h and natural gas savings of 16 million cubic meters are expected to be achieved by 2015/16.

Codes & Standards Energy Savings
(cumulative to 2015/16)



Investment in DSM

- Over the next 3 years, Manitoba Hydro will invest $104 million on Power Smart incentive based programs with an expected cumulative utility investment of $491 million by 2015/16.
- Including other program support and contingency costs, Manitoba Hydro will invest $127 million on Power Smart initiatives, with an expected cumulative utility investment of $663 million by 2015/16.
- Including participating customer costs, an investment of $162 million (only incentive based programs) is forecasted, with an expected total investment of $881 million by 2015/16, equivalent to approximately 50% of the capital cost of the Wuskwatim Generation Station. Customer investments through codes and standards, financing services, and other Power Smart drivers have not been estimated.

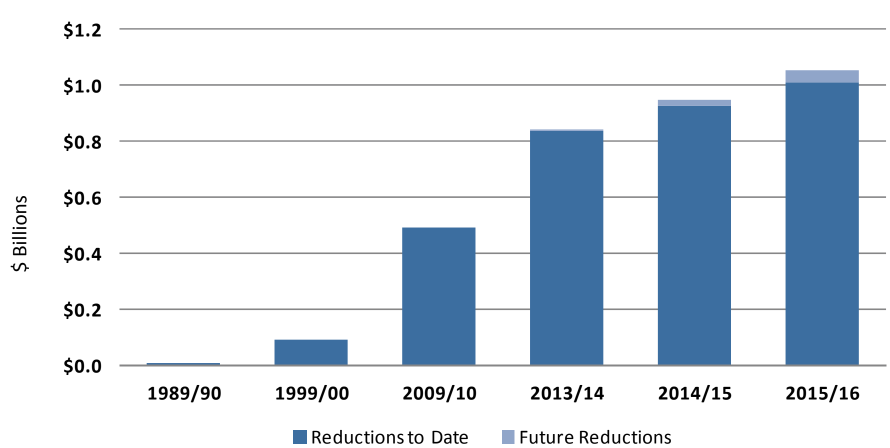


Greenhouse Gas Emission Reductions

- Targeted greenhouse gas emission reductions of 400,000 tonnes over the next 3 years.
- Including reductions achieved to date, 1.8 million tonnes are forecast to be achieved by 2015/16 which is equivalent to taking 410 000 cars off the road for one year.

Customer Bill Reductions

- Power Smart programs will save participating customers an additional $45 million in electricity and natural gas bills during 2015/16.
- Including bill reductions achieved to date, participating customers will save $1.1 billion cumulatively on electric and natural gas bills during 2015/16.



Contents

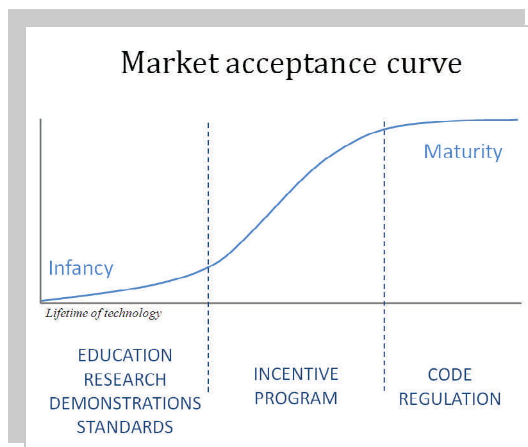
DSM Strategy

Manitoba Hydro's DSM strategy is to aggressively pursue all cost effective energy efficiency opportunities and continually monitor the market to identify emerging trends and opportunities which may become viable and cost effective DSM initiatives within the planning horizon.

Manitoba Hydro's DSM initiative, marketed under the Power Smart brand, is designed to encourage the efficient use of energy in residential, commercial, and industrial customer sectors. Manitoba Hydro's overall DSM strategy involves taking a broad approach to capturing energy efficiency opportunities: education to build awareness and understanding; creating foundations through the support of standards; motivating customers with the aid of financial tools; and entrenching energy savings through the support of federal and provincial codes and regulations.

In assessing options for pursing a DSM opportunity, Manitoba Hydro uses a number of metrics as guidelines to assess energy efficient opportunities. These metrics assist in determining whether to pursue an opportunity, how aggressive an opportunity will be pursued, the effectiveness of program design options and the relative investment sharing between ratepayers and participating customers. These metrics include the Total Resource Cost, Societal Cost, Rate Impact Measure, Levelized Utility Cost, and Customer Simple Payback. In addition to quantitative assessments, Manitoba Hydro also considers various qualitative factors including equity (i.e. reasonable participation by various ratepayer sectors such as lower income) and overall contribution towards having a balanced energy conservation strategy and plan.

Manitoba Hydro takes a three stage approach to achieving market transformation as outlined in the following graph. In the infancy stage of emerging opportunities, Manitoba Hydro supports these technologies by building customer awareness, demonstrations and/or through investments in research and development. As market acceptance increases and the opportunity becomes cost effective, financial incentives and/or other market intervention strategies are pursued to encourage customers to install the technology. As the product matures and market adoption grows, incentive based programming generally becomes uneconomic. During this phase, Manitoba Hydro's strategy involves pursuing the remaining opportunities through the adoption of codes and regulations. This latter strategy also ensures permanent market transformation for the specific energy efficiency opportunity.



An Example: Changing Furnace Efficiencies in Manitoba

In 2001, only 30% of all natural gas furnaces being installed in Manitoba were high-efficient models and customer awareness of higher efficiency options was low. In response to this market situation, Manitoba Hydro launched the Power Smart Residential Loan and supporting Home Comfort and Energy Savings campaign to educate and promote the installation of high efficient natural gas furnaces. This approach laid the foundation for customers to consider the energy efficient alternative, and provided a tool for contractors to promote this technology.

In 2005 to further increase market acceptance, a $245 incentive was introduced to encourage customers to choose high efficient natural gas furnaces over the less efficient alternative. By 2007, high efficiency furnaces had grown to represent 76% of all furnaces being replaced in Manitoba homes. In 2008, to accelerate the number of customers upgrading their furnaces, Manitoba Hydro increased their rebate to $500 for a limited time offering and aggressively promoted the financial and comfort benefits of upgrading a furnace.

As market acceptance increased, Manitoba Hydro worked with the Province of Manitoba to develop the framework to regulate the minimum efficiency of all natural gas furnaces installed in Manitoba. On December 30, 2009, with market penetration of 86%, the Power Smart incentive ended and the Provincial regulation took effect requiring a minimum 92% AFUE for natural gas furnaces installed in Manitoba.

Power Smart Plan

Manitoba Hydro's Power Smart Plan is a roadmap for the future direction of the Corporation's energy conservation program. It was developed through an intensive planning process that builds on the Corporation's experience and continuous involvement in energy conservation since 1989. The Power Smart portfolio offers programs and initiatives to pursue opportunities in all market sectors; residential, commercial and industrial. These programs are designed based on having an in-depth knowledge of the technology and the market environment. An in-depth understanding is essential to ensure that the program design is adequately and effectively addressing the appropriate target market and contains the tools and strategies to address market barriers.

The following table outlines the forecasted achievements of this three year plan.

	1989/90 to 2012/13 *	2013/14	2014/15	2015/16	Total to 2015/16
Capacity Savings (MW)	404.4	200.7	238.7	280.2	**684.6**
Energy Savings (GW.h)	1,897.1	174.4	335.5	509.5	**2,406.6**
Natural Gas Savings (million m^3)	82.2	10.0	20.2	30.0	**112.3**
Utility Investment (Millions, 2012$)	$536.6	$45.3	$42.0	$39.2	**$663.1**
Customer Investment (Millions, 2012$)	$182.4	$13.8	$10.0	$11.4	**$217.5**
Total DSM Investment (Millions, 2012$)	$719.0	$59.2	$51.9	$50.6	**$880.7**

** Includes estimates for 2012/13*

Residential

Manitoba Hydro offers a number of incentive based and financial support programs to address opportunities in the residential market.

Incentive Based Programs

Home Insulation Program

The Home Insulation Program is a 13 year program launched in May 2004 to encourage homeowners to upgrade insulation levels and air sealing in their homes' attics, walls, and foundations. Upgrading insulation offers significant energy savings, reduces customer's monthly utility bills, and provides a more comfortable living space.

The program targets existing electric and natural gas heated homes with fair or poor insulation levels; approximately 30 000 electric homes and 118 000 natural gas homes at the start of the program (excluding homes targeted by the Lower Income Energy Efficiency Program). The program has been designed to address barriers to the adoption of energy efficient insulation which include the lack of customer awareness regarding the financial and comfort benefits of increased insulation levels, the upfront capital cost of the upgrade, and the lack of priority when compared to more aesthetic and visible renovation projects. These market barriers are addressed through a comprehensive strategy that includes financial incentives to reduce the upfront cost of the upgrade, informational materials in the form of advertising campaigns, and renovation "how to" booklets which provide technical guidance for upgrading insulation to Power Smart levels. Power Smart on-bill financing programs are also promoted to provide additional encouragement for customers that are reluctant to consider allocating their renovation budget towards adding insulation to their home. Homeowners with technical barriers to upgrading insulation such as finished basements, landscaping and existing wall configurations are encouraged to consider an upgrade as a component to an already planned renovation, for example adding insulation to an exterior wall as part of a re-siding project.

To date, approximately 10 380 electric and 21 165 natural gas homes have undertaken insulation upgrades. The program is forecast to reach 40% of targeted electric customers and 25% of targeted gas customers by 2015/16 and is on target to reach 42% of targeted electric customers and 27% of targeted natural gas customers by program end in 2016/17.

	2004/05 to 2012/13 *	2013/14	2014/15	2015/16	Total to 2015/16
No. of Houses (annual)	31,545	2,771	2,644	2,523	**39,483**
Capacity Savings (MW)	22.7	2.0	3.8	5.3	**28.0**
Energy Savings (GW.h)	46.8	3.6	6.9	9.8	**56.6**
Natural Gas Savings (million m^3)	10.9	1.0	2.0	2.9	**13.8**
Utility Investment (Millions, 2012$)	$32.7	$2.9	$2.8	$2.7	**$41.0**
Customer Investment (Millions, 2012$)	$19.1	$1.8	$1.7	$1.8	**$24.4**
Total DSM Investment (Millions, 2012$)	$51.8	$4.6	$4.5	$4.5	**$65.4**

Estimated Average Annual Bill Reduction per Customer (Electric): $301

Estimated Average Annual Bill Reduction per Customer (Natural Gas): $170

** Includes estimates for 2012/13*

Lower Income Energy Efficiency Program (LIEEP)

The Lower Income Energy Efficiency Program (LIEEP) was launched in December 2007. The program's objective is to assist lower income homeowners in implementing energy efficiency upgrades, such as improved insulation, high efficiency natural gas furnaces and various low cost measures. These upgrades can provide significant energy savings, decreasing the customer's monthly energy bills while increasing the comfort of their home. The criteria for determining program eligibility are the Low Income Cut-Off (LICO) thresholds set by Statistics Canada; customers' total household income must fall below 125% of the LICO thresholds for inclusion in the program. There are approximately 82 000 homes in Manitoba, excluding multi-unit residential buildings, which fall below the LICO 125% threshold; 74 000 of customers own their home, while 8 000 customers rent. The primary targets within this market are homes with poor or fair insulation levels and standard efficient furnaces. They make up 23% (19 065) and 22% (18 319) of the market, respectively.

The program was designed recognizing the unique barriers lower income customers face in completing energy efficiency retrofits. Manitoba Hydro assists and encourages participation in this market by minimizing the financial burden with free insulation upgrades and provision of a low cost high efficiency natural gas furnace replacement, along with free low cost items (e.g. CFLs, caulking, faucet aerators). To further encourage participation, the program is delivered through a number of approaches: direct participation with individual customers or through community groups (e.g. First Nations', Neighbourhood communities, social enterprises). Through these approaches customers are made aware of the value of energy efficiency retrofits, along with the benefits of participating in the program. Customers are targeted through advertising and community-based campaigns, customized information sessions and community networks. A community led initiative, the Neighbourhood Approach, began in fall 2012 with the goal of completing energy efficiency upgrades on a block-by-block basis in lower income neighbourhoods. Under this approach, North End Community Renewal Corporation and Brandon Neighbourhood Renewal Corporation employ local residents and social enterprises, Building Urban Industries for Local Development (BUILD) and Manitoba Green Retrofit and Inner City Renovation, to bring energy efficiency upgrade opportunities direct to the customer's door.

To date, an estimated 6 781 energy efficiency retrofits have been completed. Of the total retrofits, 4 692 insulation projects have been completed and 2 555 furnaces have been replaced. The program is forecast to reach 31% (5 830) of the targeted poor or fair insulation homes and 30% (5 526) of standard furnaces within the total LICO 125% market by 2015/16.

	2007/08 to 2012/13 *	2013/14	2014/15	2015/16	Total to 2015/16
Total Participation (annual)	6,781	2,497	2,195	2,271	**13,744**
No. of Insulation Projects (annual)	4,692	1,750	1,815	1,883	**10,141**
No. of Furnaces Installed (annual)	2,555	900	937	1,018	**5,410**
Capacity Savings (MW)	3.7	1.1	2.1	3.1	**6.8**
Energy Savings (GW.h)	9.3	2.8	5.4	7.9	**17.2**
Natural Gas Savings (million m^3)	3.3	1.2	2.4	3.5	**6.9**
Utility Investment (Millions, 2012$)	$24.1	$7.2	$7.1	$6.4	**$44.9**
Customer Investment (Millions, 2012$)	$12.3	$1.0	$0.8	$0.6	**$14.8**
Total DSM Investment (Millions, 2012$)	$36.5	$8.2	$7.9	$7.1	**$59.7**

Estimated Average Annual Bill Reduction per Customer - Basic Measures: $31

Estimated Average Annual Bill Reduction per Customer (Electric) - Insulation: $923

Estimated Average Annual Bill Reduction per Customer (Natural Gas) - Insulation: $414

Estimated Average Annual Bill Reduction per Customer (Natural Gas) - Furance: $285

** Includes estimates for 2012/13*

Water and Energy Saver Program

The Power Smart Water and Energy Saver Program is a 5 year program launched in September 2010. Its primary objective is to reduce residential water heating energy consumption through the use of low flow, energy efficient plumbing fixtures. Customers are offered a free water and energy saver kit with program messaging focused on the energy and water benefits of energy efficient plumbing fixtures. The program offers three channels of participation: mail, targeted direct installation and a bulk mail option for residential property managers of multi-unit residential facilities.

The target market includes all residential dwellings that use electricity or natural gas to heat water, totaling 515 000 customers. A lack of awareness of the benefit of energy plumbing efficient fixtures and for some customers a general perception that their fixtures are already energy efficient, combined with limited availability and selection of Power Smart qualifying products at local retailers will limit customer adoption of the higher efficiency fixtures. Through advertising and the free kit offering, market acceptance of Power Smart plumbing fixtures will increase.

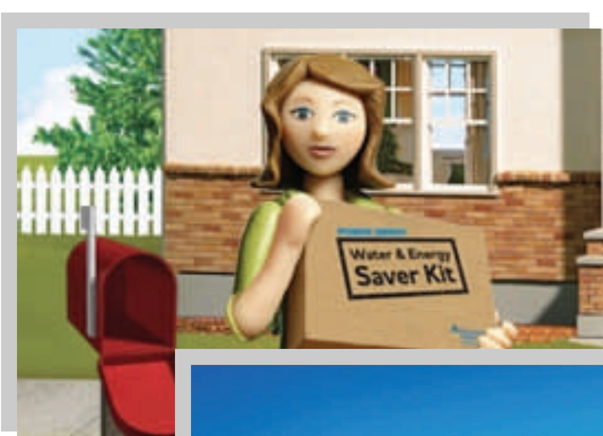
To date, over 100 000 residential dwellings have participated in the program. The program is on target to reach 31% of targeted homes by program end.

	2010/11 to 2012/13 *	2013/14	2014/15	2015/16	Total to 2015/16
No. of Houses (annual)	100,597	28,800	28,800	0	**158,197**
Capacity Savings (MW)	1.8	0.7	1.3	1.6	**3.4**
Energy Savings (GW.h)	14.2	3.3	6.6	7.8	**22.0**
Natural Gas Savings (million m^3)	2.5	0.8	1.6	1.9	**4.3**
Utility Investment (Millions, 2012$)	$4.5	$1.5	$1.5	$0.0	**$7.2**
Customer Investment (Millions, 2012$)	$0.0	$0.0	$0.0	$0.0	**$0.0**
Total DSM Investment (Millions, 2012$)	$4.5	$1.5	$1.5	$0.0	**$7.2**

Estimated Average Annual Bill Reduction per Customer (Electric): $6

Estimated Average Annual Bill Reduction per Customer (Natural Gas): $4

** Includes estimates for 2012/13*



Refrigerator Retirement Program

The Refrigerator Retirement Program is a 2.5 year program launched in June 2011. The objective of the program is to reduce residential energy consumption through the removal of old, inefficient, and often nearly empty refrigerators and freezers. The program offers free in-home pick-up of qualifying, working units plus a $40 incentive. The target market is residential homes representing approximately 190 000 older second fridges and freezers. Customers can save over $100 per year in electricity costs by removing these units. The program encourages customers to retire their secondary appliance and not replace it in order to maximize savings.

Most customers do not know the costs of operating an underutilized refrigerator or freezer, and many lack assistance in removing the appliance from the home. Through the program, customers are made aware of the costs of their second appliance and the benefits of “retiring” it. The program makes “retiring” easy by providing an in-home pick up service.

To date, over 17 000 units have been retired. The program is forecast to retire 16% of these older units by program end.

	2011/12 to 2012/13 *	2013/14	2014/15	2015/16	Total to 2015/16
Total Participation (annual)	17,283	13,600	0	0	**30,883**
No. of Fridges (annual)	15,555	12,240	0	0	**27,795**
No. of Freezers (annual)	1,728	1,360	0	0	**3,088**
Capacity Savings (MW)	1.9	1.9	2.7	2.7	**4.6**
Energy Savings (GW.h)	19.0	17.3	24.7	24.7	**43.7**
Natural Gas Savings (million m3)	0.0	0.0	0.0	0.0	**0.0**
Utility Investment (Millions, 2012$)	$3.9	$2.2	$0.1	$0.0	**$6.2**
Customer Investment (Millions, 2012$)	$2.1	$2.1	$0.0	$0.0	**$4.2**
Total DSM Investment (Millions, 2012$)	$6.0	$4.3	$0.1	$0.0	**$10.4**
Estimated Average Annual Bill Reduction per Customer (Electric) without fridge replacement : $100					
Estimated Average Annual Bill Reduction per Customer (Electric) without freezer replacement : $64					

** Includes estimates for 2012/13*

Support Programs

Manitoba Hydro offers the following convenient financing programs to support the incentive based programs by allowing customers to finance initial Power Smart project costs and pay the costs back on their monthly Manitoba Hydro bill.

Power Smart Residential Loan

The Power Smart Residential Loan (PSRL) was launched in March 2001 to provide customers with convenient on-bill financing to assist in making their home more energy efficient. Under the PSRL, the following energy efficiency improvements qualify: insulation, ventilation equipment, air leakage sealing, windows and doors, and space and water heating equipment.

The target market consists of all electric and natural gas customers in Manitoba. Participants can borrow up to $7 500 ($5 500 for furnaces) and repay the amount on their energy bill. The financial terms include a 5 year fixed interest rate over 5 year term (up to fifteen years for furnaces and boilers.)

	2001/02 to 2012/13 *	2013/14	2014/15	2015/16	Total to 2015/16
No. of Loans (annual)	70,041	5,500	5,500	5,500	**86,541**
Capacity Savings (MW)	5.1	0.2	0.4	0.6	**5.7**
Energy Savings (GW.h)	9.1	0.4	0.8	1.2	**10.3**
Natural Gas Savings (million m^3)	14.9	0.3	0.7	1.0	**15.9**
Average Loan Amount: $4,700					

** Includes estimates for 2012/13*

Power Smart PAYS Financing

Power Smart PAYS (Pay As You Save) Financing was launched in November 2012. The PAYS Program offers low interest on-bill financing over a term of up to 25 years depending upon the technology financed, with a fixed interest rate for up to 5 years. Energy efficient upgrades that may qualify for financing are:

- Insulation upgrades;
- Space heating equipment (furnaces and boilers);
- Geothermal systems;
- Drainwater heat recovery systems;
- WaterSense toilets (in conjunction with energy efficient equipment).

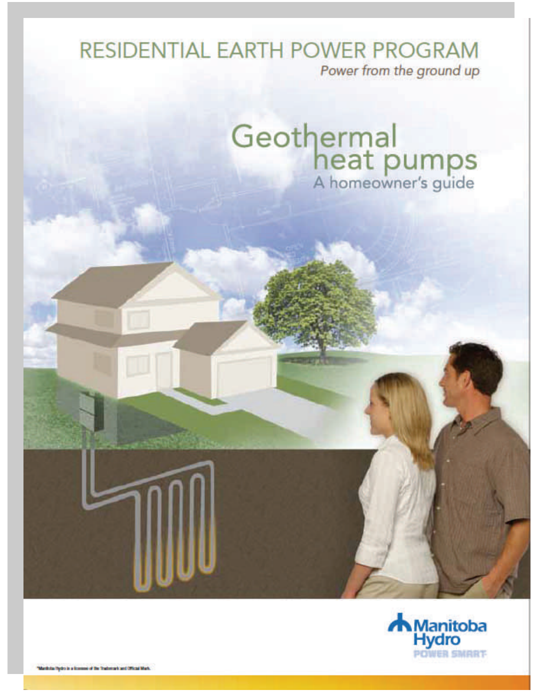
The target market consists of all electric and natural gas customers in Manitoba. This offering compliments and supports existing incentive-based programs by assisting customers in managing the installation cost of their upgrade. To qualify, upgrades must have sufficient estimated annual utility bill savings to offset the monthly financing payment, thereby resulting in a energy bill that is less than or equal to the total bill prior to the retrofit. PAYS financing also differs from Manitoba Hydro's other financing programs in that the loan is transferable between homeowners when a property is sold, and is transferable from a landlord to a tenant where the tenant is responsible for paying the energy bill.

	2012/13 to 2012/13 *	2013/14	2014/15	2015/16	Total to 2015/16
No. of Loans (annual)	84	400	400	400	**1,284**
Capacity Savings (MW)	0.1	0.2	0.3	0.5	**0.6**
Energy Savings (GW.h)	0.4	0.4	0.7	1.0	**1.3**
Natural Gas Savings (million m^3)	0.0	0.1	0.1	0.2	**0.2**
Average Loan Amount: $3,900					

** Includes estimates for 2012/13*

Residential Earth Power Loan

The Residential Earth Power Loan (REPL) was launched in April 2002 to support the adoption of geothermal heat pump technology. While more expensive to install, geothermal heat pump systems offer significant electricity savings, reducing customers' monthly utility bills. The convenience and flexibility of the on-bill REPL reduces the financial barrier that exists when installing a geothermal heat pump system. The program was also designed to build awareness of emerging technologies and foster new, growing industries supporting these technologies through education materials, technical support and training workshops. Solar hot water systems were added as an eligible technology in 2010.



Customers are eligible for up to $20 000 in financing for installing geothermal heat pump systems or $7 500 in financing for installing solar domestic water heating systems. The financial terms include a 5 year fixed interest rate over a 15 year maximum term. The interest rate for the balance of the financing period is established at Manitoba Hydro's cost of borrowing at the time the fixed interest rate term expires.

	2002/03 to 2012/13 *	2013/14	2014/15	2015/16	Total to 2015/16
No. of Loans (annual)	1,223	76	87	100	**1,486**
Capacity Savings (MW)	4.1	0.4	0.8	1.2	**5.3**
Energy Savings (GW.h)	15.0	1.7	3.3	5.0	**20.0**
Natural Gas Savings (million m^3)	2.2	0.1	0.2	0.3	**2.6**
Average Loan Amount: $19,750					

** Includes estimates for 2012/13*

Commercial

Manitoba Hydro offers a number of incentive based and one financial support program to address opportunities in the commercial market.

Incentive Based Programs

Commercial Lighting Program

The Power Smart Commercial Lighting Program was launched in May 1992 to reduce electricity consumption by accelerating the acceptance and adoption of energy efficient lighting technologies in Manitoba. Commercial, industrial and agricultural customers are encouraged to install qualifying energy efficient lighting technologies in their facilities to reduce energy bills, improve the quality of lighting, as well as increase safety, security and productivity. The program offers support through the use of educational materials, information seminars and financial incentives.

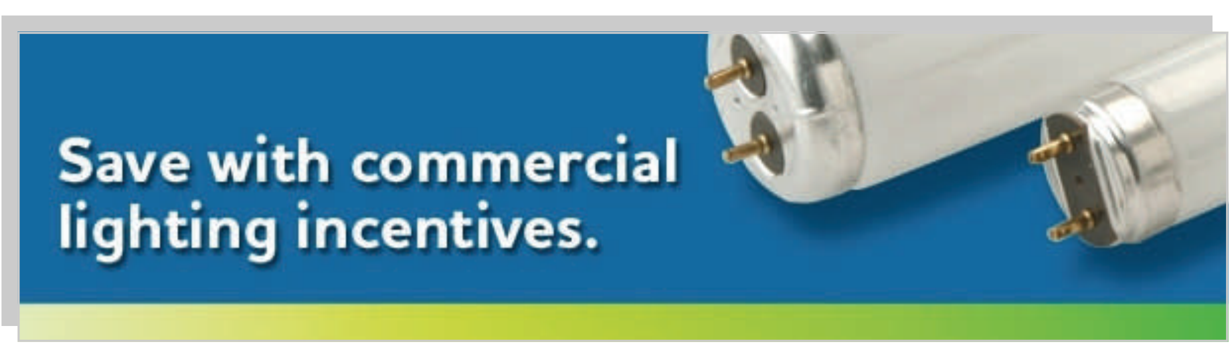
The target market consists of all commercial, industrial and agricultural existing buildings with inefficient lighting installations in Manitoba, where lighting systems operate a minimum of 2 000 hours per year. New construction projects that do not meet the New Buildings Program Eligibility Criteria may qualify. The estimated market size is 52 500 lighting projects. Many energy efficient lighting options have higher initial capital costs, and often customers have low awareness on the technologies available and the non-energy related benefits of energy efficient lighting, creating a barrier to the adoption of higher efficiency systems. In addition, many customers operate in commercial lease space where the person making decisions on lighting upgrades may not pay the utility bill, and therefore does not realize the direct financial return. Strategies in place to address these market barriers include financial incentives, education and training, as well as hands on technical and customer service support.

To date, over 12 000 energy efficient lighting projects have been completed.. The program is forecast to reach 28% of the target market by the end of 2015/16 and is on target to achieve 37% of the target market by the end of the planning horizon.

	1992/93 to 2012/13 *	2013/14	2014/15	2015/16	Total to 2015/16
No. of Projects (annual)	12,379	748	721	682	**14,530**
Capacity Savings (MW)	62.1	7.2	13.6	19.3	**81.4**
Energy Savings (GW.h)	337.2	25.9	49.2	69.9	**407.1**
Utility Investment (Millions, 2012$)	$83.8	$6.0	$5.4	$5.2	**$100.4**
Customer Investment (Millions, 2012$)	$35.4	$3.0	$2.6	$2.5	**$43.5**
Total DSM Investment (Millions, 2012$)	$119.3	$8.9	$8.0	$7.7	**$143.9**

Estimated Average Annual Bill Reduction per Customer (Electric): $338

** Includes estimates for 2012/13*



Commercial Building Envelope - Windows Program

The Power Smart Commercial Building Envelope Program (Windows) has been promoting the benefits of energy efficient windows to commercial customers since 1995. The program's primary objective is to improve building envelope performance and reduce energy consumption through the installation of high performance windows in existing buildings.

The target market consists of all existing commercial customers, primarily focused on sectors such as multi-unit residential facilities, schools, hotel/motel, personal care homes and health care facilities. The program targets facilities planning to replace existing windows, thus presenting an economic opportunity to install higher efficiency Power Smart qualifying windows at the time of replacement.

Market barriers include the incremental product cost of high performance windows, along with the lack of awareness of the significant potential energy savings and other non-energy benefits. Providing financial incentives to help offset incremental material costs, while promoting the benefits of high performance windows is effectively addressing these barriers.

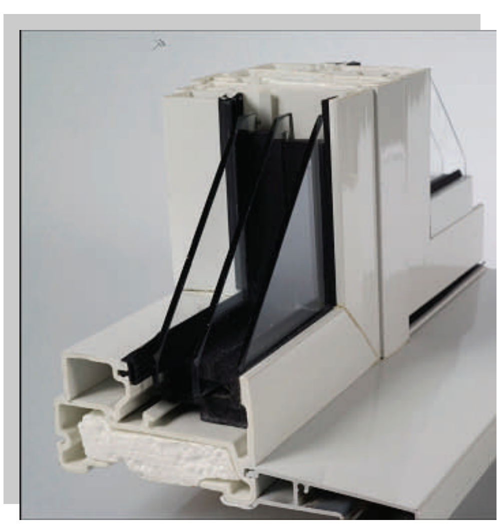
It is estimated that there are approximately 750 potential window replacement projects in Manitoba each year, of a total market of 27 000 potential projects. To date, over 900 energy efficient window projects have been completed. The program is forecast to reach 5% of the target market by the end of 2015/16 and is on pace to achieve 10% of the target market by the end of the planning horizon.

	2006/07 to 2012/13 *	2013/14	2014/15	2015/16	Total to 2015/16
No. of Projects (annual)	939	180	166	87	**1,373**
Capacity Savings (MW)	6.3	0.8	1.5	2.0	**8.3**
Energy Savings (GW.h)	15.9	2.0	3.7	4.9	**20.8**
Natural Gas Savings (million m^3)	1.5	0.3	0.6	0.8	**2.3**
Utility Investment (Millions, 2012$)	$10.9	$0.9	$0.8	$0.5	**$13.1**
Customer Investment (Millions, 2012$)	$1.7	$0.2	$0.2	$0.0	**$2.1**
Total DSM Investment (Millions, 2012$)	$12.6	$1.0	$0.9	$0.5	**$15.1**

Estimated Average Annual Bill Reduction per Customer (Electric): $945

Estimated Average Annual Bill Reduction per Customer (Natural Gas): $1,607

** Includes estimates for 2012/13*



Commercial Building Envelope - Insulation Program

The Power Smart Commercial Building Envelope Program (Insulation) was launched in April 2006. Its primary objective is to improve building envelope performance and reduce energy consumption by upgrading insulation levels in roof and wall areas of existing buildings.

The target market is comprised of all commercial customers with insulation levels that do not meet Power Smart levels. The program targets facilities planning to undergo extensive repairs to existing roofs and walls, presenting an economic opportunity to improve existing insulation levels at the time of renovation.

Market barriers include the incremental product cost of insulation upgrades, along with the lack of awareness of the significant potential energy savings and other non-energy benefits associated with upgraded insulation levels. Providing financial incentives to help offset incremental material costs while promoting the benefits of better insulated buildings is effectively addressing these barriers.

It is estimated that there are approximately 400 potential insulation replacement projects in Manitoba each year, of a total market of 15 000 potential projects. To date, 648 insulation projects have been completed. The program is forecast to reach 6% of the target market by the end of 2015/16 and is on pace to achieve 10% of the target market by the end of the planning horizon.

	2006/07 to 2012/13 *	2013/14	2014/15	2015/16	Total to 2015/16
No. of Projects (annual)	648	100	88	65	**901**
Capacity Savings (MW)	7.7	0.9	1.6	2.2	**9.8**
Energy Savings (GW.h)	16.1	2.1	4.0	5.4	**21.5**
Natural Gas Savings (million m^3)	7.8	1.0	1.8	2.5	**10.3**
Utility Investment (Millions, 2012$)	$11.4	$1.9	$1.7	$1.3	**$16.4**
Customer Investment (Millions, 2012$)	$6.9	$0.7	$0.6	$0.5	**$8.6**
Total DSM Investment (Millions, 2012$)	$18.3	$2.6	$2.3	$1.8	**$25.0**

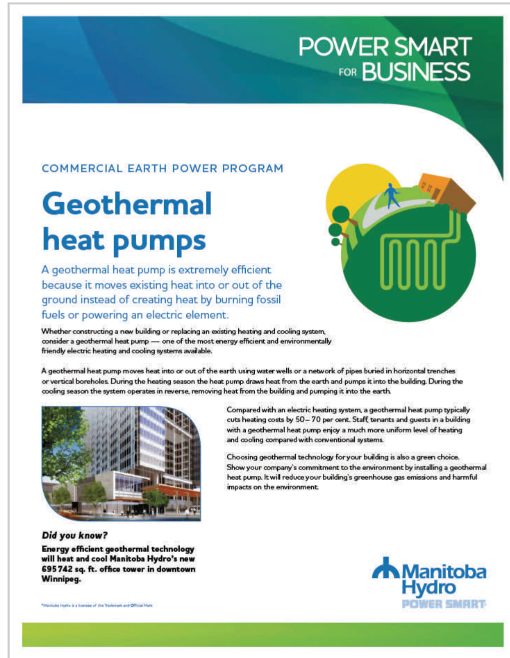
Estimated Average Annual Bill Reduction per Customer (Electric): $1,030

Estimated Average Annual Bill Reduction per Customer (Natural Gas): $3,778

** Includes estimates for 2012/13*

Commercial Earth Power Program

The Commercial Earth Power Program was launched in 2007 with the primary objective to encourage the installation of geothermal heat pumps in electrically-heated commercial buildings.



The target market consists of new and existing commercial buildings that use conventional electric technologies for space heating. There are approximately 6 084 existing electrically heated facilities using more than 30 000 kW.h per year in Manitoba, with 243 assumed to replace their electric heating systems each year. The high capital cost of installing a geothermal heat pump system, combined with the available supply of qualified installers and contractors in some regions of the province, challenging drilling and trenching conditions due to varying geological conditions, limited land area of many properties to accommodate the loop installation, and the proximity to the ground loop of underground facilities and services (water and sewer lines that may freeze, etc.) can make choosing geothermal as a heating/cooling option more challenging for the customer. Through the program, customers are provided with information on how the geothermal heat pump technology works, the energy savings available, and other benefits to increase understanding and acceptance of the technology. Financial incentives are offered to help offset the higher capital costs of the system at a rate of $1.25 per square feet of floor area heated by geothermal or $60.00 per MBH (thousands of BTUs per hour) of installed geothermal space heating capacity. Incentives are also available to support feasibility studies to ensure the project meets the heating and cooling needs of the building while achieving the necessary electrical savings to make installing a geothermal heat pump an economic option for the customer. Benefits of geothermal systems and program opportunities are communicated through the broad network of engineers, architects, consultants, contractors, and trade allies in Manitoba who have established relationships with the commercial and industrial customer base.

To date, approximately 121 commercial buildings have installed geothermal systems. The program is forecast to achieve 7% of annual heating systems upgrades being geothermal by 2015/16 and is on target to achieve 9% of annual heating systems upgrades by program end.

	2007/08 to 2012/13 *	2013/14	2014/15	2015/16	Total to 2015/16
No. of Buildings (annual)	121	17	17	17	**172**
Capacity Savings (MW)	13.7	0.4	0.9	1.3	**15.1**
Energy Savings (GW.h)	32.8	1.9	3.8	5.6	**38.4**
Utility Investment (Millions, 2012$)	$5.4	$0.4	$0.4	$0.4	**$6.4**
Customer Investment (Millions, 2012$)	$15.9	$0.9	$0.9	$0.9	**$18.7**
Total DSM Investment (Millions, 2012$)	$21.3	$1.3	$1.3	$1.3	**$25.2**
Estimated Average Annual Bill Reduction per Customer (Electric): $4,342					

** Includes estimates for 2012/13*

Commercial HVAC Program —Boilers

The Commercial HVAC Program for Boilers is a 9 year program launched in April 2006. The program's primary objective is to transform the commercial boiler market in Manitoba by increasing awareness and adoption of energy efficient condensing and near-condensing boilers. Energy efficient boilers offer significant natural gas savings, reducing customers' monthly utility bills. The program focuses on educating building owners and operators about the benefits of energy efficient equipment and works with industry contractors, engineers, consultants, designers, and equipment dealers to promote these systems. Financial incentives ranging from $2/MBH (thousands of BTUs per hour) to $8/MBH are provided for qualifying systems.

The program is designed to build market acceptance prior to, and thereby ensuring the successful adoption of, Natural Resources Canada's (NRCan) proposed amendments to Canada's Energy Efficiency Regulations requiring all commercial boilers installed in new and existing buildings to be 85% efficient by March 2, 2015. The primary target market consists of commercial buildings with existing heating equipment at or approaching end of life. On average, 267 commercial boilers are installed annually in existing buildings. Boiler replacements are not likely to occur until existing equipment is near their end of life and are often completed in an emergency situation during the heating season. Purchase decisions are therefore made with limited lead time and primarily based upon the initial capital cost, not considering the annual operating costs of the system over its 25 year life. Condensing or near-condensing natural gas boilers are also more expensive to install than conventional boilers, and require modifications to the ventilation system. Financial incentives combined with information on the lifecycle cost advantage of energy efficient systems are in place to address these market barriers

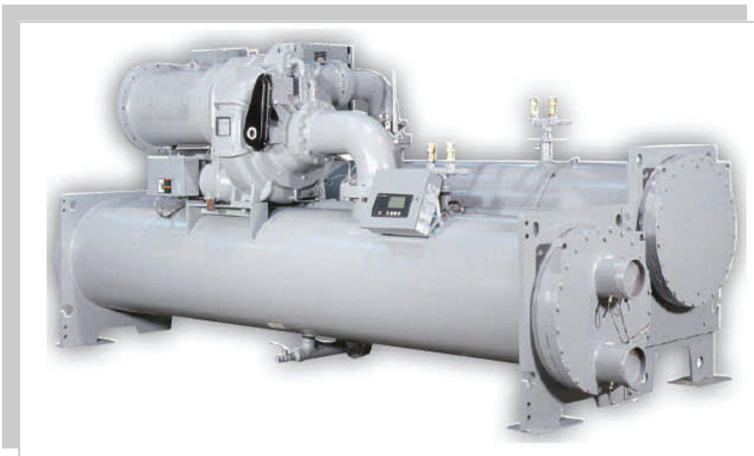
The program is forecast to achieve 46% of annual boiler sales being energy efficient by the planned program end date of March 1, 2015.

	2006/07 to 2012/13 *	2013/14	2014/15	2015/16	Total to 2015/16
No. of Boilers (annual)	766	123	124	0	**1,013**
Natural Gas Savings (million m^3)	7.7	0.4	0.8	1.0	**8.6**
Utility Investment (Millions, 2012$)	$8.3	$0.5	$0.5	$0.0	**$9.4**
Customer Investment (Millions, 2012$)	$5.6	$0.4	$0.4	$0.3	**$6.7**
Total DSM Investment (Millions, 2012$)	$14.0	$0.9	$0.9	$0.3	**$16.1**
Estimated Average Annual Bill Reduction per Customer (Natural Gas): $1,391					

** Includes estimates for 2012/13*

Commercial HVAC Program —Chillers

The Power Smart Commercial HVAC Program for Chillers is a 12 year program launched in April 2006. Its primary objective is to transform the commercial chiller market in Manitoba by increasing awareness and adoption of energy efficient water-cooled chillers and variable speed drive retrofits. Energy efficient chillers offer significant electricity savings, reducing customers' utility bills. The program focuses on educating building owners and operators about the benefits of energy efficient equipment and works with industry contractors, engineers, consultants, designers, and equipment dealers to promote these systems. Financial incentives of $81 per ton are provided for qualifying units.



The primary target market for chillers are large, older, commercial buildings, consisting primarily of large offices, large multi-residential, hospitals and large educational facilities. The high initial cost of chiller systems combined with the tendency for customers to emphasize the initial investment cost over operating efficiency or life cycle costs when making their purchase decision, has created a barrier for the higher efficiency systems. Offering aggressive financial incentives while promoting the lifecycle cost advantage is effectively addressing these barriers and ensuring that efficient chillers are chosen at the time of existing equipment replacement.

Typically, chillers have a 30 year life and are replaced when the refrigerant is required to be changed or when the equipment is reaching end of life. On average 14 chillers, representing approximately 4 200 tons of cooling capacity, are replaced annually. The program is forecast to achieve 64% of annual chiller sales being energy efficient by the end of 2015/16 and is on target to achieve 70% of annual sales by program end.

	2006/07 to 2012/13 *	2013/14	2014/15	2015/16	Total to 2015/16
No. of Chillers (annual)	49	8	8	9	**74**
Capacity Savings (MW)	0.0	0.0	0.0	0.0	**0.0**
Energy Savings (GW.h)	9.8	1.3	2.6	4.0	**13.8**
Utility Investment (Millions, 2012$)	$1.6	$0.2	$0.2	$0.2	**$2.3**
Customer Investment (Millions, 2012$)	$1.5	$0.0	$0.1	$0.1	**$1.6**
Total DSM Investment (Millions, 2012$)	$3.1	$0.3	$0.3	$0.3	**$3.9**
Estimated Average Annual Bill Reduction per Customer (Electric): $8,216					

** Includes estimates for 2012/13*

Commercial HVAC Program —CO_2 Sensors

The Commercial HVAC Program for CO_2 sensors is a 10 year program launched in April 2009. Its primary objective is to increase the awareness and adoption of CO_2 sensors in commercial facilities. CO_2 sensors reduce energy consumption by matching ventilation supply to occupant demand, reducing customers' monthly utility bills. CO_2 sensors also improve occupant comfort by providing more consistent air quality and can extend the life of heating and cooling equipment by putting less demand on these systems.

The target market for CO_2 sensors consists of over-ventilated commercial facilities with variable occupancy and that have, or are considering installing, Direct Digital Control systems or rooftop units to control heating, cooling, and ventilation. Installations typically occur when other major renovations are being made to the ventilation system. It is estimated that a total of 328 potential sensor installations in Manitoba exists each year.

CO_2 sensors are not required in commercial building operation and therefore are often one of the first retrofit measures to be discarded in the event of budgetary constraints. Customers also tend to be unfamiliar with the operation of their ventilation systems and may be unaware when a building is over-ventilated. Offering aggressive financial incentives of $200 per sensor, while promoting the lifecycle cost advantage and improved ventilation benefits, is effectively addressing these barriers.

	2009/10 to 2012/13 *	2013/14	2014/15	2015/16	Total to 2015/16
No. of Sensors (annual)	173	100	120	140	**533**
Capacity Savings (MW)	0.0	0.1	0.2	0.3	**0.3**
Energy Savings (GW.h)	0.2	0.1	0.2	0.4	**0.6**
Natural Gas Savings (million m^3)	0.3	0.1	0.2	0.3	**0.6**
Utility Investment (Millions, 2012$)	$0.1	$0.1	$0.1	$0.1	**$0.3**
Customer Investment (Millions, 2012$)	$0.0	$0.1	$0.1	$0.1	**$0.2**
Total DSM Investment (Millions, 2012$)	$0.1	$0.1	$0.1	$0.1	**$0.5**

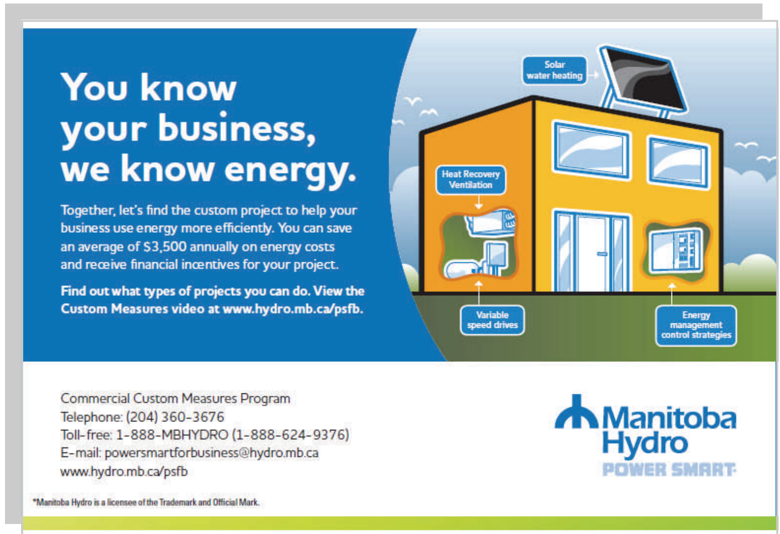
Estimated Average Annual Bill Reduction per Customer (Electric): $41

Estimated Average Annual Bill Reduction per Customer (Natural Gas): $342

** Includes estimates for 2012/13*

Custom Measures Program

The Power Smart Commercial Custom Measures Program, launched in 2006, encourages commercial customers to explore and implement energy efficient upgrades of their operations or facilities. This program offers the opportunity to explore customer-specific and unique projects or newer technologies that are not currently eligible under the other Power Smart for Business Program offerings. Technologies and projects may include digital control systems, hot water and space heating equipment, waste energy recovery systems, variable speed drive systems, and solar air and water heating systems. The program provides incentives to help cover the cost of feasibility studies that are often required for larger projects and newer or emerging technologies, and implementation incentives based on projected savings from the project.



The program targets all commercial customers planning new construction, renovation or expansion projects. Often the high incremental cost of energy efficient technologies and systems, customer uncertainty of payback, and lack of awareness of energy efficient alternatives limit a customer's propensity to invest in an energy efficient project. The Custom Measures Program addresses these barriers by promoting new and innovative technologies, by offering a feasibility study incentive to provide confidence in energy savings estimates, and by offering incentives to help reduce the implementation cost.

	2006/07 to 2012/13 *	2013/14	2014/15	2015/16	Total to 2015/16
No. of Projects (annual)	65	14	14	14	**107**
Capacity Savings (MW)	2.0	0.3	0.6	0.8	**2.9**
Energy Savings (GW.h)	23.6	1.0	2.1	3.2	**26.8**
Natural Gas Savings (million m^3)	0.3	0.1	0.2	0.3	**0.6**
Utility Investment (Millions, 2012$)	$4.5	$0.4	$0.4	$0.4	**$5.7**
Customer Investment (Millions, 2012$)	$7.5	$0.6	$0.5	$0.5	**$9.2**
Total DSM Investment (Millions, 2012$)	$12.1	$1.0	$0.9	$0.9	**$14.9**

Estimated Average Annual Bill Reduction per Customer (Electric): $4,353

Estimated Average Annual Bill Reduction per Customer (Natural Gas): $7,894

** Includes estimates for 2012/13*

Commercial Building Optimization Program

The Power Smart Commercial Building Optimization Program (CBOP), launched in 2006, encourages commercial customers with existing buildings to engage in an assessment and adjustment process known as retrocommissioning (RCx) to help return their buildings' mechanical systems to their designed operating characteristics and even further optimize their operation to save energy and improve occupant comfort. The program focuses on identifying non-capital intensive energy conservation opportunities with relatively short payback periods and offers incentives that cover a portion of the cost hiring an RCx agent and implementing the energy efficient measures identified through the investigation process.

The market consists of existing commercial buildings larger than 50 000 square feet and between 2 and 25 years of age with direct digital control systems and functioning heating, ventilating and air conditioning mechanical systems. There are approximately 470 buildings in this market, however there are significant barriers that must be overcome to reach these customers including lack of experience and availability of RCx providers in Manitoba, lack of customer awareness of the cost-saving benefits of RCx, and lack of customer time and competing priorities for capital to invest in energy efficiency projects. The program addresses these barriers by providing training and information sessions for potential and existing RCx providers, by promoting RCx at relevant industry events, and by offering incentives to reduce the capital cost and payback cycle of the RCx process.

The program plans to achieve 8% market penetration by 2015/16 and 42% market penetration by the end of the planning horizon.

	2006/07 to 2012/13 *	2013/14	2014/15	2015/16	Total to 2015/16
No. of Buildings (annual)	12	7	8	9	**36**
Capacity Savings (MW)	0.2	0.2	0.4	0.6	**0.7**
Energy Savings (GW.h)	1.6	1.0	1.9	2.8	**4.4**
Natural Gas Savings (million m^3)	0.6	0.2	0.4	0.6	**1.1**
Utility Investment (Millions, 2012$)	$1.2	$0.3	$0.3	$0.3	**$2.1**
Customer Investment (Millions, 2012$)	$1.2	$0.1	$0.2	$0.2	**$1.6**
Total DSM Investment (Millions, 2012$)	$2.4	$0.4	$0.5	$0.5	**$3.7**

Estimated Average Annual Bill Reduction per Customer (Electric): $6,531

Estimated Average Annual Bill Reduction per Customer (Natural Gas): $9,379

** Includes estimates for 2012/13*

New Buildings Program

The Power Smart New Buildings Program is an 8 year program launched in 2010. Its primary objective is to transform the commercial new construction industry in preparation for pending building codes which will require significant improvements in overall building energy efficiency. The program offers technical assistance and financial incentives for customers designing and constructing new, energy efficient commercial buildings.

It is expected that the provincial government will adopt the National Energy Code of Canada for Buildings 2011 (NECB) into the Manitoba building code in the fall of 2014. This adoption will have a significant impact on the energy efficiency of new commercial buildings and will affect many disciplines within in the construction industry in Manitoba, including the code enforcement authorities.

Two incentive options are currently offered to all customers: The Prescriptive Path, which specifies minimum design criteria for common building types or the Custom Design Path, which offers building designers flexibility to create energy efficient buildings. Power Smart buildings are designed to use at least 33% less energy than similar buildings designed to meet the Model National Energy Code of Canada for Buildings 1997 (MNECB 97). Custom Design Path participants are also given the option to enroll in the Proven Performance Path which provides further incentives for energy efficiency beyond the program's minimums. The target market is all new commercial buildings constructed in Manitoba and represents approximately 200 new commercial building projects in the province each year. In order to move the market toward the energy efficiency requirements proposed under the upcoming building code, the industry faces fundamental changes to the current methods of designing, constructing and commissioning commercial buildings. Lack of qualified, local firms offering integrated design, energy modeling, and building commissioning; industry perceptions of higher initial capital costs associated with designing and constructing energy efficient buildings; and a lack of customer and industry knowledge about lifecycle costing creates barriers to constructing energy efficient buildings. To help overcome these barriers, Manitoba Hydro has worked closely with the Province's Green Building Coordination Team to develop the Green Building Policy for Government of Manitoba Funded Projects. This policy ensures the Province's investments in new construction will help transform the local market by leading by example, and will help build industry capacity within Manitoba. Program efforts are focused towards larger and more complex projects in order to showcase the benefits of energy efficient buildings to a broader audience on a larger scale. Providing financial incentives along with industry training and support aids in addressing these barriers.

To date, 18 buildings have been constructed which meet the Power Smart requirement of at least 33% more energy efficient than the MNECB 97; in addition to these completed projects, an additional 35 projects are currently registered to participate. The program is forecast to achieve a market penetration rate of 16% of annual buildings constructed being energy efficient by the end of 2015/16 and is on target to achieve 23% of annual buildings by program end.

	2009/10 to 2012/13 *	2013/14	2014/15	2015/16	Total to 2015/16
No. of Buildings (annual)	18	18	24	32	**92**
Capacity Savings (MW)	1.5	2.9	6.5	10.5	**12.0**
Energy Savings (GW.h)	7.5	11.8	25.8	40.9	**48.4**
Natural Gas Savings (million m^3)	0.7	0.7	1.6	2.5	**3.2**
Utility Investment (Millions, 2012$)	$3.1	$1.1	$1.3	$1.6	**$7.1**
Customer Investment (Millions, 2012$)	$1.4	$1.1	$1.4	$1.9	**$5.8**
Total DSM Investment (Millions, 2012$)	$4.5	$2.2	$2.7	$3.5	**$12.9**
Estimated Average Annual Bill Reduction per Customer (Electric): $7,586					
Estimated Average Annual Bill Reduction per Customer (Natural Gas): $3,166					

** Includes estimates for 2012/13*

Commercial Refrigeration Program

The Power Smart Commercial Refrigeration Program was launched in 2006. The program helps commercial customers reduce energy consumption by providing over 15 different incentives for energy efficient upgrades to refrigeration display cases, walk-in boxes, mechanical rooms and lighting. Savings are achieved by providing customers with information about best practices and maintenance, promoting energy efficient refrigeration technologies, and optimizing the operation of new and existing refrigeration equipment.

The target market is commercial customers with foodservice refrigeration equipment, primarily grocery, retail, and convenience stores. There are approximately 1600 physical locations in the target market. Many of the qualifying energy efficient refrigeration systems have higher incremental costs, and equipment upgrade decisions are sometimes based on aesthetics considerations over energy efficiency. Offering financial incentives to lower incremental costs and promoting the energy and associated bill savings along with non-energy benefits of efficient refrigeration systems, such as increased comfort in refrigeration aisles for both customers and employees, reduced product spoilage, and extended equipment life for refrigeration motors and compressors is effectively addressing these barriers.

To date, 674 customers have participated in the program. The program is forecast to achieve 42% market penetration by the end of 2015/16 and is on target to achieve 66% market penetration by program end.

	2006/07 to 2012/13 *	2013/14	2014/15	2015/16	Total to 2015/16
No. of Locations (annual)	674	41	45	47	**807**
Capacity Savings (MW)	3.1	0.2	0.3	0.5	**3.6**
Energy Savings (GW.h)	12.2	1.4	3.0	4.7	**16.9**
Utility Investment (Millions, 2012$)	$2.1	$0.3	$0.3	$0.3	**$2.9**
Customer Investment (Millions, 2012$)	$1.1	$0.2	$0.2	$0.2	**$1.7**
Total DSM Investment (Millions, 2012$)	$3.1	$0.5	$0.5	$0.5	**$4.6**

Estimated Average Annual Bill Reduction per Customer (Electric): $1,744

** Includes estimates for 2012/13*

Commercial Kitchen Appliance Program

The Power Smart Commercial Kitchen Appliance Program is a 10 year program launched in 2008. The program encourages customers to choose ENERGY STAR steam cookers (gas and electric) and ENERGY STAR deep fat fryers (gas only) when replacing commercial appliances.

The target market consists of restaurants and foodservice establishments with either gas or electric commercial kitchen appliances. ENERGY STAR qualified appliances have a higher initial cost to purchase, and many customers are not aware that using ENERGY STAR appliances can decrease operating and maintenance costs and improve food quality. Providing financial incentives and promoting the various energy and non-energy benefits of ENERGY STAR kitchen appliances is effectively addressing these market barriers.

To date, 100 ENERGY STAR appliances have been installed. There are approximately 45 steamers and 230 fryers replaced each year in Manitoba. The program is forecast to achieve 62% market penetration for steamers and 10% for fryers by 2015/16, for combined sales of 51 appliances. The program is on target to achieve 76% market penetration for steamers and 16% for fryers by program end.

	2008/09 to 2012/13 *	2013/14	2014/15	2015/16	Total to 2015/16
No. of Appliances (annual)	100	25	44	51	**220**
Capacity Savings (MW)	0.2	0.4	1.2	1.9	**2.1**
Energy Savings (GW.h)	0.9	0.4	1.1	1.8	**2.7**
Natural Gas Savings (million m^3)	0.1	0.1	0.4	0.6	**0.7**
Utility Investment (Millions, 2012$)	$0.5	$0.1	$0.2	$0.2	**$0.9**
Customer Investment (Millions, 2012$)	$0.1	$0.0	$0.1	$0.1	**$0.3**
Total DSM Investment (Millions, 2012$)	$0.6	$0.2	$0.2	$0.3	**$1.2**
Estimated Average Annual Bill Reduction per Customer (Electric): $455					
Estimated Average Annual Bill Reduction per Customer (Natural Gas): $178					

** Includes estimates for 2012/13*

Network Energy Management Program

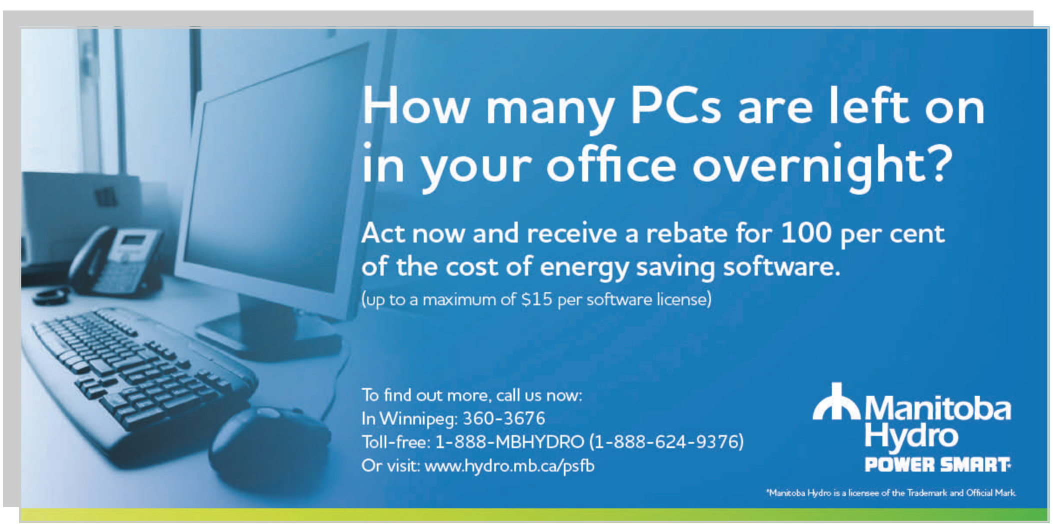
The Power Smart Network Energy Management Program is a 7 year program launched in 2009. The program encourages customers to install program-approved software that conserves energy by sending personal computers (PCs) into a mode that consumes less energy when they are not in use.

The program is aimed at commercial organizations that manage a network of PCs. The target market is comprised of approximately 2 500 physical locations in the school/college and office sectors, representing approximately 300 000 PCs. Installation, configuration, and testing of this new software on existing networks can require a significant time investment. Although management may realize operational cost savings, Information Technology (IT) staff are cautious when implementing software that they perceive may in any way restrict their ability to access individual PCs remotely for performing maintenance and system upgrades. The program provides financial incentives and promotes the product benefits through direct marketing to both management and IT staff in order to address these barriers to adoption.

The program is forecast to achieve 4% market penetration by 2015/16.

	2009/10 to 2012/13 *	2013/14	2014/15	2015/16	Total to 2015/16
No. of Licenses (annual)	1,225	2,000	3,000	5,000	**11,225**
Capacity Savings (MW)	0.2	0.2	0.4	0.6	**0.8**
Energy Savings (GW.h)	0.6	0.7	1.0	1.6	**2.2**
Utility Investment (Millions, 2012$)	$0.3	$0.1	$0.0	$0.1	**$0.5**
Customer Investment (Millions, 2012$)	$0.2	$0.0	$0.0	$0.1	**$0.3**
Total DSM Investment (Millions, 2012$)	$0.5	$0.1	$0.1	$0.1	**$0.8**
Estimated Average Annual Bill Reduction per Customer (Electric): $1,200					

** Includes estimates for 2012/13*



Support Program

The following convenient financing program offered by Manitoba Hydro supports the incentive based programs by allowing customers to finance initial project costs and pay these costs back on their monthly Manitoba Hydro bill.

Power Smart for Business PAYS Financing

PAYS Financing for commercial customers is planned to be introduced to the market in early 2013. The program's objective is to assist commercial customers in reducing their energy and water consumption by offering extended financing terms for energy efficiency upgrades such as T8 lighting, high efficiency and electric furnaces, condensing and near-condensing boilers, insulation, geothermal, CO2 sensors, custom measures, and WaterSense® labeled toilets and urinals. This offering compliments and supports the various incentive-based programs by assisting customers in managing the installation cost of their upgrade. To qualify, upgrades must have sufficient estimated annual utility bill savings to offset the monthly financing repayment, thereby resulting in an energy bill that is less than or equal to the total bill prior to the retrofit. The target market for this program consists primarily of small business owners and tenants as well as government, school and municipal buildings. Financing will be available for extended terms with 20 to 25 year amortization periods dependent on the upgrade with the interest rate being fixed for the first five years.

The program expects to finance 24 projects annually with a total annual financed amount of approximately $700,000. These are projects that would likely not have occurred without the availability of this convenient and flexible financing offering.

	2012/13 to 2012/13 *	2013/14	2014/15	2015/16	Total to 2015/16
No. of Loans (annual)	0	24	24	24	**72**
Capacity Savings (MW)	0.0	0.0	0.1	0.2	**0.2**
Energy Savings (GW.h)	0.0	0.2	0.4	0.7	**0.7**
Natural Gas Savings (million m^3)	0.0	0.0	0.0	0.0	**0.0**
Average Loan Amount: $19,100					

** Includes estimates for 2012/13*

Industrial

Manitoba Hydro offers incentive based programs to address opportunities within the industrial market. These programs take a customer-focused approach to identify and address operating and production challenges in a manner that not only improves overall energy efficiency, but enhances productivity and competitiveness for Manitoba industry.

Manitoba's industrial market can be characterized as consisting of a large variety of industries with a small number of customers represented within each classification. While some sectors are responsible for higher percentages of consumption than others, no one industry sector is dominant within the province. In Manitoba, each sector is typically dominated by one or two larger customers, with the remaining customers being smaller with more specialized operations or substantively lower outputs. This diversity presents some unique challenges as opportunities to capture substantive savings are tied directly to specific industry business cycles within each industry sector that dictate major events such as equipment change-outs, plant overhauls, facility expansions, and new plant construction. These cycles are periodic and can stretch across decades.
Manitoba Hydro's industrial Power Smart programs must have broad appeal in order to be relevant and responsive to the needs of a diverse population of industrial customers.

Incentive Based Programs

Performance Optimization Program

The Performance Optimization Program was originally launched in June of 1993 promoting energy efficiency through the optimization of electric motor-driven industrial systems such as air compressors, pumps, fans and blowers, optimization of industrial refrigeration, process heating, electro-chemical processes systems, and implementation of plant-wide energy management systems. The program is designed to provide industrial and large commercial customers with technical support and financial incentives to assist in the identification, investigation, and implementation of system-efficiency improvements throughout a facility.

The target market consists of approximately 2 000 Manitoba Hydro industrial customers, with the program being available to both existing facilities and new construction projects. Emphasis is placed on the 300 largest customers who represent about 1/3 of the energy consumed in Manitoba. The average duration of a project from identification of the opportunity to implementation ranges from 6 months to 2 years, averaging approximately 18 months.

The actual number of project applications facilitated in any fiscal year and the savings achieved per project can vary dramatically based on project size, equipment age, and remaining life of the individual systems being optimized. Savings levels are however relatively consistent reflecting the capability within Manitoba Hydro's programs to adapt to available opportunities. Targeted companies may have multiple eligible energy conservation projects that are captured in a short period of time, resulting in intense periods of activity within a company or industry sector followed by a lull in activity thereafter as investment is recouped and productivity gains are utilized.

	1993/94 to 2012/13 *	2013/14	2014/15	2015/16	Total to 2015/16
Capacity Savings (MW)	88.0	2.2	4.4	6.6	**94.7**
Energy Savings (GW.h)	418.0	14.2	28.4	42.6	**460.6**
Utility Investment (Millions, 2012$)	$31.8	$2.8	$2.8	$2.8	**$40.1**
Customer Investment (Millions, 2012$)	$62.9	$1.7	$1.7	$1.7	**$68.0**
Total DSM Investment (Millions, 2012$)	$94.7	$4.5	$4.5	$4.5	**$108.1**
Estimated Average Annual Bill Reduction per Customer (Electric): $7,283					

** Includes estimates for 2012/13*

Industrial Natural Gas Optimization Program

The Power Smart Natural Gas Optimization Program (NGOP) is a 12 year program launched in September 2006. Its primary objective is to support the systematic improvement of natural gas equipment and processes for industrial and large institutional customers. The program supports customers by offering financial incentives for steam trap audits, feasibility studies and for energy efficient project implementation. The program was principally developed to promote custom applications within large industrial, institutional and commercial facilities comprised of roughly 1 400 customers in Manitoba. Since the launch of the program, it has become apparent that the small to medium industrial customers are also interested in pursuing energy efficiency with support from Manitoba Hydro. The scope of the NGOP has since been expanded to allow the program to respond to all industrial customer inquiries, regardless of the size of the facility or volume of natural gas consumed.

Like the Performance Optimization Program, the NGOP is a custom program that supports a variety of technologies across a wide variety of applications, including; boiler conversions, process water and air heat recovery, process equipment and pipe insulation, boiler economizers, and other available technologies. The program is designed to address key market barriers related to project costs, available benefits, cost/benefit ratios and desired return on investment. Current low natural gas commodity prices are challenging Manitoba Hydro customers' desired rates of return on investment in conservation initiatives.

	2006/07 to 2012/13 *	2013/14	2014/15	2015/16	Total to 2015/16
Natural Gas Savings (million m^3)	11.4	1.6	3.0	4.2	**15.6**
Utility Investment (Millions, 2012$)	$3.7	$0.8	$0.6	$0.6	**$5.7**
Customer Investment (Millions, 2012$)	$18.8	$2.7	$2.0	$2.0	**$25.6**
Total DSM Investment (Millions, 2012$)	$22.5	$3.5	$2.7	$2.7	**$31.3**
Estimated Average Annual Bill Reduction per Customer (Natural Gas): $26,204					

** Includes estimates for 2012/13*

Bioenergy Optimization Program

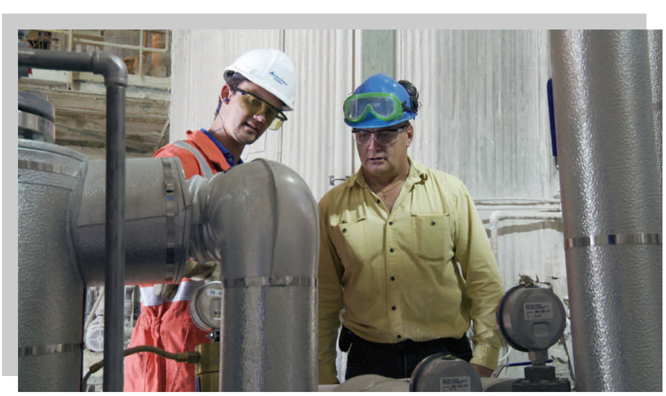
The Bioenergy Optimization Program, launched in 2008, encourages customers to install, operate and maintain customer-sited load displacement generation systems that employ combined heat and power (CHP) and renewable fuels; specifically biomass. The target market consists of customers that have readily available, low cost sources of biomass, continual needs for heat and power, and the capability to operate and maintain biomass to energy conversion systems.

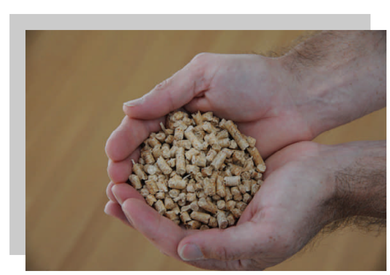
A lack of proven demonstration projects of biomass to energy is a key barrier for many customers, considering the high initial costs for many of these systems. To increase awareness and knowledge of bioenergy opportunities, Manitoba Hydro has undertaken five demonstration projects over the past two years. Increased awareness combined with incentives are expected to increase customer interest and acceptance of bioenergy systems. Manitoba Hydro's program further supports customers in developing a thorough understanding of the costs and benefits of bioenergy systems, assisting with the development of strong business cases for future installations.

Major customer sectors targeted by the program include large industrial, medium-small industrial, Hutterite colonies, and hog production. The size of these systems is anticipated to be smaller during the earlier stages of the program, due primarily to the high costs of the systems. Installations are anticipated to grow in size as comfort with these technologies matures. While initial projections for customer participation are relatively modest, opportunities for larger savings exist in larger industrial facilities with substantial waste streams and considerable need for combined heat and power systems to support their operations. Government policy on renewable energy is anticipated to be a factor in future uptake of load displacement generation systems in Manitoba, particularly larger systems.

	2008/09 to 2012/13 *	2013/14	2014/15	2015/16	Total to 2015/16
Capacity Savings (MW)	0.6	1.4	2.8	4.4	**5.0**
Energy Savings (GW.h)	5.1	12.0	24.9	38.4	**43.5**
Natural Gas Savings (million m^3)	0.0	0.3	0.6	1.1	**1.1**
Utility Investment (Millions, 2012$)	$12.9	$2.3	$1.9	$2.5	**$19.6**
Customer Investment (Millions, 2012$)	$24.1	$3.0	$2.2	$3.7	**$33.0**
Total DSM Investment (Millions, 2012$)	$37.0	$5.4	$4.0	$6.2	**$52.6**
Estimated Average Annual Bill Reduction per Customer (Electric): $89,267					
Estimated Average Annual Bill Reduction per Customer (Natural Gas): $121,773					

** Includes estimates for 2012/13*



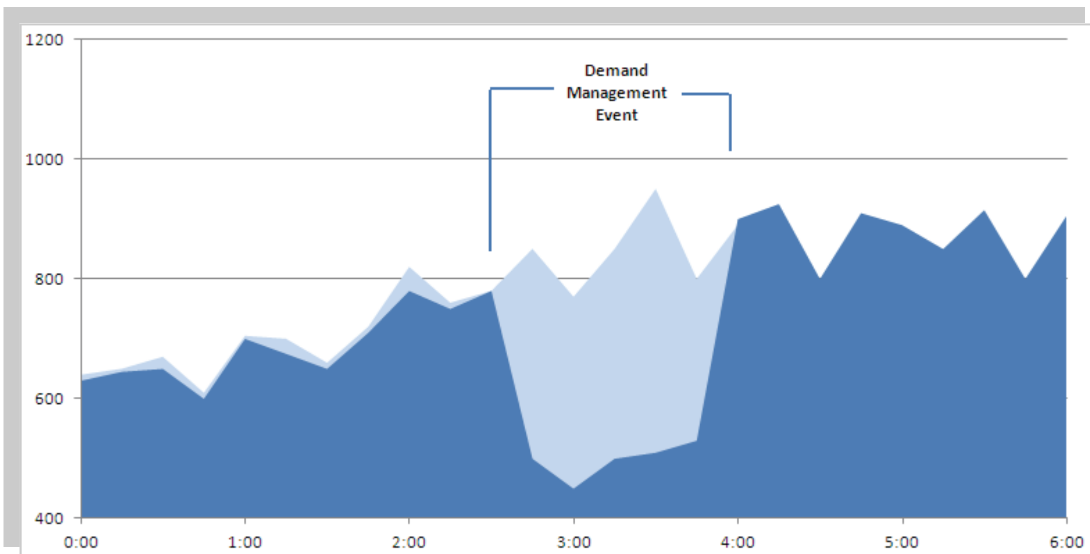


Curtailable Rates Program

Under the Curtailable Rate Program, qualifying customers receive a monthly credit on load (kW) which can be curtailed on notice from Manitoba Hydro. To be eligible, customers' load/processes must be configured to allow them to meet the requested curtailment within the notification period as outlined under their chosen contract option.

	1990/00 to 2012/13 *	2013/14	2014/15	2015/16	Total to 2015/16
No. of Customers (annual)	46	3	3	3	**55**
Capacity Savings (MW)	161.1	161.1	161.1	161.1	**161.1**
Utility Investment (Millions, 2012$)	$85.1	$5.8	$5.8	$5.8	**$102.4**

** Includes estimates for 2012/13*



PUB/CENTRA I-53

Subject: **Tab 7 DSM**

Reference: **Tab 7 Pages 2 and 3 of 4; Appendix 7.1 2011 Power Smart Plan**

b) **Please provide an updated chart of integrated natural gas savings forecasted for the years 2011/12 through 2024/25 and explain any changes from the forecast in the 2011 Power Smart Plan.**

ANSWER:

The 2011 Power Smart Plan is Centra's current approved DSM plan.

PUB/CENTRA I-53

Subject: **Tab 7 DSM**

Reference: **Tab 7 Pages 2 and 3 of 4; Appendix 7.1 2011 Power Smart Plan**

c) Please file the update to the 2011 Power Smart Plan when it becomes available.

ANSWER:

The update to the 2011 Power Smart Plan will be filed when it becomes available.

PUB/CENTRA I-54

Subject: **Tab 7 DSM**

Reference: **Tab 7 Appendix 7.1 Page 19**

a) Please explain what factors are leading to a reduction in natural gas DSM spending in 2013/14 through the 15 year planning cycle.

ANSWER:

The reduction in natural gas DSM spending is the result of programs coming to an end as planned. Power Smart Programs are designed to achieve economic energy savings. The duration of these programs depends on market factors including expected code or regulation changes, or where market penetration reaches a point where the continuation of the program is no longer economic. In the latter case, generally the integrated benefits of continuing to run the program are less than the integrated costs from a combined customer/utility perspective.

PUB/CENTRA I-54

Subject: **Tab 7 DSM**

Reference: **Tab 7 Appendix 7.1 Page 19**

b) **Please provide a schedule which shows the DSM program spending and relative proportion of total DSM spending by customer type for each of the years 2009/10 through 2013/14.**

ANSWER:

The following table outlines the DSM program spending and relative proportion of total program spending. Customer Service Initiatives, Support and Contingency costs are excluded from the total DSM program spending used in calculating percentages.

	(in $000's)									
	Actual		Actual		Actual		Plan		Plan	
	2009/10		2010/11		2011/12		2012/13		2013/14	
	(2009$)		(2010$)		(2011$)		(2011$)		(2011$)	
RESIDENTIAL										
Home Insulation	2,945		2,230		2,104		2,600		2,538	
Lower Income:										
Power Smart	*737*		*791*		*822*		*692*		*686*	
Furnace Replacement Program	*815*		*1,312*		*1,627*		*2,330*		*2,330*	
Apportioned Affordable Energy Fund	*1,337*		*2,133*		*2,505*		*3,219*		*3,207*	
Lower Income Total	2,890		4,236		4,954		6,242		6,223	
HE Gas Furnace	1,531		31		0		0		0	
New Homes	87		108		64		96		107	
Water & Energy Saver	40		686		1,024		644		637	
	7,494		7,291		8,146		9,582		9,504	
Discontinued/Completed	1		0		8		0		0	
RESIDENTIAL TOTAL	7,494	63%	7,291	55%	8,154	62%	9,582	58%	9,504	60%
COMMERCIAL										
Commercial Insulation	1,242		2,205		1,752		3,373		3,373	
HVAC	1,120		1,227		915		868		882	
Commercial Windows	779		997		1,093		503		503	
Commercial Building Optimization	234		205		118		314		335	
Commercial Custom	140		154		158		92		99	
New Buildings	108		193		198		248		239	
Power Smart Shops	80		95		11		0		0	
Power Smart Energy Manager	71		0		51		0		0	
Commercial Kitchen Appliances	55		29		47		79		91	
Spray Valves	27		21		1		2		0	
Commercial Hot Water	22		31		14		91		97	
City of Winnipeg Agreement	0		0		0		0		0	
Commercial Clothes Washers	0		0		0		0		0	
	3,878		5,155		4,360		5,573		5,619	
Discontinued/Completed	0		0		11		0		0	
COMMERCIAL TOTAL	3,878	32%	5,155	39%	4,371	33%	5,573	33%	5,619	35%
INDUSTRIAL										
Industrial Natural Gas Optimization	597		700		707		923		763	
INDUSTRIAL TOTAL	597	5%	700	5%	707	5%	923	6%	763	5%
EFFICIENCY PROGRAMS SUBTOTAL	11,969		13,147		13,232		16,077		15,885	
CUSTOMER SELF-GENERATION										
Bioenergy Optimization	0		0		0		572		30	
	0	0%	0	0%	0	0%	572	3%	30	0%
PROGRAMS SUBTOTAL	11,969	100%	13,147	100%	13,232	100%	16,649	100%	15,915	100%
CUSTOMER SERVICE INITIATIVES, SUPPORT AND CONTINGENCY	2,102		2,970		2,142		3,551		3,410	
GRAND TOTAL	14,072		16,117		15,374		20,200		19,325	

PUB/CENTRA I-55

Subject: **Tab 7 DSM**

Reference: **Tab 7 Appendix 7.1 Page 17 of 49; Appendix 7.2 Pages 80 to 83 of 142; 2008 Power Smart Plan**

a) **Please provide details of the actual and forecasted DSM expenditures by natural gas program for 2010/11 through 2013/14, breaking out the costs between internal and external costs.**

ANSWER:

Please see the table below.

Expenditure Breakdown (1000s)												
	2010/11- Actual (nominal $)			**2011/12 - Actual (nominal $)**			**2012/13 - Forecast (2011$)**			**2013/14 - Forecast (2011$)**		
	Total	**Internal**	**External**	**Total**	**Internal**	**External**	**Total**	**Internal**	**External**	**Total**	**Internal**	**External**
RESIDENTIAL												
New Home Program	$108	$0	$108	$64	$0	$64	$96	$0	$96	$107	$0	$107
Home Insulation Program	$2,230	$337	$1,893	$2,104	$324	$1,780	$2,600	$342	$2,258	$2,538	$334	$2,204
Water and Energy Saver Program	$686	$120	$566	$1,024	$172	$853	$644	$86	$559	$637	$85	$552
Lower Income Energy Efficiency Program	$791	$181	$610	$822	$240	$582	$692	$121	$571	$686	$120	$565
	$3,815	$638	$3,178	$4,014	$736	$3,279	$4,033	$549	$3,484	$3,967	$539	$3,428
COMMERCIAL												
Commercial Custom Measures Program	$154	$58	$95	$158	$90	$68	$92	$41	$52	$99	$44	$55
Commercial Windows Program	$1,000	$167	$833	$1,093	$171	$922	$503	$142	$362	$503	$142	$362
Commercial Insulation Program	$2,212	$235	$1,977	$1,752	$265	$1,486	$3,373	$216	$3,157	$3,373	$216	$3,157
Commercial New Construction Program	$193	$119	$75	$198	$124	$75	$248	$59	$190	$239	$56	$182
Commercial Building Optimization Program	$203	$147	$56	$118	$79	$39	$314	$136	$178	$335	$145	$190
Commercial Kitchen Appliance Program	$28	$9	$20	$46	$25	$21	$79	$17	$62	$91	$19	$71
CO2 Sensors	$32	$22	$10	$35	$23	$12	$64	$38	$26	$66	$39	$27
Commercial Water Heater Program	$30	$30	$0	$14	$14	$0	$91	$53	$38	$97	$57	$40
Power Smart Energy Manager	$41	$39	$2	$3	$3	$0	$0	$0	$0	$0	$0	$0
Power Smart Shops	$87	$83	$4	$11	$11	$0	$0	$0	$0	$0	$0	$0
Commercial Boiler Program	$1,227	$256	$970	$881	$258	$623	$804	$232	$571	$816	$236	$580
Commercial Rinse & Save Program	$21	$2	$19	$1	$1	$0	$2	$2	$1	$0	$0	$0
	$5,227	$1,167	$4,060	$4,310	$1,064	$3,246	$5,573	$936	$4,637	$5,619	$954	$4,664
INDUSTRIAL												
Industrial Natural Gas Optimization Program	$700	$117	$583	$707	$172	$535	$923	$260	$663	$763	$215	$548
CUSTOMER SELF-GENERATION												
Bioenergy Optimization Program	$0	$0	$0	$0	$0	$0	$572	$56	$516	$30	$30	$0
Option 1 & Customer Service Initiatives	$195	$791	-$596	$481	$1,161	-$680	$1,265	$789	$477	$1,260	$785	$475
Support Activity & Continency	$1,222	$591	$632	$1,393	$699	$694	$1,894	$915	$979	$1,894	$915	$979
Total Power Smart Utility Cost - Natural Gas	**$11,161**	**$3,304**	**$7,857**	**$10,906**	**$3,832**	**$7,074**	**$14,259**	**$3,504**	**$10,755**	**$13,532**	**$3,438**	**$10,094**

PUB/CENTRA I-55

Subject: **Tab 7 DSM**

Reference: **Tab 7 Appendix 7.1 Page 17 of 49; Appendix 7.2 Pages 80 to 83 of 142; 2008 Power Smart Plan**

b) Please identify the natural gas DSM measures and programs that have been added, significantly altered, or canceled since publication of the 2008 Power Smart Plan, and explain why these program changes were made.

ANSWER:

A number of changes have been made to natural gas programs since the publication of the 2008 Power Smart Plan.

Programs added to the portfolio:

- Commercial Water Heaters
- Commercial CO2 Sensors

Programs with significant changes:

- New Homes Program – most energy efficient measures promoted under the program were successfully incorporated into the Manitoba Building Code in 2011.
- Residential Earth Power – participation and savings were adjusted to better reflect program experience.
- Commercial Windows – participation and savings were adjusted to better reflect program experience.

- Commercial Insulation – participation and savings were adjusted to better reflect program experience.
- Commercial New Construction – the planned end date was advanced to 2018/19 to reflect the anticipated adoption of the 2011 National Energy Code for Buildings in Manitoba.
- Commercial Boilers – the planned end date was advanced to March 2015 to align with proposed federal minimum efficiency performance regulations.
- Industrial Natural Gas Optimization – participation and savings were adjusted to better reflect program experience.

Programs removed from the portfolio:

- Residential Appliances – the program ended to coincide with new federal minimum energy efficiency standards for appliances.
- Residential High Efficiency Furnaces and Boilers – the program ended with the introduction of Provincial regulations requiring high efficiency furnaces and boilers.
- Commercial Rinse & Save – the program ended after successfully transforming the market earlier than was originally anticipated.
- Power Smart Energy Manager – the program was not cost-effective.
- Power Smart Shops – the program was not cost-effective.
- Commercial Furnaces – the program ended with the introduction of Provincial regulations requiring high efficiency furnaces and boilers.

PUB/CENTRA I-56

Subject: **Tab 7 DSM**

Reference: **Tab 7 Appendix 7.1 2011 Power Smart Plan; 2008 Power Smart Plan - LIEEP**

a) Please provide demographic data on for both LICO and LICO-125 households broken down by dwelling type and ownership. Please include actual numbers and % of total low income households.

ANSWER:

Please see table below.

	LICO Households in Manitoba					
	ALL FUEL					
Dwelling Type	Own	% of Total LICO	Rent	% of Total LICO	Total By Dwelling Type	% of Total LICO
Single Detached	46,049	62%	3,592	5%	49,641	67%
Multi-Attached	3,975	5%	2,953	4%	6,928	9%
Apartment Suite	4,302	6%	13,344	18%	17,646	24%
Total by Ownership	54,327	73%	19,889	27%	74,216	100%

	LICO-125 Households in Manitoba					
	ALL FUEL					
Dwelling Type	Own	% of Total LICO-125	Rent	% of Total LICO-125	Total By Dwelling Type	% of Total LICO-125
Single Detached	67,410	64%	4,292	4%	71,703	68%
Multi-Attached	6,647	6%	3,753	4%	10,399	10%
Apartment Suite	5,221	5%	17,763	17%	22,984	22%
Total by Ownership	79,278	75%	25,808	25%	105,086	100%

PUB/CENTRA I-56

Subject: **Tab 7 DSM**

Reference: **Tab 7 Appendix 7.1 2011 Power Smart Plan; 2008 Power Smart Plan - LIEEP**

b) Please provide the LICO table that Centra currently uses to determine eligibility for the LIEEP.

ANSWER:

The table below is used to determine eligibility for the LIEEP, calculated as 125% of the before tax LICO table provided by Statistics Canada

Total Income Threshold (dollars) (Income qualifications are based on how many people live in your home and the total income (before deductions) of the household.			
Household Size	**Community Size**		
	Less than 30,000	**Between 30,000 and 99,999**	**500,000 or more**
1 person	23,150	25,300	29,559
2 persons	28,819	31,495	36,800
3 persons	35,429	38,720	45,241
4 persons	43,018	47,013	54,928
5 persons	48,789	53,320	62,299
6 persons	55,026	60,136	70,261
7 persons or more	61,263	66,953	78,226

PUB/CENTRA I-57

Subject: **Tab 7 DSM**

Reference: **Tab 7 Appendix 7.1 Page 20 of 49; 2012/13 & 2013/14 GRA PUB/MH I-108(a)**

a) Please provide the input data for determining the RIM, LUC, and customer payback for natural gas DSM programs similar to that provided in PUB/MH I-108(a) for the 2012/13 & 2013/14 GRA.

ANSWER:

The following table provides the input data to calculate the various cost effectiveness measures of each incentive-based program in the 2011 Power Smart Plan.

	Marginal Benefits			Program Admin Costs			Incremental Product Cost	Revenue Loss	Incentives			Year 1			Energy Saved
	PV of Marginal Benefit	*PV of Non-Energy (Water) Benefits*	*PV of Interactive Revenue Gain*	*PV of Utility Program Admin Costs*	*PV of AEF Program Admin Costs*	*PV of FRP Program Admin Costs*	*PV of Incremental Product Costs*	*PV of Revenue Loss*	*PV of Utility Incentives*	*PV of AEF Incentives*	*PV of FRP Incentives*	*Net Customer Costs*	*Year 1 Revenue Loss*	*Year 1 Water Benefits*	*PV of Energy Saved @ Gen (kW.h)*
Residential															
New Home Program	$ 9,818,672	$ -	$ 29,831	$ 86,915	$ -	$ -	$ 18,302,624	$ 11,048,128	$ 442,705	$ -	$ -	$ 367,215	$ 15,154	$ -	26,412,970
Home Insulation Program	$ 30,823,709	$ -	$ -	$ 2,777,081	$ -	$ -	$ 19,600,717	$ 35,213,913	$ 10,411,633	$ -	$ -	$ 1,931,643	$ 469,364	$ -	85,103,334
Water and Energy Saver Program	$ 6,278,553	$ 4,535,975	$ 202,058	$ 1,699,984	$ -	$ -	$ 680,423	$ 7,550,063	$ 680,415	$ -	$ -	$ -	$ -	$ 119,055	17,947,100
Lower Income Energy Efficiency Program	$ 17,229,328	$ 11,288,666	$ 337,088	$ 822,959	$ 4,192,030	$ 3,000,670	$ 19,515,584	$ 20,307,266	$ 2,226,324	$ 10,004,379	$ 7,286,337	$ 3,962,834	$ 450,630	$ 253,125	48,578,295
Commercial															
Commercial Custom Measures Program	$ 3,598,347	$ -	$ -	$ 685,461	$ -	$ -	$ 2,095,081	$ 3,667,865	$ 329,081	$ -	$ -	$ 142,034	$ 20,635	$ -	9,853,102
Commercial Windows Program	$ 17,391,998	$ -	$ -	$ 1,518,882	$ -	$ -	$ 3,576,818	$ 18,949,078	$ 2,938,849	$ -	$ -	$ 86,394	$ 158,764	$ -	47,411,950
Commercial Insulation Program	$ 76,565,093	$ -	$ -	$ 2,030,808	$ -	$ -	$ 34,163,026	$ 83,554,913	$ 24,446,895	$ -	$ -	$ 1,490,988	$ 788,096	$ -	209,252,008
Commercial New Construction Program	$ 25,891,596	$ -	$ -	$ 942,204	$ -	$ -	$ 2,181,562	$ 26,345,374	$ 924,575	$ -	$ -	$ 76,780	$ 88,317	$ -	70,990,363
Commercial Building Optimization Program	$ 11,270,207	$ -	$ -	$ 1,410,888	$ -	$ -	$ 4,638,629	$ 11,730,851	$ 2,511,823	$ -	$ -	$ 115,932	$ 69,147	$ -	31,132,813
Commercial Kitchen Appliance Program	$ 4,989,968	$ 482,742	$ -	$ 208,782	$ -	$ -	$ 2,716,616	$ 5,333,356	$ 397,979	$ -	$ -	$ 35,830	$ 12,548	$ 4,110	13,481,197
Commercial Clothes Washers Program	$ 188,033	$ -	$ -	$ -	$ -	$ -	n/a	$ 197,235	$ -	$ -	$ -	$ -	$ -	$ -	529,101
CO2 Sensors	$ 3,446,247	$ -	$ -	$ 266,463	$ -	$ -	$ 1,040,565	$ 3,560,020	$ 189,301	$ -	$ -	$ 44,707	$ 22,275	$ -	9,558,405
Commercial Boiler Program	$ 17,438,649	$ -	$ -	$ 853,148	$ -	$ -	$ 6,547,161	$ 18,505,015	$ 2,323,202	$ -	$ -	$ 349,147	$ 307,742	$ -	48,504,485
Commercial Water Heater Program	$ 3,362,685	$ -	$ -	$ 323,548	$ -	$ -	$ 1,745,359	$ 3,604,786	$ 297,539	$ -	$ -	$ 66,425	$ 15,152	$ -	9,322,001
Commercial Rinse & Save Program	$ 25,131	$ 45,925	$ -	$ 4,741	$ -	$ -	$ -	$ 28,455	$ -	$ -	$ -	$ -	$ -	$ 3,042	74,811
Industrial															
Industrial Natural Gas Optimization Program	$ 25,265,998	$ -	$ -	$ 1,667,880	$ -	$ -	$ 16,019,096	$ 24,809,882	$ 2,912,563	$ -	$ -	$ 2,880,000	$ 461,920	$ -	74,544,852
Customer Self Generation															
Bioenergy Optimization Program	$ 11,884,323	$ -	$ -	$ 183,513	$ -	$ -	$ 1,940,785	$ 12,435,665	$ 989,244	$ -	$ -	$ 34,934	$ 16,467	$ -	33,758,675

PUB/CENTRA I-57

Subject: **Tab 7 DSM**

Reference: **Tab 7 Appendix 7.1 Page 20 of 49; 2012/13 & 2013/14 GRA PUB/MH I-108(a)**

b) Please provide the Societal Cost Test results for each of the gas DSM programs.

ANSWER:

Please see the table below.

Programs	2011 Power Smart Plan	
	TRC	**SCT**
Residential		
New Home Program	0.5	0.6
Home Insulation Program	1.4	1.5
Water and Energy Saver Program	4.5	5.0
Lower Income Energy Efficiency Program*	1.0	1.1
Commercial		
Commercial Custom Measures Program	1.3	1.4
Commercial Windows Program	3.4	3.8
Commercial Insulation Program	2.1	2.3
Commercial New Construction Program	8.3	9.1
Commercial Building Optimization Program	1.9	2.0
Commercial Kitchen Appliance Program	1.9	2.1
CO2 Sensors	2.6	2.9
Commercial Boiler Program	2.4	2.6
Commercial Water Heater Program	1.6	1.8
Commercial Rinse & Save Program (Market Effects)	15.0	16.5
Industrial		
Industrial Natural Gas Optimization Program	1.4	1.6
Customer Self Generation		
Bioenergy Optimization Program	5.6	6.2

* *Includes Furnace Replacement Program and apportioned Affordable Energy Fund expenditures.*

PUB/CENTRA I-57

Subject: **Tab 7 DSM**

Reference: **Tab 7 Appendix 7.1 Page 20 of 49; 2012/13 & 2013/14 GRA PUB/MH I-108(a)**

c) Please provide the values that Centra uses in its DSM cost effectiveness tests for avoided cost of gas, avoided cost of infrastructure, avoided greenhouse gas emissions, measureable non-energy benefits, and discount rate.

ANSWER:

Avoided cost of gas – Centra's forecast of natural gas prices as contained in the Power Smart Plan is commercially sensitive information, and as such, Centra respectfully declines to provide the requested information.

Avoided cost of infrastructure – Centra does not include any avoided cost of infrastructure associated with the Corporation's natural gas DSM efforts.

Avoided greenhouse gas emissions – The following values are used:

	GHG Credits/tonne 2011$
2011/12	$4.66
2012/13	$5.75
2013/14	$6.72
2014/15	$7.95
2015/16	$9.01
2016/17	$9.88
2017/18	$10.71
2018/19	$11.51
2019/20	$12.27
2020/21	$13.01
2021/22	$13.72
2022/23	$14.41
2023/24	$15.09
2024/25	$15.75
2025/26	$16.40
2026/27	$17.05
2027/28	$17.70
2028/29	$18.35
2029/30	$19.01
2030/31	$19.67

Measurable non-energy benefits – Water bill savings are included in the cost effectiveness tests. Please refer to the response to PUB/Centra I – 58(b) for details on the water costs used in these calculations.

Discount rate – 6.1%

PUB/CENTRA I-57

Subject: **Tab 7 DSM**

Reference: **Tab 7 Appendix 7.1 Page 20 of 49; 2012/13 & 2013/14 GRA PUB/MH I-108(a)**

d) In calculating RIM, please confirm whether lost revenue includes both gas and non-gas revenue or only non-gas revenue.

ANSWER:

The lost revenue calculation included within the natural gas RIM metric includes gas revenue and non-gas revenue.

PUB/CENTRA I-57

Subject: **Tab 7 DSM**

Reference: **Tab 7 Appendix 7.1 Page 20 of 49; 2012/13 & 2013/14 GRA PUB/MH I-108(a)**

e) Please demonstrate the calculation of the SCT, TRC, RIM, and LUC for the Home Insulation Program.

ANSWER:

Please see the calculations below.

$$\textbf{TRC} = \frac{\text{PV of Marginal Benefits + PV of Non-Energy Benefits}}{\text{PV of Admin Costs + PV of Incremental Product Costs}}$$

$$= \frac{\$30,823,709 + \$0}{\$2,777,081 + \$19,600,717}$$

$$= 1.4$$

$$\textbf{SCT} = \frac{\text{(PV of Marginal Benefits + PV of Non-Energy Benefits) + 10\%}}{\text{PV of Admin Costs + PV of Incremental Product Costs}}$$

$$= \frac{(\$30,823,709 + \$0) \times 1.1}{\$2,777,081 + \$19,600,717}$$

$$= 1.5$$

$$\textbf{RIM} = \frac{\text{PV of Marginal Benefits}}{\text{PV of Admin Costs + PV of Utility Incentives + PV of Revenue Loss}}$$

$$= \frac{\$30,823,709}{\$2,777,081 + \$10,411,633 + \$35,213,913}$$

$$= 0.6$$

$$\textbf{LUC} = \frac{\text{PV of Admin Costs + PV of Utility Incentives}}{\text{PV of Energy}}$$

$$= \frac{\$2,777,081 + \$10,411,633}{85,103,334}$$

$$= 15.5\text{¢ per cu.m}$$

PUB/CENTRA I-58

Subject: **Tab 7 DSM**

Reference: **Tab 7 Appendix 7.1 Pages 26 and 27 of 49**

a) Please provide supporting calculations for the forecasted residential and commercial customer bill reductions.

ANSWER:

Customer bill reductions are calculated by multiplying the forecast cubic metre gas savings each year for a program by the forecast natural gas rates in each year for that program. Individual program bill reductions are then aggregated to determine the total customer bill reductions.

Centra's forecast of natural gas prices as contained in the Power Smart Plan is commercially sensitive information, and as such, Centra respectfully declines to provide the requested detailed information.

PUB/CENTRA I-58

Subject: **Tab 7 DSM**

Reference: **Tab 7 Appendix 7.1 Pages 26 and 27 of 49**

b) Please provide the unit cost of water used in the calculation of cumulative water benefits and provide the source of this unit cost.

ANSWER:

The 2011 City of Winnipeg water and sewer rates were used in the calculation of water benefits as found on the following website:

http://www.winnipeg.ca/waterandwaste/pdfs/billing/2011_rates_en.pdf

The 2011 water rate was $1.34 per cubic metre and the sewer rate was $1.97 per cubic metre.

To convert to a cost per litre:

$1.34 + $1.97 = $3.31 per cubic metre

$3.31 per cubic metre ÷1 000 litres per cubic metre = $0.00331 per litre.

PUB/CENTRA I-59

Subject: **Tab 7 DSM**

Reference: **Tab 7 Appendix 7.3 - FRP**

a) **Please complete the table below showing the opening and closing fund balances, annual disbursements, annual funding from rates, and interest since the inception of the FRP and forecasted to March 31, 2015. Please include the number of furnace and boiler installations completed each year and the cumulative number of furnace and boiler installations.**

Furnace Replacement Fund ending March 31:	2009	2010	2011	2012	2013	2014 (forecast)	2015 (forecast)
Opening Balance							
Funding from SGS Class							
Disbursements							
Interest							
Ending Balance							
Number of Furnace Installations							
Number of Boiler Installations							
Cumulative Furnace Installations							
Cumulative Boiler Installations							

ANSWER:

Furnace Replacement Fund ending March 31 (000's)	**2008/9**	**2009/10**	**2010/11**	**2011/12**	**2012/13***	**2013/14 Forecast**	**2014/15 Forecast**
Opening Balance	$ 2,327	$ 5,972	$ 9,050	$ 11,644	$ 14,145	$ 15,853	$ 17,644
Funding from SGS Class	$ 3,855	$ 3,800	$ 3,762	$ 3,838	$ 3,800	$ 3,800	$ 3,800
Disbursements	$ (264)	$ (815)	$ (1,312)	$ (1,627)	$ (2,378)	$ (2,378)	$ (2,378)
Interest	$ 54	$ 93	$ 144	$ 290	$ 286	$ 369	$ 555
Ending Balance	$ 5,972	$ 9,050	$ 11,644	$ 14,145	$ 15,853	$ 17,644	$ 19,621
Number of Furnace Installations	280	508	445	662	660	1,016	937
Number of Boiler Installations	5	9	16	18	9	15	9
Cumulative Furnace Installations	280	788	1,233	1,895	2,555	3,571	4,508
Cumulative Boiler Installations	5	14	30	48	57	72	81

* 2012/13 values are a combination of actual values to the end of February, 2013 and forecasted values for March, 2013

PUB/CENTRA I-59

Subject: **Tab 7 DSM**

Reference: **Tab 7 Appendix 7.3 - FRP**

b) Please provide the December 31, 2012 LIEEP and FRP status report.

ANSWER:

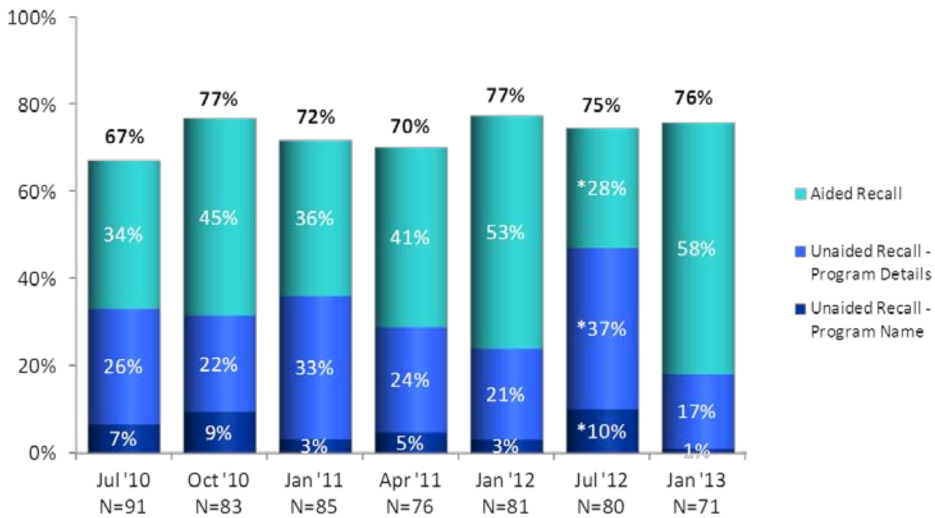
Please see attached to this response the Report on the Lower Income Energy Efficiency Program and the Furnace Replacement Program for the third quarter of 2012/13.

Report on the Lower Income Energy Efficiency Program and the Furnace Replacement Program For the Period Ending December 31, 2012

LIEEP Program Awareness

Currently, 76% of LICO-125 respondents say they heard of Manitoba Hydro's *Lower Income Energy Efficiency Program.* This includes 1% of LICO-125 respondents who independently recall (unaided awareness) the LIEEP or Power Smart Lower Income Program name, 17% who say they are aware of the key details of the LIEEP such as helping lower income homeowners upgrade their insulation or furnaces/boilers but cannot recall the program name (unaided awareness of program details), and 58% who say they recognized the program name after the LIEEP name is stated (aided awareness).

Unaided Recall decreased significantly relative to the previous wave. However, Aided Recall offset the decrease by increasing significantly relative to previous waves thus Total Awareness remained on par with its historical average.



Unaided Awareness Question: "What, if any, MH programs or services are you aware of that help Lower Income Homeowners reduce electricity or natural gas energy used in their homes?"
Aided Awareness Question: "Have you heard of MH's Lower Income Energy Efficiency Program which helps lower income homeowners upgrade their furnaces or insulation through home energy efficiency evaluations, rebates or long-term financing.

Target Furnace Replacement Market - As at December 31, 2012

The following table has been updated to provide an estimate of the standard furnaces being used in Manitoba and an indication for the target market for Manitoba Hydro's Furnace Replacement Program.

LIEEP Standard Efficiency Furnace Target Market Review (updated as of December 31, 2012)

Furnace Marketplace at Dec 1 2009*	LICO 125%	Non-LICO	All Dwellings
Standard Furnaces			
Owners	16,034	39,858	55,892
Rentals	2,285	2,152	4,437
Total Standard Furnaces (2009* Survey)	18,319	42,010	60,329
Estimated Installation from Dec 1/09 to December 31/12**			
Total	6,253	18,597	24,851
Remaining Standard Furnaces at December 31st, 2012***			
Total	**12,066**	**23,413**	**35,478**
All Natural Gas Furnaces (2009 survey)*****	**49,406**	**175,674**	**225,080**
Standard % of Marketplace	**24%**	**13%**	**16%**

* Statistics from November 2009 survey, gas heated billed customers - excluding boilers and including apts. Estimated number of standard efficiency furnaces has been slightly refined in Q4 2011/12 report.

** Estimated total number of natural gas furnace replacements from Dec 1, 2009 to December 31, 2012 is based on permit data shown in following table, for a total of 27,612 furnace replacements. It is assumed that 90% of all furnaces replaced since December 2009 were standard efficient furnaces. The breakdown between LICO and Non-LICO has been further refined based on analysis from the 2009 survey.

*** The standard furnaces being replaced in the lower income market are reflective of Manitoba Hydro's lower income program, normal furnace failures and marketing efforts by the HVAC industry. Although the lower income market might not be influenced by the HVAC marketing efforts as much as other market sectors, the average age of the furnaces within the lower income market is higher and therefore, it is expected that this market sector might experience higher overall failure rates. "All Gas Furnace" numbers have been slightly refined from 2010/11 Q3.

**** Represents the total number of natural gas furnaces in the marketplace, including those in renter-occupied dwellings; however, LIEEP targets owner-occupied dwellings only.

Natural Gas Furnace Replacements - As at December 31, 2012

The following table provides data on all furnace replacements, based on information from installation permits. Information updated as of December 31, 2012.

Replacement Furnace Permits Manitoba										
	2003	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
January	545	457	539	1002	811	769	953	1231	734	1064
February	410	362	540	650	715	616	633	657	550	1096
March	384	408	514	847	669	719	653	587	655	997
April	259	463	372	594	525	663	727	441	462	518
May	272	367	425	644	598	530	682	398	401	478
September	298	414	341	581	572	538	743	507	457	518
July	298	317	338	543	619	743	662	449	497	509
August	291	426	452	612	695	736	527	442	536	512
September	556	584	775	876	811	1581	705	750	725	592
October	830	850	1047	1452	1500	2080	986	935	994	1123
November	648	990	975	1350	1426	1426	1201	1073	1286	1129
December	692	735	823	731	1035	1110	1516	884	1124	785
TOTALS	**5483**	**6373**	**7141**	**9882**	**9976**	**11511**	**9988**	**8354**	**8421**	**9321**

Target Insulation Upgrade Market - As at December 31, 2012

The following table provides an updated estimate of the target insulation upgrade market in Manitoba.

Q3 - 2012/13 Report - without apartments

Insulation Target Market Review	**LICO 125%**	**Non-LICO Dwellings**	**All Dwellings**
Dwellings with Insulation Rated "Poor/Fair"			
Owners	15,704	45,052	60,756
Renters	3,361	4,747	8,108
Total Dwellings with Insulation Rated "Poor/Fair" (2009 Insulation Upgrade Target Market)*	19,065	49,799	68,864
Estimate of Number of Dwellings Insulated from Dec 2009 to December 31,2012**	1,131	2,063	3,194
2010 Insulation Upgrade Target	**17,934**	**47,736**	**65,670**
Total Dwellings	82,102	301,121	383,223
Fair/Poor % of Marketplace	22%	16%	17%

*Statistics from November 2009 Survey, gas and electric heated billed customers; excludes apartments. The table reflects LICO x 125% and uses the two categories of "poor and fair" to determine the target market.

**Number of "fair/poor" insulation dwellings being insulated from Dec 1/09 to December 31/12 is based on:

- Non-LICO dwellings: based on approximately 12,503 dwellings being insulated through the Home Insulation Program from December 1, 2009 to December 31, 2012; prorated this number based on proportion on "poor/fair" to all dwellings in Residential Study (16.5%); and
- LICO x 125% dwellings: based on estimate of 57% of approximately 1,984 private individual homes insulated through LIEEP since December 2009 as being rated as "fair/poor"; 57% is proportion of LIEEP insulation participants where insulation upgrade cost was $3000 or more in a sample of 466 customers.

LIEEP Program Participation Highlights - Oct 1 to December 31, 2012

The following provides a high level overview of the status of the LIEEP Program to date, with more details provided in the following section of the report.

A. Homes Completed

Program Participation Overview	FY 2012/13 Q3 (Oct 1 – Dec 31, 2012)	Cumulative (to Dec 31, 2012)
Individual	326	3,820
Community	0	1,717
First Nation	63	670
Total	**389**	**6,207**

B. Furnace and Boiler Installations Completed

Program Participation Overview		FY 2012/13 Q3 (Oct 1 – Dec 31, 2012)	Cumulative (to Dec 31, 2012)
Individual:	Furnace	223	2,283
	Boiler	2	55
Community:	Furnace	0	72
	Boiler	0	1
First Nation		0	0
Total:	**Furnace**	**223**	**2,355**
	Boiler	**2**	**56**

C. Insulation Installations Completed

Program Participation Overview	FY 2012/13 Q3 (Oct 1 – Dec 31, 2012)	Cumulative (to Dec 31, 2012)
Individual	202	2,162
Community	0	1,698*
First Nation	63	670
Total	**265**	**4,530**

*There were 19 homes with Low Cost No Cost retrofits only, so they are not included in the insulation totals

LIEEP Program Participation Details – Oct 1 to December 31, 2012

Detailed Program Participation	FY 2012 Q3 (Oct 1 – Dec 31, 2012)	Cumulative (to Dec 31, 2012)
1. Individual Approach		
Eligibility applications through Hydro:		
Received	628	6,284
Approved	422	4,681
In-Home Pre-Retrofit Evaluations[1]:		
ecoENERGY D's Completed	0	2,339
In-home Reviews Completed	378	2,192
Total Pre-Retrofits Completed	**378**	**4,531**
In-home Reviews Scheduled	n/a	39
Homes Completed[2]:		
Basic Retrofits (CFL's, etc.)	52	756
Deep Retrofits (Insulation and/or Furnace)	274	3,064
Total Homes Completed	**326**	**3,820**
Furnace Replacement Program:		
Furnaces Installed	223	2,283
Boilers Installed	2	55
Furnaces In Process[3]	n/a	111
Insulation Upgrade Program:		
Insulation Upgrades Completed	202	2,162
Insulation in Process[4]	n/a	299
2. Community Approach		
a) Private Homeowners		
Retrofits Completed through BUILD	**0**	**177**
Furnaces Installed	0	72
Boilers Installed	0	1
Retrofits Completed through BNRC	**0**	**17**
Furnaces Installed	0	0
b) Manitoba Housing/Community Housing		
Centennial (BUILD) Retrofits Complete	**0 MH Homes 0 DOFNHA 0 Kanata 0 Kinew**	**899 MH Homes 35 DOFNHA[5] 14 Kanata 71 Kinew**

Report on Lower Income Energy Efficiency Program and the Furnace Replacement Program
For the Period Ending December 31, 2012

Manitoba Green Retrofit (MGR) Complete	**0 Kinew**	**2 Kinew**[6]
Brandon (BNRC) Retrofits Complete	**0 - MH Homes**	**502 - MH Homes**
3. First Nations Power Smart Program		
Total Retrofits Completed	**63**	**670**
Manto Sipi (God's River)	13	13
Sapotaweyak	10	20
Long Plain	0	10
God's Lake First Nation	0	15
Norway House	0	15
Poplar River	0	14
Keeseekoowenin	10	20
Birdtail Souix	0	20
Skownan	0	20
Canupawakpa Dakota First Name	0	36
Chemawawin (Easterville) Cree Nation	0	45
Mosakahiken (Moose Lake) First Nation	0	29
Sayisi Dene - 1 (Tadoule) First Nation	0	27
Ebb & Flow First Nation	0	20
Crane River First Nation	0	9
Peguis First Nation	20	90
Cross Lake First Nation	0	60
Fisher River First Nation	10	29
Northlands Dene First Nation	0	38
Pine Creek First Nation	0	30
Barren Lands First Nation	0	51
Nelson House First Nation	0	19
OCN (The Pas) First Nation	0	20
O-Pipon-Na-Piwin Cree First Nation	0	10
Misipawistik (Grand Rapids) First Nation	0	10

[1] "D" Evaluations are pre-retrofit evaluations to determine the energy efficiency opportunities in each home. LIEEP introduced revised In-home Reviews after the cancellation of ecoENERGY program (March 2010). The ecoENERGY program was re-introduced in July, 2011 and ended June 2012. In-home Reviews were re-introduced in January 2012.

[2] "Homes Completed" are the total number of homes that have completed retrofits. The completed homes are divided into the following two levels of customer participation: basic installation level, which includes installation of basic energy efficiency items such as low flow showerheads, CFLs, etc.; and deep installation level, which includes additional retrofit work of furnace and/or insulation upgrades.

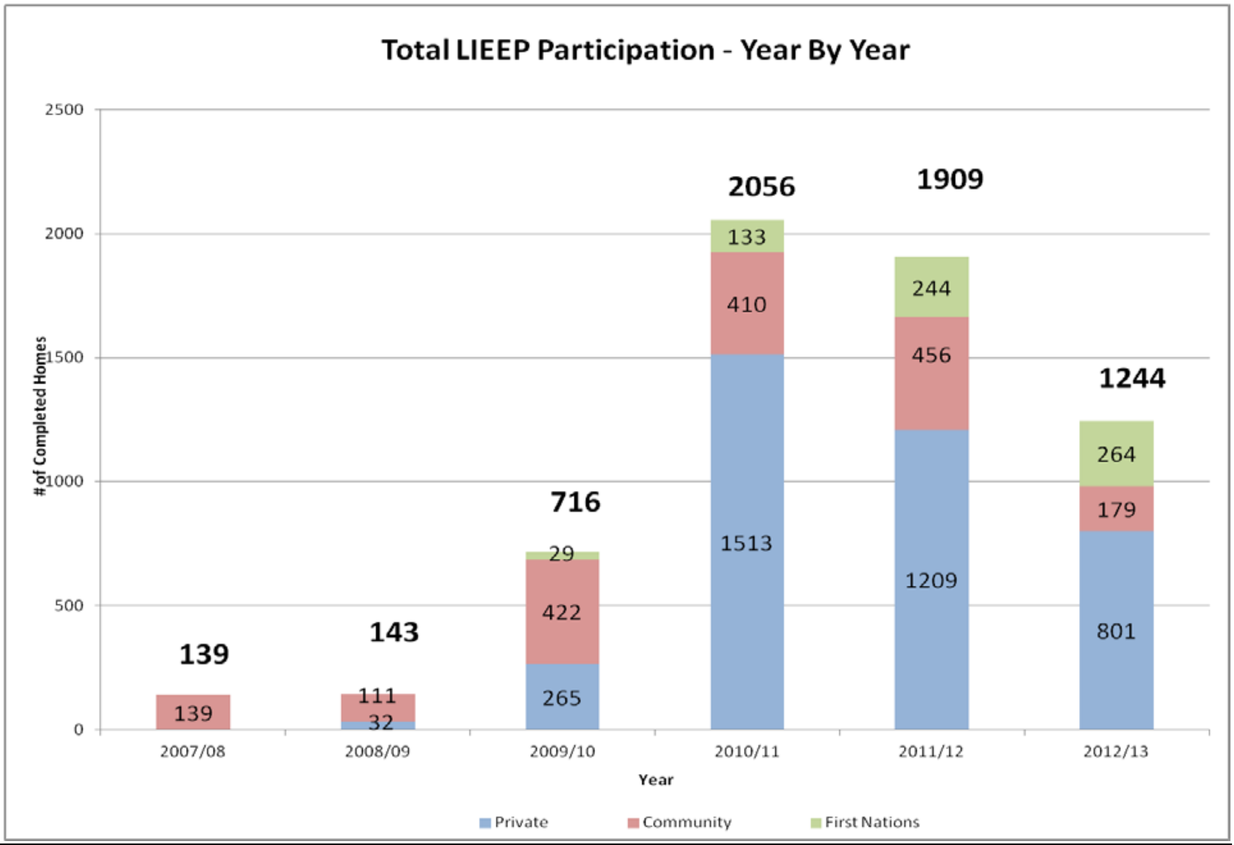
[3] As of December 31, 2012, there are a total of 111 furnace installations in progress (received furnace application, but no completion certificates).

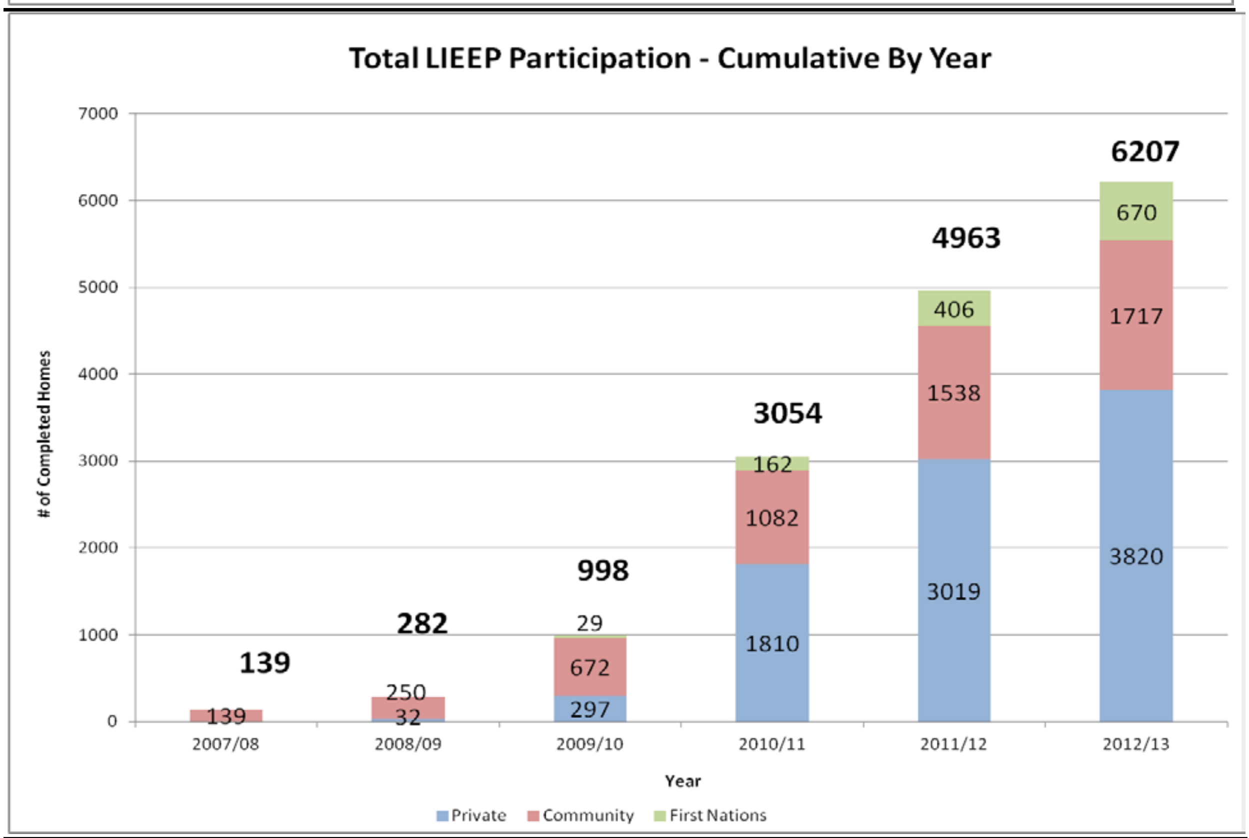
[4] There are 299 customers with in progress insulation work (received insulation applications, but no completion certificate).

[5] Dakota Ojibway First Nations Housing Authority (DOFNHA).

[6] Work completed on 2 MGR Kinew units in Q4 2011/12 but not counted until Q1 2012/13

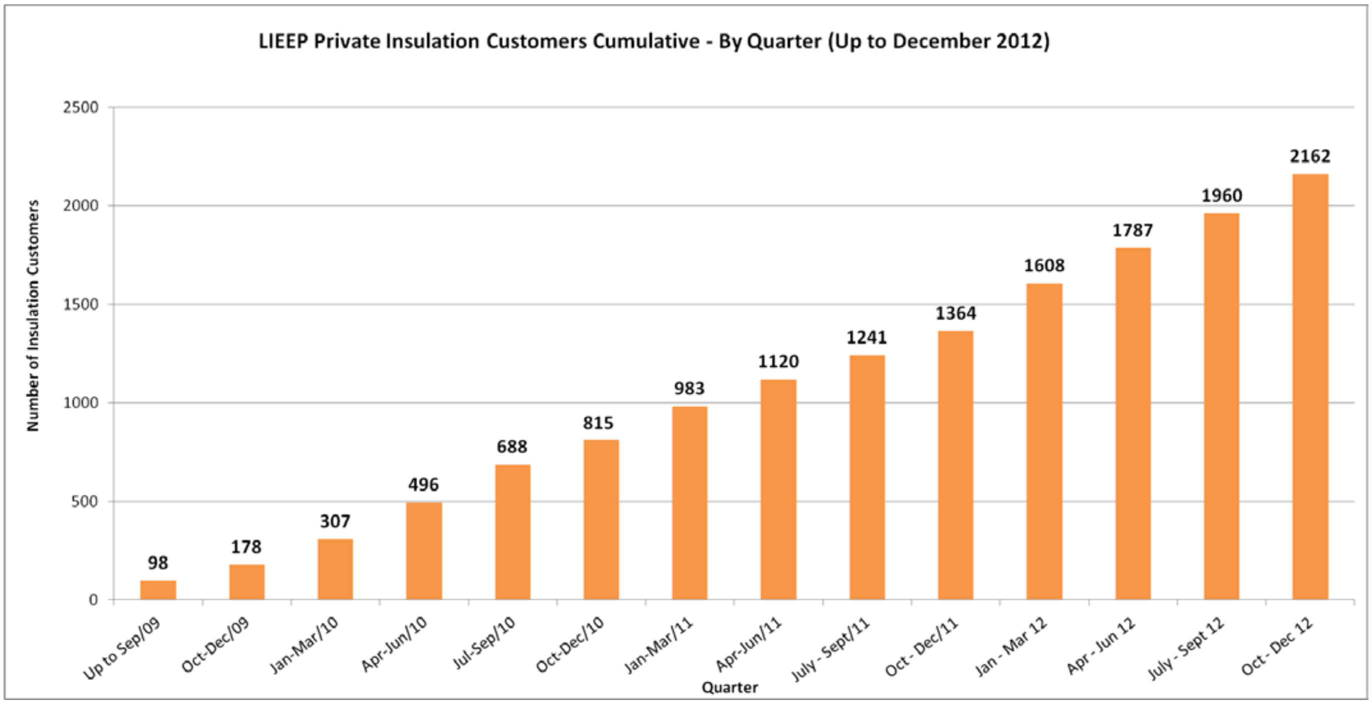
Trending Charts: LIEEP Completed Homes Since Program Inception

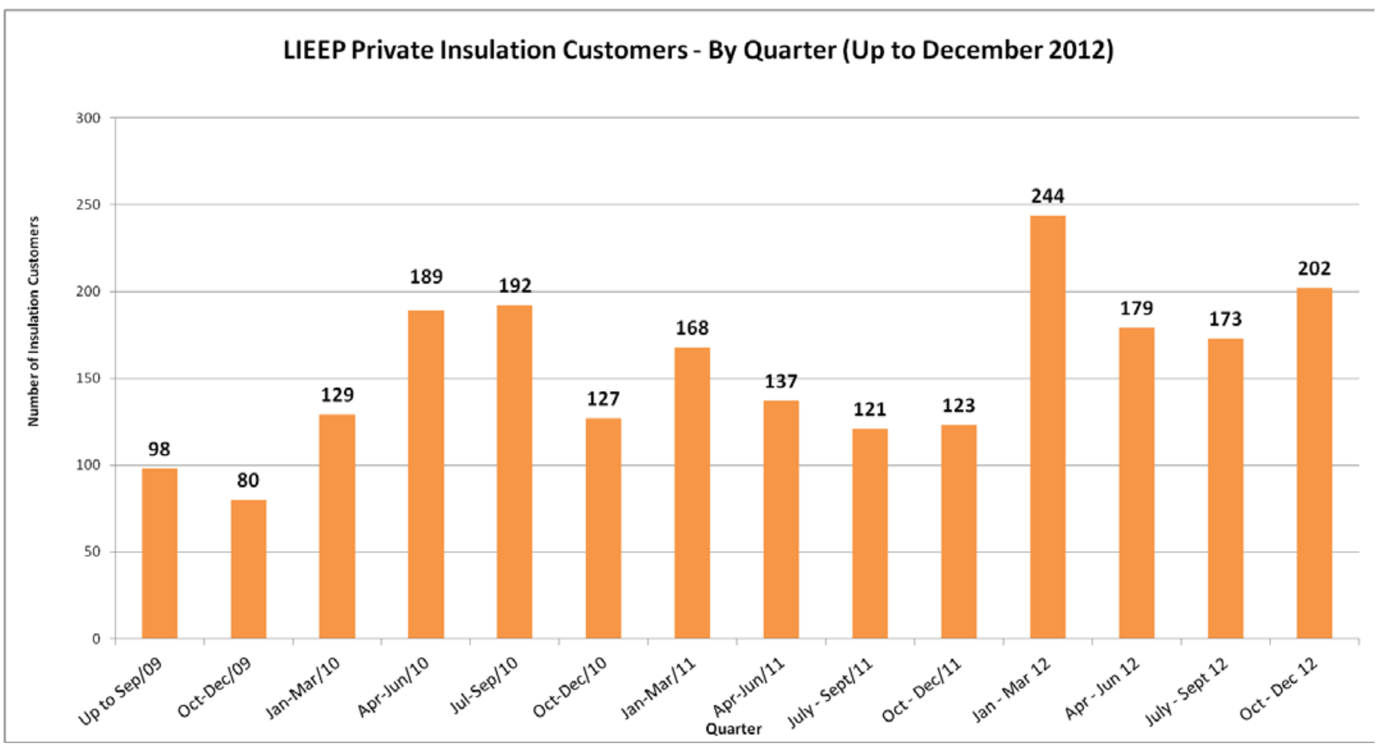




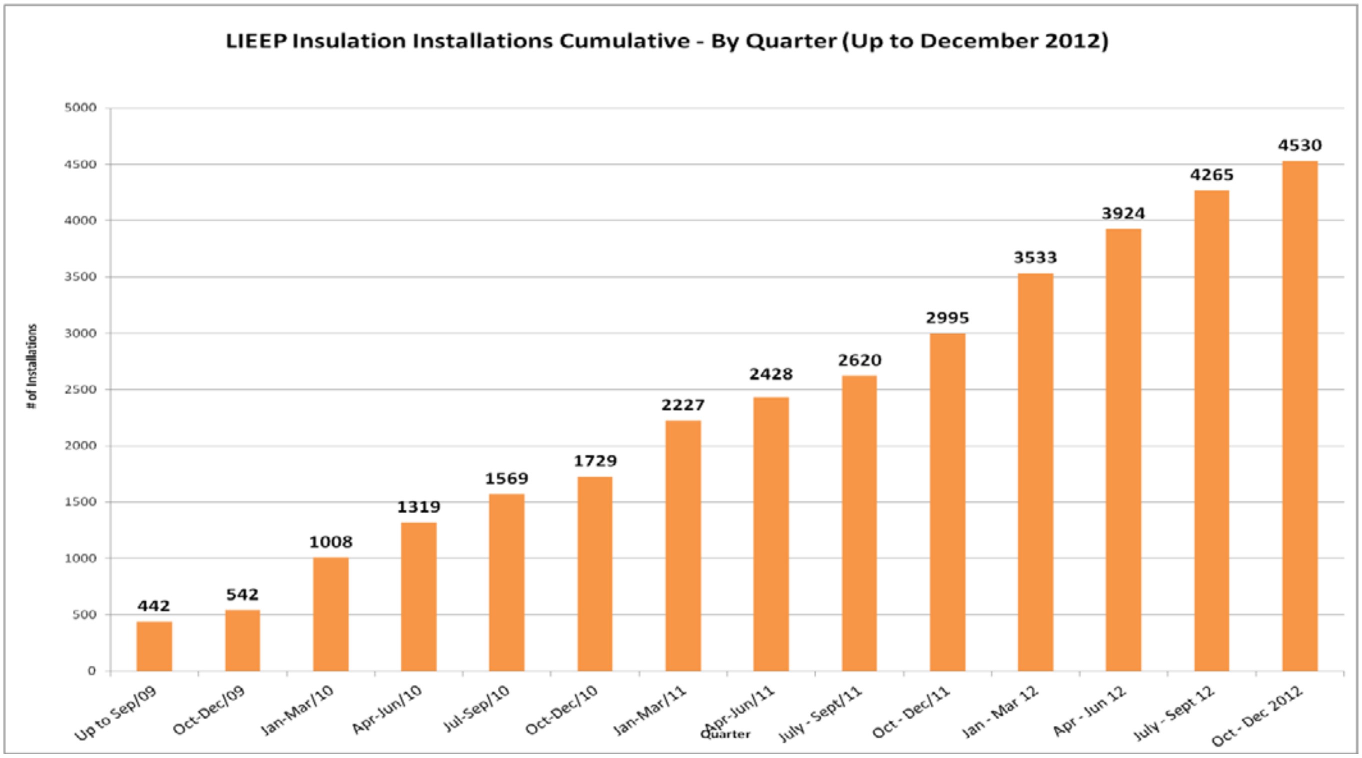
Trending Charts: LIEEP Insulation Installation Since Program Inception

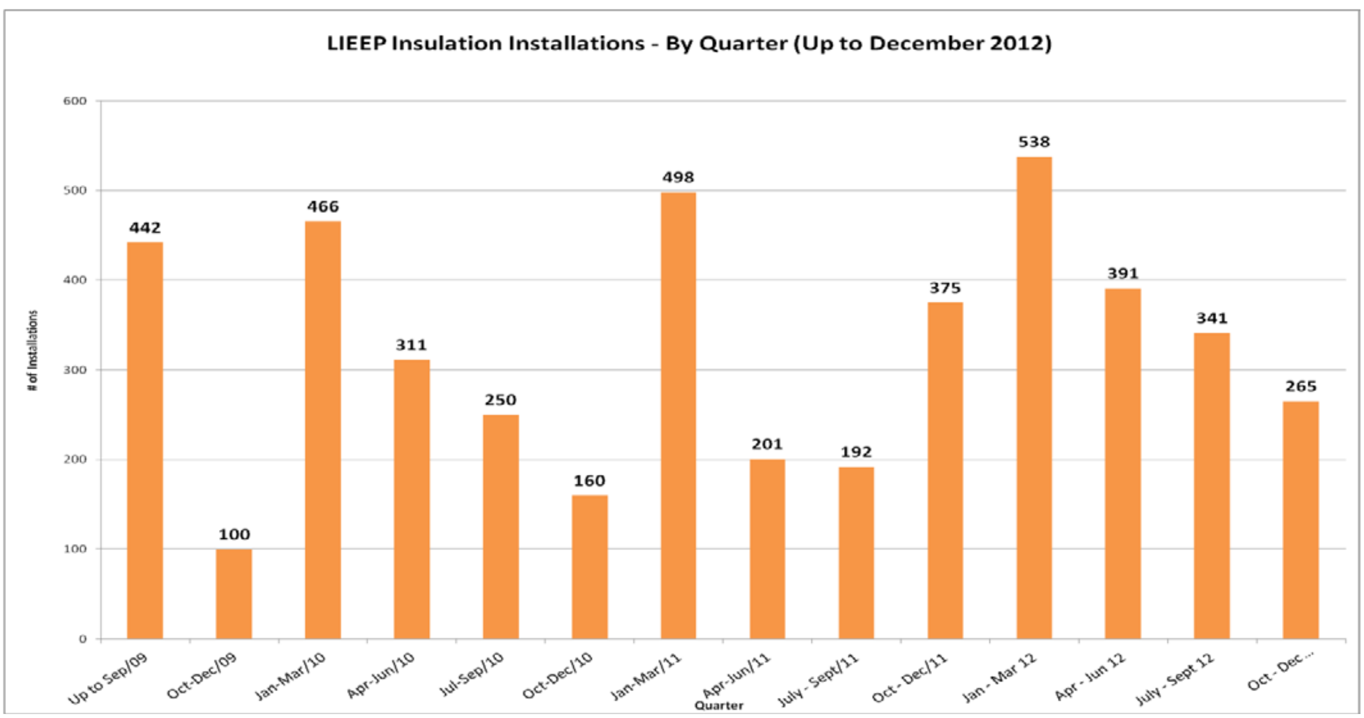
a) Individual Approach Only





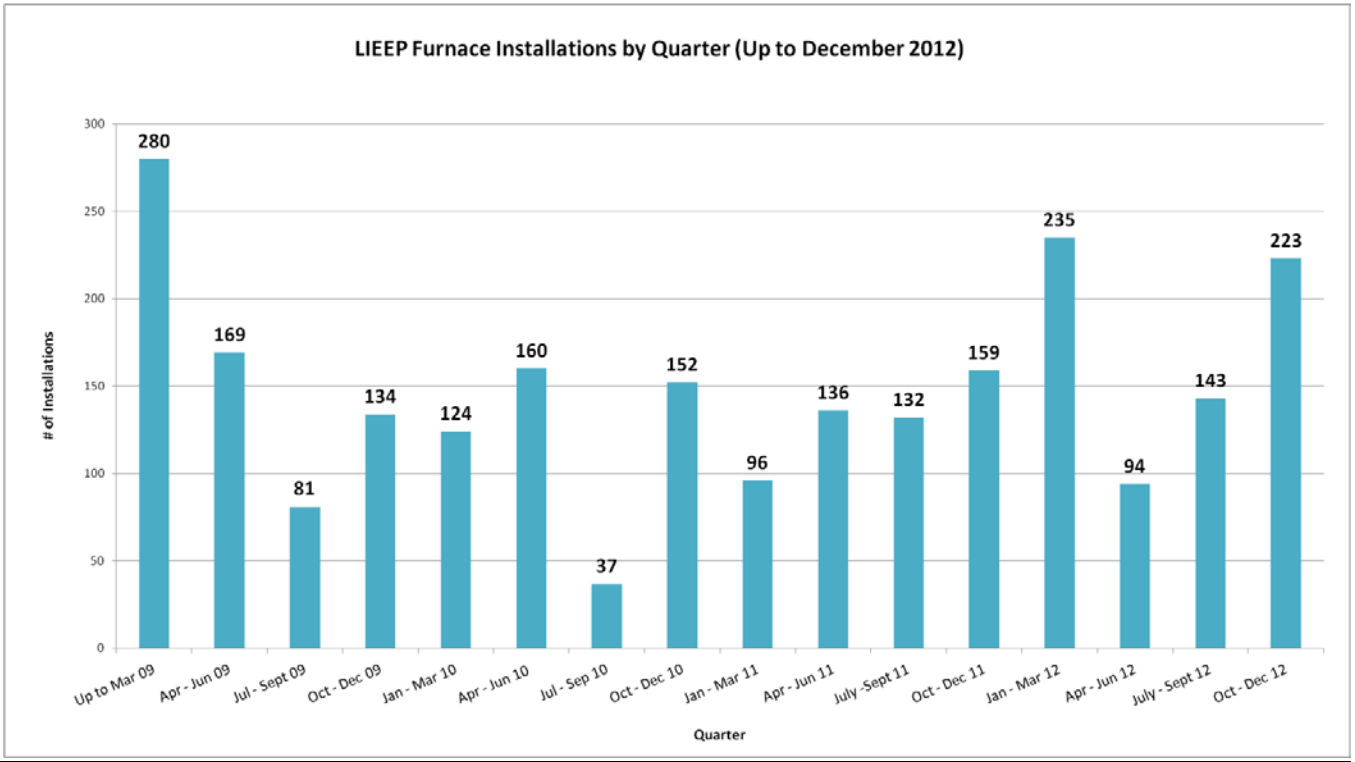
b) All Approaches (Individual, Community and First Nations)

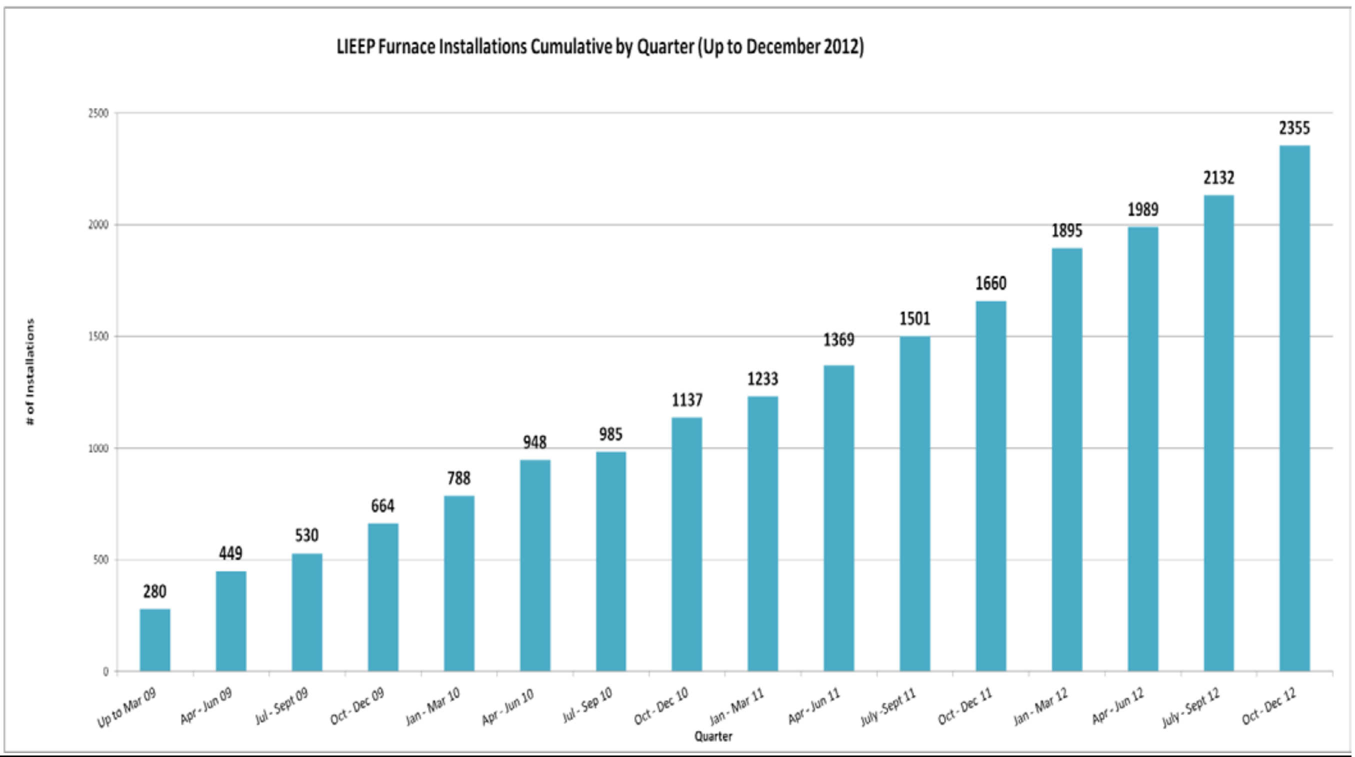




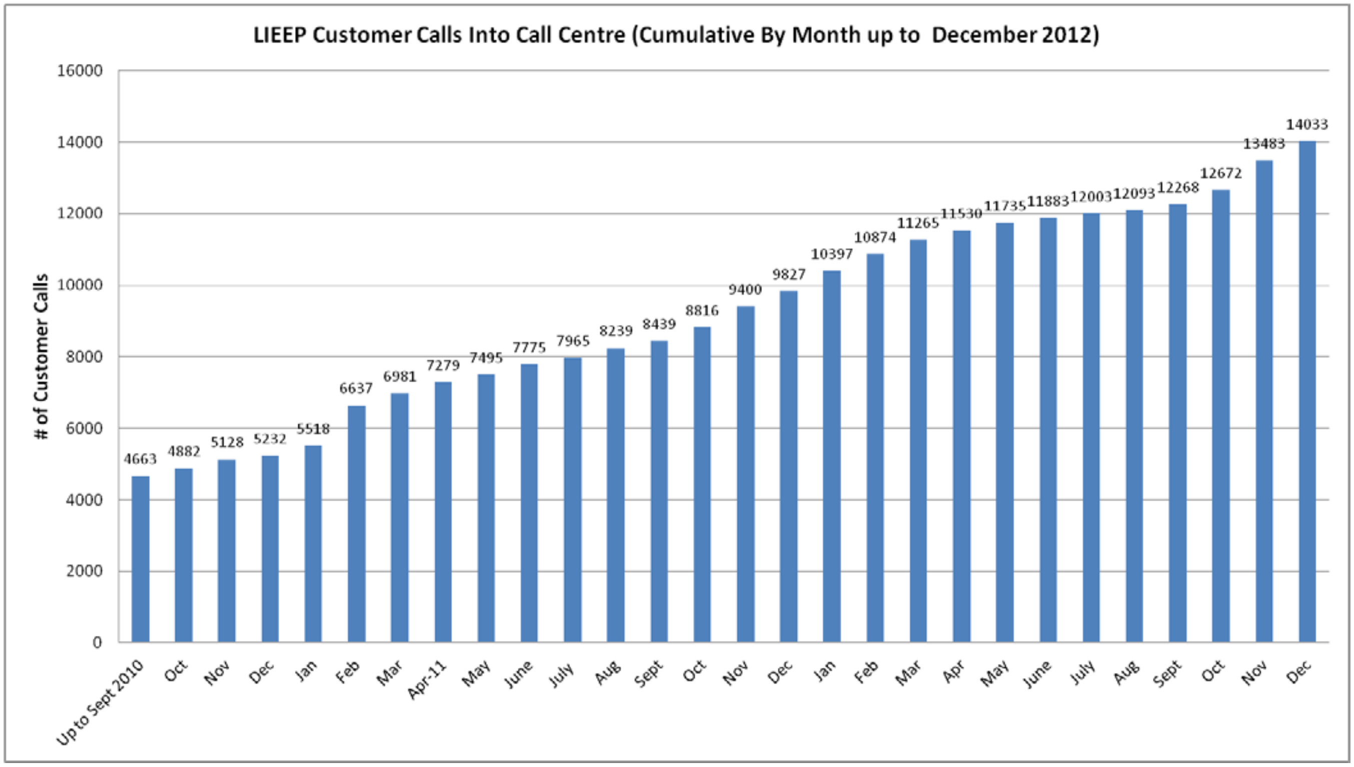
Data includes individual approach (2,162 cumulative to end of December 2012), community approach (1,698 cumulative to end of December 2012) and First Nations (670 cumulative to end of December 2012). In the October - December 2012 period, there were a total of 202 for individual approach, 0 for community approach (MHA, DOFNHA, Kanata, Kinew, MGR and private homeowners) and 63 for First Nations. Completions are counted once all paperwork is finalized from community groups. Assumes all upgrades for community approach are insulation upgrades with an exception of 19 Kinew homes that were Low Cost No Cost retrofits only.

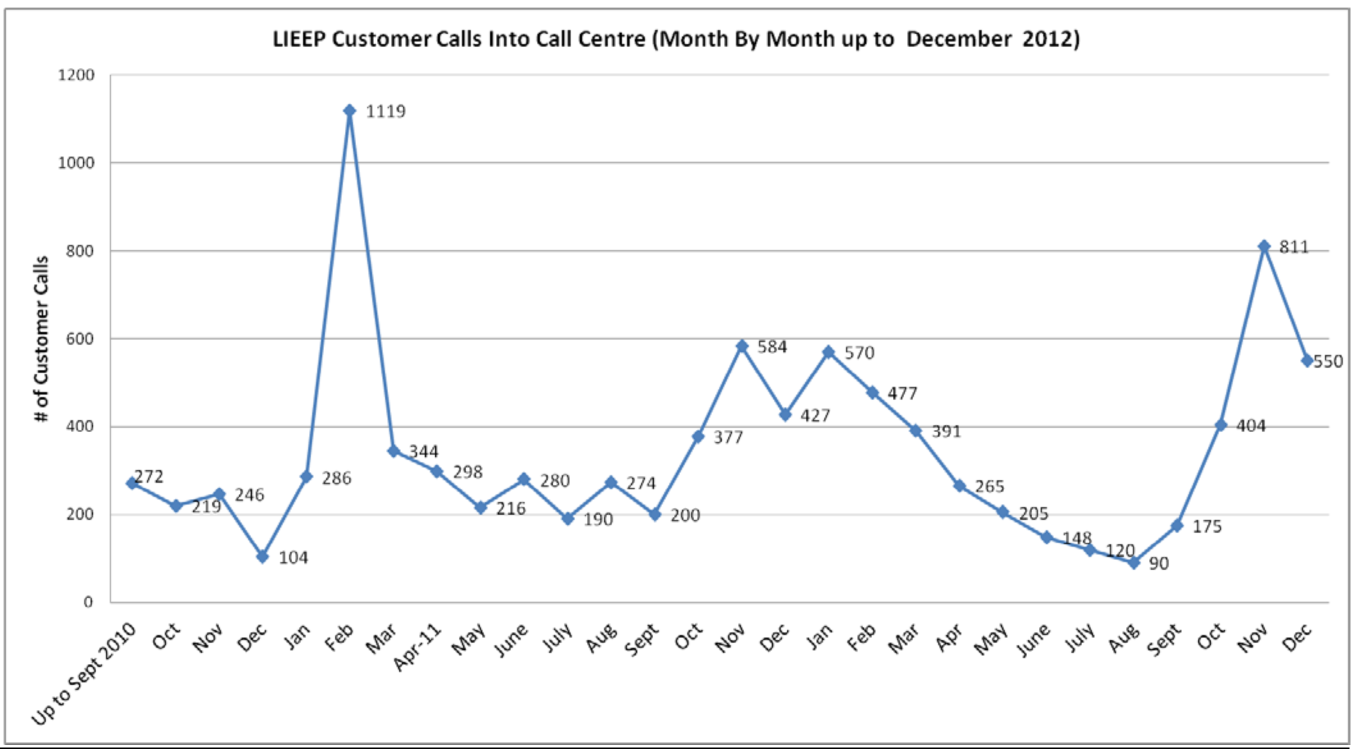
Trending Charts: Furnace Replacements Since Program Inception



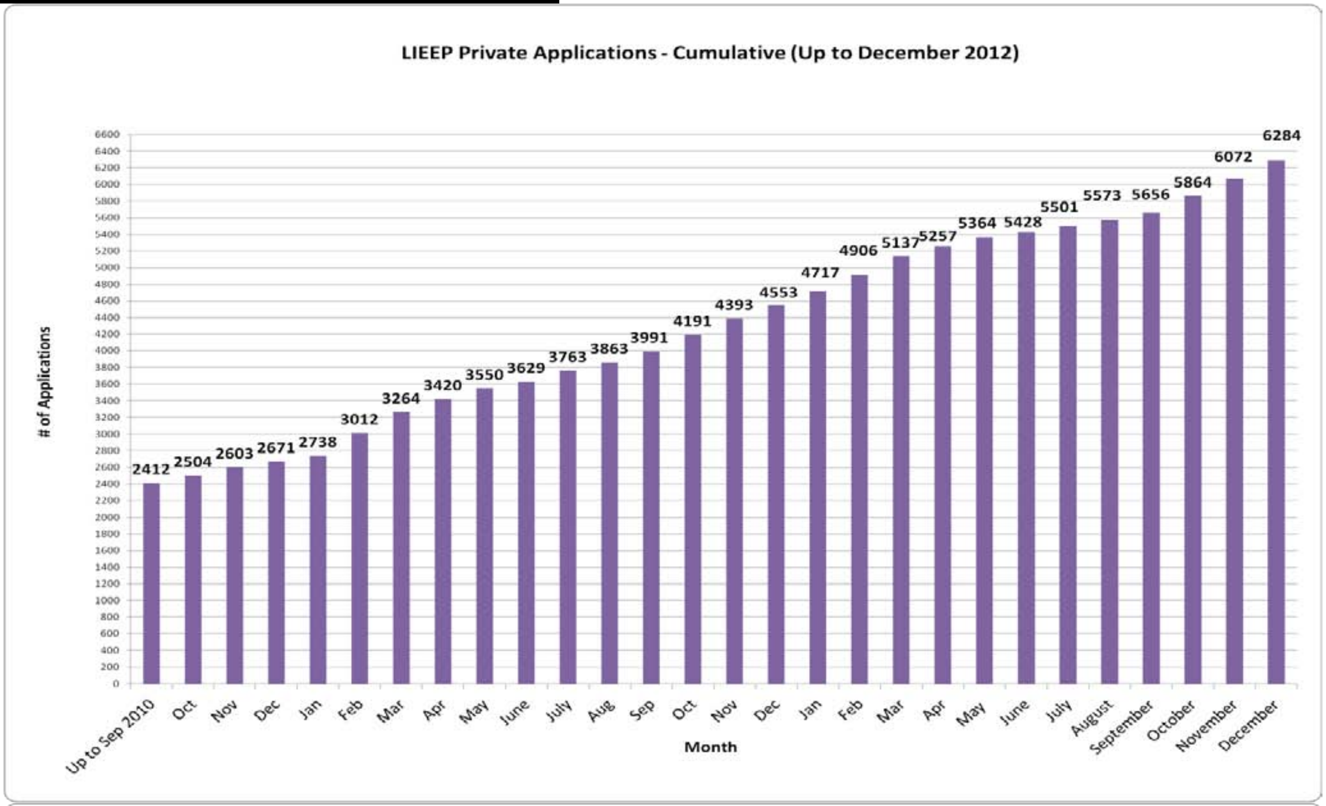


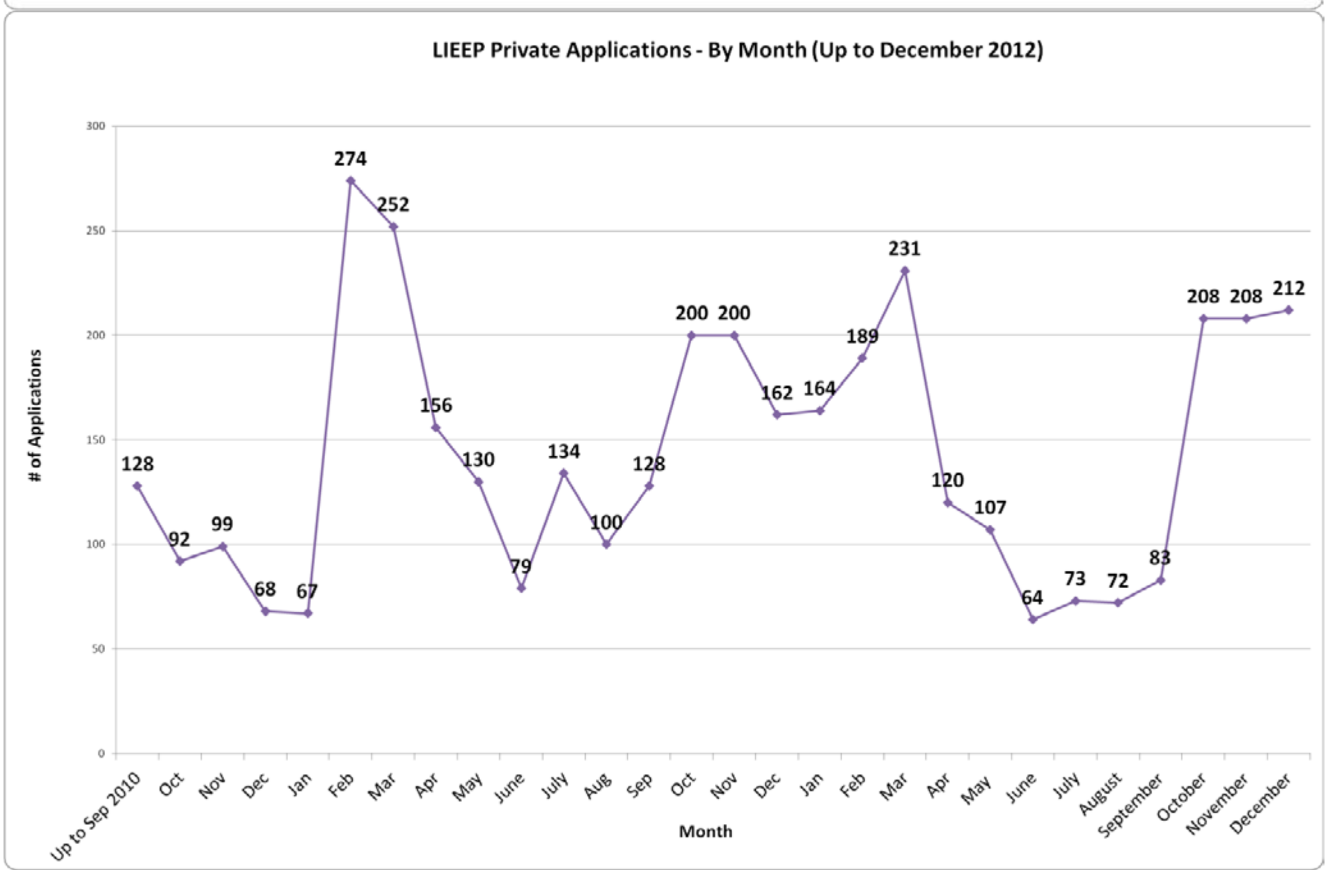
Trending Charts: Contact Centre Calls





Trending Charts: LIEEP Applications





Furnace Replacement Program Details – Oct 1 to Dec 31, 2012

Furnace Installations from October 1, 2012 to December 31, 2012

Lower Income FRP	Total Program		Individual Approach		Community Approach	
	Furnaces	Boilers	Furnaces	Boilers	Furnaces	Boilers
Oct 1, 2012 – December 31, 2012	223	2	223	2	0	0
Cumulative (Since Inception of FRP)	2,355	56	2,283	55	72	1
Scheduled Installations	111	0				
Estimated Installations (next 6 months)	325					

Contact Centre Calls and Credit/Collection Referrals

Lower Income FRP	Customer Contact Centre Calls	Credit & Collections Referrals
Oct 1, 2012 – December 31, 2012	1,765	15
Cumulative (Since Inception of FRP)	13,464	356

Furnace Failures

Furnace Failures*	Furnaces Replaced due to Failure	Furnaces Replaced Before the End of Life
Oct 1, 2012 – December 31, 2012	22	201
Cumulative to December 31, 2012	90**	1,477

*Furnace failures started being recorded as of Q2 Report (Apr-Sep/10), therefore cumulative data is starting July 1, 2010 and is not comparable to other cumulative data reported which started at the beginning of the FRP.
** In addition to the above furnace failures, there was one boiler failure during Q3 2011/12 period and one during the Q4 2011/12 period.

Furnace Installations by Neighbourhood

FURNACES - Individual Customers		
	Oct 1 – December 31, 2012	Cumulative to December 31, 2012
Postal Code	Total # Installations	Total # Installations
R0A	0	11
R0C	3	13
R0E	0	15
R0G	4	23
R0H	0	1
R0J	1	12
R0K	0	5
R0L	1	7
R0M	0	6
R1A	2	21
R1C	0	1
R1N	2	10
R2B	0	1
R2C	7	102
R2E	0	7
R2G	9	86
R2H	3	35
R2J	2	49
R2K	15	156
R2L	16	108
R2M	7	79
R2N	7	59
R2P	13	83
R2R	13	88
R2V	12	152
R2W	14	175
R2X	18	125
R2Y	6	53
R3A	0	8
R3B	0	11
R3C	1	7
R3E	16	113
R3G	12	135
R3J	5	89

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R3K	2	23
R3L	2	45
R3M	2	58
R3N	0	33
R3P	0	9
R3R	4	51
R3T	12	80
R3V	1	24
R3W	0	2
R3X	1	10
R3Y	0	2
R4A	0	4
R4L	0	1
R5A	1	1
R5G	1	21
R5H	0	2
R6M	2	15
R6W	1	11
R7A	0	15
R7B	0	16
R7N	5	14
TOTAL	**223**	**2283**

FURNACES - BUILD		
	Oct 1 – December 31, 2012	**Cumulative to December 31, 2012**
Postal Code	**Total # Installations**	**Total # Installations**
R2H	0	1
R2L	0	1
R2P	0	1
R2W	0	38
R2X	0	7
R3B	0	5
R3E	0	3
R3G	0	15
R3J	0	1
TOTAL	**0**	**72**

BOILERS - Individual Customers

Postal Code	Oct 1 - December 31, 2012 Total # Installations	Cumulative to December 31, 2012 Total # Installations
R0C	0	1
R1N	0	1
R2G	0	1
R2H	0	8
R2C	0	2
R2K	0	2
R2L	0	2
R2M	0	1
R2V	0	1
R2W	0	9
R2X	0	3
R3B	0	0
R3E	0	4
R3G	0	11
R3J	1	3
R3N	0	1
R3M	0	2
R3T	0	1
R5H	1	1
R6M	0	1
TOTAL	2	55

BOILERS - Community Customers

Postal Code	Oct 1 – December 31, 2012 Total # Installations	Cumulative to December 31, 2012 Total # Installations
R3G	0	1
TOTAL	**0**	**1**

Marketing Activities

Below is a review of marketing efforts undertaken by Manitoba Hydro up to December 31, 2012.

I. ADVERTISING AND PROMOTIONAL ACTIVITIES

a) Manitoba Hydro Advertising

LIEEP's advertising campaign for the 2012/13 fiscal year launched in October, and continued into December with advertising on silver boxes, bus benches, transit shelters and convenient store posters in targeted low income neighbourhoods in Winnipeg to raise awareness of the Program.

Preparation is in place for another direct mail drop in January 2013 to targeted neighbourhoods and advertisement placed in Winnipeg and rural newspapers.

b) Outbound Calling Initiative

i) As part of the Water & Energy Saver Program (WESP), customers in targeted areas were offered direct installation of a Water & Energy Saver kit by a program contractor. While in the home, the contractor noted the type of heating system the customer had and asked if Manitoba Hydro may contact them in the future to tell them about different programs.

- Students were hired to make outbound calls to those customers who agreed that Manitoba Hydro could contact them and who may have a standard efficiency natural gas furnace.
- The purpose of the call is to inform customers of the different Power Smart programs that are available to help them reduce their energy bills, including the Lower Income Energy Efficiency Program. Calls are made between 4:00 – 8:00 pm, Monday to Friday, and started September 10th, 2012.
- For the current fiscal year to date, the students have called a total of 2702 customers and had conversations with 2231 of these customers. As a result of the calls, 439 Lower Income Energy Efficiency Program application packages and 754 Power Smart Information packages have been sent out.
- 79 applications have been filled out and submitted to the Lower Income Energy Efficiency Program; a current return rate of eighteen percent.

ii) In addition to the calls above, the students started following up with customers who were sent a Lower Income Energy Efficiency Program application by Contact Centre staff between June – November 2012.

- The students followed up with approximately 361 customers to answer questions and encourage those who qualify to submit their application to the Program.
- Seventeen applications have been filled out and submitted to the Program as a result of these calls.

c) Direct Mail to Higher Natural Gas Use Customers

An addressed letter was sent to customers deemed to have a standard efficiency furnace, high natural gas consumption, and living in selected low income neighbourhoods (based on Statistic Canada data). The letter explained replacing a standard efficiency furnace is one of the best ways to lower energy bills. Customers were provided with information on LIEEP and the Power Smart Residential Loan as two programs available to help them replace older furnaces.

II. PROMOTION THROUGH PROGRAM PARTNERS

B. Other Community Groups and Program Partners

a) **Power Smart Neighbourhood Project**
AEU and CES staff developed a training presentation for two social enterprise contractors (Inner City Renovations and Manitoba Green Retrofit) working with North End Community Renewal Corporation (NERC). The technical training session was held on December 6, 2012 with three staff from each contractor in attendance, as well as NECRC staff and representation from PrairieHouse Performance Inc. (the contractor performing in-home reviews).

b) **Good Neighbours Active Living Centre LIEEP Presentation**
Staff provided seniors from the Good Neighbours Active Living Centre with a presentation on Power Smart Programs including the LIEEP. The Centre provides programming for seniors and is located in one of LIEEP's target neighbourhoods.

Furnace Contractors

The furnace contractors on the participation list for LIEEP are noted below.

In Winnipeg

- Fair Service and Air Conditioning
- Gallery Mechanical
- Global Mechanical Inc.
- Heat Plus
- Heritage Heating and Air Conditioning Ltd.
- Mr. Furnace Heating and Air Conditioning
- Superior Heating and Air Conditioning
- Tradesman Mechanical Services Ltd.
- RR Heating and Cooling Services Ltd.

Outside Winnipeg

- Bayview Plumbing and Heating Ltd.- Brandon
- Polar Plumbing and Heating Ltd. – Winkler
- Browns Plumbing and Heating Ltd. - Steinbach
- Hanover Plumbing and Heating Inc. - Steinbach
- Steiner Plumbing and Heating

Customers can choose from any of the above contractors in their geographical area. If the customer shows no preference they are provided with the name of one of the contractors on a rotational basis. Centra is not experiencing any capacity issues in meeting the demands of the Furnace Replacement Program.

Centra has a standard comprehensive contract for all our contractors. This contract includes pricing schedule, terms and conditions and warranty. The terms of the contracts are the same for all contractors.

Report on Lower Income Energy Efficiency Program and the Furnace Replacement Program
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Financial

Centra Gas Manitoba Inc. Quarterly Gas Furnace Replacement Program Report For 2012/13 Q3 (October 1, 2012 to December 31, 2012)		(000's)
Beginning Balance October 1, 2012	**$**	**14,175**
Disbursements		(646)
Additional Funding from SGS Customer Class		1,312
Accrued Interest		72
Ending Balance December 31, 2012	**$**	**14,913**

Centra Gas Manitoba Inc. Quarterly Gas Furnace Replacement Program Report Cumulative Since Program Inception as at December 31, 2012		(000's)
Beginning Balance August 1, 2007	**$**	**-**
Disbursements (life to date)		(5,468)
Additional Funding from SGS Customer Class (life to date)		19,560
Accrued Interest (life to date)		821
Ending Balance December 31, 2012	**$**	**14,913**

* Note disbursements include both incentives and administration for 2012/13.
Calculations using installations and disbursements do not reflect accurate cost per unit figures due to timing differences.

PUB/CENTRA I-59

Subject: **Tab 7 DSM**

Reference: **Tab 7 Appendix 7.3 - FRP**

c) Please provide the average costs to replace a furnace and a boiler showing the funding contributions from Centra, from the customer, and any other funding sources.

ANSWER:

Please see below.

	Standard Furnace Replacement		Standard Boiler Replacement	
	Average for 2011/12	Average Year to Date	Average for 2011/12	Average Year to Date
Customer contribution	$ 1,140	$ 1,140	$ 5,958	$ 6,445
Centra contribution	$ 2,420	$ 2,387	$ 2,500	$ 2,500
Total cost	$ 3,560	$ 3,527	$ 8,458	$ 8,945

PUB/CENTRA I-59

Subject: **Tab 7 DSM**

Reference: **Tab 7 Appendix 7.3 - FRP**

d) Please provide the levelized utility cost for the FRP.

ANSWER:

The Levelized Utility Cost for FRP is 100.07 (¢/m3)

PUB/CENTRA I-59

Subject: **Tab 7 DSM**

Reference: **Tab 7 Appendix 7.3 - FRP**

e) Please update the trending charts on pages 9 to 13 of the September 2012 LIEEP and FRP report to include data as of March 31, 2013 (when available).

ANSWER:

The trending charts will be provided to include data as of March 31, 2013 when available.

PUB/CENTRA I-59

Subject: **Tab 7 DSM**

Reference: **Tab 7 Appendix 7.3 - FRP**

f) Please comment on the changes in both LIEEP and FRP participation in 2012/13 compared with 2011/12.

ANSWER:

Individual homeowner participation is slightly lower in 2012/13 compared to 2011/12. There were 20% fewer applications to the program during the 2012/13 fiscal year which lead to fewer furnace replacements under the Furnace Replacement Program, and fewer total completed homes (participants). Centra recognizes that the population of standard efficiency furnaces is finite and as more are converted to high efficiency each year, there are fewer standard efficiency furnaces to convert which may reduce annual participation each year going forward.

Community participation in natural gas served areas is lower than last year. This variance is due to delays in receiving final documented notification of project completion from housing partners.

Participants – Natural Gas				
	Total Completed Homes		Furnace Replacement Program	
	Individual	Community	Individual	Community
2011/12	1090	345	662	0
2012/13 (Forecast to March)	1064	78	620	0

PUB/CENTRA I-59

Subject: **Tab 7 DSM**

Reference: **Tab 7 Appendix 7.3 - FRP**

g) **Please provide a table of FRP disbursements broken down into internal labour, external marketing and production costs, and payments to contractors by year since FRP inception.**

ANSWER:

Please see the table below.

	2008/09	**2009/10**	**2010/11**	**2011/12**	**Total**
Internal - Labour			$358,204	$405,447	**$763,651**
Internal – Non Labour		$1,231	$1,993	$3,259	**$6,482**
External Marketing			$88,167	$113,821	**$201,988**
Payments to Contractors	$264,258	$813,975	$863,256	$1,104,506	**$3,045,994**
Total	**$264,258**	**$815,205**	**$1,311,620**	**$1,627,033**	**$4,018,116**

PUB/CENTRA I-59

Subject: **Tab 7 DSM**

Reference: **Tab 7 Appendix 7.3 - FRP**

h) Please provide a table showing the annual residential gas DSM budget, the annual gas LIEEP budget, the LIEEP budget as a percentage of the total DSM budget, and the cumulative percentage spent on LIEEP for the years 2006/07 to 2012/13.

ANSWER:

	Actual						Forecast
	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13
Residential Natural Gas DSM Budget	$ 3,991,272	$ 4,878,773	$ 7,137,897	$ 7,618,351	$ 7,589,864	$ 8,490,352	$ 9,974,232
LIEEP Natural Gas Budget	$ 256,676	$ 325,265	$ 1,183,491	$ 2,889,875	$ 4,235,793	$ 4,954,228	$ 6,241,691
LIEPP Natural Gas as % of Total Residential Budget	6.4%	6.7%	16.6%	37.9%	55.8%	58.4%	62.6%
Cumulative Residential Natural Gas Budget	$ 3,991,272	$ 8,870,045	$ 16,007,941	$ 23,626,292	$ 31,216,156	$ 39,706,508	$ 49,680,740
Cumulative LIEEP Natural Gas Budget	$ 256,676	$ 581,941	$ 1,765,432	$ 4,655,307	$ 8,891,099	$ 13,845,327	$ 20,087,018
Cumulative LIEEP Natural Gas as % of Total Residential Budget	6.4%	6.6%	11.0%	19.7%	28.5%	34.9%	40.4%

PUB/CENTRA I-59

Subject: **Tab 7 DSM**

Reference: **Tab 7 Appendix 7.3 - FRP**

i) Please summarize Centra's findings from its 2009 Residential Energy Use Survey in respect of the relationship between income and natural consumptions.

ANSWER:

The following table summarizes the relationship between total annual household income and weather adjusted annual natural gas consumption per dwelling.

Annual Household Income	Average Annual Gas Use m^3/Dwelling	Average Square Feet	Average Use m^3/Sqft
Under $25,000	2,362	1,023	2.31
$25,000 To $49,999	2,406	1,109	2.17
$50,000 To $74,999	2,480	1,216	2.04
$75,000 To $99,999	2,490	1,297	1.92
$100,000 and Over	2,816	1,539	1.83

(Manitoba Hydro 2009 Residential Energy use Survey)

Average annual natural gas consumption per dwelling does not increase appreciably by household income until the "$100,000 and Over" range is reached. The average annual gas use of the "$100,000 and Over" is approximately 400 cubic metres per year higher than the other income groups. When average dwelling size is introduced into the analysis, results show that as annual household income increases the gas use per square foot decreases.

PUB/CENTRA I-60

Subject: **Tab 8: Load Forecast**

Reference: **Tab 8 Page 1 of 6; Appendix 8.1 Page 47 of 52**

Please identify any changes made to the load forecasting methodologies compared to those reviewed in the 2011/12 Cost of Gas proceeding.

ANSWER:

The following changes were made to the methodologies between the 2010 and 2012 Natural Gas Volume Forecasts.

- In 2010, the number of SGS Residential customers was forecast using an econometric delta model that was based on the historical annual number of SGS Residential customers. This model was changed to model customers explicitly by dwelling type, area, and heating type. New gas heated homes were linked to the total number of new homes to give growth numbers that would be consistent with Manitoba Hydro's Electric Load Forecast. The current methodology is described in Tab 8 Appendix 8.1 pages 44 to 46.

- In 2010, the number of SGS Commercial and LGS customers was forecast using an econometric delta model. The parameters of the econometric model were only found to be marginally significant and the model was simplified to be a straight average growth model. The current methodology to forecast these customers is as described in Tab 8 Appendix 8.1 page 47.

PUB/CENTRA I-61

Subject: **Tab 8: Load Forecast**

Reference: **Tab 8 Page 2 of 6**

Please provide the details of the Residential End Use Model including the regression equation, inputs, and tables listing appliance saturation (including numbers, average use, and total volumes, similar to 2011/12 Cost of Gas proceeding PUB/Centra 29) for 2012/13 and 2013/14.

ANSWER:

The regression equation and inputs are described in Tab 8 Appendix 8.1 page 44 to 46.

		2012/13			
Efficiency	End Use	Saturation (%)	Number of Appliances	Average Use (m^3)	Volume (10^3m^3)
Low (60%)	Existing Furnace (Single)	15.9%	38,690	2,587	100,092
Mid (82%)	Existing Furnace (Single)	24.5%	59,649	1,940	115,719
Hi (92%)	Existing Furnace (Single)	42.7%	104,228	1,687	175,832
Low (60%)	Existing Furnace (Multi)	2.2%	5,282	1,824	9,635
Mid (82%)	Existing Furnace (Multi)	2.7%	6,699	1,368	9,164
Hi (92%)	Existing Furnace (Multi)	4.0%	9,749	1,190	11,601
Mid (82%)	New Furnace (Single)	0.0%	0	0	0
Hi (92%)	New Furnace (Single)	1.1%	2,681	1,849	4,958
	Boiler	3.9%	9,432	3,608	34,030
	Water Heater	71.1%	173,556	494	85,678
	Miscellaneous	100.0%	243,947	171	41,786
	Total Gas Residential		243,947	2,412	588,495

		2013/14			
		Saturation	Number of	Average Use	Volume
Efficiency	End Use	(%)	Appliances	(m^3)	(10^3m^3)
Low (60%)	Existing Furnace (Single)	14.3%	35,213	2,587	91,095
Mid (82%)	Existing Furnace (Single)	22.8%	56,137	1,940	108,906
Hi (92%)	Existing Furnace (Single)	45.0%	110,845	1,687	186,996
Low (60%)	Existing Furnace (Multi)	1.9%	4,711	1,824	8,593
Mid (82%)	Existing Furnace (Multi)	2.6%	6,354	1,368	8,693
Hi (92%)	Existing Furnace (Multi)	4.3%	10,636	1,190	12,657
Mid (82%)	New Furnace (Single)	0.0%	0	0	0
Hi (92%)	New Furnace (Single)	1.1%	2,741	1,849	5,069
	Boiler	3.8%	9,427	3,608	34,011
	Water Heater	68.3%	168,474	494	83,169
	Miscellaneous	101.6%	246,563	176	43,453
	Total Gas Residential		246,563	2,363	582,642

PUB/CENTRA I-62 (Revised)

Subject: **Tab 8: Load Forecast**

Reference: **Tab 8 Schedules 8.2.0 to 8.4.5 2011/12 COG Hearing; PUB/Centra 29 (a)**

Please provide schedules showing the number of customers, average use, and volumes by customer class for the years 2003/04 through 2013/14 for System Supply, Fixed Rate Primary Gas Service, and Direct Purchase customers, showing the percentage change each year. Please organize in a similar fashion to the schedules prepared for PUB/Centra 29(a) from the 2011/12 COG proceeding.

ANSWER:

Please find attached schedules providing the number of customers, average use and volumes by customer class. Data for 2012/13 and 2013/14 are forecast.

Average number of customers in the year	2003/04 Actual	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
System Supply											
SGS Residential	192,762	189,605	183,549	185,270	192,364	195,682	201,450	210,546	221,449	229,349	235,325
SGS Commercial	14,673	15,391	15,070	15,063	15,180	15,417	15,600	15,696	15,765	16,013	16,219
Large General Service	7,951	6,918	6,883	6,934	6,970	6,933	6,956	6,908	6,789	6,776	6,646
High Volume Firm	67	61	63	66	65	65	67	63	59	60	60
Mainline Firm	2	1	1	1	1	1	1	1	1	1	1
Interruptible Sales	41	38	38	37	35	33	32	32	30	30	30
Fixed Price Supply											
SGS Residential							135	273	398	413	486
SGS Commercial							4	11	12	15	35
Large General Service							15	42	43	60	96
Western Transportation Service											
SGS Residential	33,988	39,498	47,429	48,140	42,731	41,615	37,102	29,422	19,997	14,186	10,752
SGS Commercial	796	1,287	1,572	1,572	1,437	1,281	1,128	1,036	1,040	919	883
Large General Service	549	634	764	763	767	856	851	897	1,063	1,008	994
High Volume Firm	20	20	21	24	27	26	23	26	28	27	27
Mainline Firm	2	2	2	2	2	2	1	1	1	1	1
Interruptible Sales	9	11	10	9	9	8	9	9	7	7	7
Transportation Service											
Large General Service	-	-	-	-	-	-	-	-	-		
High Volume Firm	2	2	3	3	3	3	3	4	5	5	5
Mainline Firm	4	5	5	5	5	5	6	6	6	6	6
Interruptible Sales	3	4	4	4	4	4	4	3	3	3	3
Power Stations	2	2	2	2	2	2	2	2	2	2	2
Special Contract	1	1	1	1	1	1	1	1	1	1	1
Total Customers	250,872	253,478	255,416	257,895	259,602	261,935	263,391	264,978	266,699	268,880	271,578

	2003/04 Actual	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
System Supply											
SGS Residential		-1.6%	-3.2%	0.9%	3.8%	1.7%	2.9%	4.5%	5.2%	3.6%	2.6%
SGS Commercial		4.9%	-2.1%	0.0%	0.8%	1.6%	1.2%	0.6%	0.4%	1.6%	1.3%
Large General Service		-13.0%	-0.5%	0.7%	0.5%	-0.5%	0.3%	-0.7%	-1.7%	-0.2%	-1.9%
High Volume Firm		-8.4%	3.7%	4.6%	-2.3%	0.1%	2.8%	-5.4%	-6.9%	1.6%	0.8%
Mainline Firm		-33.5%	-24.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Interruptible Sales		-7.7%	-1.3%	-2.4%	-4.3%	-5.9%	-3.3%	-0.8%	-5.8%	0.6%	0.0%
Fixed Price Supply											
SGS Residential								102.4%	45.8%	3.9%	17.5%
SGS Commercial								183.3%	5.2%	27.9%	126.2%
Large General Service								176.7%	0.4%	39.7%	60.9%
Western Transportation Service											
SGS Residential		16.2%	20.1%	1.5%	-11.2%	-2.6%	-10.8%	-20.7%	-32.0%	-29.1%	-24.2%
SGS Commercial		61.6%	22.2%	0.0%	-8.6%	-10.9%	-11.9%	-8.2%	0.5%	-11.7%	-3.9%
Large General Service		15.5%	20.5%	-0.1%	0.5%	11.7%	-0.6%	5.3%	18.5%	-5.2%	-1.4%
High Volume Firm		0.0%	6.8%	12.3%	13.1%	-4.4%	-8.5%	11.4%	5.8%	-1.8%	0.0%
Mainline Firm		0.0%	0.0%	0.0%	0.0%	-21.0%	-36.7%	0.0%	0.0%	0.0%	0.0%
Interruptible Sales		22.4%	-8.4%	-8.3%	-1.9%	-10.2%	11.4%	-4.7%	-13.5%	-5.7%	0.0%
Transportation Service											
Large General Service											
High Volume Firm		0.0%	46.0%	2.7%	0.0%	0.0%	0.0%	27.7%	30.5%	0.0%	0.0%
Mainline Firm		17.6%	0.0%	0.0%	-3.4%	12.2%	10.7%	0.0%	0.0%	0.0%	0.0%
Interruptible Sales		17.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-18.8%	-12.9%	6.0%	0.0%
Power Stations		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Special Contract		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total Customers		1.0%	0.8%	1.0%	0.7%	0.9%	0.6%	0.6%	0.6%	0.8%	1.0%

1	Volumes are stated in 10^3m^3	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
2		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Forecast	Forecast
3												
4	**System Supply**											
5	SGS Residential	556,069	565,590	460,226	501,528	534,365	547,683	494,756	525,252	470,402	556,687	558,622
6	SGS Commercial	83,029	95,887	76,513	81,772	89,361	94,452	83,062	88,405	74,830	90,750	91,946
7	Large General Service	476,323	483,331	415,739	442,767	458,345	469,731	414,646	425,483	362,218	423,068	414,964
8	High Volume Firm	87,118	84,653	77,716	84,967	90,692	88,920	85,316	82,688	72,216	79,490	84,530
9	Mainline Firm	17,047	1,645	1,426	1,408	1,442	1,559	1,756	1,966	2,296	2,498	2,498
10	Interruptible Sales	97,654	88,701	82,354	84,943	84,447	84,508	79,858	76,636	67,493	73,387	74,501
11												
12	**Fixed Price Supply**											
13	SGS Residential						.	445	674	851	1,033	1,169
14	SGS Commercial						.	43	83	64	106	214
15	Large General Service						.	1,083	2,159	3,291	4,087	6,336
16												
17	**Western Transportation Service**											
18	SGS Residential	96,841	115,522	118,721	118,416	113,107	109,661	83,880	64,441	36,555	30,775	22,851
19	SGS Commercial	5,212	9,421	9,166	8,721	8,842	7,834	6,585	6,633	5,704	5,879	5,650
20	Large General Service	43,204	61,669	59,217	58,341	68,793	77,296	70,794	71,074	75,029	79,657	78,587
21	High Volume Firm	24,869	28,028	29,752	35,852	39,642	38,346	30,282	36,757	37,594	39,098	39,098
22	Mainline Firm	34,813	33,298	28,605	26,419	29,645	22,479	11,104	11,235	10,072	10,998	10,998
23	Interruptible Sales	23,362	30,095	23,007	19,227	19,598	19,360	20,885	18,821	18,153	17,511	17,813
24												
25	**Transportation Service**											
26	Large General Service	-	-	-	-	-	-	-	-	-	.	.
27	High Volume Firm	25,491	25,806	26,845	27,644	27,877	26,669	22,717	31,305	36,597	39,819	39,819
28	Mainline Firm	67,074	82,617	74,395	72,353	78,342	117,389	129,090	119,273	114,253	120,550	121,466
29	Interruptible Sales	26,470	31,069	30,483	29,198	28,989	26,729	22,814	17,807	16,689	16,411	19,736
30	Power Stations	94,006	11,645	5,620	24,093	7,161	8,094	13,513	15,440	17,048	15,196	15,196
31	Special Contract	364,277	407,863	460,955	438,853	475,800	423,847	430,490	400,234	444,686	421,289	421,289
32												
33	**Total Volumes**	2,122,858	2,156,841	1,980,740	2,056,503	2,156,447	2,164,558	2,003,119	1,996,366	1,866,039	2,028,289	2,027,285

Centra Gas Manitoba Inc.
2013/14 General Rate Application
Volumes % Change

	2003/04 Actual	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
System Supply											
SGS Residential		1.7%	-18.6%	9.0%	6.5%	2.5%	-9.7%	6.2%	-10.4%	18.3%	0.3%
SGS Commercial		15.5%	-20.2%	6.9%	9.3%	5.7%	-12.1%	6.4%	-15.4%	21.3%	1.3%
Large General Service		1.5%	-14.0%	6.5%	3.5%	2.5%	-11.7%	2.6%	-14.9%	16.8%	-1.9%
High Volume Firm		-2.8%	-8.2%	9.3%	6.7%	-2.0%	-4.1%	-3.1%	-12.7%	10.1%	6.3%
Mainline Firm		-90.4%	-13.3%	-1.3%	2.4%	8.2%	12.6%	11.9%	16.8%	8.8%	0.0%
Interruptible Sales		-9.2%	-7.2%	3.1%	-0.6%	0.1%	-5.5%	-4.0%	-11.9%	8.7%	1.5%
Fixed Price Supply											
SGS Residential								51.6%	26.2%	21.4%	13.2%
SGS Commercial								95.0%	-22.8%	65.8%	101.6%
Large General Service								99.3%	52.4%	24.2%	55.0%
Western Transportation Service											
SGS Residential		19.3%	2.8%	-0.3%	-4.5%	-3.0%	-23.5%	-23.2%	-43.3%	-15.8%	-25.7%
SGS Commercial		80.8%	-2.7%	-4.9%	1.4%	-11.4%	-15.9%	0.7%	-14.0%	3.1%	-3.9%
Large General Service		42.7%	-4.0%	-1.5%	17.9%	12.4%	-8.4%	0.4%	5.6%	6.2%	-1.3%
High Volume Firm		12.7%	6.1%	20.5%	10.6%	-3.3%	-21.0%	21.4%	2.3%	4.0%	0.0%
Mainline Firm		-4.4%	-14.1%	-7.6%	12.2%	-24.2%	-50.6%	1.2%	-10.3%	9.2%	0.0%
Interruptible Sales		28.8%	-23.6%	-16.4%	1.9%	-1.2%	7.9%	-9.9%	-3.6%	-3.5%	1.7%
Transportation Service											
Large General Service											
High Volume Firm		1.2%	4.0%	3.0%	0.8%	-4.3%	-14.8%	37.8%	16.9%	8.8%	0.0%
Mainline Firm		23.2%	-10.0%	-2.7%	8.3%	49.8%	10.0%	-7.6%	-4.2%	5.5%	0.8%
Interruptible Sales		17.4%	-1.9%	-4.2%	-0.7%	-7.8%	-14.6%	-21.9%	-6.3%	-1.7%	20.3%
Power Stations		-87.6%	-51.7%	328.7%	-70.3%	13.0%	67.0%	14.3%	10.4%	-10.9%	0.0%
Special Contract		12.0%	13.0%	-4.8%	8.4%	-10.9%	1.6%	-7.0%	11.1%	-5.3%	0.0%
Total Customers		1.6%	-8.2%	3.8%	4.9%	0.4%	-7.5%	-0.3%	-6.5%	8.7%	0.0%

1	Average Use is stated in m^3/cust	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
2		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Forecast	Forecast
3												
4	**System Supply**											
5	SGS Residential	2,885	2,983	2,507	2,707	2,778	2,799	2,456	2,495	2,124	2,427	2,374
6	SGS Commercial	5,659	6,230	5,077	5,429	5,887	6,126	5,324	5,632	4,747	5,667	5,669
7	Large General Service	59,905	69,870	60,401	63,857	65,759	67,750	59,607	61,594	53,354	62,440	62,439
8	High Volume Firm	1,310,042	1,389,578	1,230,271	1,285,819	1,404,332	1,374,976	1,282,955	1,314,184	1,232,768	1,335,961	1,408,833
9	Mainline Firm	8,523,350	1,236,695	1,426,000	1,407,569	1,441,739	1,559,334	1,756,497	1,966,037	2,295,746	2,498,094	2,498,094
10	Interruptible Sales	2,367,360	2,329,340	2,191,421	2,316,409	2,407,262	2,560,862	2,501,817	2,419,842	2,262,591	2,446,245	2,483,383
11												
12	**Fixed Price Supply**											
13	SGS Residential							3,299	2,470	2,137	2,499	2,407
14	SGS Commercial							10,647	7,330	5,378	6,971	6,212
15	Large General Service							70,665	50,903	77,278	68,685	66,177
16												
17	**Western Transportation Service**											
18	SGS Residential	2,849	2,925	2,503	2,460	2,647	2,635	2,261	2,190	1,828	2,169	2,125
19	SGS Commercial	6,546	7,323	5,832	5,547	6,152	6,115	5,837	6,404	5,483	6,401	6,402
20	Large General Service	78,732	97,335	77,543	76,488	89,721	90,273	83,157	79,257	70,587	79,038	79,055
21	High Volume Firm	1,264,291	1,424,927	1,416,757	1,520,449	1,486,383	1,503,770	1,297,975	1,413,736	1,367,056	1,448,061	1,448,061
22	Mainline Firm	17,406,550	16,649,189	14,302,600	13,209,683	14,822,318	14,227,102	11,103,947	11,234,510	10,072,304	10,998,215	10,998,215
23	Interruptible Sales	2,619,013	2,755,948	2,300,720	2,096,751	2,177,591	2,396,100	2,320,510	2,193,638	2,446,475	2,501,636	2,544,770
24												
25	**Transportation Service**											
26	Large General Service											
27	High Volume Firm	12,745,300	12,903,093	9,193,390	9,214,833	9,292,224	8,889,578	7,572,211	8,173,521	7,319,461	7,963,761	7,963,761
28	Mainline Firm	15,782,217	16,523,394	14,878,940	14,470,509	16,219,912	21,658,437	21,514,990	19,878,835	19,042,220	20,091,623	20,244,405
29	Interruptible Sales	7,739,883	7,767,213	7,620,700	7,299,390	7,247,337	6,682,183	5,703,591	5,479,023	5,897,055	5,470,397	6,578,763
30	Power Stations	47,002,788	5,822,423	2,809,750	12,046,499	3,580,639	4,046,858	6,756,318	7,720,088	8,523,792	7,598,129	7,598,129
31	Special Contract	364,277,000	407,862,732	460,954,700	438,853,488	475,800,114	423,847,345	430,490,196	400,233,854	444,685,729	421,288,809	421,288,809

1		2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
2		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Forecast	Forecast
3												
4	**System Supply**											
5	SGS Residential		3.4%	-15.9%	8.0%	2.6%	0.8%	-12.3%	1.6%	-14.9%	14.3%	-2.2%
6	SGS Commercial		10.1%	-18.5%	6.9%	8.4%	4.1%	-13.1%	5.8%	-15.7%	19.4%	0.0%
7	Large General Service		16.6%	-13.6%	5.7%	3.0%	3.0%	-12.0%	3.3%	-13.4%	17.0%	0.0%
8	High Volume Firm		6.1%	-11.5%	4.5%	9.2%	-2.1%	-6.7%	2.4%	-6.2%	8.4%	5.5%
9	Mainline Firm		-85.5%	15.3%	-1.3%	2.4%	8.2%	12.6%	11.9%	16.8%	8.8%	0.0%
10	Interruptible Sales		-1.6%	-5.9%	5.7%	3.9%	6.4%	-2.3%	-3.3%	-6.5%	8.1%	1.5%
11												
12	**Fixed Price Supply**											
13	SGS Residential								-25.1%	-13.5%	16.9%	-3.7%
14	SGS Commercial								-31.2%	-26.6%	29.6%	-10.9%
15	Large General Service								-28.0%	51.8%	-11.1%	-3.7%
16												
17	**Western Transportation Service**											
18	SGS Residential		2.6%	-14.4%	-1.7%	7.6%	-0.4%	-14.2%	-3.1%	-16.5%	18.7%	-2.0%
19	SGS Commercial		11.9%	-20.4%	-4.9%	10.9%	-0.6%	-4.5%	9.7%	-14.4%	16.7%	0.0%
20	Large General Service		23.6%	-20.3%	-1.4%	17.3%	0.6%	-7.9%	-4.7%	-10.9%	12.0%	0.0%
21	High Volume Firm		12.7%	-0.6%	7.3%	-2.2%	1.2%	-13.7%	8.9%	-3.3%	5.9%	0.0%
22	Mainline Firm		-4.4%	-14.1%	-7.6%	12.2%	-4.0%	-22.0%	1.2%	-10.3%	9.2%	0.0%
23	Interruptible Sales		5.2%	-16.5%	-8.9%	3.9%	10.0%	-3.2%	-5.5%	11.5%	2.3%	1.7%
24												
25	**Transportation Service**											
26	Large General Service											
27	High Volume Firm		1.2%	-28.8%	0.2%	0.8%	-4.3%	-14.8%	7.9%	-10.4%	8.8%	0.0%
28	Mainline Firm		4.7%	-10.0%	-2.7%	12.1%	33.5%	-0.7%	-7.6%	-4.2%	5.5%	0.8%
29	Interruptible Sales		0.4%	-1.9%	-4.2%	-0.7%	-7.8%	-14.6%	-3.9%	7.6%	-7.2%	20.3%
30	Power Stations		-87.6%	-51.7%	328.7%	-70.3%	13.0%	67.0%	14.3%	10.4%	-10.9%	0.0%
31	Special Contract		12.0%	13.0%	-4.8%	8.4%	-10.9%	1.6%	-7.0%	11.1%	-5.3%	0.0%
32												
33												

PUB/CENTRA I-63

Subject: **Tab 8: Load Forecast**

Reference: **Tab 8 Appendix 8.1 Page 1 of 52**

a) Please provide the monthly heating values for the past five years.

ANSWER:

Please find below the monthly heating values (MJ/m^3) for the past five (5) fiscal years:

	2008/09	**2009/10**	**2010/11**	**2011/12**	**2012/13**
APR	37.31	37.42	37.43	37.52	37.54
MAY	37.29	37.43	37.29	37.47	37.77
JUN	37.38	37.43	37.45	37.53	37.73
JUL	37.39	37.43	37.42	37.56	37.51
AUG	37.40	37.36	37.42	37.59	37.54
SEP	37.41	37.34	37.45	37.53	37.59
OCT	37.49	37.43	37.50	37.54	37.59
NOV	37.38	37.35	37.43	37.51	37.58
DEC	37.75	37.30	37.43	37.54	37.59
JAN	37.46	37.38	37.45	37.60	37.62
FEB	37.36	37.42	37.52	37.53	37.68
MAR	37.39	37.42	37.49	37.53	n/a

PUB/CENTRA I-63

Subject: **Tab 8: Load Forecast**

Reference: **Tab 8 Appendix 8.1 Page 1 of 52**

b) Please give Centra's view whether a heating value of 37.8 MJ/m3 is still the appropriate base heating value to use for rate setting purposes.

ANSWER:

As shown in the response to PUB/Centra I-63(a), the actual heating value of gas on Centra's system has been lower than the forecast heating value of 37.8 MJ/m^3 assumed in the natural gas volume forecast. The result is that on an actual basis, customers consume more volumes given the lower energy content of the natural gas. Correspondingly, a variance in gross margin occurs and is reflected in the Heating Value Margin Deferral Account.

Given that the Heating Value Margin Deferral account balances tend to be immaterial, Centra believes that the current heating value of 37.8 MJ/m^3 remains appropriate.

PUB/CENTRA I-63

Subject: **Tab 8: Load Forecast**

Reference: **Tab 8 Appendix 8.1 Page 1 of 52**

c) Centra may physically receive gas from the United States through Emerson now that the Great Lakes Gas Pipeline has experienced bidirectional flows. Please explain how Centra will address the different heating values that parts of its system will experience if there are physical flows of gas to Centra's service territory from the United States.

ANSWER:

There are five TCPL stations within Centra's service territory between Emerson and the TCPL compressor station at Ile des Chenes which may have gas flowing through them from the United States (i.e., receipts onto TCPL's Mainline at the GLGT/TCPL interconnect at Emerson, MB). Those stations are as follows: Altona; St. Malo; St. Pierre; Ste. Agathe; and Niverville.

Please find in the chart below the weighted average heating value of these five (5) stations as compared with Centra's system average heating value, by month, since January 2012 which is the approximate timeframe at which physical reversal of gas flow on the GLGT system first occurred. The difference in the weighted average heating value of gas flowing through these five (5) stations and Centra's system average heating value is not material to date. No action appears to be warranted at this time; however, Centra will continue to monitor these heating values. Centra notes that the range of acceptable heating values as per TCPL's Transportation Tariff is from 36.00 MJ/m^3 to 41.34 MJ/m^3.

The following chart compares the weighted average heating value for the five (5) TCPL stations referenced earlier in this response with Centra's system average heating value (both in MJ/m^3):

	5 Stations Weighted Average	Centra System Weighted Average
Jan-12	37.60	37.60
Feb-12	37.53	37.53
Mar-12	37.54	37.53
Apr-12	37.54	37.54
May-12	37.69	37.77
Jun-12	37.74	37.73
Jul-12	37.52	37.51
Aug-12	37.55	37.54
Sep-12	37.58	37.59
Oct-12	37.59	37.59
Nov-12	37.58	37.58
Dec-12	37.59	37.59
Jan-13	37.71	37.62
Feb-13	38.05	37.68

PUB/CENTRA I-63

Subject: **Tab 8: Load Forecast**

Reference: **Tab 8 Appendix 8.1 Page 1 of 52**

d) **Please provide the heating values for any gas received into Centra's service territory from US pipelines to date.**

ANSWER:

Please see Centra's response to PUB/Centra I-63(c).

PUB/CENTRA I-64

Subject: **Tab 8: Load Forecast**

Reference: **Tab 8 Appendix 8.1 p. 17 of 52**

The LGS class volumes have decreased on average by 0.3% annually for the past nine years, while Centra forecasts LGS volumes will decrease by 1% annually in the future. Likewise, the combined SGS Commercial and LGS volumes have decreased 0.2% annually, but are now forecasted to decrease at 0.7%. Please explain the reasons for the higher decreases in the forecast compared to the historical trend.

ANSWER:

Historic volumes reflect efficiency gains in these customer classes. However, it must be recognized that the Corporation's Demand Side Management (DSM) natural gas programs were not introduced until 2006, mid way through the period. The 2012 Natural Gas Volume Forecast incorporates projected decreases due to the DSM initiatives as outlined in 2011 Power Smart Plan. The forecast volumes are a direct result of natural gas efficiency gains achieved through Power Smart programs in addition to the impact of regulation changes under the Manitoba Energy Act mandating minimum efficiency requirements for furnaces and boilers.

PUB/CENTRA I-65

Subject: **Tab 8: Load Forecast**

Reference: **Tab 8 Appendix 8.1 Page 35 of 52**

Please explain how Centra determines the weather effects for each class and provide the inputs used in the calculations.

ANSWER:

The methodology employed is a straight linear regression where the monthly DDH is regressed against the Heat Value Adjusted Volume for the month. The regression formula is:

Volume in the month = Base load + Weather effect * DDH in the month.

- Data inputs to the regression model are the “volume in the month” and the “DDH in the month”

Centra determines weather effect for all classes except Power Stations and the Special Contract customer. Usage in these classes is not significantly affected by weather.

PUB/CENTRA I-66

Subject: **Tab 8: Load Forecast**

Reference: **Tab 8 Appendix 8.1 Pages 36 and 43 of 52**

a) Please describe EDDH and explain how Centra uses EDDH to forecast gas consumption and to normalize that consumption.

ANSWER:

Degree Days Heating (DDH) is the number of degrees colder than 14 degrees Celsius each day, based on the average of the high and low temperature of the day. The DDH for each day is calculated as follows:

IF Average Temperature < 14; DDH = 14 – Average Temperature

If Average Temperature > or = to 14; DDH = 0

Where:

Average Temperature = (Daily high + Daily low) / 2

Total DDH = sum of DDH over all days

Historical monthly volumes are then heat value and weather adjusted to the 25 year average of DDH. The weather adjustment is calculated as follows:

Historical volume weather adjusted = historical actual volume + (25 year average DDH – actual DDH) * weather effect

Centra determines the “weather effect” for each class as described in the response to PUB/Centra I-65.

The heat value and weather adjusted historical volumes that are based on normal weather are used as inputs into the Natural Gas Volume Forecast. All forecasts are thus based on normal weather.

PUB/CENTRA I-66

Subject: **Tab 8: Load Forecast**

Reference: **Tab 8 Appendix 8.1 Pages 36 and 43 of 52**

b) **Please provide the effective degree days heating (EDDH) for Winnipeg for the years 2008/09 to 2012/13.**

ANSWER:

Monthly DDH for Winnipeg													
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Annual
2008/09	319.8	180.9	21.3	0.0	3.0	56.3	227.9	546.4	1,033.0	1,052.3	800.9	676.4	4,918.2
2009/10	321.4	177.1	47.4	3.8	2.4	19.8	330.1	396.9	895.9	860.1	793.6	451.1	4,299.6
2010/11	173.5	108.8	10.3	0.0	9.0	79.9	188.7	520.6	878.1	1,031.2	788.9	698.8	4,487.8
2011/12	286.8	110.3	12.9	0.0	0.0	60.8	204.0	481.2	683.6	767.8	698.9	371.3	3,677.6
2012/13	244.3	82.7	9.9	0.0	0.0	89.1	310.9	601.1	889.6	951.1	781.7	N/A	N/A

Please note that March 2013 was not available at the time of the preparation of this response.

PUB/CENTRA I-66

Subject: **Tab 8: Load Forecast**

Reference: **Tab 8 Appendix 8.1 Pages 36 and 43 of 52**

c) **Please provide the normal EDDH calculated for each of the above years using the 25 year average method as well as the 10 year average method.**

ANSWER:

The following table presents normal Degree Days Heating (DDH) based upon the 25 year average method and the 10 year average method.

Normal DDH from 2008/09 to 2012/13		
Fiscal Year	10 Year Average	25 Year Average
2008/09	4,429.8	4,549.8
2009/10	4,518.1	4,561.6
2010/11	4,555.7	4,547.1
2011/12	4,522.6	4,536.7
2012/13	4,466.4	4,518.4

PUB/CENTRA I-66

Subject: **Tab 8: Load Forecast**

Reference: **Tab 8 Appendix 8.1 Pages 36 and 43 of 52**

d) **Please provide the coldest year on record EDDH and the warmest year on record EDDH.**

ANSWER:

Centra's records contain Winnipeg DDH weather dating back to the 1960/61 fiscal year. The coldest year during this period of record for Winnipeg is the 1995/96 fiscal year at 5,439.3 DDH. The warmest year during this period of record for Winnipeg is the 2011/12 fiscal year at 3,677.6 DDH

PUB/CENTRA I-66

Subject: **Tab 8: Load Forecast**

Reference: **Tab 8 Appendix 8.1 Pages 36 and 43 of 52**

e) Please provide the approximate relationship between EDDH and net income.

ANSWER:

The relationship between EDDH and Centra's net income would be approximately $15,000 per EDDH.

PUB/CENTRA I-66

Subject: Tab 8: Load Forecast

Reference: Tab 8 Appendix 8.1 Pages 36 and 43 of 52

f) Please detail the effect on forecasted net income if the warmest or the coldest winters were experienced in 2013/14.

ANSWER:

The estimated effect on Centra's net income would be calculated as:

Extreme Warm/Cold Fiscal Year	2013/14 Normal EDD	Extreme Year EDD	EDD Variance	Net Income Impact *	2013/14 Forecast Net Income	2013/14 Net Income with extreme weather
2011/12	4 518	3 678	(840)	$ (12 600 000)	$ 4 821 000	$ (7 779 000)
1995/96	4 518	5 439	921	$ 13 815 000	$ 4 821 000	$ 18 636 000

*Net income impact is estimated at $15,000 per effective degree day (reference PUB/Centra I-66e).

PUB/CENTRA I-67

Subject: **Tab 8: Load Forecast**

Reference: **Tab 8 Appendix 8.1 Page 39 of 52**

Please provide the historical weather and heating value adjusted load forecast accuracies for the SGS Residential, SGS Commercial, and LGS classes for the past five years.

ANSWER:

Forecast Accuracy For 2007

Class	Forecast Created	Year Being Forecasted	Forecast 10^3m^3	W/A Actual 10^3m^3	Diff	% Diff	Absolute % Diff	Over	Under	Actual 10^3m^3
SGS Residential	2007	2007/08	605,643	600,501	5,142	.9%	.9%	1	0	647,472
SGS Commercial	2007	2007/08	87,824	90,977	-3,153	-3.5%	3.5%	0	1	98,203
LGS	2007	2007/08	486,956	490,616	-3,660	-.7%	.7%	0	1	527,138
Total For Year 1							1.7%	1	2	
SGS Residential	2007	2008/09	601,882	592,395	9,488	1.6%	1.6%	1	0	657,344
SGS Commercial	2007	2008/09	86,980	91,552	-4,573	-5.0%	5.0%	0	1	102,286
LGS	2007	2008/09	482,274	496,223	-13,948	-2.8%	2.8%	0	1	547,028
Total For Year 2							3.1%	1	2	

Forecast Accuracy For 2008

Class	Forecast Created	Year Being Forecasted	Forecast 10^3m^3	W/A Actual 10^3m^3	Diff	% Diff	Absolute % Diff	Over	Under	Actual 10^3m^3
SGS Residential	2008	2008/09	601,009	598,276	2,733	.5%	.5%	1	0	657,344
SGS Commercial	2008	2008/09	91,482	92,532	-1,050	-1.1%	1.1%	0	1	102,286
LGS	2008	2008/09	498,110	500,791	-2,681	-.5%	.5%	0	1	547,028
Total For Year 1							.7%	1	2	
SGS Residential	2008	2009/10	597,688	586,838	10,850	1.8%	1.8%	1	0	579,081
SGS Commercial	2008	2009/10	90,925	91,139	-214	-.2%	.2%	0	1	89,690
LGS	2008	2009/10	495,081	492,404	2,677	.5%	.5%	1	0	486,523
Total For Year 2							.8%	2	1	

Forecast Accuracy For 2009

Class	Forecast Created	Year Being Forecasted	Forecast 10^3m^3	W/A Actual 10^3m^3	Diff	% Diff	Absolute % Diff	Over	Under	Actual 10^3m^3
SGS Residential	2009	2009/10	605,142	596,436	8,707	1.5%	1.5%	1	0	579,081
SGS Commercial	2009	2009/10	92,939	92,795	143	.2%	.2%	1	0	89,690
LGS	2009	2009/10	509,181	500,034	9,147	1.8%	1.8%	1	0	486,523
Total For Year 1							1.2%	3	0	
SGS Residential	2009	2010/11	601,109	588,258	12,851	2.2%	2.2%	1	0	590,368
SGS Commercial	2009	2010/11	92,210	94,831	-2,622	-2.8%	2.8%	0	1	95,120
LGS	2009	2010/11	507,963	496,794	11,168	2.2%	2.2%	1	0	498,716
Total For Year 2							2.4%	2	1	

Forecast Accuracy For 2010

Class	Forecast Created	Year Being Forecasted	Forecast 10^3m^3	W/A Actual 10^3m^3	Diff	% Diff	Absolute % Diff	Over	Under	Actual 10^3m^3
SGS Residential	2010	2010/11	593,998	591,387	2,610	.4%	.4%	1	0	590,368
SGS Commercial	2010	2010/11	93,723	95,381	-1,658	-1.7%	1.7%	0	1	95,120
LGS	2010	2010/11	502,986	499,302	3,684	.7%	.7%	1	0	498,716
Total For Year 1							.9%	2	1	
SGS Residential	2010	2011/12	591,758	595,982	-4,224	-.7%	.7%	0	1	507,807
SGS Commercial	2010	2011/12	94,315	96,193	-1,878	-2.0%	2.0%	0	1	80,599
LGS	2010	2011/12	501,444	512,048	-10,604	-2.1%	2.1%	0	1	440,537
Total For Year 2							1.6%	0	3	

Forecast Accuracy For 2011

Class	Forecast Created	Year Being Forecasted	Forecast 10^3m^3	W/A Actual 10^3m^3	Diff	% Diff	Absolute % Diff	Over	Under	Actual 10^3m^3
SGS Residential	2011	2011/12	583,581	594,884	-11,303	-1.9%	1.9%	0	1	507,807
SGS Commercial	2011	2011/12	96,196	96,000	197	.2%	.2%	1	0	80,599
LGS	2011	2011/12	493,152	511,155	-18,003	-3.5%	3.5%	0	1	440,537
Total For Year 1							1.9%	1	2	

PUB/CENTRA I-68

Subject: **Tab 8: Load Forecast**

Reference: **Tab 8 Appendix 8.1 Page 13, 42 to 45 of 52**

a) Centra forecasts the year-over-year increase in the number of residential gas customers as 1.1%. Please estimate the year-over-year increase in the number of residential customers if the input into the model is for electricity price increases of 3.95%, based on the most recently approved Manitoba Hydro IFF, instead of 3.5% as was used in the preparation of the load forecast.

ANSWER:

An increase of 0.45% to the electricity price every year for 10 years is estimated to add an additional 13 gas customers a year. Instead of 2,736 new gas customers per year there would be 2,749 new gas customers per year. The additional 13 customers represent 0.005% of the total number of gas customers, and will not change the year-over-year growth significantly from 1.1%.

PUB/CENTRA I-68

Subject: **Tab 8: Load Forecast**

Reference: **Tab 8 Appendix 8.1 Page 13, 42 to 45 of 52**

b) Please estimate the year-over-year increase in the number of residential customers if the input into the model is for gas prices 50% higher than currently assumed.

ANSWER:

If total natural gas prices (commodity and non-commodity components) increased by 50%, then the number of new residential gas customers is estimated to decrease 351 customers per year, from 2,736 new gas customers per year down to 2,385 customers per year.

PUB/CENTRA I-68

Subject: **Tab 8: Load Forecast**

Reference: **Tab 8 Appendix 8.1 Page 13, 42 to 45 of 52**

c) Please provide the percentage of newly constructed homes in the Winnipeg area that elected gas service in each of the past five years and are forecasted to elect gas service for the test year.

ANSWER:

The table shows the estimated percentage of new single detached homes in Winnipeg installing natural gas for space heat:

New Single Detached Homes in Winnipeg with gas space heat	
2007/08	95.0%
2008/09	95.8%
2009/10	95.2%
2010/11	96.5%
2011/12	97.4%
2012/13 forecast	97.6%
2013/14 forecast	97.8%

Multi-family homes and apartments are modeled only for Manitoba as a whole. Survey data indicated that from 2005 to 2009, 57% of new multi-family homes in Winnipeg were installing natural gas for space heating. There are no new apartment dwellings installing individual suite natural gas heating systems.

PUB/CENTRA I-68

Subject: Tab 8: Load Forecast

Reference: Tab 8 Appendix 8.1 Page 13, 42 to 45 of 52

d) Please provide the percentage of newly constructed homes in gas-available areas outside Winnipeg (by specific geographic region) that elect gas service in each of the past five years and are forecasted to elect gas service for the test year.

ANSWER:

The table shows the estimated percentage of new single detached homes in gas-available areas outside Winnipeg installing natural gas for space heat:

New Single Detached Homes in South Gas Available Areas with gas space heat	
2007/08	38.7%
2008/09	30.0%
2009/10	32.0%
2010/11	40.2%
2011/12	44.6%
2012/13 forecast	46.0%
2013/14 forecast	45.1%

New homes are forecast for the south-gas available area overall, not by specific geographic region; multi-family homes and apartments are modeled only for Manitoba as a whole. Survey data indicated that from 2005 to 2009, 26% of new multi-family homes in gas-available areas outside Winnipeg were installing natural gas for space heating. There are no new apartment dwellings installing individual suite natural gas heating systems.

PUB/CENTRA I-69

Subject: Tab 8: Load Forecast

Reference: Tab 8 Schedules 8.2.5 and 8.4.5

a) Please provide support for Centra's forecast of 617 Fixed Rate Primary Gas Service customers in 2013/14, a 36% increase over 2011/12 actuals, and for Centra's forecast of 7,719,000 m3 consumption, an increase of 83% over 2011/12 actuals.

ANSWER:

The 2012 Customer and Volume Forecast are based on the assumptions that the Fixed Rate Primary Gas Service would have quarterly offerings with 35 Residential Customers, 5 Small Commercial Customers and 10 Large General Service Customers per offering spread across three terms (1, 3 and 5 year). The forecast also assumes 50% of the customers currently enrolled on a fixed price contract would renew a new contract when their existing contract was completed.

The number of customers forecast per offering was based on both past experiences within the Fixed Rate Primary Gas Service and market assumptions into the future as of June 2012. Participation experienced within the first year of the forecast has been lower than anticipated, which will be reflected within the 2013 Customer & Volume Forecast.

PUB/CENTRA I-69

Subject: Tab 8: Load Forecast

Reference: Tab 8 Schedules 8.2.5 and 8.4.5

b) Please confirm whether Centra's forecast for 60 LGS FRPGS customers in 2012/13 is still valid, since only 5 LGS customers enrolled in FRPGS in 2012/13 according to Appendix 13.3.

ANSWER:

The current projected average customers for 2012/13 are 46 LGS customers. The forecast for 2012/13 is 60 LGS customers, which included not only new enrollments, but also customers who were already enrolled and were continuing their contract.

PUB/CENTRA I-70

Subject: **Tab 9: Rate Base**

Reference: **Tab 9 Page 6 of 63**

a) Please re-file the table on page 6 to include the numbers of meters changed each year.

ANSWER:

Please see the following table for the requested information.

	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
Meters	$1,263	$1,416	$1,478	$3,460	$3,164	$3,695
Meter (Units)	12,274	16,852	20,792	38,328	34,000	34,000

The number of meters exchanged each year as required under the Electric and Gas Inspection Act, vary by type, class and unit cost of meter. Annually groups of meters are sampled/tested based on the meter certificate expiry date, the size of these groups fluctuate from year to year. Meters are tested one year in advance of the expiry date. There was a large increase in the Residential meters that were replaced in 2011/12 due to failure or the certification expiry. The forecast reflects the anticipated number of exchanges per Measurement Canada specifications.

PUB/CENTRA I-70

Subject: Tab 9: Rate Base

b) If Centra has identified the transmission mains that it plans to relocate in 2012/13 and 2013/14, please state the locations and size of the pipe.

ANSWER:

As the requests for relocation of plant varies from year to year, Centra forecasts a split between Transmission and Distribution. For 2012/13, all third party requests for relocation of plant were for Distribution Mains. For 2013/14, two Transmission relocates have been identified: (1) Hartney - 114.3 mm, and (2) north of LaSalle primary - 219.1 mm and 323.9 mm.

PUB/CENTRA I-71

Subject: **Tab 9: Rate Base**

Reference: **Tab 9 Pages 10 and 37 of 63**

Please confirm whether the transmission pipeline crossing the Souris River at Bunclody was one of the eight locations identified in the 2004/05 geotechnical survey for remediation or mitigation of ground movement and erosion.

ANSWER:

The Souris River crossing at Bunclody was not one of the identified locations in the 2004/05 geotechnical survey. In the spring of 2011, the Souris River experienced extraordinarily high flow conditions which resulted in damage to the river bank adjacent to the Bunclody Bridge and necessitated the replacement of the pipeline river crossing at that location.

PUB/CENTRA I-72

Subject: **Tab 9: Rate Base**

Reference: **Tab 9 Page 16 of 63**

Please explain the reasons that the cost to complete the Saskatchewan and Buchanan High Pressure System Tie-In of $1.6 million was nearly 30% over the budgeted amount of $1.25 million as listed in 2009/10 GRA Tab 5 Page 36 of 64.

ANSWER:

The cost overrun on this project was due to complications in procuring land for the pressure regulation station which resulted in regulation station re-design and an increase in contract labour due to this change in project scope.

PUB/CENTRA I-73

Subject: Tab 9: Rate Base

Reference: Tab 9 Page 17 of 63

a) Please describe Manitoba Hydro's current plans for electric Advanced Metering Infrastructure, and identify any impacts on Centra if Manitoba Hydro proceeds.

ANSWER:

Manitoba Hydro is currently assessing the merits of an Advanced Metering Infrastructure (AMI) initiative. As there are no formalized plans for upgrading Manitoba Hydro's meters at this time, it is premature to identify any potential impacts on Centra.

PUB/CENTRA I-73

Subject: **Tab 9: Rate Base**

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

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

ANSWER:

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

Manitoba Hydro

PO Box 815 • Winnipeg Manitoba Canada • R3C 0G8
Street Location for DELIVERY: 22nd Floor - 360 Portage Avenue
Telephone / *N° de téléphone:* (204) 360-3468 • Fax / *N° de télécopieur:* (204) 360-6147
mmurphy@hydro.mb.ca

February 2, 2010

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

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

Dear Mr. Singh:

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

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

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

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

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

Yours truly,
MANITOBA HYDRO LAW DEPARTMENT
Per:

M Murphy

Marla D. Murphy
Barrister and Solicitor
Att.

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

EXECUTIVE SUMMARY

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

What is AMI?

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

Preliminary Results - Benefit Assessment

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

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

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

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

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

Summary of Pilot Findings

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

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

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

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

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

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

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

Industry

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

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

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

Future in Manitoba

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

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

TABLE OF CONTENTS

1.0 Status Statement

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

2.0 Background

2.1 Current Meter Reading Practice

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

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

2.2 What is Advanced Metering Infrastructure (AMI)?

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

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

2.3 Technology Options

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

2.3.1 Mobile AMR

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

2.3.2 Fixed Network AMR

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

2.3.3 Fixed Network AMI

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

3.0 Manitoba Hydro AMI Pilot Project

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

3.1 Pilot Project Objectives

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

3.2 Pilot Project Background

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

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

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

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

3.2 Pilot Project Technical Infrastructure

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

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

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

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

3.4 Pilot Project Findings

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

3.4.1 Technical Performance

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

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

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

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

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

3.4.2 Implementation Findings

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

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

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

3.4.3 Lessons Learned

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

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

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

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

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

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

4.0 The AMI Industry

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

4.1 Government Perspectives

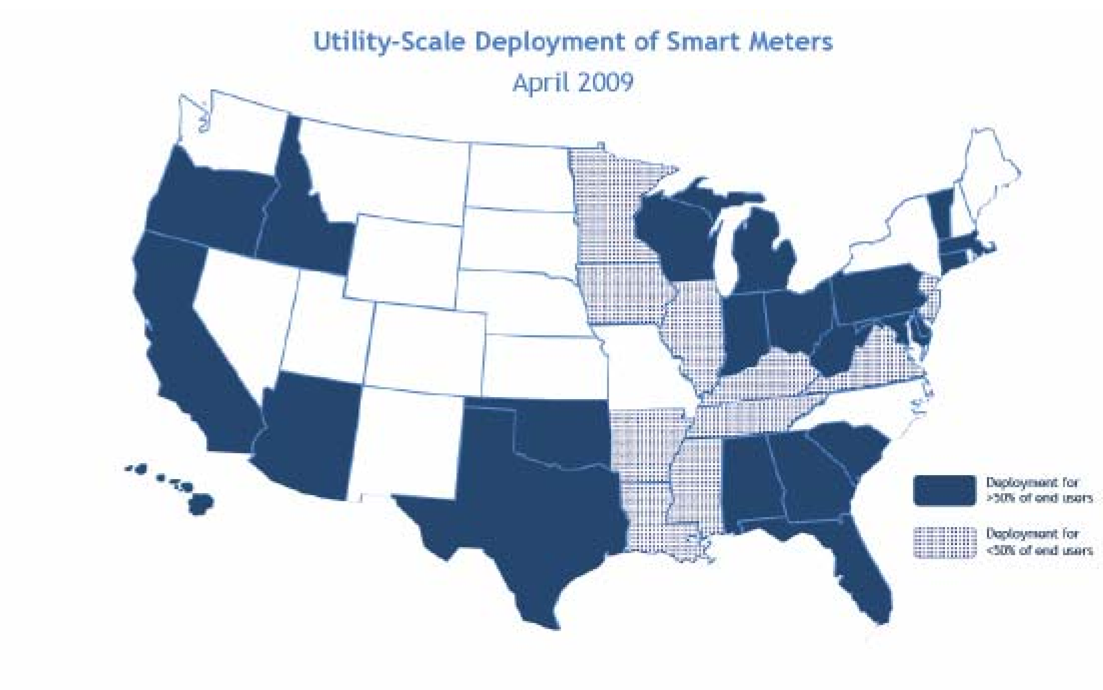
Provincial and state government energy policies are driving AMI adoption in other jurisdictions, with the focus on managing electricity capacity concerns. Ontario and British Columbia have established provincial policies on the implementation of AMI as a means of alleviating significant forecasted electricity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

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

4.2 Utility Perspectives

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

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



Source: EEI

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

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

4.3 Vendors/Suppliers

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

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

4.4 Product Functionality & Associated Benefits

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

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

- Regular Meter Readings
  - Reduced data collection costs

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

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

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

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

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

5.0 Costs & Benefits Assessment

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

1. Financial - cost reductions and improved revenue streams.

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

5.1 Preliminary Financial Assessment

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

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

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

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

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

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

5.2 Productivity/Operational Benefits

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

5.3 Qualitative Benefits

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

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

Environment - Manual meter reading operations require meter readers to travel from location to location to perform readings. In the 2008/09 fiscal year, MHUS staff travelled approximately 734,000 km to perform meter reading activities. The adoption of AMI may significantly reduce this travel requirement, therefore resulting in an estimated annual reduction of approximately 250 tonnes of CO2 equivalent emissions.

6.0 Future Considerations

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

6.1 Measurement Canada

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

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

6.2 Product Enhancements

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

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

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

6.3 Time of Use Rates

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

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

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

6.4 Smart Grid and the Application of AMI Technologies

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

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

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

7.0 Conclusion & Next Steps

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

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

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

PUB/CENTRA I-74

Subject: **Tab 9: Rate Base**

Reference: **Tab 9 Page 22 and 23 of 63**

Please explain the reasons that the Brandon Capacity Upgrade project was completed at a cost of only $3.7 million, approximately 30% below the budgeted amount of $5.5 million as stated in the 2009/10 GRA Tab 5 Page 42 of 64.

ANSWER:

The project cost estimate was based on historical experience. The successful contractor was able to complete the project at a substantially lower cost than originally estimated.

PUB/CENTRA I-75

Subject: **Tab 9: Rate Base**

Reference: **Tab 9 Page 29 of 63**

Please provide a breakdown of the estimated and actual costs for the CentrePort project by labour and material. Please identify the contingency amounts included in the estimate. Please identify Centra's share of the costs as well as the total project costs.

ANSWER:

Please see table below.

		(000's)
	Project Estimate	**Project Actual**
Labour	2,169	3,994
Materials	649	1,058
Contingency	665	-
Total	**3,483**	**5,052**
Centra's Share	**1,743**	**2,526**

Actual costs exceeded project estimates primarily due to two factors:

- Inadequate subsurface conditions of the site required re-work and added significant extra work to install the pipe through these areas, also requiring additional material; and,
- Design changes during construction caused significant delays, increasing the duration of the project from three to six months.

PUB/CENTRA I-76

Subject: **Tab 9: Rate Base**

Reference: **Tab 9 Pages 29 and 30 of 63; Appendix 6.1 CEF-12 page 2 of 5**

a) Please reconcile the Gas SCADA total cost of $4.14 million shown on page 30 with the costs of $4.6 million shown in Appendix 6.1 CEF-12 page 2 of 5.

ANSWER:

The $4.1 million of costs on page 30 of Tab 9 includes an allocation of the Customer Service & Distribution target adjustment shown in Appendix 6.1, CEF12, page 1 of 5. The target adjustments represent the difference between the detailed capital project budgets and the annual capital spending targets.

PUB/CENTRA I-76

Subject: Tab 9: Rate Base

Reference: Tab 9 Pages 29 and 30 of 63; Appendix 6.1 CEF-12 page 2 of 5

b) Please state the total lifecycle cost of this SCADA system, including the cost of spares and anticipated future replacements until this system is retired.

ANSWER:

The lifecycle costs of the SCADA system will include maintenance and operational costs. For these costs, a maintenance contract has been agreed to that will keep the software up to date. Additionally, hardware is “off the shelf” with an expected lifespan of five years. A reasonable length of time to expect the system to be in operation is ten years. The costs of ownership for ten years are estimated to be:

Cost category	Amount (000's)[1]	Comment
Project Capital	4,600	
Hardware Replacement	400	After 5 years
Software Maintenance*	950	Years 2 through 10
Internal Support costs	1,000	
Total	6,950	

[1]All values are presented in 2012 dollars.
*Software maintenance represents the estimated cumulative costs for years 2 through 10.

PUB/CENTRA I-76

Subject: **Tab 9: Rate Base**

Reference: **Tab 9 Pages 29 and 30 of 63; Appendix 6.1 CEF-12 page 2 of 5**

c) Please identify the expected lifespan of this replacement SCADA system.

ANSWER:

The system software is expected to be maintained and upgraded for the foreseeable future. A maintenance agreement assures new releases of the base product software will be made available to Centra at no extra cost. The system hardware is expected to be replaced every five years.

PUB/CENTRA I-76

Subject: **Tab 9: Rate Base**

Reference: **Tab 9 Pages 29 and 30 of 63; Appendix 6.1 CEF-12 page 2 of 5**

d) Please describe the alternate product offered by the vendor and explain its deficiencies such that it "does not meet the complete system requirements for Manitoba Hydro".

ANSWER:

When the existing SCADA system was no longer maintained by the vendor a complete system replacement was required. The replacement project included a competitive bid process to award the software solution. Although the vendor's alternate product could have met the requirements, the vendor's alternate product was considered but did not score as high as the product ultimately selected.

PUB/CENTRA I-76

Subject: **Tab 9: Rate Base**

Reference: **Tab 9 Pages 29 and 30 of 63; Appendix 6.1 CEF-12 page 2 of 5**

e) Please identify the costs for the alternate product offered by the vendor, both capital cost and total lifecycle cost.

ANSWER:

During the vendor evaluation process the choice of supplier was short listed to three vendors. The direct costs for the three proponents were evaluated. This comparison did not include internal costs, hardware, and in-house support, which would be equivalent for all systems evaluated.

	Vendor, Product	Project Cost (millions)	Lifecycle (millions)
1	Open Systems International Incorporated	1.05	2.37
2	Proponent B	1.90	4.32
3	Proponent C	2.40	4.15

PUB/CENTRA I-76

Subject: **Tab 9: Rate Base**

Reference: **Tab 9 Pages 29 and 30 of 63; Appendix 6.1 CEF-12 page 2 of 5**

f) Please describe other systems Centra considered for the SCADA system replacement, their benefits and drawbacks, and explain why Centra chose the system it did.

ANSWER:

Vendor information was solicited in a Request for Information. Eleven vendors replied. Four were eliminated and the remaining seven were invited to respond to a Request for Proposal. Vendors invited included the existing system vendor and vendors for the SCADA Systems. Those seven and two additional vendors responded. The project team eliminated six through a system of scoring responses. Each question in the Request for Proposal was weighted. All questions were scored by at least three members of the project team.

The remaining three vendors were further considered through interviews and visits to their customers as well as visits to their head offices. All activities were scored. The final evaluation resulted in the following scores Open Systems International Incorporated with 76.1%, the others with 53.9% and 46.1%.

PUB/CENTRA I-76

Subject: **Tab 9: Rate Base**

Reference: **Tab 9 Pages 29 and 30 of 63; Appendix 6.1 CEF-12 page 2 of 5**

g) Please identify other gas utilities or gas transmission companies that use the SCADA system selected by Centra.

ANSWER:

At this time there are no other gas utilities or gas transmission companies that use the SCADA system selected by Centra. Open Systems International Incorporated has a number of electric and water utility customers that use their SCADA systems.

PUB/CENTRA I-76

Subject: **Tab 9: Rate Base**

Reference: **Tab 9 Pages 29 and 30 of 63; Appendix 6.1 CEF-12 page 2 of 5**

h) If Centra prepared an analysis comparing the benefits to the costs of this system, please file it.

ANSWER:

Centra did not prepare a cost/benefit analysis for the SCADA replacement system as it is considered to be "Necessary".

Capital projects that are required to maintain facilities in adequate operating condition are categorized as being "Necessary". Centra will classify capital projects in this category if the expenditure maintains facilities to a reasonable standard in order to serve customers. Projects in this category maintain prudent operating standards or address situations where equipment has reached a stage of functional obsolescence.

PUB/CENTRA I-77

Subject: **Tab 9: Rate Base**

Reference: **Tab 9 Page 30 of 63**

a) Please confirm the year that the referenced high volume customer in Minnedosa was connected.

ANSWER:

A new dedicated high pressure pipeline was constructed in 2007 to accommodate the above referenced customer's plant expansion. In October 2007, this customer was disconnected from the existing high pressure system and re-connected to the newly constructed dedicated high pressure pipeline.

PUB/CENTRA I-77

Subject: **Tab 9: Rate Base**

Reference: **Tab 9 Page 30 of 63**

b) **Please confirm whether the high volume customer in Minnedosa paid a capital contribution for their original gas service, and whether the contribution is subject to a true-up.**

ANSWER:

The high volume customer originally received gas service in 1981 and there is no outstanding true-up calculation for the original gas service.

Centra confirms that the customer paid a contribution in 2007 for the construction required to accommodate their expansion. The project is subject to a true-up as of December 31, 2012.

PUB/CENTRA I-78

Subject: Tab 9: Rate Base

Reference: Tab 9 Page 34 of 63

a) Please confirm whether Centra has undertaken any studies or initiatives aimed at improving the accuracy and consequently the life of its meters.

ANSWER:

Meter accuracy is mandated by Measurement Canada as outlined under the Electricity and Gas Inspection Act and supporting federal regulations. Centra requires contracted suppliers of meters to be compliant with Measurement Canada's meter accuracy requirements.

PUB/CENTRA I-78

Subject: **Tab 9: Rate Base**

Reference: **Tab 9 Page 34 of 63**

b) Please confirm whether Centra has undertaken any actions to mitigate the increase in meter-related costs.

ANSWER:

Centra issues Requests for Proposals for supply of natural gas meters to meter manufacturers across North America to ensure Centra obtains the most competitive pricing available.

PUB/CENTRA I-79

Subject: **Tab 9: Rate Base**

Reference: **Tab 9 Page 41 of 63**

Please explain why upgrades are required for the Elie pressure regulating station if this station was replaced following the tornado in 2008.

ANSWER:

To accommodate the addition of five (5) colonies to the Elie gas distribution system, a high pressure outlet was required to be installed at the station.

PUB/CENTRA I-80

Subject: Tab 9: Rate Base

Reference: Tab 9 Page 45 of 63

Please explain why Centra is not charging the customers in the Southglen Trailer Park for the costs to relocate its plant if Centra's plant is installed in easements.

ANSWER:

Centra extended service to the Southglen Trailer Park in 1972 and at that time, easements were not generally taken when such lines were extended on private property. Since the time of the original installation, there have been several house trailers relocated on the property, and as a result, were situated in locations that encroached upon the previously installed gas plant.

Due to the safety-related concerns with this encroachment, Centra has relocated the gas plant on the property to conform to codes and to ensure that safe clearances have been re-established. Centra assumed those costs and did not charge the individual customers for this work.

PUB/CENTRA I-81

Subject: **Tab 9: Rate Base**

Reference: **Tab 9 Page 50 of 63 Schedule 9.1.0 to 9.1.5**

a) Please explain the large increases in plant retirements in 2009/10 and 2011/12.

ANSWER:

Please see Centra's response to PUB/Centra I-81(b).

PUB/CENTRA I-81

Subject: **Tab 9: Rate Base**

Reference: **Tab 9 Page 50 of 63 Schedule 9.1.0 to 9.1.5**

b) Please provide reasons the following retirements are higher than in other years:

a. Computer System Development in 2009/10 through 2011/12

b. Measuring and Regulating Equipment in 2009/10

c. Communication Structures and Equipment in 2009/10

d. Transmission Mains in 2010/11

e. Office Furniture in 2011/12

f. Tools and Work Equipment in 2012/13 and 2013/14

ANSWER:

a. Computer system development uses amortization method accounting. As a result, the following systems were fully depreciated and retired:

2009/2010	
SCADA	1,304
Y2K	1,075
Other	225
2011/2012	
DFIS	4,147
Western T	416
Other	22

b. Measuring and regulating equipment retirements related to the disposal of odourant tanks, regulator upgrades and the rebuild of the Elie town border station due to damage caused by the 2008 tornado.

c. Communication structures and equipment uses amortization method accounting. The assets related to telecom services became fully depreciated and were retired.

d. The retirement of transmission mains in 2010/11 was a result of the relocation of the natural gas transmission pipeline due to the Province of Manitoba's Centerport project.

e. Office furniture uses amortization method accounting. These assets became fully depreciated and were retired.

f. Tools and work equipment uses amortization method accounting. Assets in this category will be retired when they become fully depreciated.

PUB/CENTRA I-82

Subject: **Tab 9: Rate Base**

Reference: **Tab 9 Schedule 9.5.5**

a) **Please explain why Contributions In Aid of Construction for 2013/14 make use of depreciation rates that incorporate the Equal Life Group methodology as well as the elimination of asset retirement costs (net salvage), since these methodology changes have not been approved and will not be implemented during the Test Year.**

ANSWER:

The amortization rates for Contributions in Aid of Construction for 2013/14 do not incorporate the Equal Life Group methodology, and do not include any provision for net salvage.

Following the 2010 Depreciation Study, Centra reviewed the approach to the amortization of Contributions in Aid of Construction. Centra determined that it was inappropriate to use the plant depreciation rates to amortize contributions, as the plant depreciation rates include factors that are not applicable to contributions. As contributions use the amortization method of accounting and are not physical in nature, plant asset assumptions with respect to retirement timing (IOWA curves), net salvage, and the inclusion of a true-up amount designed to allocate any accumulated depreciation variance on the plant asset accounts do not pertain to the contribution accounts.

Effective April 1, 2011, Centra implemented revised amortization rates for Contributions in Aid of Construction, which are designed to evenly allocate the unamortized net book value of the contributions over the expected remaining life of the associated physical assets. The revised amortization rate for each contribution account was determined using March 31, 2010 Contribution balances and the probable remaining live of associated physical plant assets as determined during the 2010 Depreciation Study, using the following two-step calculation:

$$1)\ \text{Annual Amortization Expense} = \frac{\text{Net Book Value of Contributions}}{\text{Probable Remaining Life of Associated Plant Assets}}$$

$$2)\ \text{Amortization Rate} = \frac{\text{Annual Amortization Expense}}{\text{Gross Contribution Amount (Depreciable Base)}}$$

PUB/CENTRA I-82

Subject: **Tab 9: Rate Base**

Reference: **Tab 9 Schedule 9.5.5**

b) Please re-file schedule 9.5.5 utilizing the appropriate amortization rates in effect for 2013/14. Please adjust any other schedules as required, including those schedules filed in response to these information requests.

ANSWER:

Centra has filed amended Schedules 9.5.3, 9.5.4 & 9.5.5 along with the responses to Round I Information Requests. The typographical error in the amortization rates presented did not impact the amortization expense presented in the Schedules, as the amortization expense was calculated using the appropriate rates.

PUB/CENTRA I-83

Subject: **Tab 9: Rate Base**

Reference: **Tab 9 Page 54 of 63; Schedule 9.6.5**

Please provide all the calculations to determine the working capital requirements for gas in storage for 2009/10 to 2013/14.

ANSWER:

Please see the tables below.

Actual and Forecast Gas Storage
PUB/CENTRA I-83
(000's)

	2009/10 Actual				2010/11 Actual				2011/12 Actual			
	Primary Storage	Supplemental Storage	T&D Storage	Total Gas Inventory	Primary Storage	Supplemental Storage	T&D Storage	Total Gas Inventory	Primary Storage	Supplemental Storage	T&D Storage	Total Gas Inventory
March	-	14,039	694	14,733	4,737	26,940	1,337	33,014	-	20,675	814	21,489
April	4,597	17,487	1,079	23,164	9,976	26,940	1,589	38,504	4,774	21,392	1,099	27,265
May	11,585	18,948	1,479	32,011	15,169	26,940	1,810	43,919	10,996	21,937	1,073	34,005
June	18,148	20,507	1,866	40,521	20,280	26,940	2,051	49,271	16,694	22,471	1,679	40,845
July	24,742	22,222	2,266	49,230	25,841	26,940	2,315	55,096	22,970	23,019	2,044	48,033
August	30,981	23,799	2,602	57,381	30,927	26,940	2,589	60,455	28,890	23,584	2,423	54,897
September	36,604	25,023	2,869	64,496	35,574	26,940	2,843	65,357	34,516	24,103	2,752	61,372
October	42,003	26,940	3,150	72,092	38,739	26,940	3,018	68,697	37,774	24,599	2,959	65,332
November	41,712	26,893	3,134	71,739	33,917	26,940	2,774	63,631	35,198	24,599	2,825	62,622
December	29,688	25,656	2,498	57,842	25,508	26,940	2,349	54,797	30,113	24,599	2,561	57,273
January	18,388	24,803	1,913	45,104	12,916	26,940	1,713	41,569	22,498	24,599	2,166	49,263
February	6,409	26,940	1,419	34,767	2,910	26,940	1,208	31,057	17,325	24,599	1,897	43,821
March	4,737	26,940	1,337	33,014	-	20,675	814	21,489	14,780	24,599	1,765	41,144
13 month average				**45,853**				**48,220**				**46,720**

Actual and Forecast Gas Storage
PUB/CENTRA I-83
(000's)

	2012/13 Forecast				2013/14 Forecast			
	Primary Storage	Supplemental Storage	T&D Storage	Total Gas Inventory	Primary Storage	Supplemental Storage	T&D Storage	Total Gas Inventory
March	14,780	24,599	1,765	41,144	-	24,551	857	25,408
April	16,108	24,599	1,862	42,568	3,310	24,878	1,044	29,231
May	17,661	24,599	1,974	44,235	6,975	25,218	1,250	33,442
June	19,668	24,599	2,057	46,324	10,852	25,550	1,467	37,869
July	21,788	24,599	2,180	48,566	15,462	25,897	1,723	43,083
August	24,147	24,599	2,307	51,053	19,884	26,247	1,969	48,101
September	26,471	24,599	2,432	53,502	24,386	26,585	2,218	53,190
October	28,644	24,599	2,546	55,789	28,207	26,939	2,429	57,576
November	25,463	24,599	2,359	52,421	24,454	26,939	2,230	53,623
December	19,250	24,599	1,993	45,841	17,334	26,939	1,851	46,124
January	10,629	24,599	1,485	36,712	7,674	26,939	1,338	35,951
February	4,768	24,599	1,139	30,506	986	26,939	982	28,907
March	-	24,551	857	25,408	0	19,971	689	20,660
13 month average				**44,159**				**39,474**

PUB/CENTRA I-84

Subject: **Tab 9: Rate Base**

Reference: **Tab 9 Page 58 of 63 - ROE**

a) Please file the referenced reviews of Return on Equity.

ANSWER:

The referenced reviews were undertaken by the British Columbia Utilities Commission ("BCUC"), the Alberta Utilities Commission ("AUC"), the Ontario Energy Board ("OEB") and the National Energy Board ("NEB"). The table below provides the most recently approved ROE for each jurisdiction. What follows is a description of the referenced reviews of ROE.

OEB	8.98% ROE for May 1, 2013 rate changes
BCUC	9.5% Benchmark ROE effective January 1, 2013 interim
AUC	8.75% Generic ROE for 2012
NEB	7.58% ROE for 2012 based on formula discontinued in 2009*

OEB

On March 16, 2009, the OEB initiated a consultation process to help it to determine whether current economic and financial market conditions warranted an adjustment to any of its cost of capital parameter values (i.e., the ROE, long-term debt rate, and/or short-term debt rate). The consultation was initiated, in part, by (i) the fact that the spread between the cost of equity and the cost of long-term debt values determined by the Board for 2009 was only 39 basis points versus a spread of 247 basis points in 2008; and (ii) concern that the Board did not have a sufficiently robust approach within which to exercise its discretion to adjust any or all of the values produced by the application of the methodology.

The Board determined that there was not sufficient basis to vary the 2009 parameter values for 2009 rates, but that further examination of its policy regarding the cost of capital was warranted to ensure that, on a going forward basis, changing economic and financial conditions are accommodated if required. Therefore, the Board advised that it would proceed with a review of its policy regarding the cost of capital.

The process culminated in a Report of the Board on the Cost of Capital for Ontario's Regulated Utilities issued December 11, 2009 (A copy of the report can be found at: http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2009-0084/CostofCapital_Report_20091211.pdf). The OEB determined that it would continue to use a formula based ROE. However, it also concluded the existing formula needed to be reset and refined. The formula was reset to address the difference between the allowed ROE arising from the application of the formula and the ROE for a low-risk proxy group that could not be reconciled based on differences in risk alone. The formula was refined to reduce its sensitivity to changes in government bond yields due to monetary and fiscal conditions that did not reflect changes in the utility cost of equity. The OEB concluded that there is a statistically significant relationship between corporate bond yields and the cost of equity, and that a corporate bond yield variable should be incorporated in the ROE formula. The Board determined that a review period of five years would ensure the ROE formula continued to meet the Fair Return Standard and would maintain regulatory efficiency and transparency.

BCUC

FortisBC Energy Utilities ("FEU," then the Terasen Utilities) initiated a ROE review by application of May 15, 2009 to the BCUC regarding Return on Equity and Capital Structure. FEU applied for an increase in the ROE from the 8.47 percent which resulted from the approved formula to 11 percent and applied to increase the equity component of their capital structure from 35.01 percent to 40 percent. FEU also requested that the Commission eliminate the use of an ROE automatic adjustment mechanism ("AAM") in the determination of the ROE.

FEU identified four main considerations that justified a review of Return on Equity and Capital Structure.

1. The Commission's 2006 Decision set a review period of 5 years while noting that any party was free at any time to apply to the Commission to consider a review of the AAM. The Commission also committed to consult parties on the need for a review should the Benchmark ROE fall below 8 percent or above 12 percent. Long Canada Bond yields fell below the level which would produce an ROE of 8 percent in December 2008 and January 2009.
2. On March 19, 2009 the NEB discarded the ROE determined by the formula from RH-2-94 in determining the appropriate ROE for the Trans Québec & Maritimes Pipeline.
3. The BCUC ROE formula no longer provided investors in the utility opportunity to earn a fair return on their capital as required by the Commission's obligations under the *Utilities Commission Act*.
4. Changing market conditions, evidenced by the dramatic widening of corporate credit spreads, strongly suggested the Commission should reset the Benchmark ROE. As further evidence FEU pointed to the increasing gap between returns in jurisdictions which employ a formula tied to the Long Canada Bond rate and those in jurisdictions that do not rely on a formula.

The Commission convened an Oral Hearing Process that concluded on November 24, 2009 and issued Order G-158-09 on December 16, 2009 (A copy of this Order can be found at: http://www.bcuc.com/Documents/Proceedings/2009/DOC_23953_G-158-09_TUS_ROE-Decision.pdf; a copy of the Decision can be found at http://www.bcuc.com/Documents/Proceedings/2009/DOC_24241_TUS_ROE-Decision-Web.pdf). The Commission determined that the ROE produced by the formula then in existence (8.43 percent for the benchmark utility) did not meet the fair return standard. Consequently, the BCUC approved an ROE for the benchmark utility of 9.5 percent, which was maintained for 2010 and 2011. The Commission acknowledged that a single variable, the Government of Canada bond yield, was unlikely to capture the many causes of changes in ROE. The Commission accordingly directed that the AAM be eliminated.

On February 28, 2012 the BCUC issued an Order initiating a Generic Cost of Capital Proceeding. The proceeding will review: (a) the setting of the appropriate cost of capital for a benchmark low-risk utility; (b) the possible return to an ROE AAM; and (c) the establishment of a deemed capital structure and deemed cost of capital methodology. Stage one of the proceeding concluded February 26, 2013, an Order has not been issued. Stage two begins April 25, 2013.

AUC

In the 2004 Generic Cost of Capital Decision the Alberta Energy and Utilities Board established a generic ROE and an annual adjustment formula. In the Decision, the Board determined that it would seek the views of parties on whether the adjustment formula continued to yield a fair ROE prior to 2009. The AUC initiated a proceeding on February 21, 2008 to determine whether the ROE formula and/or the common equity ratios should again be reviewed on a generic basis. The utilities were unanimous in arguing that the existing ROE formula did not provide a fair return and should be reviewed. They gave 5 main reasons:

1. Capital market conditions had changed significantly since the 2004 GCC proceeding and that risks faced by utilities had increased.

2. Government Bonds yields were artificially low, partially due to increasing investor preference for lower risk investments, which also raised the required return on equity.
3. U.S. utility returns were higher for utilities with similar risks and the gap was widening.
4. Certain newer pipeline utilities had negotiated returns higher than the typical formula returns and that in some cases these newer pipelines had lower risks due to long-term contracts, volume deferral accounts or protection from supply risk.
5. Globalization and integration of capital markets had increased competition for capital and thus required returns.

The Commission found that there was a reasonable basis to review the ROE level and the adjustment mechanism in a generic proceeding.

On July 25, 2008, the Alberta Utilities Commission ("AUC" or "the Commission") initiated the 2009 Generic Cost of Capital Proceeding ("2009 GCC Proceeding"). The 2009 GCC Proceeding dealt with the level of the generic return on equity for 2009, the ROE adjustment formula and the capital structures of the utilities on a utility-specific basis. It did not deal with the cost of debt component of the cost of capital. Utilities and intervenors retained experts to provide evidence on the above mentioned matters. The yearlong proceeding also involved rounds of information requests and 21 days of public hearings.

In AUC 2009-216 dated November 12, 2009 the Commission decided to suspend the application of the ROE adjustment formula and set a revised generic ROE for 2009 determined independently of the existing adjustment formula, and based solely on the record of the proceeding (A copy of the Decision can be found at: http://www.auc.ab.ca/applications/decisions/Decisions/2009/2009-216.pdf) The Commission set a generic ROE for 2009 and 2010 of 9.0 percent. In accordance with past practice, the

Commission applied the generic ROE uniformly to all utilities and accounted for the differences in risk among the individual companies by adjusting their capital structures. In 2009-216 the AUC also ruled that it would initiate a proceeding in 2011 to consider the final ROE for 2011 and to consider whether to implement an annual ROE adjustment formula.

The AUC initiated the 2011 Generic Cost of Capital Proceeding ("2011 GCC Proceeding") on December 16, 2010. For expediency and in order to minimize costs, the complete record of the 2009 GCC proceeding was incorporated into the 2011 proceeding. The proceeding also included rounds of information requests and public hearings.

In AUC Decision 2011-474 the Commission found that a generic ROE of 8.75 percent was reasonable for 2011 and 2012 (A copy of the Decision can be found at: http://www.auc.ab.ca/applications/decisions/Decisions/2011/2011-474.pdf). The generic ROE for 2013 was set at 8.75 percent on an interim basis. The Commission also considered the reintroduction of the Automatic Adjustment Mechanism. The Commission stated that a modified formula including corporate bond yield spreads (similar to the OEB formula) would partially correct for the draw backs of a single-variable formula. Nevertheless, based on the evidence of continuing credit market volatility, the Commission found that a return to the formula adjustment mechanism was not warranted for the time. At the same time, as noted in the Decision 2009-216, the Commission was not prepared to preclude a return to a formula-based adjustment mechanism in the future, once the capital markets have stabilized. Also in 2011-474 the AUC committed to initiating a proceeding to establish a final allowed ROE for 2013 and to revisit the matter of a return to a formula for setting the allowed ROE on a go forward basis.

The AUC initiated the 2013 Generic Cost of Capital Proceeding ("2013 GCC") on October 18, 2012. The 2013 GCC was subsequently suspended until other ongoing proceedings were completed. On April 4, 2013, the AUC recommenced the 2013 GCC proceeding, and requested comments from parties on the scope and timing of the proceeding be submitted by May 31, 2013. A hearing is expected in early 2014.

NEB

On July 3, 2009, the National Energy Board ("NEB" or "the Board") initiated a review of its 1994 multi-pipeline cost of capital decision (RH-2-94) in which it had approved a uniform ROE and a formula which adjusted ROE annually based upon changes in long-term Government of Canada bond rates. The Board observed that the circumstances surrounding cost of capital decisions in 2009 were different from those prior to 1994. The Board noted that in recent years, compared to the years prior to RH-2-94, litigation cases have decreased and negotiated settlements had become common practice. As a result of this change the Board was of the view that it is neither necessary nor appropriate to replace the RH-2-94 Decision with another multi-pipeline cost of capital decision at this time.

As a result, the NEB released a decision on October 8, 2009 stating that the Board's 1994 multi-pipeline return on equity formula, used to determine cost of capital for pipeline companies, is no longer in effect (A copy of the Decision can be found at: http://publications.gc.ca/collections/collection_2010/one-neb/NE22-1-2010-1-eng.pdf?).

Given the reference to the RH-2-94 Formula in some current settlements, the Board published the ROE resulting from the Formula for 2010 and 2011. On December 2, 2011 the NEB announced that by request it would continue to publish the results of the formula until 2014. The result of the formula for 2012 was an ROE of 7.58%.

PUB/CENTRA I-84

Subject: Tab 9: Rate Base

Reference: Tab 9 Page 58 of 63 - ROE

b) Please provide Centra's views of the reviews.

ANSWER:

The referenced reviews overwhelmingly found that a return on equity (ROE) adjustment formula tied to a single variable, the yield on long term Government of Canada bonds, was no longer appropriate, and specifically resulted in returns on equity which were below a fair return. Centra observes that many of the factors which moved other jurisdictions to review, revise and in some cases discontinue, the formula approach to setting ROE are also pertinent to Centra i.e. historically low Long Canada Bond yields and the general state of capital markets.

Centra's rates are set primarily on the basis of the Cost of Service methodology, and the Rate Base/Rate of Return calculation is provided for comparison purposes. In light of the findings in other jurisdictions, Centra is of the view that its existing ROE formula does not provide appropriate results in the current economic environment. However, Centra believes it is not necessary to undertake an extensive and costly independent review of the appropriate ROE but believes it can draw on the conclusions of the referenced reviews discussed in Centra's response to PUB/Centra I-84(a).

PUB/CENTRA I-84

Subject: **Tab 9: Rate Base**

Reference: **Tab 9 Page 58 of 63 - ROE**

c) Please provide Centra's understanding of its allowed return based on Board findings in Order 128/09.

ANSWER:

In Order 128/09 the PUB concluded that the "Cost of Service model for determining rates is now the only model that is practical with respect to Centra." (p.95)

With regards to Rate Base/Rate of Return the Board stated:

> "The Board will continue to review that [Rate Base and Rate of] return as long as the legislative provision remains; it will do so in the context of the circumstances of the time, on a weather-normalized basis, and in taking into account more than one year's experience." (p.87)

Centra's understanding is that the Board will rely on the Cost of Service model to determine rates, and will continue to review Centra's return on rate base.

PUB/CENTRA I-85 (Revised)

Subject: **Tab 9: Rate Base**

Reference: **Tab 9 Schedule 9.0.0; 2009/10 & 2010/11 GRA CAC/MSOS/Centra I-20**

Please file an update to the table provided in response to CAC/MSOS I-20 at the 2009/10 & 2010/11 GRA for each of the years 2006/07 through 2011/12 showing approved and actual amounts.

ANSWER:

Please see the table below which includes 2006/07 through 2011/12 approved and actual amounts.

Rate Base Rate of Return - Approved vs. Actual Results **($000's)**

	2006/07		2007/08		2008/09		2009/10		2010/11		2011/12
	Approved	Actual	Approved	Actual	Approved	Actual	Approved	Actual	Approved	Actual	Actual
Cost of Gas	432,881	378,664	404,918	386,490	407,142	430,759	318,785	315,840	331,442	260,835	197,099
Other Income	(2,565)	(2,199)	(2,232)	(1,967)	(2,115)	(1,901)	(2,026)	(1,924)	(2,026)	(1,394)	(991)
Operating & Administrative	55,182	53,505	56,600	56,270	58,000	59,803	59,160	60,951	60,343	60,644	62,117
Depreciation & Amortization	19,613	18,323	24,332	23,293	23,072	24,901	25,047	23,697	27,367	25,591	25,501
Furnace Replacement Program [1]	-	-	-	-	3,855	-	3,800	-	3,800	-	-
Capital & Other Taxes	24,405	22,248	22,839	23,021	23,063	23,412	23,703	23,351	23,940	20,490	19,274
Corporate Allocation	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000
Return on Rate Base	32,454	34,757	32,687	33,039	34,279	33,692	32,767	31,196	32,262	32,201	33,559
Revenue Requirement from Gas Rates	573,970	517,298	551,144	532,146	559,296	582,667	473,236	465,111	489,128	410,367	348,559
Gas Plant in Service	553,463	545,841	569,749	565,585	590,745	598,287	611,116	606,434	634,052	621,136	637,887
Accumulated Depreciation	(198,680)	(186,170)	(196,583)	(195,010)	(207,652)	(205,961)	(216,739)	(214,029)	(229,807)	(221,126)	(227,334)
Net Plant	354,783	359,671	373,166	370,575	383,093	392,325	394,377	392,406	404,245	400,010	410,553
Contributions in Aid of Construction	(44,548)	(46,639)	(47,334)	(46,974)	(46,698)	(46,150)	(48,857)	(46,712)	(50,956)	(48,566)	(49,936)
Working Capital Allowance	95,259	118,603	97,760	107,195	105,098	115,867	117,975	91,986	132,576	100,022	104,247
Rate Base	405,494	431,635	423,592	430,796	441,492	462,042	463,495	437,680	485,865	451,466	464,864

[1] Treated as a reduction to revenue for actual and forecast purposes

PUB/CENTRA I-86 (Revised)

Subject: **Tab 9: Rate Base**

Reference: **Tab 9 Schedules 9.7.0 to 9.7.5; 2009/10 & 2010/11 GRA PUB/Centra 77**

a) Please provide a schedule showing Centra's actual capital structure (i.e. schedule 9.7.0 column 1) and weighting (i.e. schedule 9.7.0 column 2) for the years 2003/04 to 2011/12, and projected for 2012/13 to 2013/14.

ANSWER:

Please see schedule included below. Please note that this information does not represent Centra's actual capital structure but rather the calculation of capital structure that has been specified by the PUB. The 2013/14 column includes the impact of the requested rate increase for 2013/14.

('000s)

	2003/04 Actual	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Test Year
Capital Structure ($000's)											
Long Term Debt (13 month average)	256,177	253,117	250,057	243,362	240,261	238,001	253,260	297,671	297,671	296,244	295,000
Short Term Debt	35,705	37,945	56,157	88,058	97,321	102,164	80,145	21,600	16,224	11,177	27,103
Equity (simple mid year average)	152,260	147,491	143,990	141,840	145,505	152,138	155,168	157,997	158,426	156,332	159,524
Total Capitalization (simple mid year average)	444,142	438,553	450,204	473,260	483,087	492,303	488,573	477,268	472,320	463,752	481,627
Weight											
Long Term Debt	57.7%	57.7%	55.5%	51.4%	49.7%	48.3%	51.8%	62.4%	63.0%	63.9%	61.3%
Short Term Debt	8.0%	8.7%	12.5%	18.6%	20.1%	20.8%	16.4%	4.5%	3.5%	2.4%	5.6%
Equity	34.3%	33.6%	32.0%	30.0%	30.1%	30.9%	31.8%	33.1%	33.5%	33.7%	33.1%
Total Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

PUB/CENTRA I-86 (Revised)

Subject: **Tab 9: Rate Base**

Reference: **Tab 9 Schedules 9.7.0 to 9.7.5; 2009/10 & 2010/11 GRA PUB/Centra 77**

b) Please provide a continuity schedule of Centra's equity, detailing the net income (loss) in each year and other adjustments for the years 2003/04 through 2013/14.

ANSWER:

Please see the schedule below.

2013/14 General Rate Application
Equity **($000's)**

	2003/04 Actual	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Forecast	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Test Year
Opening Retained Earnings	34,967	27,054	25,428	20,053	21,127	27,383	27,383	34,394	33,443	40,052	34,301	35,863
Net Income (Loss)	(7,912)	(1,626)	(5,375)	1,074	5,899	3,038	8,596	(950)	6,609	(5,751)	1,562	4,821
Ending Retained Earnings	27,054	25,428	20,053	21,127	27,027	30,421	35,979	33,443	40,052	34,301	35,863	40,684
Retained Earnings Adjustment					356 [1]		(1,585) [2]					
Share Capital	121,250	121,250	121,250	121,250	121,250	121,250	121,250	121,250	121,250	121,250	121,250	121,250
Total Equity	148,304	146,678	141,303	142,377	148,633	151,671	155,644	154,693	161,302	155,551	157,113	161,934

[1] Adjustment of $356 for the implementation of the financial instrument standards.

[2] Adjustment of $1 585 for the implementation of the goodwill and intangible standard. Represents cumulative reduction to retained earnings related to the write-off of general advertising and promotion costs related to Centra's Power Smart programs.

PUB/CENTRA I-87

Subject: **Tab 9: Rate Base**

Reference: **Tab 9 Schedules 9.9.4 and 9.9.5**

For 2013/14 please demonstrate that the requested revenue requirement (corporate allocation, finance expense and net income) on a cost of service basis does not exceed the overall approved return on rate base by preparing the following:

a) **In a similar fashion to PUB/Centra 78 from the 2009/10 & 2010/11 GRA, for the test year, please file a schedule which shows the total expenditures for the following components of revenue requirement: finance expense, corporate allocation and net income. Compare that total with the return on rate base of $30.9 million for 2013/14 and provide the differences.**

ANSWER:

The following table provides the total expenditures for the finance expense, corporate allocation and net income components of revenue requirement:

(000's)	2013/14
Finance expense	17,296
Corporate allocation	12,000
Net income	4,821
	34,117

In the schedule provided above, the Corporate Allocation and Net Income components of revenue requirement have been developed in accordance with post-acquisition rate decisions. These amounts consider cost savings that have accrued to the customers of Centra as a result of its acquisition by Manitoba Hydro as well as the retained earnings required by Centra to ensure its financial stability.

The Return on Rate Base provided in Schedule 9.9.5 is calculated as support to the Cost of Service revenue requirement and do not, in themselves, consider the costs and benefits of acquisition. The return amount is calculated in accordance with pre-acquisition standards.

Because of these fundamental differences in the way each of these methodologies determines net income, no direct comparison can be made.

The most appropriate comparison of these different return methodologies is that of the total revenue requirement calculated under each methodology. These are provided in Centra's response to PUB/Centra I-12 for Cost of Service methodology and in Schedule 9.0.0 for Rate Base Rate of Return methodology. In these schedules, the Rate Base Rate of Return methodology shows a substantially higher revenue requirement.

This result is due to the Rate Base Rate of Return schedule incorporating income as would have been calculated pre acquisition plus the Corporate Allocation which approximates the minimum net level of benefits to Centra as a result of its acquisition by Manitoba Hydro. By comparison, the Cost of Service Revenue Requirement incorporates a reduced level of income, thereby passing on an appropriate level of the acquisition benefit to the customers of Centra.

The following table provides a comparison of Revenue Requirement under each methodology:

(000's)	**2013/14**
Rate Base Methodology	326,780
Cost of Service Methodology	318,171
Net Difference	8,609

PUB/CENTRA I-87

Subject: **Tab 9: Rate Base**

Reference: **Tab 9 Schedules 9.9.4 and 9.9.5**

For 2013/14 please demonstrate that the requested revenue requirement (corporate allocation, finance expense and net income) on a cost of service basis does not exceed the overall approved return on rate base by preparing the following:

b) Please file an update to response to PUB/Centra I-78 (b) from the last GRA.

ANSWER:

Please see Centra's response to PUB/Centra I-87(a).

PUB/CENTRA I-88

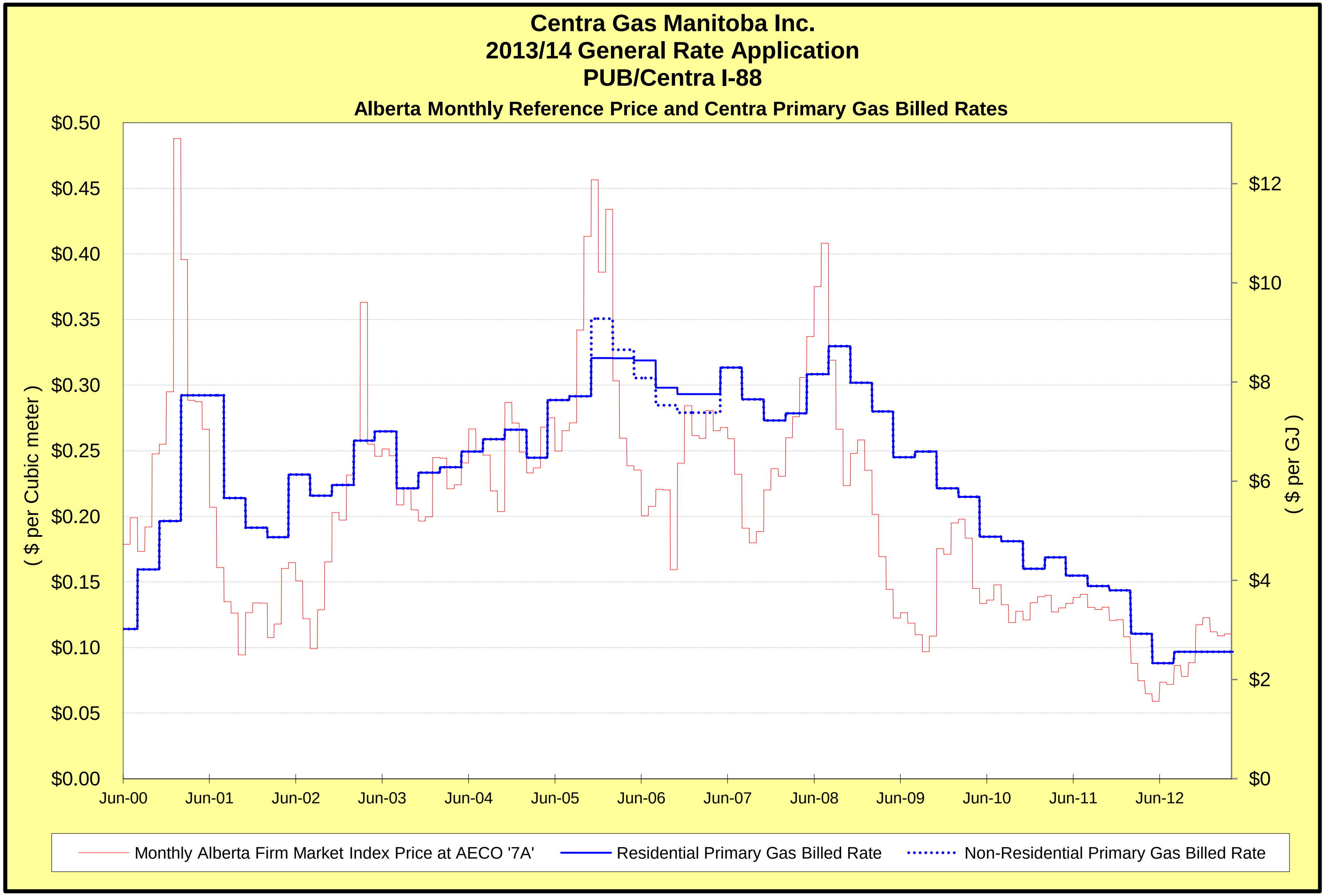
Subject: **Tab 10 – Gas Costs**

Reference: **Tab 10 Page 5 of 63**

Please provide a graph showing the AECO monthly reference price and Centra's Primary Gas rates (both residential and non-residential) since 2000.

ANSWER:

Please see the attachment to this response.


Centra Gas Manitoba Inc.
2013/14 General Rate Application
PUB/Centra I-88
Alberta Monthly Reference Price and Centra Primary Gas Billed Rates
($ per Cubic meter)
($ per GJ)
$0.50
$0.45
$0.40
$0.35
$0.30
$0.25
$0.20
$0.15
$0.10
$0.05
$0.00
$12
$10
$8
$6
$4
$2
$0
Jun-00
Jun-01
Jun-02
Jun-03
Jun-04
Jun-05
Jun-06
Jun-07
Jun-08
Jun-09
Jun-10
Jun-11
Jun-12
Monthly Alberta Firm Market Index Price at AECO '7A'
Residential Primary Gas Billed Rate
Non-Residential Primary Gas Billed Rate

PUB/CENTRA I-89

Subject: **Tab 10 – Gas Costs**

Reference: **Tab 10 Pages 8 and 20 of 63 – Peak Day Loads**

a) Please provide the Design Firm Peak Day loads as originally forecasted since the 2006/07 gas year.

ANSWER:

Centra's Design Firm Peak Day loads in GJ as originally forecasted since the 2006/07 Gas Year are as follow:

	GJ
2006/07	447,400
2007/08	439,200
2008/09	452,000
2009/10	484,000
2010/11	481,300
2011/12	470,100
2012/13	466,400

PUB/CENTRA I-89

Subject: Tab 10 – Gas Costs

Reference: Tab 10 Pages 8 and 20 of 63 – Peak Day Loads

b) Please provide the Design Firm Peak Day loads in the summer period (i.e. shoulder months) for the past five years as originally forecasted since the 2006/07 gas year.

ANSWER:

Centra's Design Firm Peak Day in the summer period occurs in April. The loads in GJ for Centra's Design Firm "Summer" Peak Day as originally forecasted since the 2010/11 Gas Year are as follow:

	GJ
2010/11	310,200
2011/12	310,100
2012/13	307,600

Information prior to these periods is not readily available and would require a significant amount of time and effort to recreate.

PUB/CENTRA I-89

Subject: **Tab 10 – Gas Costs**

Reference: **Tab 10 Pages 8 and 20 of 63 – Peak Day Loads**

c) Please provide the sources of supply that were arranged to meet the summer period (i.e. shoulder month) Design Firm Peak Day loads since the 2006/07 gas year.

ANSWER:

The following table depicts the sources of supply required to meet the Manitoba market's Design Firm "Summer" Peak Day requirement for the 2010/11, 2011/12, and 2012/13 Gas Years. Information prior to these periods is not readily available and would require a significant amount of time and effort to recreate.

	2010/11	**2011/12**	**2012/13**
Centra Supply	114,064	87,320	154,506
WTS Supply	23,136	23,880	19,919
Total Supply - FT/ STFT	137,200	111,200	174,425
Primary Gas Delivered Service	45,000	65,700	10,000
Emerson Supply			21,000
Peaking Delivered Services	128,000	133,200	102,175
	310,200	**310,100**	**307,600**

PUB/CENTRA I-90 (Revised)

Subject: **Tab 10 – Gas Costs**

Reference: **Tab 10 Pages 8, 32-33, and 49-50 of 63**

a) Please identify each of the days Interruptible customers were curtailed in the 2010/11 and 2011/12 gas years.

b) Please provide the Alternate Service price on each of these days as well as the corresponding AECO daily index price.

ANSWER:

Please find below a chart outlining the days on which Interruptible customers were curtailed and provided Alternate Supply Service in the 2010/11 and 2011/12 Gas Years.

GAS DAY CURTAILED	ALTERNATE SERVICE BILLED RATE ($/m³)	AECO C DAILY INDEX PRICE ($/m³)
2010/11		
3-Apr-11	$ 0.1691	$ 0.1408
4-Apr-11	$ 0.1690	$ 0.1355
5-Apr-11	$ 0.1574	$ 0.1345
6-Apr-11	$ 0.1570	$ 0.1309
13-Apr-11	$ 0.1476	$ 0.1307
14-Apr-11	$ 0.1468	$ 0.1307
15-Apr-11	$ 0.1479	$ 0.1338
16-Apr-11	$ 0.1494	$ 0.1326
17-Apr-11	$ 0.1493	$ 0.1319
18-Apr-11	$ 0.1492	$ 0.1327
19-Apr-11	$ 0.1507	$ 0.1330
20-Apr-11	$ 0.1512	$ 0.1330
30-Apr-11	$ 0.1525	$ 0.1450
1-May-11	$ 0.1634	$ 0.1461
2-May-11	$ 0.1755	$ 0.1474

GAS DAY CURTAILED	ALTERNATE SERVICE BILLED RATE ($/m³)	AECO C DAILY INDEX PRICE ($/m³)
2011/12		
8-Apr-12	$ 0.0880	$ 0.0655
9-Apr-12	$ 0.0891	$ 0.0626
10-Apr-12	$ 0.0801	$ 0.0629
11-Apr-12	$ 0.0805	$ 0.0613
15-Apr-12	$ 0.0877	$ 0.0638
16-Apr-12	$ 0.0877	$ 0.0582
5-Oct-12	$ 0.1267	$ 0.1004
6-Oct-12	$ 0.1235	$ 0.0894
9-Oct-12	$ 0.1209	$ 0.1013
10-Oct-12	$ 0.1288	$ 0.1077
11-Oct-12	$ 0.1261	$ 0.1132
24-Oct-12	$ 0.1287	$ 0.1219
25-Oct-12	$ 0.1354	$ 0.1208
26-Oct-12	$ 0.1340	$ 0.1203
27-Oct-12	$ 0.1339	$ 0.1246
28-Oct-12	$ 0.1338	$ 0.1214
29-Oct-12	$ 0.1339	$ 0.1226

PUB/CENTRA I-91

Subject: **Tab 10 – Gas Costs**

Reference: **Tab 10 Pages 16 and 17 of 63 – Gas Supply Contract**

a) Please file the redacted evaluation matrix used by Centra to select its new Primary Gas supplier with the respective scoring.

ANSWER:

Please see the attachment to this response.

RFP WESTERN CANADIAN GAS SUPPLY 2012-14
CENTRA GAS MANITOBA INC. -- EVALUATION MATRIX

Description of Criteria:	Total Category Weight	Sub Category Weight	CONOCO PHILLIPS	PARTY B	PARTY C	PARTY D	PARTY E	PARTY F
			Criteria Score "0-10" or "Yes / No" as necessary					
1) Provides Reliable Supply	0.40							
1.1 Reliable supply to customers		0.40	10	8.5	8.5	8	6.5	8.5
2) Minimizes Total Cost of Supply	0.30							
2.1 Minimize commodity costs		0.20	10	9.5	8.5	7.5	9	5
2.2 Minimize fixed asset costs		0.05	10	10	10	10	10	10
2.3 Minimize internal gas supply management costs		0.05	10	10	10	10	10	6
3) Credit / Financial Substantiation (must be investment grade)	0.15	Yes / No	Yes	Yes	Yes	Yes	No	Yes
3.1 Credit rating / worthiness		0.10	4.3	3.2	4.3	5.0	0	3.2
3.2 Credit requirements placed on Centra		0.05	8	10	10	2	6	10
4) Counterparty Quality	0.10							
4.1 Customer service / responsiveness		0.05	8	10	8	6	9.5	4
4.2 Proven performance / references and existing contracts		0.05	10	9	8	8.5	9	6
5) Consistent with other Corporate Goals	0.05							
5.1 Sustainable development / reduced environmental impacts		0.05	8.5	7.9	7.9	7.0	6.4	7.0
6) Meets WTS Requirements								
6.1 Provide for monthly contract level modification (must be present)		Yes / No	Yes	Yes	Yes	Yes	Yes	Yes
7) Provide Operational Nomination Flexibility								
7.1 Use of all nomination windows (must be present)		Yes / No	Yes	Yes	Yes	Yes	Yes	No
Total of All Categories			**9.16**	**8.47**	**8.23**	**7.38**	**6.95**	**6.87**
		RANK	**1**	**2**	**3**	**4**	**5**	**6**

PUB/CENTRA I-91

Subject: **Tab 10 – Gas Costs**

Reference: **Tab 10 Pages 16 and 17 of 63 – Gas Supply Contract**

b) **Please explain how Centra evaluated the different proponents for the new gas supply contract in terms of: 1) providing reliable supply, 2) credit rating/worthiness, 3) credit requirements placed on Centra, 4) Customer service and responsiveness, 5) proven performance, and 6) sustainable development. Please elaborate on the differentiators for each criteria (i.e. why certain companies scored higher than others).**

ANSWER:

Centra considered the following factors in performing the evaluation of the gas supply proposals:

1) Providing Reliable Supply - The proponents were evaluated on factors such as their magnitude of operations in the WCSB including production volumes, their ability to move large volumes of gas to Empress, and Centra's experience with the proponent.
2) Credit Rating/Worthiness - The proponents were first identified as investment grade based on their credit ratings from major credit rating agencies. The credit ratings of the parent companies were used in the case of unrated subsidiary companies. A credit rating was given slightly greater weight if the rating was for the proponent rather than its parent company. The proponents were then

scored based on their credit ratings against a continuum of ten investment grade rating levels.

3) Credit Requirements Placed on Centra - The proponents were evaluated based on the credit assurances that each expected to seek from Centra. Higher scores are reflective of less credit security sought by the proponent.

4) Customer Service and Responsiveness - The proponents were evaluated based on Centra's experience with the proponents from a customer service perspective including timeliness of response to inquiries, problem resolution, sharing of market intelligence, and willingness to provide accommodating and flexible service.

5) Proven Performance - The proponents were evaluated based on Centra's experience transacting with the proponents in addition to references from other parties as necessary to confirm the experience and performance of the proponent as a supplier.

6) Sustainable Development - The proponents were evaluated based on corporate commitments to sustainable development and environmental stewardship, and the availability of low environmental impact sources of natural gas supply to serve Centra. A consultant was retained to provide this evaluation.

PUB/CENTRA I-91

Subject: Tab 10 – Gas Costs

Reference: Tab 10 Pages 16 and 17 of 63 – Gas Supply Contract

c) Please detail the non-price-related differences between the new gas supply contract and the recently expired contract.

ANSWER:

Non-price-related features of the new contract that differ from the recently expired contract are as follow:

1) Term

New contract: two-year term.

Expired contract: three-year term.

2) Maximum Baseload and Swing Quantities

New contract: maximum baseload and swing quantities vary by month according to the following table.

Months	Baseload maximum (GJ/d)	Swing maximum (GJ/d)
Dec, Jan, Feb	130,000	70,000
Mar, Apr, May, Oct, Nov	95,000	100,000
Jun, Jul, Aug, Sep	85,000	75,000

Expired contract: maximum baseload of 140,800 GJ/day and maximum swing of 120,000 GJ/day do not vary by month.

3) <u>Termination process</u>

New contract: specifies a termination process in the event of substantive changes in the NOVA Alberta System's or TCPL Mainline's respective tariff or tolling methodology and the inability of the parties to agree to amended contract terms, should amendment of the contract be deemed necessary by either party.

Expired contract: specifies that the parties will negotiate in good faith to amend the contract in the event of substantive changes in the NOVA Alberta System's tariff or tolling methodology.

PUB/CENTRA I-91

Subject: **Tab 10 – Gas Costs**

Reference: **Tab 10 Pages 16 and 17 of 63 – Gas Supply Contract**

d) Please calculate the forecasted Primary Gas costs at Empress for the 2012/13 Gas Year for each proponent and compare the results.

ANSWER:

Forecast 2012/13 Gas Year Commodity Cost ($ millions)	
ConocoPhillips	133.6
Party B	133.9
Party C	134.4
Party D	134.8
Party E	134.1
Party F	N/A

Note: Party F's proposed pricing was incomplete and inconsistent with Centra's operating requirements, and is therefore not included in the comparison.

PUB/CENTRA I-91

Subject: **Tab 10 – Gas Costs**

Reference: **Tab 10 Pages 16 and 17 of 63 – Gas Supply Contract**

e) **Please calculate the total Primary Gas supply costs at Empress for the 2009/10, 2010/11, and 2011/12 gas years for the recently expired ConocoPhillips contract and compare to the costs Centra would have incurred with the other contract proponents (i.e. those proponents with compliant proposals in 2009).**

ANSWER:

A comparison of actual costs incurred under the ConocoPhillips contract to costs that may have been incurred under the other proposals can only be made on a theoretical basis. Due to changing market conditions, Centra significantly reduced its firm transportation capacity from Empress and baseload quantities taken under the ConocoPhillips contract, and replaced this deliverability with Primary Gas Delivered Service in the 2010/11 and 2011/12 gas years. The ConocoPhillips contract contained sufficient flexibility on contract levels and supply exclusivity to allow Centra to enact these portfolio changes and to realize associated portfolio savings of $6.6 million and $9.6 million in the 2010/11 and 2011/12 gas years, respectively. As Centra did not finalize contract terms with the other proponents, it is unknown whether such portfolio changes would have been feasible under contracts negotiated with other proponents, thus making the attainment of similar portfolio savings uncertain.

Theoretical Commodity Cost Comparison by Gas Year ($ millions)			
	2009/10	**2010/11**	**2011/12**
ConocoPhillips	176.5	120.4	53.0
Party B	175.6	117.4	49.4
Party C	177.2	NA	NA
Party F (1)	178.1	121.7	53.7
Party F (2)	178.1	121.6	53.6

- Party B suffered a credit downgrade and was sold since its proposal was submitted.
- Party C's proposal included a trigger that would have required renegotiation of pricing terms after the 2009/10 gas year. Theoretical costs therefore cannot be calculated under this proposal for the 2010/11 and 2011/12 gas years.
- Party D's proposed pricing was incomplete. Therefore Party D is not included in the comparison.
- Party E's proposed pricing was only valid under certain assumptions that were not consistent with Centra's operating requirements. This proposal is therefore not included in the comparison.
- Party F is on a provincial government credit watch. Party F provided two pricing proposals.

PUB/CENTRA I-92

Subject: **Tab 10 – Gas Costs**

Reference: **Tab 10 Pages 8 and 9 of 63**

Please describe the order of dispatch for Centra's gas supplies for firm supplies and for interruptible supplies.

ANSWER:

During the winter of the 2011/12 Gas Year, the dispatch order for Centra's various gas supply options to meet both Firm and Interruptible customer peak day requirements was as follows:

1. Baseload Supply - comprised of Western Canadian supplies (Centra and WTS supplies at Empress), Oklahoma supplies, and Primary Gas Delivered Service for Firm and Interruptible customers;
2. Swing Supply - comprised of Western Canadian supplies (Centra and WTS supplies at Empress) for Firm and Interruptible customers;
3. Michigan Storage - comprised of Primary and Supplemental supplies for Firm and Interruptible customers;
4. Alternate Supply Service and/or curtailment of Interruptible customers; and
5. Peaking Delivered Services - for Firm customers only.

During the winter of the 2012/13 Gas Year, the dispatch order was as follows:

1. Baseload Supply - comprised of Western Canadian supplies (Centra and WTS supplies at Empress), Oklahoma supplies, and Primary Gas Delivered Service for Firm and Interruptible customers;

2. Swing Supply - comprised of Western Canadian supplies (Centra and WTS supplies at Empress) for Firm and Interruptible customers;
3. Michigan Storage and U.S. Supplies - comprised of Primary and Supplemental supplies out of storage and supply purchased in Michigan for Firm and Interruptible customers;
4. Alternate Supply Service and/or curtailment of Interruptible customers; and
5. Peaking Delivered Services - for Firm customers only.

PUB/CENTRA I-93

Subject: **Tab 10 – Gas Costs**

Reference: **Tab 10 Page 11 of 63**

Please confirm whether the reversals of flow on the GLGT pipeline will impact Centra's ability to obtain gas supplies from its US storage and transportation assets.

ANSWER:

Any reversal of flow on GLGT will not impact Centra's ability to obtain gas supplies from its U.S. transportation and storage assets. Centra has a contractually firm path from storage to the load in Manitoba.

PUB/CENTRA I-94

Subject: **Tab 10 – Gas Costs**

Reference: **Tab 10 Page 27 of 63**

a) Please provide an update on TCPL's application to the NEB for its Business and Services Restructuring. If there is no update to the information in Tab 10 by the time Centra files responses to this round of information requests, please provide an update in the second round information request responses.

ANSWER:

The National Energy Board ("NEB") issued its Reasons for Decision related to RH-003-2011, the matter of TCPL's Business and Services Restructuring Proposal and Mainline Final Tolls for 2012 and 2013, on March 27, 2013. Please find below a link which contains the NEB's Reasons for Decision and Toll Order TG-002-2013. Centra is reviewing these documents and will provide a high level update in the second round Information Request process.

https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/130635/939799/A3G4A3_-_TransCanada_PipeLines_Limited,_NOVA_Gas_Transmission_Ltd._and_Foothills_Pipe_Lines_Ltd._Hearing_Order_RH-003-2011_Reasons_for_Decision?nodeid=939800&vernum=0

PUB/CENTRA I-94

Subject: **Tab 10 – Gas Costs**

Reference: **Tab 10 Page 27 of 63**

b) Please provide Centra's closing argument that was filed in the NEB proceeding.

ANSWER:

Centra's closing argument can be found at the link below:

https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90465/92833/92843/665035/711778/718167/736207/882311/C22-11-2_-_Final_Argument_of_Centra_Gas_Manitoba_Inc._-_A3D2A8?nodeid=882378&vernum=0

PUB/CENTRA I-94

Subject: Tab 10 – Gas Costs

Reference: Tab 10 Page 27 of 63

c) Please provide the reference Eastern Zone Tolls since 2006/07.

ANSWER:

Please find below the annualized Empress to Eastern Zone tolls on the Mainline back to 2006. These tolls are annualized on the calendar year. Please note that going forward TCPL will be using Empress to Union SWDA (Dawn) as its new reference or benchmark toll given the elimination of toll zones. Empress to Union SWDA is a shorter distance of haul than Empress to the Eastern Zone.

2006	$0.935
2007	$1.03
2008	$1.40
2009	$1.19
2010	$1.64
2011	$2.24
2012	$2.24

PUB/CENTRA I-95

Subject: **Tab 10 – Gas Costs**

Reference: **Tab 10 Page 30 of 63; Schedule 10.4.2(a)**

a) **Please provide the Primary Gas billing percentages for Firm and Interruptible customers since August 1, 2009.**

ANSWER:

Please see the table below:

	Firm Service		**Interruptible Service**	
Effective Date of Bill Percentage Implementation	**Primary Gas**	**Supplemental**	**Primary Gas**	**Supplemental**
February 1, 2013	90%	10%	88%	12%
November 1, 2012	90%	10%	88%	12%
August 1, 2012	94%	6%	89%	11%
May 1, 2012	98%	2%	89%	11%
February 1, 2012	99%	1%	95%	5%
November 1, 2011	97%	3%	95%	5%
August 1, 2011	89%	11%	37%	63%
May 1, 2011	90%	10%	45%	55%
February 1, 2011	81%	19%	67%	33%
November 1, 2010	81%	19%	67%	33%
August 1, 2010	100%	0%	74%	26%
May 1, 2010	100%	0%	74%	26%
April 1, 2010	100%	0%	74%	26%
February 1, 2010	94%	6%	67%	33%
November 1, 2009	96%	4%	67%	33%
August 1, 2009	81%	19%	40%	60%

PUB/CENTRA I-95

Subject: **Tab 10 – Gas Costs**

Reference: **Tab 10 Page 30 of 63; Schedule 10.4.2(a)**

b) Please explain why Centra did not reset the billing percentage to 100% for August 2011, considering the Supplemental Gas PGVA was in a large credit to customers position, and additional WACOG outflows in the final gas quarter of the year resulted in an even larger credit.

ANSWER:

Primary and Supplemental Gas billing percentages are set at the outset of each new gas year on November 1st, and adjusted thereafter as necessary, in order to ensure that the relative Primary and Supplemental Gas volumes billed to customers match as closely as possible to the underlying Primary and Supplemental Gas volumes purchased on their behalf over the course of each gas year. Billing percentages are not adjusted in order to mitigate or prevent the accumulation of PGVA deferral balances resulting from differences between the base WACOG rates being billed to customers and the underlying cost of gas purchases being made on their behalf.

PUB/CENTRA I-96

Subject: Tab 10 – Gas Costs

Reference: Tab 10 Schedule 10.4.3(a); 2011/12 COG Schedule 5.1.2

Please explain why the Total Fixed Costs do not decrease substantially to reflect the lower contract demand levels in July and August, as forecasted in 2011/12 COG Schedule 5.1.2.

ANSWER:

At the time of the preparation of Centra's 2010/11 gas year purchased gas cost forecast it was assumed that Centra's Primary Gas supply requirements direct from Western Canada would be transported via TransCanada Mainline FT capacity (2011/12 COG schedule 5.1.2 lines 1 and 2). The majority of TransCanada FT costs are in the form of fixed monthly demand charges and were depicted in Centra's 2010/11 gas year forecast as such (2011/12 COG schedule 5.1.3 (a), lines 3 and 4).

However, on an actual basis, Centra's portfolio optimization activities resulted in a portion of these requirements being supplied via Primary Gas Delivered Service arrangements, as opposed to purchasing those volumes under Centra's western Canadian Primary Gas supply agreement and transporting them on TCPL Mainline FT capacity as had been assumed at the time that the 2010/11 gas year forecast was prepared. The costs associated with Primary Gas Delivered Service supplies, which include both the cost of the commodity as well as transportation, do not bear fixed monthly demand charges, but do include a variable transportation cost element per unit of volume purchased. These variable costs associated with Primary Gas Delivered Service Supplies are separated from the cost of the commodity itself and are depicted on line 5 of Tab 10, schedule 10.4.3 (a).

Therefore, in order to replicate the total fixed transportation costs shown on line 14 of schedule 5.1.3 (a) (2011/12 COG) using the information depicted in Tab 10 schedule 10.4.3 (a), lines 2 and 5 must be added together in order generate an equivalent basis of comparison. This comparison is provided in the table below, which illustrates that these costs did in fact decrease by $346,000 and $307,000 respectively for the months of July and August relative to June actuals. Actual costs incurred for July and August were also lower than June 2011 COG forecast figures by $590,000 and $551,000 respectively.

MONTH	2011/12 COG TAB 5 SCHED. 5.1.3 (A) LINE 14	2013/14 GRA TAB 10 SCHED. 10.4.3 (A) SUM OF LINES 2 & 5	Actual Gas Costs Relative to June Actuals	Actual Gas Costs Relative to June Forecast
JUNE	$4,989,015	$4,745,121		
JULY	$4,502,900	$4,399,233	($345,888)	($589,782)
AUGUST	$4,502,900	$4,438,162	($306,959)	($550,853)

PUB/CENTRA I-97

Subject: **Tab 10 – Gas Costs**

Reference: **Tab 10 Schedules 10.7.1 and 10.10.1**

Please explain why the heating values listed in Schedules 10.7.1 and 10.10.1 do not correspond with the heating values published on TCPL's website: www.transcanada.com/customerexpress/2881.html www.transcanada.com/customerexpress/docs/ab_nominations/emprs_hv_forecast.pdf

ANSWER:

There are a number of factors which have the potential to influence variation in TCPL's heating values at Empress and Centra's stated heating values. There is a time lag of two to three days (depending on the extent of compression) for gas from Empress to reach Centra, thus the gas at Empress on a given day is not the same gas which is moving through TCPL's meters within Centra's service territory on the same day. Heating values at Empress do not include the effect of Saskatchewan receipts onto the Mainline. There is variation in the flow patterns through Empress relative to Centra's consumption patterns. The monthly heating values in Schedules 10.7.1 and 10.10.1 reflect a volume weighted average of the daily heating values at TCPL meter stations throughout both the MDA and SSDA. All of these factors are at play in influencing the observed variations in heating values.

PUB/CENTRA I-98

Subject: **Tab 10 – Gas Costs**

Reference: **Tab 10 Schedule 10.7.2(b)**

a) **Please explain why there is a positive rider amortization for June 2011, since rate riders are refunding a net balance to customers.**

ANSWER:

In June 2011, Centra provided a lump sum refund to the Special Contract Class pertaining to its allocation of the 2010/11 Heating Value Margin Deferral balance. This refund amount was greater than the offsetting monies collected from all other customers through the various rate riders in place during the month of June 2011, resulting in a net cash outflow for June 2011.

Centra notes that the April 30, 2011 Prior Period Gas Deferral Account balance was $4.58 million owing to Centra and not owing to customers as indicated in the question. As such, rider amortizations denoted as credit (i.e. negative) amounts represent net monies collected from customers.

PUB/CENTRA I-98

Subject: **Tab 10 – Gas Costs**

Reference: **Tab 10 Schedule 10.7.2(b)**

b) Please explain why there are any rider amortizations after April 2012, since PUB Order 54/12 eliminated any rate riders on non-PG rates as of May 1, 2012.

ANSWER:

Rate riders were removed from non-Primary Gas rates effective May 1, 2012 as approved in Order 54/12. The relatively small amounts shown as rate rider amortizations in line 24 of Schedule 10.7.2(b) are the result of routine billing adjustments made to customer accounts that occur from time to time in the normal line of business activity.

PUB/CENTRA I-99

Subject: **Tab 10 – Gas Costs**

Reference: **Tab 10 Pages 29 and 46 of 63**

a) Please explain how Centra calculates its UFG true-ups.

ANSWER:

The UFG True-up is conducted annually in the month of June and results in the actual UFG experienced during the prior twelve months being recorded in the Distribution PGVA. Actual UFG losses experienced are calculated as a percentage of total system receipts, where the UFG True-up is allocated to the prior twelve months based upon system receipts of Primary Gas and Supplemental Gas. The respective monthly Primary Gas and Supplemental Gas average unit costs of deliveries to the Manitoba marketplace are applied to the UFG True-up volumes to determine the financial impact.

The UFG calculation is defined as the difference between the Forced Unbilled and the Theoretical Unbilled for any given month:

UFG = Forced Unbilled – Theoretical Unbilled.

The Forced Unbilled is defined as the difference between Net Resale and Monthly Cycle Billing Sales for any given month:

Forced Unbilled = Net Resale – Monthly Cycle Billing Sales.

Net Resale is defined as Total Receipts less the amount booked for UFG. The amount booked for UFG is based on the assumed UFG%:

Net Resale = Total Receipts – UFG Booked.

The Total Receipts is equal to the sum of Purchases and Transport Volumes. Purchases represent the gas purchased for System Supply and WTS customers. Transport Volumes represent the gas required for Transport Service customers:

Total Receipts = Purchases + Transport Volumes.

The UFG Booked is the based on the assumed UFG percentage:

UFG Booked = Total Receipts * UFG%.

Monthly Cycle Billing Sales represent the amount of sales that is booked in any given month. It is estimated based on the Cycle Billing Sales from the Banner billing system and the Theoretical Unbilled calculation. The Theoretical Unbilled calculation is based on regression coefficients that relate Residential SGS, Commercial SGS and LGS average use (m^3/customer) versus effective degree days heating (EDDH). These coefficients are calculated from historical monthly sales data. In theory, the amount of unbilled sales is a function of the number of effective degree-days heating in any given month. The HVF, MLF and INT classes are not adjusted because these customers are billed on a calendar month basis. Since the Theoretical Unbilled portion of sales is added in one month, an equivalent amount must be subtracted out the following month:

Monthly Cycle Billing Sales = Cycle Billing Sales (Banner) + current Theoretical Unbilled – previous Theoretical Unbilled.

By combining all the above definitions, the UFG calculation can be collapsed into the following equation:

UFG True Up = ((Purchases + Transport Volumes) * (1-UFG%)) – (Cycle Billing Sales + current Theoretical Unbilled – previous Theoretical Unbilled).

PUB/CENTRA I-99

Subject: **Tab 10 – Gas Costs**

Reference: **Tab 10 Pages 29 and 46 of 63**

b) Please provide the actual (trued-up) UFG percentages for the past five years.

ANSWER:

Actual UFG percentages for the past five years are as follows:

Period	Actual UFG %
June 2007 to May 2008	0.68%
June 2008 to May 2009	1.35%
June 2009 to May 2010	0.73%
June 2010 to May 2011	1.01%
June 2011 to May 2012	0.52%

PUB/CENTRA I-100

Subject: **Tab 10 – Gas Costs**

Reference: **Tab 10 Schedules 10.12.1 to 10.12.3**

a) **Please provide a schedule showing the difference between forecasted gas costs for 2012/13 and the gas costs recoverable with existing rates in a format similar to that of 2011/12 COG Schedule 5.1.4(a).**

ANSWER:

Please see the attachment to this response.

Centra Gas Manitoba Inc. | **PUB/Centra I-100(a)**
2013/14 General Rate Application | **Attachment**
Difference Between Forecasted Non-Primary Gas Costs | **April 12, 2013**
and Non-Primary Gas Costs Recoverable With Existing Base Rates
Supply prices for 2012/13 Gas Year per forward strip as of November 1, 2012

		(1) Recoverable at Existing Base Rates	(2) Forecast for 2012/13	(3) Difference
1	Primary Gas	$105,569,914	$130,222,314	$24,652,400
2	Supplemental Gas	$19,089,719	$23,305,702	$4,215,983
3	Transportation[1]	$52,168,031	$48,194,521	($3,973,510)
4	Distribution	$3,127,437	$2,464,200	($663,238)
5				
6				
7	**Totals**	**$179,955,101**	**$204,186,737**	**$24,231,635**
8				
9				
10	**Non-Primary Gas Cost Totals**	**$74,385,188**	**$73,964,423**	**($420,765)**
11				
12	Note 1: Transportation costs including $6.3 mm Capacity Management forecast.			

PUB/CENTRA I-100

Subject: **Tab 10 – Gas Costs**

Reference: **Tab 10 Schedules 10.12.1 to 10.12.3**

b) Please provide a schedule showing the difference between forecasted gas costs for 2012/13 and the approved 2010/11 gas costs in a format similar to that of 2011/12 COG Schedule 5.1.4(b).

ANSWER:

Please see the attachment to this response.

Centra Gas Manitoba Inc.
2013/14 General Rate Application **PUB/Centra I-100 (b)**
Difference Between 2010/11 Gas Year Approved and 2012/13 Gas Year Forecast Costs **Attachment**
Supply prices for 2012/13 Gas Year per forward strip as of November 1, 2012 **April 12, 2013**

		(1)	(2)	(3)
		Approved for 2010/11	Forecast for 2012/13	Difference
1	Primary Gas	$155,081,267	$130,222,314	($24,858,953)
2	Supplemental Gas	$37,755,692	$23,305,702	($14,449,990)
3	Transportation	$52,140,493	$48,194,521	($3,945,972)
4	Distribution	$3,032,337	$2,464,200	($568,137)
5				
6				
7	**Totals**	**$248,009,789**	**$204,186,737**	**($43,823,052)**
8				
9				
10	**Non-Primary Gas Cost Totals**	**$92,928,522**	**$73,964,423**	**($18,964,099)**

PUB/CENTRA I-101

Subject: **Tab 10 – Gas Costs**

Reference: **Tab 10 Page 62 of 63**

a) Please provide the actual Canada-US dollar exchange rates to date for the 2012/13 gas year.

ANSWER:

Please see the table below detailing actual CAD/USD Exchange Rates for the months of November 2012 through February 2013.

	Nov Actual	Dec Actual	Jan Actual	Feb Actual
CAD/USD Exchange Rates	**0.9932**	**0.9949**	**0.9992**	**1.0285**

PUB/CENTRA I-101

Subject: **Tab 10 – Gas Costs**

Reference: **Tab 10 Page 62 of 63**

b) Please quantify the impact on the 2013/14 gas cost forecast utilizing the actual CAD/USD exchange rates for the months November through February.

ANSWER:

The impact on the 2012/13 gas year cost forecast in this Application of the actual CAD/USD exchange rates for the months November 2012 through February 2013 is a net gas cost addition of approximately $31,000.

PUB/CENTRA I-102

Subject: **Tab 10 – Gas Costs**

Reference: **Tab 10 Schedules 10.4.1, 10.4.2, 10.8.1, 10.8.2**

a) Please provide the monthly unit costs for the 2010/11 and 2011/12 gas years for the following sources of supply:

i. Primary supply at Empress according to the ConocoPhillips contract

ii. Oklahoma (ANR SW) Supply

iii. Louisiana (ANR SE) Supply

iv. Seasonal Delivered Service(s)

v. Delivered Service(s)

vi. Emerson supply

vii. Primary Supply from Storage

viii. Supplemental Supply from Storage

ix. AECO

x. Michigan city gate

xi. NYMEX

ANSWER:

Please see the attachment to this response that provides the monthly unit costs for the 2010/11 and 2011/12 gas years under the various sources of supply and market indices.

1	**Monthly Average Unit Cost of Purchases**		**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**
2														
3	Primary Supply at Empress from ConocoPhillips	$CAD/GJ	$3.5427	$3.8162	$3.8752	$3.7720	$3.6286	$3.6701	$3.7824	$3.8731	$3.8721	$3.6169	$3.5947	$3.4948
4	Oklahoma Supply	$CAD/GJ	$2.8033	$3.4516	$3.5578	$3.5782	$3.2622	$3.7126	$3.7969	$3.8433	$3.8105	$3.9366	$3.7270	$3.4512
5	Louisiana Supply	$CAD/GJ	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
6	Primary Gas Delivered Service	$CAD/GJ	n/a	n/a	n/a	n/a	n/a	$3.4552	$3.5661	$3.7362	n/a	n/a	$3.3439	$3.3127
7	Supplemental Gas Peaking Delivered Service	$CAD/GJ	$3.0831	$3.4516	$3.5578	$3.5782	$3.2622	$3.5512	$3.9182	n/a	n/a	n/a	n/a	n/a
8	Emerson Supply	$CAD/GJ	n/a	n/a	n/a	n/a	n/a	$3.8784	n/a	n/a	n/a	n/a	n/a	n/a
9	Primary Supply fron Storage	$CAD/GJ	$3.8521	$3.8521	$3.8521	$3.8521	$3.8521	n/a	n/a	n/a	n/a	n/a	n/a	n/a
10	Supplemental Supply from Storage	$CAD/GJ	$4.9408	$4.9408	$4.9408	$4.9408	$4.9408	n/a	n/a	n/a	n/a	n/a	n/a	n/a
11														
12														
13	**Market Index Prices**													
14														
15	AECO	$CAD/GJ	$3.1983	$3.6025	$3.6712	$3.6991	$3.3622	$3.4426	$3.5354	$3.6558	$3.7166	$3.4546	$3.4087	$3.4601
16	Michigan City Gate	$CAD/GJ	$3.4049	$4.2610	$4.1796	$4.1723	$3.7120	$4.0999	$4.2698	$4.1860	$4.0681	$4.2194	$4.0372	$3.7384
17	NYMEX	$CAD/GJ	$3.2026	$3.9688	$4.0048	$3.9877	$3.4909	$3.9587	$4.0219	$3.9575	$3.9416	$4.0618	$3.7910	$3.5406
18														
19														
20														
21	**Monthly Average Unit Cost of Purchases**		**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**
22														
23	Primary Supply at Empress from ConocoPhillips	$CAD/GJ	$3.2902	$3.2077	$2.8573	$2.2996	$1.9316	$1.7703	$2.0874	$2.0413	$2.0533	$2.3989	$2.2911	$3.0903
24	Oklahoma Supply	$CAD/GJ	$3.2933	$2.8255	$2.8273	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
25	Louisiana Supply	$CAD/GJ	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
26	Primary Gas Delivered Service	$CAD/GJ	$2.8521	$2.8255	$2.4806	$1.9944	$1.7715	$1.3964	$1.4360	n/a	n/a	n/a	$2.2144	$2.4888
27	Supplemental Gas Peaking Delivered Service	$CAD/GJ	n/a	n/a	$2.6176	$2.4846	$2.5949	$2.0187	n/a	n/a	n/a	n/a	n/a	$3.3294
28	Emerson Supply	$CAD/GJ	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
29	Primary Supply fron Storage	$CAD/GJ	$3.6749	$3.6749	$3.6749	$3.6749	$3.6749	n/a	n/a	n/a	n/a	n/a	n/a	n/a
30	Supplemental Supply from Storage	$CAD/GJ	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
31														
32														
33	**Market Index Prices**													
34														
35	AECO	$CAD/GJ	$3.1914	$3.2062	$2.8617	$2.3222	$1.9732	$1.7126	$1.5586	$1.9472	$1.8967	$2.2794	$2.0597	$2.3382
36	Michigan City Gate	$CAD/GJ	$3.7113	$3.4894	$3.1155	$2.6744	$2.4810	$2.1828	$2.1285	$2.4534	$2.6576	$2.9634	$2.5640	$3.0129
37	NYMEX	$CAD/GJ	$3.4059	$3.2427	$2.9383	$2.5042	$2.3163	$2.0526	$1.9971	$2.3462	$2.6329	$2.8138	$2.4559	$2.8613

PUB/CENTRA I-102

Subject: **Tab 10 – Gas Costs**

Reference: **Tab 10 Schedules 10.4.1, 10.4.2, 10.8.1, 10.8.2**

b) Please provide the monthly volumes associated with the inflows listed on lines 2 through 5 of Schedules 10.4.1 and 10.8.1.

ANSWER:

Please see the attachment to this response that details the monthly Primary Gas volumes as per Schedules 10.4.1 and 10.8.1.

Centra Gas Manitoba Inc. | **PUB/Centra I-102 (b)**

2013/14 General Rate Application | **Attachment**

Primary Gas Inflow Volumes - 2010/11 & 2011/12 Gas Years | **April 12 2013**

1	**November 2010 to October 2011 Inflow GJ's**													
2														
3	**Primary Gas Inflow Volumes (GJ)**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**Total**
4														
5	Primary Supply	2,861,540	3,343,665	3,187,933	2,923,273	3,318,706	2,093,823	1,123,683	687,364	905,022	951,092	804,564	1,660,928	**23,861,593**
6	Primary Gas Delivered Service	0	0	0	0	0	1,050,000	775,000	450,000	0	0	450,000	775,000	**3,500,000**
7	Primary Gas from Storage	577,196	1,092,469	749,408	1,812,408	488,405	0	0	0	0	0	0	0	**4,719,886**
8	Primary Gas Storage via Exchanges with Counterparties	667,098	1,077,283	2,500,369	770,880	259,947	0	0	0	0	0	0	0	**5,275,577**
9	**Total**	**4,105,834**	**5,513,417**	**6,437,710**	**5,506,561**	**4,067,058**	**3,143,823**	**1,898,683**	**1,137,364**	**905,022**	**951,092**	**1,254,564**	**2,435,928**	**37,357,056**
10														
11	**November 2011 to October 2012 Inflow GJ's**													
12														
13	**Primary Gas Inflow Volumes (GJ)**	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Total**
14														
15	Primary Supply	2,188,421	2,458,334	1,838,761	1,780,409	1,149,820	1,294,152	669,421	988,230	857,890	935,067	1,086,448	2,132,783	**17,379,736**
16	Primary Gas Delivered Service	1,650,000	2,480,000	2,945,000	2,755,000	2,170,000	1,371,000	930,000	0	0	0	317,400	1,112,900	**15,731,300**
17	Primary Gas from Storage	297,371	664,347	1,972,305	1,336,742	435,795	0	0	0	0	0	0	0	**4,706,560**
18	Primary Gas from Storage via Exchanges with Counterpartie	427,908	678,000	82,747	59,387	251,200	0	0	0	0	0	0	0	**1,499,242**
19	**Total**	**4,563,700**	**6,280,681**	**6,838,813**	**5,931,538**	**4,006,815**	**2,665,152**	**1,599,421**	**988,230**	**857,890**	**935,067**	**1,403,848**	**3,245,683**	**39,316,838**

PUB/CENTRA I-103

Subject: Tab 11: Cost Allocation and Rate Design

Reference: Tab 11 General

Please update the status of Manitoba Hydro's review of its Cost Allocation Methodology and identify any potential or proposed changes to Centra's Cost Allocation Methodology that have resulted from this review, including any changes that are being considered for future GRAs.

ANSWER:

Manitoba Hydro has completed a review of its Cost of Service Methodologies and has filed evidence regarding electric Cost of Service matters with the PUB. A public review of that topic is expected to be conducted in 2013; however the nature and timing of that process has yet to be established.

The Corporation is satisfied that the natural gas cost allocation methodology remains to be appropriate and is not proposing any changes at this time.

PUB/CENTRA I-104

Subject: **Tab 11: Cost Allocation and Rate Design**

Reference: **Tab 11 Page 1 of 17**

Please provide a summary, in tabular form, of all changes in Centra's Cost Allocation Methodology since 2004/05 including methodology, process for functionalization, classification and allocation factor determinations.

ANSWER:

The Functionalization, Classification and Allocation factors have been updated to reflect the 2013/14 forecast data. In a manner consistent with past GRA practice, the updated forecast data includes volumes, number of customers, coincident peak, rate base and revenue requirement. In addition, slight modifications are made to the Cost Allocation Study as part of each GRA to adapt to operational changes and accounting changes, but the intent of the allocation of the costs has not changed or the modifications do not have a material effect on the results of the Study.

The allocation process related to DSM amortization expense represents a change from the last GRA. Overall, Centra continues to assign DSM amortization expense on the basis of anticipated participation which is forecast by customer class. In the 2013/14 GRA, total DSM amortization expense is $7.2 million (Tab 5, Schedule 5.9.6, line 20) and has been assigned to each class on the basis of forecast participation as shown in the table below.

Centra has now functionalized this expense to Transmission and classified it as being Energy-related. Previously, Centra functionalized this expense as Onsite and classified these costs on the basis of number of customers. This change better aligns the cost with its driver.

While this change does not impact the assignment of DSM amortization expense to each class, it does shift the costs from being recovered through the Basic Monthly Charge to the Volumetric Charge (Distribution to Customer). There is no impact of this change to the SGS and LGS Classes because the BMC is set independent (at $14 and $77 per customer per month, respectively) of costs determined to be customer-related with the residual recovered in the volumetric distribution rate.

For the Larger Volume Classes, the DSM amortization expense will be recovered volumetrically from customers within a class. The larger volume consumers within these classes stand to benefit to a greater extent from DSM opportunities and therefore DSM costs recovered volumetrically will align more directly with its cost recovery. Absent this change in allocation, the increase in the forecasted participation in DSM for these larger volume customer classes (HVF, MLF and INT) and corresponding assigned cost increases, would have caused a significant increase in their BMC, due to the very small number of customers in each of these classes.

The following table compares the cost allocation treatment and DSM amortization costs approved in the 2010/11 GRA and those proposed in the 2013/14 GRA:

GRA	Total $	Function	Classify	Allocate				
				SGS	LGS	HVF	MLF	INT
2010/11 Approved		On-Site	Customer	77%	21%	1%	1%	0%
2010/11 Approved	$4,918.1			$3,786.9	$1,032.8	$49.2	$49.2	$0.0
2013/14 Proposed		Transmission	Energy	58%	34%	2%	4%	2%
2013/14 Proposed	$7,198.2			$4,175.0	$2,447.4	$144.0	$287.9	$144.0
Change in costs/class				$388.0	$1,414.6	$94.8	$238.7	$144.0

PUB/CENTRA I-105

Subject: **Tab 11: Cost Allocation and Rate Design**

Reference: **Tab 11 Page 14 of 17**

a) Please explain why customer classes are developed for Primary Gas , Supplemental Gas-Firm, Supplemental Gas-Interruptible and Fixed Rate Primary Gas, and illustrate how the allocations to these classes affect the allocations to the various other customer classes.

ANSWER:

Customer classes were introduced for Primary Gas and Supplemental Gas Firm and Interruptible in response to the introduction of the Western Transportation Service in 1999. The Primary Gas and Supplemental Gas Firm and Interruptible classes are not traditional customer classes in that they represent a group of customers with similar consumption and cost behaviours but rather have been created to address these service offerings. These classes were developed as a convenient way to segregate gas costs and related costs including:

- The removal of commodity costs from transportation and distribution rates; and
- Gas procurement and other program and administrative costs.

This also allowed Centra to present Primary Gas Costs on a basis that was comparable to the broker supplied Primary Gas costs. Firm and Interruptible Supplemental Gas classes were similarly developed to recognize that Centra would continue to provide some commodity services to customers notwithstanding their Primary Gas supplier choice and to recognize the cost distinctions between Firm and Interruptible services.

The Fixed Rate Primary Gas Service class was created in response to the Fixed Rate Primary Gas Service introduced in 2009 as a convenient way to segregate and allocate costs related to this service offering.

Customers who elect these services bear responsibility for the costs of the service through the applicable Primary Gas, Supplemental Gas and FRPGS rates. The result is that these costs are then removed from the remaining revenue requirement and are not allocated to the traditional customer classes namely, SGS, LGS, HVF, Co-op, Mainline, Interruptible, Special Contract and Power Stations.

PUB/CENTRA I-105

Subject: **Tab 11: Cost Allocation and Rate Design**

Reference: **Tab 11 Page 14 of 17**

b) Please provide a summary of the calculations used for the non-gas cost overhead component embedded in the 2013/14 Primary Gas Rate.

ANSWER:

The following is a summary of the requested calculations.

Calculation of PG OH rate	($000's)
Gas Supply	331.4
Gas Accounting	220.3
Other O&A	62.9
Total O&A	614.6
Other Revenue	(5.3)
Depr. & Amor	42.5
Capital & Other Taxes	64.6
Finance Expense	147.0
Corporate Allocation	102.0
Net Income (Loss)	47.6
Total Cost of Service	1,013.0
PG Volumes (10^3m^3)	1,102,093
PG OH Rate/10^3m^3	$ 0.92

PUB/CENTRA I-106

Subject: **Tab 11: Cost Allocation and Rate Design**

Reference: **Tab 11 Page 4 of 17**

a) **Please discuss the rationale used to assign weightings by customer class with respect to the allocation of UFG.**

ANSWER:

The issue of the allocation of Unaccounted for Gas ("UFG") costs to customer classes was canvassed as part of Centra's 2004/05 Cost of Gas application. Centra had conducted a study that identified three major causes of UFG including measurement error, physical loss and accounting factors. In Order 131/04, the PUB approved changes to Centra's allocation of UFG costs which established the allocation weightings by customer class as shown in the table below. Centra has utilized those weightings for the purposes of allocating UFG costs in all subsequent non-Primary Gas rate applications.

2013/14 GRA ($)	SGS	LGS	High Volume Firm	Mainline	Special Contract	Power Stations	Interruptible
	38.0%	27.5%	8.8%	7.3%	2.8%	5.5%	9.7%
$2,265.8	$870.1	$623.1	$199.4	$165.4	$63.4	$124.6	$219.8

PUB/CENTRA I-106

Subject: **Tab 11: Cost Allocation and Rate Design**

Reference: **Tab 11 Page 4 of 17**

b) Please indicate and explain the changes in customer class weightings, if any, since that time.

ANSWER:

Please see Centra's response to PUB/Centra I-106(a).

PUB/CENTRA I-107

Subject: **Tab 11: Cost Allocation and Rate Design**

Reference: **Tab 11 Page 12 of 17**

Please provide a summary of the allocation results for each customer class for both current rates and for proposed rates showing the:

a. **Percentage of customer-related costs recovered by the BMC.**

b. **Percentage of customer-related costs recovered by the commodity charge.**

c. **Percentage of demand-related costs recovered by the demand charge.**

ANSWER:

Please see the schedules attached to this response.

a) Percentage of customer-related costs recovered by the BMC

	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT
Proposed Rates								
Allocation of Customer-related costs (as per sch.11.1.1 line 9)	$86,589,691	$12,493,080	$1,357,168	$3,842	$120,635	$42,114	$196,785	$606,538
BMC	$14	$77	$1,229	$320	$1,257	$119,492 [1)]	$8,199	$1,264
Number of downstream customers (as per sch. 11.1.1 line 22)	3,194,330	93,577	1,104	12	96	12	24	480
BMC Revenue	$44,720,620	$7,205,429	$1,357,169	$3,842	$120,635	$1,433,906	$196,785	$606,538
Percentage of customer-related costs recovered by BMC	52%	58%	100%	100%	100%	100%	100%	100%
Current Rates								
Allocation of Customer-related costs	$86,676,736	$13,357,583	$1,301,718	$3,289	$225,919	$119,569	$277,574	$575,581
BMC	$14	$77	$1,118.31	$274.06	$2,353.33	$135,338.63 [1)]	$11,565.60	$1,042.72
Number of downstream customers	3,118,230	94,509	1,164	12	96	12	24	552
BMC Revenue	$43,655,220	$7,277,193	$1,301,713	$3,289	$225,920	$1,624,064	$277,574	$575,581
Percentage of customer-related costs recovered by BMC	50%	54%	100%	100%	100%	100%	100%	100%

1) BMC for Special Contracts recovers 100% of customer and capacity related costs

b) Percentage of customer-related costs recovered by the commodity charge

	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT
Proposed Rates								
Allocation of Customer-related costs (as per sch.11.1.1 line 9)	$86,589,691	$12,493,080	$1,357,168	$3,842	$120,635	$42,114	$196,785	$606,538
BMC	$14	$77	$1,229	$320	$1,257	$119,492 1)	$8,199	$1,264
Number of downstream customers (as per sch. 11.1.1 line 22)	3,194,330	93,577	1,104	12	96	12	24	480
BMC revenue	$44,720,620	$7,205,429	$1,357,169	$3,842	$120,635	$1,433,906	$196,785	$606,538
Customer-related costs recovered by commodity charge ($)	$41,869,071	$5,287,651	$0	$0	$0	$0	$0	$0
Percentage of customer-related costs recovered by commodity charge	48%	42%	0%	0%	0%	0%	0%	0%
Current Rates								
Allocation of Customer-related costs	$86,676,736	$13,357,583	$1,301,718	$3,289	$225,919	$119,569	$277,574	$575,581
BMC	$14	$77	$1,118.31	$274.06	$2,353.33	$135,338.63 1)	$11,565.60	$1,042.72
Number of downstream customers	3,118,230	94,509	1,164	12	96	12	24	552
BMC revenue	$43,655,220	$7,277,193	$1,301,713	$3,289	$225,920	$1,624,064	$277,574	$575,581
Customer-related costs recovered by commodity charge ($)	$43,021,516	$6,080,390	$0	$0	$0	$0	$0	$0
Percentage of customer-related costs recovered by commodity charge	50%	46%	0%	0%	0%	0%	0%	0%

1) BMC for Special Contracts recovers 100% of customer and capacity related costs

c) Percentage of demand-related costs recovered by the demand charge

	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT
Proposed Rates								
Percentage of demand-related costs recovered by demand charge (as per sch.11.1.1 line 24)	0%	0%	65%	100%	100%	100%	100%	65%
Current Rates								
Percentage of demand-related costs recovered by demand charge	0%	0%	65%	100%	100%	100%	100%	65%

PUB/CENTRA I-108

Subject: Tab 11: Cost Allocation and Rate Design

Reference: Tab 11 Page 6 of 17

a) Please discuss whether Centra has considered using methods, other than the Peak and Average method, of allocating demand related cost.

ANSWER:

Centra has considered other methods for allocating demand related costs but is of the view that the Peak and Average methodology continues best represent the balance between cost causation, fairness and equity between customer classes.

PUB/CENTRA I-108

Subject: **Tab 11: Cost Allocation and Rate Design**

Reference: **Tab 11 Page 6 of 17**

b) Please list and describe the methods used by other Canadian natural gas utilities to allocate demand (Capacity) related costs.

ANSWER:

Centra has conducted an informal survey of methods used by other Canadian natural gas utilities to allocate demand related costs which identifies the use of various allocators including Peak Day, Peak over Average, Non-Coincident Peak and Peak and Average. Most of the utilities surveyed are segmented in their approach and apply, in some cases, several different demand allocators.

In contrast, Centra uses a Peak and Average methodology for purposes of allocating demand related costs and its application is uniform in that it is applied across all functions. Centra is satisfied that its cost allocation methodology remains appropriate and is not proposing any changes at this time.

PUB/CENTRA I-109

Subject: **Tab 11: Cost Allocation and Rate Design**

Reference: **Tab 11 Page 7 of 17**

a) Please explain Centra's methodology for assigning or allocating DSM costs to the customer classes, specifically explaining how the costs for residential, commercial, and industrial DSM programs are assigned or allocated.

ANSWER:

Please see Centra's response to PUB/Centra I-104.

PUB/CENTRA I-109

Subject: **Tab 11: Cost Allocation and Rate Design**

Reference: **Tab 11 Page 7 of 17**

b) Please provide the results of Centra's allocation of DSM costs to each customer class.

ANSWER:

Please see Centra's response to PUB/Centra I-104.

PUB/CENTRA I-110

Subject: Tab 11: Cost Allocation and Rate Design

Reference: Tab 11 Page 10 of 17

Please provide the approved revenue to cost ratios for 2009/10 and 2010/11 for the SGS and LGS classes.

ANSWER:

Please see the schedule attached to this response.

	2009/10 Approved		2010/11 Approved	
	SGS	LGS	SGS	LGS
Approved Rates (Non-Gas)				
BMC	13.00	70.00	14.00	77.00
Transportation Commodity ($/10^{3}m^3)	7.11	7.09	7.11	7.09
Distribution Commodity ($/10^{3}m^3)	85.22	34.46	85.22	34.46
Billing Determinants				
Downstream Demand (10^{3}m^3-day)	67,368	45,998	66,997	45,752
Downstream Commodity (10^{3}m^3)	688,613	494,811	684,811	492,165
Downstream Customer (customers)	3,094,863	94,261	3,118,230	94,509
Non-Gas Revenue				
BMC Revenue	40,233,219	6,598,270	43,655,220	7,277,193
Transportation Commodity Revenue	4,896,581	3,507,543	4,869,547	3,488,787
Distribution Commodity Revenue	58,686,147	17,051,385	58,362,142	16,960,203
Total	103,815,947	27,157,198	106,886,909	27,726,183
Non-Gas Rev Req (per Scheds 9.1.2 & 9.2.2, line 43)	105,062,813	26,675,313	106,833,325	27,134,759
Non-Gas Revenue Sufficiency/(Deficiency)	(1,246,866)	481,885	53,584	591,424
Revenue to Cost Ratio	98.8%	101.8%	100.1%	102.2%

PUB/CENTRA I-111

Subject: **Tab 11: Cost Allocation and Rate Design**

Reference: **Tab 11 Page 11 of 17**

Please discuss the allocation process for Capacity Management revenue, and discuss any changes since 2005.

ANSWER:

Capacity Management revenue is functionalized to the Pipeline function and classified as demand related. Capacity Management revenue is allocated to customers classes (SGS, LGS, HVF, MLF and INT) on the basis of a class' contribution to peak day and average annual use (PAVG allocator) and flows through to the Transportation to Centra rate. The allocation of these revenues for the forecast year 2013/14 is consistent with the last GRA.

PUB/CENTRA I-112

Subject: **Tab 11: Cost Allocation and Rate Design**

Reference: **Tab 11 Schedule 11.1.5**

Please identify and provide the rationale for the 2013/14 cost of service elements that are directly assigned to customer classes.

ANSWER:

Please see the schedule attached to this response.

2013/14 directly assigned cost of service elements

Direct Assignment	($000's)	Allocation Basis	Rationale
Gas Supply T-Service	$230	To all large volume classes (HVF, ML, INT, SC, PS)	*Based on the number of T-service customers in each class.*
Line Locates	$2,938	To all customer classes	*Directly assign the costs of line location activities to customer classes on the basis of number of customers per class.*
Odorant	$444	To all customer classes (except SC)	*Directly assign the costs of gas odorization to all customer classes except Special Contract which requires unodorized gas.*
Customer Contact Center	$1,894	To SGS and LGS customer classes	*Directly assign Contact Centre costs to customer classes based on estimated call volumes by class.*
FRPGS amortization	$100	To FRPGS	*Recovery of the regulatory and start-up costs of the FRPGS program in the Program Cost Rate (PCR).*

PUB/CENTRA I-113

Subject: **Tab 11: Cost Allocation and Rate Design**

Reference: **Tab 11 Schedule 11.1.2**

a) Please confirm whether the large increase in the classification of downstream non-gas commodity costs compared to the classifications shown in the 2009/10 & 2010/11 GRA Schedules 9.1.2 and 9.2.2 (filed June 9, 2009) is related to the reclassification of DSM costs to Commodity from Customer.

ANSWER:

Yes, the large increase in the classification of downstream non-gas commodity costs compared to the classification shown in the 2009/10 & 2010/11 GRA is related to the reclassification of DSM costs to Commodity from Customer.

PUB/CENTRA I-113

Subject: Tab 11: Cost Allocation and Rate Design

Reference: Tab 11 Schedule 11.1.2

b) Please explain the large decrease in the classification of upstream non-gas commodity costs compared to the classification shown in the 2009/10 & 2010/11 GRA Schedules 9.1.2 and 9.2.2 (filed June 9, 2009).

ANSWER:

The decrease in the classification of upstream non-gas commodity costs compared to the 2009/10 & 2010/11 GRA is mainly due to the impact of the decline in gas costs from the last GRA. The decline in gas costs causes a decline in the cash working capital component of rate base. The shift in working capital causes revenue requirement components that are functionalized by rate base (such as Finance Expense, Corporate Allocation, Net Income, some OM&A and to a lesser extent taxes) to be shifted away from Production to other functions.

PUB/CENTRA I-114

Subject: Tab 11: Cost Allocation and Rate Design

Reference: Tab 11 Schedule 11.1.1

Please confirm whether the costs related to the operation of Centra's storage and transportation assets, including the interest costs related to gas storage inventory, are allocated only to non-Transportation Service customers.

ANSWER:

Centra allocates costs related to its storage and transportation assets to all customer classes with the exception of the Special Contract and Power Stations Classes. These costs are then recovered from customers who elect the transportation and storage service through the Transportation to Centra Demand and Commodity Rates. Given that Transportation Service customers do not elect this service, they are not charged the Transportation to Centra Demand and Commodity Rates and, therefore, Centra does not recover transportation and storage costs from T-Service customers.

PUB/CENTRA I-115

Subject: Tab 11: Cost Allocation and Rate Design

Reference: Tab 11 Schedule 11.1.5

Please show how the PAVG and PAVG-T allocators are derived, and identify which cost of service details are allocated using these allocators.

ANSWER:

Please see the attachment to this response for the calculation of PAVG and PAVG-T allocators. PAVG and PAVG-T allocators are used to allocate demand (capacity) related costs to customer classes. Peak and average (PAVG) allocates costs related to Centra's upstream pipeline and storage functions; peak and average transmission (PAVG-T) allocates Centra's transmission system costs. Each of the peak and average allocators have been designed to ensure that customer classes are only allocated costs for components of Centra's system that they use. As an example, the Special Contract and Power Station classes are not allocated distribution demand costs because these customers are served directly through the transmission system.

			Total	SGS-R	SGS-C	LGS	HVF	CO-OP	ML	SC	GS	INT
	PAVG (peak & average excluding T-Service)											
	PAVG (peak & average excluding T-Service											
1	Volumes	10^3M^3	1,409,778	582,642	97,810	499,617	123,628	270	13,496			92,315
2	% of Total Volumes			41.3%	6.9%	35.4%	8.8%	0.0%	1.0%	0.0%	0.0%	6.5%
3												
4	Coincident Peak-Day	10^3M^3	9,787	4,491	750	3,712	762	2	70			
5	% of Total Coincident Peak			45.9%	7.7%	37.9%	7.8%	0.0%	0.7%	0.0%	0.0%	0.0%
6												
7	System Load Factor		39.5%									
8	1 - System Load Factor		60.5%									
9	Note: System load factor = total volumes/365/coincident peak day (1,409,778/365/9,787 = 39.5%)											
10												
11	% of Total Volumes			41.3%	6.9%	35.4%	8.8%	0.0%	1.0%	0.0%	0.0%	6.5%
12	System Load Factor			39.5%	39.5%	39.5%	39.5%	39.5%	39.5%	39.5%	39.5%	39.5%
13	Average Component			16.3%	2.7%	14.0%	3.5%	0.0%	0.4%	0.0%	0.0%	2.6%
14												
15	% of Total Coincident Peak			45.9%	7.7%	37.9%	7.8%	0.0%	0.7%	0.0%	0.0%	0.0%
16	1 - System Load Factor			60.5%	60.5%	60.5%	60.5%	60.5%	60.5%	60.5%	60.5%	60.5%
17	Peak Component			27.8%	4.6%	23.0%	4.7%	0.0%	0.4%	0.0%	0.0%	0.0%
18												
19	PAVG allocator (row 13 + row 17)		100.0%	44.09%	7.37%	36.94%	8.18%	0.02%	0.81%	0.00%	0.00%	2.58%
20												
21												
22	**PAVG-T (peak & average including T-Service)**											
23	Volumes	10^3M^3	2,027,285	582,642	97,810	499,617	163,446	270	134,963	421,289	15,196	112,051
24	% of Total Volumes			28.7%	4.8%	24.6%	8.1%	0.0%	6.7%	20.8%	0.7%	5.5%
25												
26	Coincident Peak-Day	10^3M^3	11,929	4,491	750	3,712	934	2	487	1,296	257	
27	% of Total Coincident Peak			37.6%	6.3%	31.1%	7.8%	0.0%	4.1%	10.9%	2.2%	0.0%
28												
29	System Load Factor		46.6%									
30	1 - System Load Factor		53.4%									
31												
32												
33	% of Total Volumes			28.7%	4.8%	24.6%	8.1%	0.0%	6.7%	20.8%	0.7%	5.5%
34	System Load Factor			46.6%	46.6%	46.6%	46.6%	46.6%	46.6%	46.6%	46.6%	46.6%
35	Average Component			13.4%	2.2%	11.5%	3.8%	0.0%	3.1%	9.7%	0.3%	2.6%
36												
37	% of Total Coincident Peak			37.6%	6.3%	31.1%	7.8%	0.0%	4.1%	10.9%	2.2%	0.0%
38	1 - System Load Factor			53.4%	53.4%	53.4%	53.4%	53.4%	53.4%	53.4%	53.4%	53.4%
39	Peak Component			20.1%	3.4%	16.6%	4.2%	0.0%	2.2%	5.8%	1.2%	0.0%
40												
41	PAVG allocator (row 35 + row 39)		100.0%	33.50%	5.60%	28.10%	7.94%	0.02%	5.28%	15.48%	1.50%	2.57%

PUB/CENTRA I-116

Subject: Tab 12: Rate Schedules & Customer Impacts

Reference: Tab 12 Page 3 of 8

Please file the most current Home Heating Cost Comparison as well as a pro forma of the August 1, 2013 Home Heating Cost Comparison that incorporates any proposed electricity and gas rate changes.

ANSWER:

Please see the attached current Space and Water Heating Cost Comparison Chart based on energy prices in effect February 1, 2013. Also attached is a pro forma Space and Water Heating Cost Comparison Chart including Manitoba Hydro's proposed electricity and natural gas rate increases, which, if approved, would be in effect August 1, 2013. The natural gas rate assumes the current February 1st primary gas rate and billing percentages as the August 1, 2013 values are unknown at this time.

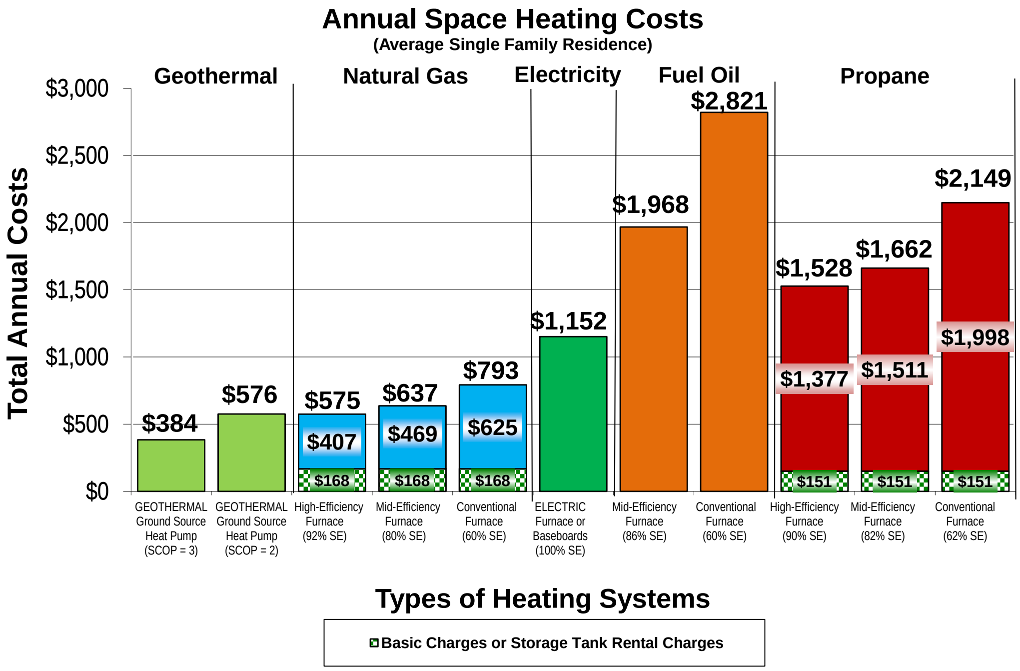
Typical space & water heating costs

Average single family residence at rates in effect February 1, 2013

1

Wondering about your energy options for heating?

1. Consult the charts to identify the costs of your current home heating and water heating systems.
2. Review the costs of other systems to see how your costs compare.
3. Consult the accompanying notes for guidance if you are thinking of switching systems or building a new home.



Energy rates

Natural gas:
$0.2336/cubic metre

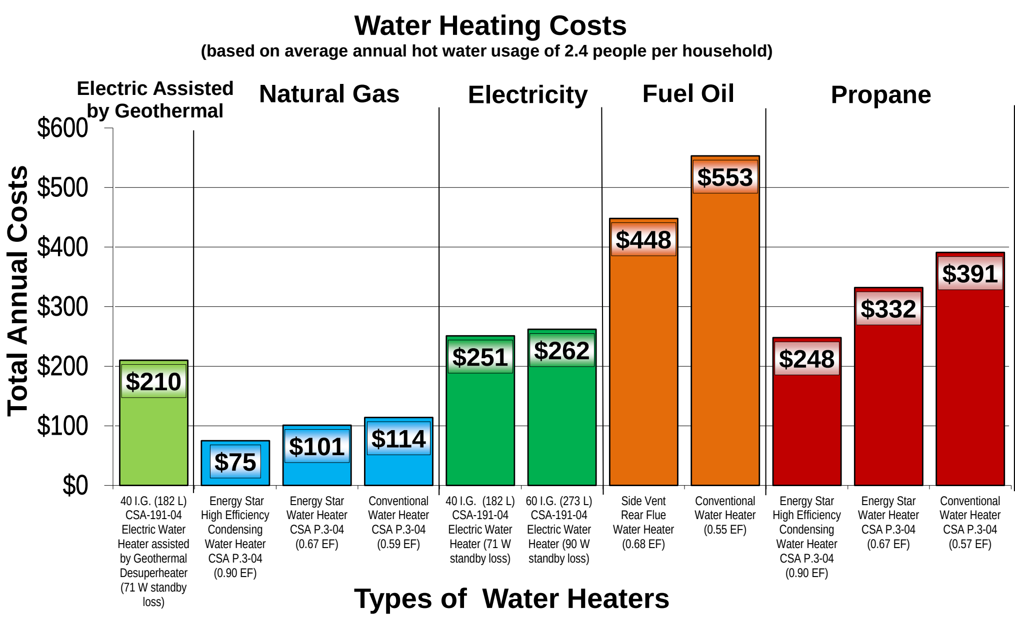
Electricity:
$0.0694/kilowatt-hour

Fuel oil:
$1.090/litre

Propane:
$0.529/litre

Basic monthly charge for natural gas is **$14** (**$168** per year)

Annual propane tank rental: **$151**



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Typical space & water heating costs

Average single family residence at rates in effect February 1, 2013

2

Weigh your options

The home heating costs shown in the chart are based on the amount of gas used to heat the average natural gas-heated home served by Manitoba Hydro. This average home is about 1,200 square feet and uses a mid-efficiency furnace and conventional gas water heater. Your heating costs may differ due to a variety of factors, such as weather, heating equipment, insulation levels, air tightness and lifestyle. Water heating costs are based on typical usage of the average Manitoba household of 2.4 people.

Annual cost estimates

The charts present annual costs as if all energy rates remained fixed for the coming year at rates in effect on February 1, 2013.

Your actual annual costs will vary, since natural gas rates change four times a year, while propane and oil rates can change weekly. Note that Primary Gas represents the bulk of the gas used. With Manitoba Hydro's Quarterly Rate Service, the price you pay for Primary Gas is the same price we pay for the gas in the marketplace. This rate changes every 3 months and is currently $0.0967 per cubic metre. If you buy Primary Gas on a Fixed Rate Service contract from Manitoba Hydro or a Gas Broker, you will continue to pay Manitoba Hydro for Supplemental Gas as well as transportation and distribution charges. The figure of 0.2336 per cubic metre of natural gas that we've used in the charts is known as a "re-bundled" effective rate. It includes charges for Primary and Supplemental gas, as well as for transportation and distribution of the gas on Manitoba Hydro's Quarterly Rate Service.

Key points if you are thinking of converting

Is it economically feasible?

Note that the costs of switching to another system to heat your home and hot water may be economically feasible only if your current system is at or near the end of its useful life, or if you are building a new home. Be sure to obtain quotations from at least three reputable heating contractors before you make your decision.

Conventional furnaces no longer manufactured

The space heating chart includes conventional natural gas, fuel oil, and propane furnaces. These conventional furnaces have not been manufactured since 1992, but many are still in operation.

High efficiency furnaces are now required by law

Effective December 30, 2009 the Province of Manitoba enacted legislation controlling the sale and lease of gas and propane heating equipment. Visit www.greenmanitoba.ca (click on the energy tab) for more information on this regulation.

Size of existing electrical service

Your electrical system may need to be upgraded if you want it to carry a heating load.

Depending on the capacity of the electrical appliances and equipment currently installed, and the size of your home, the Manitoba Electrical Code will allow a maximum of 8 to 10 kilowatts of electric heating on a standard 100-amp service. Most homes will need more than this.

Increasing the size of an electrical service usually involves changing your electrical panel or installing an additional one. An electrician should perform an electrical code load calculation to advise whether your existing service is adequate to serve the heating equipment required to heat your home.

Other gas appliances

If you have other appliances in your home like a range, clothes dryer, fireplace, or swimming pool heater, switching to an all-electric system may be quite costly.

Flue Gas Venting

When natural gas is burned, flue gases are produced which primarily contain carbon dioxide and water vapour which are not harmful to people. However, flue gases can also contain trace amounts of carbon monoxide and other gases that can present a health hazard. High-efficiency natural gas furnaces will not use the existing chimney to vent (remove) flue gases from the home. Instead they will be vented via approved plastic piping through the home's side wall or roof.

If you have a standard natural gas water heater, the Manitoba Gas Notices allow it to continue to use the existing chimney if it is in good condition and meets the requirements of the Code Authority Having Jurisdiction (Manitoba Dept. of Labour). Your heating contractor should inform you if the chimney has corroded or does not meet the code requirements. Generally, installing a new approved smaller diameter chimney liner may meet the requirements.

Issues that can arise once the natural gas water heater vents alone on the old chimney include: flue gases condensing in the chimney, or flue gas spillage into the home. If these venting problems occur, you may need to upgrade your venting system or have other work performed to rectify them. If the upgrades are costly, other options to consider are replacing the conventional heater with a side-wall vented gas water heater or an electric water heater.

Reduced chimney ventilation

Converting to electric heat or to a high-efficiency gas furnace will reduce the uncontrolled ventilation provided by the chimney. The uncontrolled chimney ventilation will be completely eliminated if you also replace your conventional gas water heater and either remove or cap off the chimney.

With a conventional gas furnace, warm moist air continuously exits the house through the chimney. This draws cold and dry replacement air into the house through cracks in walls and around windows and doors. This uncontrolled ventilation dehumidifies your home in winter, but consumes heating energy.

Reducing or eliminating this chimney ventilation can save energy but may also increase humidity levels and change the way that air leaks into and out of your home. Homes usually become slightly more positively pressurized.

The increase in humidity and change in air leakage patterns may cause increased condensation/icing: on interior surfaces of well-sealed windows, and anywhere warm moist air leaks out of the home such as electrical outlets, between the panes of poorly sealed windows, on door seals, in door lock mechanisms and around chimney and plumbing stacks. A very small percentage of homeowners have reported experiencing some of these issues.

There is not one solution that works in every home and for every issue. Here are some of the measures that individually or in combination can minimize or eliminate the effects of reduced chimney ventilation:

- improved weatherstripping and caulking on doors and windows and other areas of air leakage (but not on storm doors)
- seasonal window insulator kits (clear heat shrink poly over inside windows and frames)
- improved windows (preferably triple pane)
- a ventilation system which may consist of:
  - exhaust fan(s)
  - exhaust fan(s) combined with a fresh air intake
  - heat recovery ventilator (HRV)

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Typical space & water heating costs

Average single family residence at rates in effect February 1, 2013

3

Carbon monoxide safety

If you are burning heating oil, diesel, propane, kerosene, natural gas, wood, or coal in your home, or if you have an attached garage, we recommend that you install at least one carbon monoxide detector in your home.

The building code now requires permanently mounted carbon monoxide detectors in all new homes with fuel burning appliances or attached garages.

For further details, contact us for a copy of our brochure on "Carbon monoxide safety — Because your family comes first!"

What is the payback?

Determining how many years it will take for a new heating system to pay for itself may help you reach a decision.

Determine the potential savings

Subtract the annual cost of the new heating system you are considering from the annual cost of your current heating system (check the charts).

The difference is approximately what you can expect to save each year, at current energy rates.

Determine the costs of the new system

Determine how much it will cost to buy and install the new system, along with any other adjustments required. Get quotations from three reputable contractors.

Factor in the cost of financing, if necessary.

Determine the payback

Divide the estimated cost of switching your system, by the estimated savings.

The result is the number of years it will take for the new system to pay for itself.

Explanation of technical information in the charts

- Typical annual home heating requirement (output) of 60 Gigajoules is based on Manitoba Hydro's system average for natural gas heated homes.
- Water heating usage is based on Manitoba Hydro's average electric and natural gas water heating household of 2.4 people consuming about 140 litres per day that are heated up an average temperature rise of 50 C.
- The Electric water heating assisted by geothermal desuperheater option is based on Manitoba Hydro's field monitoring of nine homes with geothermal heating and desuperheaters where 80 per cent of the average water heating load was provided by the electric heating elements of the water tank and 20 per cent by the desuperheater.
- The cost of heating with propane includes a propane tank rental or lease charge of $151 per year for a typical 500 US gallon tank. See table below. This charge may not apply to all customers and may vary.
- The cost of space heating with natural gas includes a basic monthly charge of $14 ($168 per year).
- SE (seasonal efficiency) is defined as the total heat output delivered by the furnace during one heating season as a percentage of the total energy input to the system. SE takes into consideration not only normal operating losses but also the fact that most furnaces rarely run long enough to reach their steady-state efficiency temperature, particularly during milder weather at the beginning and end of the heating season.
- Energy Factor (EF) is an overall efficiency rating of the water heater. The higher the EF, the more efficient the model. Electric water heaters are required to have maximum standby losses of 71 watts for a 40 gallon and 90 Watts for a 60 gallon.
- SCOP (Seasonal Coefficient of Performance) = 2 and = 3 appears in the home heating chart under geothermal closed loop heat pump. It refers to the Seasonal Coefficient of Performance of the heat pump over an entire heating season.

  SCOP is defined as the total heat output of the system during the heating season, divided by the total energy input to the system.

  The SCOP of a geothermal heat pump system typically ranges from 2.0 to 3.0. For reference, the SCOP of an electric baseboard heater is 1.0. The SCOP rating accounts for cycling losses, circulating fan and pump energy and auxiliary electric heating loads which are not included in the manufacturer's COP rating of the heat pump "unit". The overall system SCOP will therefore always be significantly lower than the unit COP.

  The SCOP of a geothermal system can vary significantly and is highly dependent on the quality of the system design, installation, commissioning and ongoing maintenance practices.
- Note that the natural gas energy price reflected in the charts is a bundled price that includes primary and supplemental gas, and transportation and distribution charges. For reference, one of the major components of the bundled price is the price of Primary Gas, at 0.0967 per cubic metre. Primary Gas currently comprises 90 per cent of the gas supplied (supplemental gas is 10 per cent.)
- Taxes are not included in these calculations and costs.

ENERGY RATES — in effect February 1, 2013

	Commodity charge	Heating value	
Natural gas	$0.2336/cubic metre	35,310	Btu/cubic metre
Electricity	$0.0694/kilowatt-hour	3,413	Btu/kilowatt-hour
Fuel oil	$1.090/litre	36,500	Btu/litre
Propane	$0.529/litre	24,200	Btu/litre

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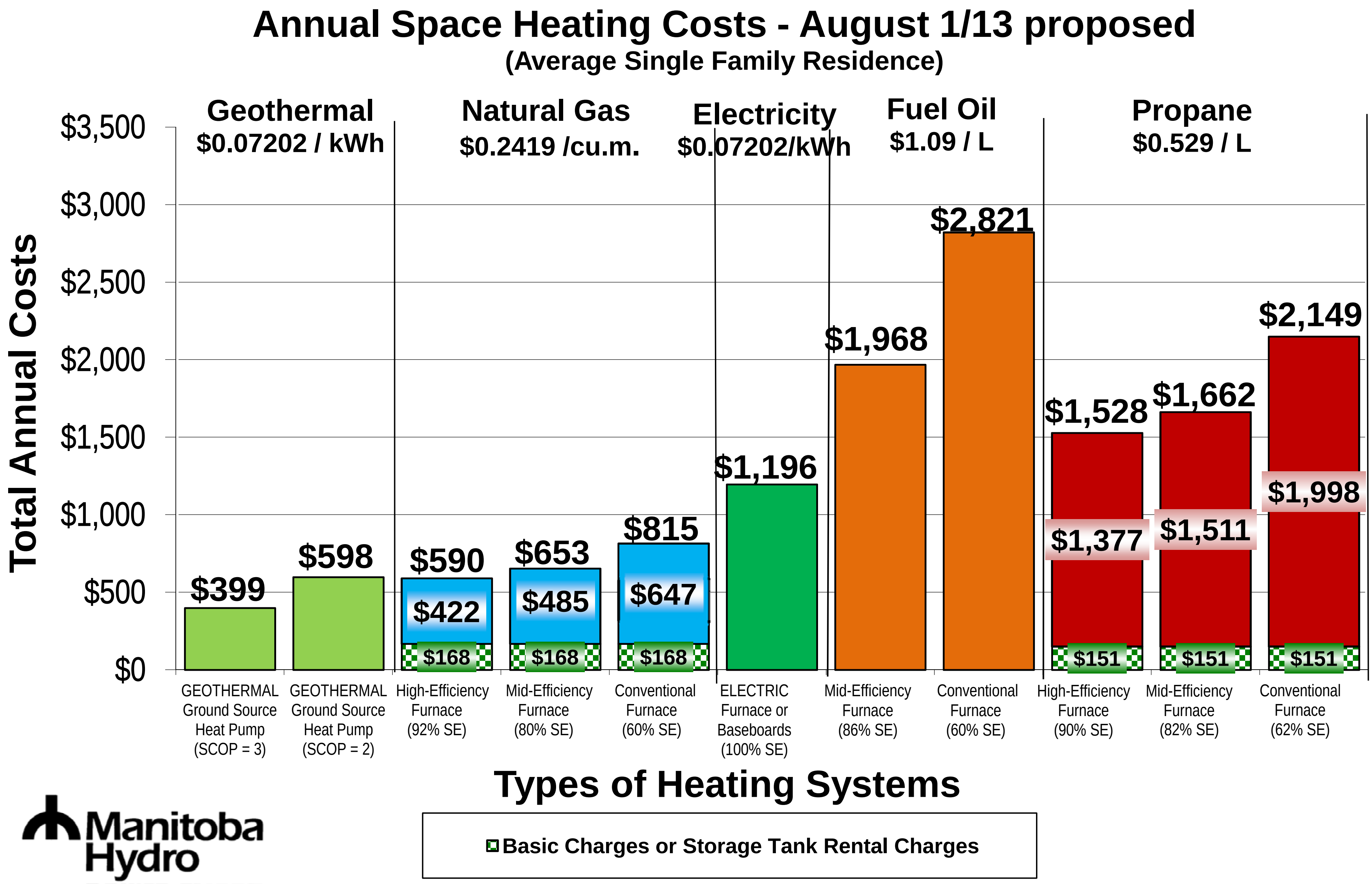

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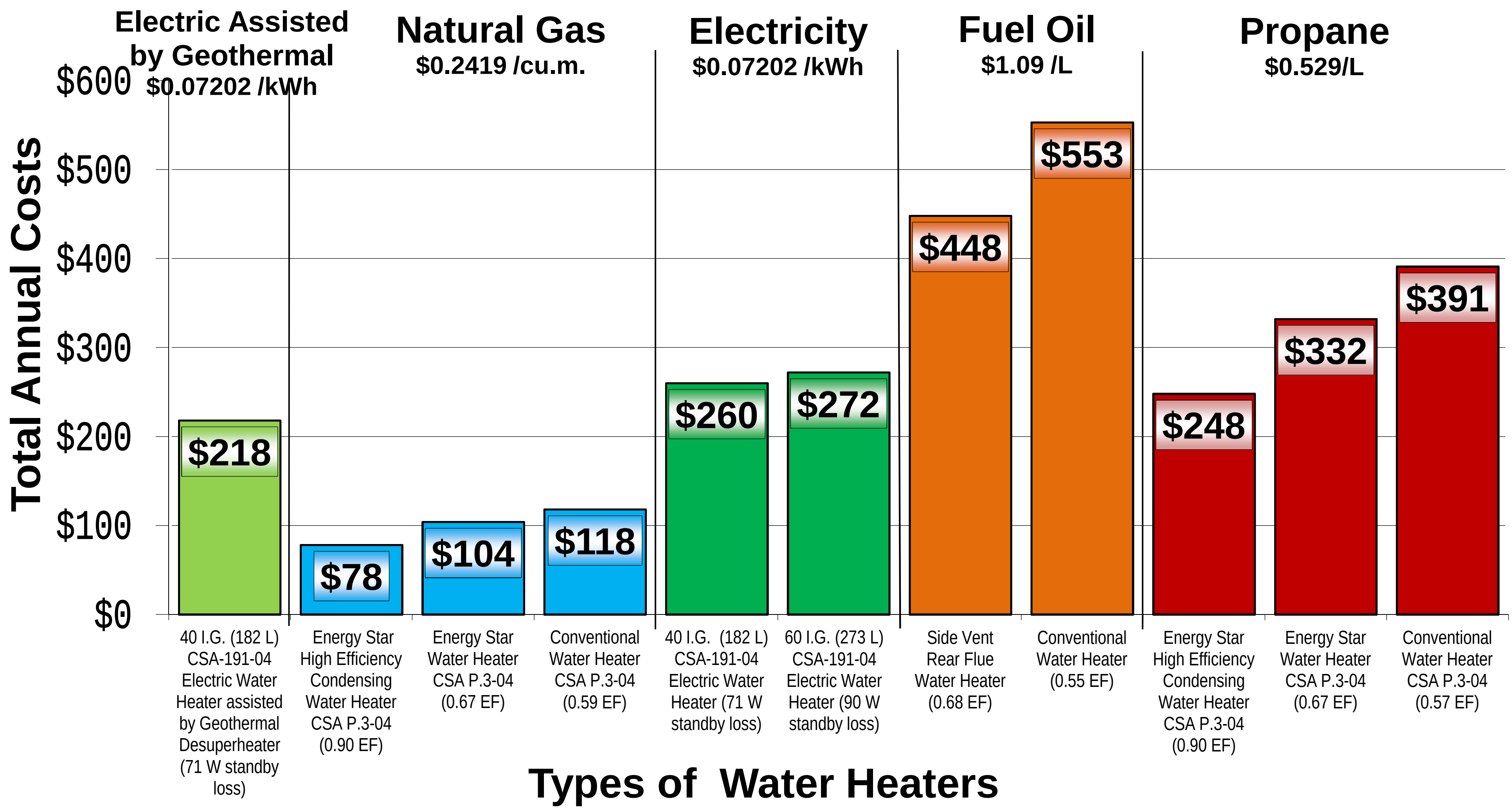
Water Heating Costs - August 1/13 proposed

(based on average annual hot water usage of 2.4 people per household)



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PUB/CENTRA I-117

Subject: Tab 12: Rate Schedules & Customer Impacts

Reference: Tab 12 Page 5 of 8

Please explain the process for allocating cost inflows to each rate class and determining the portion of WACOG outflows attributed to each class.

ANSWER:

The allocation of Supplemental, Transportation, and Distribution PGVA balances to customer classes consists of preparing a Cost Allocation Study using actual data and costs and compares the outcome of the Study with actual billing data. For purposes of this Application, historical data from the completed gas year(s), 2010/11 and 2011/12, was used. The actual gas costs (inflows) are functionalized, classified and allocated to customer classes using actual volume and coincident peak data in the same fashion as a forecast test year cost allocation study. Actual WACOG outflows (recorded actual billings for each class) are compared to the allocated inflows and the net difference results in a refund or recovery by customer class for the Supplemental, Transportation and Distribution PGVAs.

PUB/CENTRA I-118

Subject: Tab 12: Rate Schedules & Customer Impacts

Reference: Tab 12 Page 6 of 8

Please explain why the SGS and LGS class rate riders are in a net collection-from-customers position, while the higher volume class rate riders are in a net refund-to-customers position.

ANSWER:

The SGS and LGS class rate riders are in a net collection (owing to Centra) position because the Transportation PGVA allocated to the SGS & LGS classes exceeds the combined totals of their allocated portions of remaining deferrals (including Capacity Management, Heating Value deferral, Distribution and Supplemental) which are in a refund (owing to customer) position. As shown in Schedule 12.3.0(a), in the 2010/11 gas year the Transportation PGVA was largely offset by the large Supplemental PGVA (owing to Customers). In the 2011/12 gas year (Schedule 12.3.0(b)), the classification of Delivered Service to Primary Gas meant, in part, that the accumulated balances in the Supplemental PGVA were significantly less and much less influential in offsetting the Transportation PGVA. In the case of the SGS and LGS classes, the factors that influence a PGVA balance include the forecast versus actual cost, their allocation of the cost, and the forecast versus actual revenue collection. These classes bear greatest responsibility of the Supplemental PGVA by virtue of their annual consumption (in comparison with other classes), and of the Transportation PGVA because these classes are the most significant users of Centra's upstream transportation assets. Additionally, forecast versus actual usage impacts these classes to a greater extent by virtue of their dominant volumetric rate structure.

PUB/CENTRA I-119

Subject: **Tab 12: Rate Schedules & Customer Impacts**

Reference: **Tab 12 Page 7 of 8**

a) **What is the dollar amount of the Minimum Annual Gross Margin Amount payable by the Power Station class customer. Please confirm whether this amount is aggregate or for each power station.**

ANSWER:

The Minimum Annual Gross Margin for the Brandon Power Station is $572,600 and the Selkirk Power Station is $374,500.

PUB/CENTRA I-119

Subject: **Tab 12: Rate Schedules & Customer Impacts**

Reference: **Tab 12 Page 7 of 8**

b) **Please confirm whether the Amount is fixed throughout the term of the contract or if it is subject to variation. If subject to variation, please explain the extent and the reasons for the variation.**

ANSWER:

The amounts are fixed throughout the term of the contracts.

PUB/CENTRA I-119

Subject: **Tab 12: Rate Schedules & Customer Impacts**

Reference: **Tab 12 Page 7 of 8**

c) **Please detail the number of times that the Power Station class customer has had to pay Centra additional funds to meet the Minimum Annual Gross Margin Amount, and what each of those payments were.**

ANSWER:

Please see the attachment to this response.

Centra Gas Manitoba Inc. **PUB/Centra 119 c**
2013/14 General Rate Application **Attachment**
Power Stations Payments required to meet Minimum Gross Margin Amount - 9 years **April 12, 2013**

	2004	2005	2006	2007	2008	2009	2010	2011	2012	Total
Minimum Annual Gross Margin										
Brandon	$ 572,600	$ 572,600	$ 572,600	$ 572,600	$ 572,600	$ 572,600	$ 572,600	$ 572,600	$ 572,600	$ 5,153,400
Selkirk	$ 374,504	$ 374,504	$ 374,504	$ 374,504	$ 374,504	$ 374,504	$ 374,504	$ 374,504	$ 374,504	$ 3,370,536
Total	$ 947,104	$ 947,104	$ 947,104	$ 947,104	$ 947,104	$ 947,104	$ 947,104	$ 947,104	$ 947,104	$ 8,523,936
Actual billed demand and BMC charges										
Brandon	$ 573,785	$ 740,913	$ 344,686	$ 474,408	$ 315,957	$ 271,263	$ 250,564	$ 516,040	$ 440,993	$ 3,928,610
Selkirk	$ 446,495	$ 449,317	$ 255,967	$ 394,218	$ 240,183	$ 215,506	$ 245,938	$ 375,621	$ 348,765	$ 2,972,010
Total	$ 1,020,280	$ 1,190,230	$ 600,653	$ 868,627	$ 556,140	$ 486,769	$ 496,502	$ 891,662	$ 789,757	$ 6,900,621
Difference - Over /(Under) Minimum Annual Gross Margin										
Brandon	$ 1,185	$ 168,313	$ (227,914)	$ (98,192)	$ (256,643)	$ (301,337)	$ (322,036)	$ (56,560)	$ (131,607)	$ (1,224,790)
Selkirk	$ 71,991	$ 74,813	$ (118,537)	$ 19,714	$ (134,321)	$ (158,998)	$ (128,566)	$ 1,117	$ (25,739)	$ (398,526)
Total	$ 73,176	$ 243,126	$ (346,451)	$ (78,477)	$ (390,964)	$ (460,335)	$ (450,602)	$ (55,442)	$ (157,347)	$ (1,623,315)
Required Payments										
Brandon	$ -	$ -	$ (227,914)	$ (98,192)	$ (256,643)	$ (301,337)	$ (322,036)	$ (56,560)	$ (131,607)	$ (1,394,288)
Selkirk	$ -	$ -	$ (118,537)	$ -	$ (134,321)	$ (158,998)	$ (128,566)	$ -	$ (25,739)	$ (566,161)
Total	$ -	$ -	$ (346,451)	$ (98,192)	$ (390,964)	$ (460,335)	$ (450,602)	$ (56,560)	$ (157,347)	$ (1,960,449)

PUB/CENTRA I-119

Subject: **Tab 12: Rate Schedules & Customer Impacts**

Reference: **Tab 12 Page 7 of 8**

d) **Please confirm whether a new contract has been executed to replace the previous contract, which is nearing or beyond its original 10 year term, and if there is a new contract, please file it along with a summary of the major changes from the previous contract.**

ANSWER:

No new contract has been executed to replace the Power Stations contracts. While the initial term of each contract is set to expire July 31, 2013, each contract contains an evergreen provision that allows it to continue until either party gives one year written notice of termination. No termination notice has been provided by either party.

PUB/CENTRA I-120

Subject: **Tab 13 FRPGS**

Reference: **Tab 13 Page 2 of 11 - Results**

For each completed FRPGS contract, please estimate the amount of additional or reduced Primary Gas costs compared to the system supply Primary Gas costs, assuming annual consumption for typical residential customers.

ANSWER:

Please see the attachment to this response.

Table 1

Estimated PG costs on completed 1 year contracts compared to system supply PG costs

Fixed Rate Contract Start Date	FRPGS offerings ($/m³)	Quarterly PG Effective Date	Quarterly PG Rates ($/m³)	Typical Residential Quarterly/Monthly consumption (m³)	Quarterly PG Total	FRPGS offerings Total	Difference
1-May-09	$0.2670	1-May-09	$0.2451	177	$531.38	$633.85	$102.46
		1-Aug-09	$0.2494	257			
		1-Nov-09	$0.2213	1,106			
		1-Feb-10	$0.2148	834			
1-Dec-09	$0.2389	1-Nov-09	$0.2213	839	$486.67	$567.04	$80.37
		1-Feb-10	$0.2148	834			
		1-May-10	$0.1844	177			
		1-Aug-10	$0.1810	257			
		1-Nov-10	$0.1600	267			
1-Feb-10	$0.2679	1-Feb-10	$0.2148	834	$435.25	$636.02	$200.77
		1-May-10	$0.1844	177			
		1-Aug-10	$0.1810	257			
		1-Nov-10	$0.1600	1,106			
1-May-10	$0.2703	1-May-10	$0.1844	177	$396.81	$641.75	$244.94
		1-Aug-10	$0.1810	257			
		1-Nov-10	$0.1600	1,106			
		1-Feb-11	$0.1687	834			
1-Nov-10	$0.1939	1-Nov-10	$0.1600	1,106	$382.78	$460.28	$77.50
		1-Feb-11	$0.1687	834			
		1-May-11	$0.1548	177			
		1-Aug-11	$0.1468	257			
1-Feb-11	$0.1808	1-Feb-11	$0.1687	834	$364.64	$429.12	$64.48
		1-May-11	$0.1548	177			
		1-Aug-11	$0.1468	257			
		1-Nov-11	$0.1436	1,106			
1-Mar-11	$0.1905	1-Feb-11	$0.1687	470	$343.47	$452.31	$108.83
		1-May-11	$0.1548	177			
		1-Aug-11	$0.1468	257			
		1-Nov-11	$0.1436	1,106			
		1-Feb-12	$0.1105	364			
1-May-11	$0.1913	1-May-11	$0.1548	177	$316.11	$454.05	$137.94
		1-Aug-11	$0.1468	257			
		1-Nov-11	$0.1436	1,106			
		1-Feb-12	$0.1105	834			
1-May-12	$0.1500	1-May-12	$0.0880	177	$228.03	$356.10	$128.07
		1-Aug-12	$0.0967	257			
		1-Nov-12	$0.0967	1,106			
		1-Feb-13	$0.0967	834			

Table 2

Estimated PG costs on completed 3 years contracts compared to system supply PG costs

Fixed Rate Contract Start Date	FRPGS offerings ($/m^3)	Quarterly PG Effective Date	Quarterly PG Rates ($/m^3)	Typical Residential Quarterly/Monthly consumption (m^3)	Quarterly PG Total	FRPGS offerings Total	Difference
1-May-09	$0.3234	1-May-09	$0.2451	177	$1,244.30	$2,303.25	$1,058.95
		1-Aug-09	$0.2494	257			
		1-Nov-09	$0.2213	1,106			
		1-Feb-10	$0.2148	834			
		1-May-10	$0.1844	177			
		1-Aug-10	$0.1810	257			
		1-Nov-10	$0.1600	1,106			
		1-Feb-11	$0.1687	834			
		1-May-11	$0.1548	177			
		1-Aug-11	$0.1468	257			
		1-Nov-11	$0.1436	1,106			
		1-Feb-12	$0.1105	834			
1-Dec-09	$0.2766	1-Nov-09	$0.2213	839	$1,143.95	$1,969.95	$825.99
		1-Feb-10	$0.2148	834			
		1-May-10	$0.1844	177			
		1-Aug-10	$0.1810	257			
		1-Nov-10	$0.1600	1,106			
		1-Feb-11	$0.1687	834			
		1-May-11	$0.1548	177			
		1-Aug-11	$0.1468	257			
		1-Nov-11	$0.1436	1,106			
		1-Feb-12	$0.1105	834			
		1-May-12	$0.0880	177			
		1-Aug-12	$0.0967	257			
		1-Nov-12	$0.0967	267			
1-Feb-10	$0.2882	1-Feb-10	$0.2148	834	$1,039.43	$2,052.56	$1,013.13
		1-May-10	$0.1844	177			
		1-Aug-10	$0.1810	257			
		1-Nov-10	$0.1600	1,106			
		1-Feb-11	$0.1687	834			
		1-May-11	$0.1548	177			
		1-Aug-11	$0.1468	257			
		1-Nov-11	$0.1436	1,106			
		1-Feb-12	$0.1105	834			
		1-May-12	$0.0880	177			
		1-Aug-12	$0.0967	257			
		1-Nov-12	$0.0967	1,106			
1-May-10	$0.2833	1-May-10	$0.1844	177	$940.95	$2,017.66	$1,076.72
		1-Aug-10	$0.1810	257			
		1-Nov-10	$0.1600	1,106			
		1-Feb-11	$0.1687	834			
		1-May-11	$0.1548	177			
		1-Aug-11	$0.1468	257			
		1-Nov-11	$0.1436	1,106			
		1-Feb-12	$0.1105	834			
		1-May-12	$0.0880	177			
		1-Aug-12	$0.0967	257			
		1-Nov-12	$0.0967	1,106			
		1-Feb-13	$0.0967	834			

PUB/CENTRA I-121

Subject: **Tab 13 FRPGS**

Reference: **Tab 13 Page 7 of 11 – Offering Periods**

a) **Please confirm whether Centra intends to maintain discrete offering periods, or whether FRPGS will be available at all times. If the former, please state the proposed offering periods.**

ANSWER:

Centra plans to continue with regular quarterly FRPGS offerings. Enrolment periods are expected to coincide with Centra's Quarterly Primary Gas rate changes on February 1, May 1, August 1 and November 1 each year.

PUB/CENTRA I-121

Subject: **Tab 13 FRPGS**

Reference: **Tab 13 Page 7 of 11 – Offering Periods**

b) Please explain whether and in what circumstances Centra would terminate the availability of an offering or amend its rate under the proposed methodology (for example, in the event of a dramatic market price movement).

ANSWER:

Centra intends to review the FRPGS program when any of the thresholds stated in Tab 13, section 13.2.5 are reached. Centra may discontinue an offering if it is determined that one or more of the thresholds have been reached and risk exposure is significant. Centra may, in those circumstances, seek to amend the Rate Setting Methodology.

PUB/CENTRA I-122

Subject: **Tab 13 FRPGS**

Reference: **Tab 13 Pages 8 and 9 of 11 – SRP**

a) **Please explain the differences in the modeling undertaken for the current process to determine the Self-insurance Risk Premium compared to the modeling undertaken in 2008 to determine the Volumetric Risk Premium.**

ANSWER:

The process undertaken by Centra to determine the Self-Insurance Risk Premium ("SRP") employed the same market simulation model as that used to determine the Volumetric Risk Premium ("VRP"), except that the model's hedge parameters are set to levels consistent with the assumption that no hedge instruments would have been placed throughout the entire period studied. Centra is also including three years of additional data.

PUB/CENTRA I-122

Subject: **Tab 13 FRPGS**

Reference: **Tab 13 Pages 8 and 9 of 11 – SRP**

b) **Using the current inputs, please update the analysis performed in support of the determination of the VRP in the 2008 FRPGS Application as shown in Centra's September 5, 2008 response to Order 125/08 (Question 1).**

ANSWER:

As noted in response to PUB/Centra I-122(a), Centra has undertaken this analysis using current inputs for the period through March 2011.The following table indicates the SRP's required to achieve the recommended, maximum and minimum risk hurdles considered for the Self-Insurance approach for all small volume customer classes and contract terms in aggregate.

	Risk Premium
@ Maximum Risk Mitigation Hurdle Cumulative total settled program risk margin net positive in 67% of months during the period studied	10.0%
@ ***Recommended Risk Mitigation Hurdle*** Cumulative total settled program risk margin net positive in 51% of months during the period studied	***8.0%***
@ Minimum Risk Mitigation Hurdle % of all completed contracts with no risk margin loss > or = 50%	4.0%

Note: The results shown in the table reflect 396 simulated small volume customer class contracts

PUB/CENTRA I-122

Subject: **Tab 13 FRPGS**

Reference: **Tab 13 Pages 8 and 9 of 11 – SRP**

c) **In its 2008 application for FRPGS, Centra originally proposed VRPs ranging from 3% to 14%. Please discuss whether a SRP of only 8% is sufficient, considering there is no hedging to protect against price risk movements.**

ANSWER:

Centra seeks to balance its exposure to financial risks under the FRPGS while making these products available to customers at reasonable prices. As such, Centra believes that its revised Rate Setting Methodology incorporating an 8% SRP, combined with the use of the four supplementary risk mitigation measures discussed in the response to PUB/Centra 123 (a), is sufficient to manage Centra's financial risks under the FRPGS, given the highly volatile market conditions during the historical period over which the SRP was modeled and tested.

PUB/CENTRA I-122

Subject: **Tab 13 FRPGS**

Reference: **Tab 13 Pages 8 and 9 of 11 – SRP**

d) **Please provide a table demonstrating the results of potential losses based on the range of SRPs modeled.**

ANSWER:

Please see the attachment provided containing the Time Series of Total Cumulative Risk Margin Profit/Loss Distributions for SRP's ranging from 0% to 15%, as well as statistics reflecting the Percentage of Months where Cumulative Monthly Risk Margin Positions were greater than $0, along with Worst Case Interim Cumulative Risk Margin Profits/(Losses).

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PUB/Centra 122 (d)

Time Series of Total Cumulative Risk Margin Profit/Loss Distribution Across All 1, 3 and 5-Year Fixed Price Agreement Terms and Across All SGS and LGS Customer Rate Classes

	SRP	0%			1%			2%		
		Mean	Maximum	Minimum	Mean	Maximum	Minimum	Mean	Maximum	Minimum
1	May-00	($443)	($165)	($731)	($402)	($71)	($655)	($315)	($96)	($540)
2	Jun-00	($2,507)	($1,330)	($3,714)	($2,413)	($1,182)	($3,908)	($2,161)	($1,172)	($3,129)
3	Jul-00	($5,230)	($2,957)	($7,509)	($5,092)	($2,789)	($7,900)	($4,615)	($2,790)	($6,447)
4	Aug-00	($6,539)	($3,554)	($9,733)	($6,287)	($3,381)	($9,583)	($5,617)	($3,239)	($8,585)
5	Sep-00	($11,158)	($6,369)	($15,852)	($10,709)	($6,357)	($15,611)	($9,621)	($5,933)	($14,298)
6	Oct-00	($38,083)	($25,766)	($47,809)	($37,473)	($26,234)	($52,048)	($34,861)	($23,433)	($44,177)
7	Nov-00	($93,401)	($66,496)	($116,222)	($92,466)	($67,385)	($127,354)	($86,614)	($59,854)	($109,570)
8	Dec-00	($246,383)	($179,940)	($310,196)	($244,745)	($188,949)	($328,221)	($233,058)	($164,655)	($288,109)
9	Jan-01	($479,303)	($348,887)	($598,363)	($477,915)	($370,736)	($625,058)	($459,162)	($332,294)	($566,114)
10	Feb-01	($633,932)	($458,963)	($790,900)	($630,930)	($496,152)	($822,057)	($605,795)	($441,420)	($748,827)
11	Mar-01	($721,497)	($522,875)	($901,425)	($716,735)	($568,489)	($933,786)	($687,100)	($502,486)	($850,181)
12	Apr-01	($771,318)	($560,839)	($963,475)	($765,385)	($609,486)	($997,277)	($732,935)	($537,520)	($906,351)
13	May-01	($787,377)	($573,057)	($983,219)	($780,622)	($623,048)	($1,018,366)	($746,825)	($548,748)	($924,095)
14	Jun-01	($781,922)	($568,495)	($977,325)	($774,359)	($618,986)	($1,012,368)	($739,912)	($543,265)	($915,882)
15	Jul-01	($767,993)	($557,316)	($961,696)	($759,588)	($603,581)	($996,660)	($724,657)	($531,043)	($898,433)
16	Aug-01	($749,479)	($542,464)	($941,698)	($740,125)	($583,448)	($976,129)	($704,755)	($514,546)	($876,063)
17	Sep-01	($723,108)	($521,187)	($913,476)	($712,415)	($555,046)	($946,717)	($676,385)	($490,274)	($844,323)
18	Oct-01	($603,658)	($418,370)	($790,084)	($587,492)	($425,554)	($817,034)	($549,716)	($382,947)	($707,528)
19	Nov-01	($506,301)	($320,387)	($685,525)	($484,542)	($312,057)	($712,844)	($444,438)	($294,541)	($598,151)
20	Dec-01	($383,389)	($193,557)	($575,907)	($353,586)	($155,104)	($581,359)	($309,783)	($152,691)	($465,922)
21	Jan-02	($254,401)	($68,980)	($459,020)	($215,573)	$10,831	($436,043)	($166,960)	$16,787	($341,142)
22	Feb-02	($130,256)	$51,789	($344,956)	($84,066)	$156,181	($298,451)	($32,084)	$165,284	($224,174)
23	Mar-02	($35,888)	$159,222	($258,362)	$16,522	$265,556	($198,437)	$73,256	$286,043	($137,833)
24	Apr-02	($8,819)	$191,082	($234,011)	$46,673	$298,723	($167,961)	$105,879	$324,162	($110,475)
25	May-02	$5,222	$207,878	($221,021)	$62,879	$317,788	($152,170)	$123,560	$344,673	($98,809)
26	Jun-02	$15,307	$218,681	($210,979)	$73,890	$330,664	($140,880)	$135,138	$356,720	($89,647)
27	Jul-02	$30,252	$233,268	($195,928)	$89,625	$347,319	($124,029)	$151,133	$373,194	($75,303)
28	Aug-02	$57,465	$259,583	($167,647)	$117,957	$376,958	($93,535)	$179,725	$402,136	($48,880)
29	Sep-02	$80,391	$282,581	($143,908)	$142,187	$402,627	($69,922)	$204,543	$427,364	($26,730)
30	Oct-02	$88,889	$296,271	($134,486)	$154,165	$419,740	($66,116)	$219,375	$442,091	($17,828)
31	Nov-02	$63,928	$278,105	($159,860)	$133,219	$402,825	($93,812)	$202,752	$427,108	($41,950)
32	Dec-02	$37,766	$259,230	($186,524)	$111,998	$386,049	($122,820)	$186,960	$413,992	($67,186)
33	Jan-03	($28,757)	$201,439	($260,845)	$50,991	$330,223	($188,013)	$133,802	$363,315	($127,940)
34	Feb-03	($222,817)	$20,737	($482,949)	($139,813)	$144,143	($381,874)	($47,558)	$187,791	($317,382)
35	Mar-03	($627,105)	($367,247)	($940,347)	($547,332)	($260,040)	($810,820)	($443,222)	($199,275)	($716,217)
36	Apr-03	($706,940)	($442,496)	($1,033,578)	($626,048)	($328,025)	($894,737)	($518,024)	($268,963)	($791,581)
37	May-03	($733,406)	($467,797)	($1,065,164)	($652,035)	($350,001)	($922,668)	($542,585)	($291,686)	($817,004)
38	Jun-03	($748,201)	($482,273)	($1,083,050)	($666,589)	($362,486)	($938,382)	($556,374)	($304,409)	($830,902)
39	Jul-03	($763,628)	($497,128)	($1,101,926)	($681,656)	($375,133)	($954,518)	($570,512)	($317,178)	($845,472)
40	Aug-03	($764,970)	($497,941)	($1,104,557)	($682,396)	($374,413)	($955,720)	($570,655)	($317,102)	($845,911)
41	Sep-03	($771,722)	($503,658)	($1,114,110)	($688,204)	($377,578)	($962,708)	($575,317)	($321,170)	($851,158)

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PUB/Centra 122 (d)

Time Series of Total Cumulative Risk Margin Profit/Loss Distribution Across All 1, 3 and 5-Year Fixed Price Agreement Terms and Across All SGS and LGS Customer Rate Classes

	SRP	0%			1%			2%		
		Mean	Maximum	Minimum	Mean	Maximum	Minimum	Mean	Maximum	Minimum
42	Oct-03	($766,343)	($495,697)	($1,112,048)	($680,543)	($365,156)	($956,540)	($565,828)	($311,352)	($842,302)
43	Nov-03	($739,233)	($461,379)	($1,092,613)	($647,248)	($319,688)	($928,291)	($527,863)	($273,405)	($804,749)
44	Dec-03	($764,817)	($482,227)	($1,130,435)	($666,850)	($323,181)	($957,954)	($541,166)	($284,886)	($820,032)
45	Jan-04	($892,039)	($604,481)	($1,278,911)	($788,185)	($420,982)	($1,092,729)	($651,728)	($391,447)	($935,298)
46	Feb-04	($980,160)	($679,473)	($1,381,723)	($871,779)	($488,584)	($1,186,675)	($727,319)	($458,790)	($1,012,301)
47	Mar-04	($1,032,420)	($721,439)	($1,443,148)	($919,739)	($522,212)	($1,242,437)	($768,807)	($488,949)	($1,054,895)
48	Apr-04	($1,076,986)	($759,223)	($1,494,126)	($961,516)	($554,939)	($1,289,160)	($805,993)	($520,218)	($1,092,849)
49	May-04	($1,135,561)	($813,140)	($1,559,496)	($1,018,612)	($604,947)	($1,349,321)	($859,246)	($568,752)	($1,145,315)
50	Jun-04	($1,180,524)	($855,447)	($1,609,500)	($1,062,958)	($644,677)	($1,394,987)	($901,121)	($607,515)	($1,186,314)
51	Jul-04	($1,202,344)	($875,403)	($1,633,714)	($1,084,260)	($663,655)	($1,417,207)	($920,944)	($625,343)	($1,206,197)
52	Aug-04	($1,219,645)	($890,946)	($1,653,006)	($1,100,797)	($678,214)	($1,434,493)	($936,040)	($638,494)	($1,221,180)
53	Sep-04	($1,220,607)	($889,865)	($1,656,057)	($1,100,540)	($676,780)	($1,435,131)	($934,293)	($633,355)	($1,219,381)
54	Oct-04	($1,219,048)	($884,300)	($1,659,245)	($1,095,727)	($669,359)	($1,432,687)	($925,759)	($615,814)	($1,212,752)
55	Nov-04	($1,327,278)	($988,365)	($1,782,875)	($1,200,776)	($765,170)	($1,552,273)	($1,023,452)	($701,344)	($1,309,030)
56	Dec-04	($1,467,564)	($1,113,963)	($1,945,790)	($1,334,581)	($882,145)	($1,707,201)	($1,145,446)	($799,020)	($1,433,067)
57	Jan-05	($1,553,285)	($1,181,774)	($2,055,097)	($1,412,665)	($943,017)	($1,803,650)	($1,210,859)	($834,370)	($1,498,338)
58	Feb-05	($1,582,569)	($1,196,957)	($2,099,906)	($1,435,702)	($953,930)	($1,837,335)	($1,225,442)	($825,667)	($1,513,342)
59	Mar-05	($1,637,060)	($1,241,485)	($2,167,586)	($1,484,876)	($992,665)	($1,897,476)	($1,266,715)	($848,253)	($1,555,918)
60	Apr-05	($1,697,989)	($1,298,358)	($2,236,973)	($1,543,712)	($1,047,982)	($1,961,296)	($1,321,408)	($895,753)	($1,611,819)
61	May-05	($1,731,880)	($1,330,155)	($2,275,158)	($1,575,688)	($1,076,539)	($1,996,444)	($1,350,858)	($921,116)	($1,641,505)
62	Jun-05	($1,740,234)	($1,337,038)	($2,286,841)	($1,582,957)	($1,081,574)	($2,004,963)	($1,356,709)	($924,279)	($1,648,336)
63	Jul-05	($1,753,829)	($1,349,425)	($2,303,352)	($1,595,538)	($1,092,962)	($2,018,276)	($1,367,880)	($933,674)	($1,660,865)
64	Aug-05	($1,768,088)	($1,362,926)	($2,318,310)	($1,609,186)	($1,105,407)	($2,033,197)	($1,380,576)	($945,880)	($1,674,478)
65	Sep-05	($1,832,548)	($1,427,858)	($2,384,641)	($1,673,399)	($1,171,063)	($2,098,866)	($1,442,441)	($1,008,118)	($1,740,721)
66	Oct-05	($2,079,239)	($1,681,303)	($2,637,769)	($1,920,584)	($1,425,936)	($2,349,147)	($1,682,458)	($1,249,733)	($1,994,026)
67	Nov-05	($2,485,747)	($2,095,584)	($3,046,943)	($2,326,792)	($1,853,335)	($2,755,304)	($2,075,134)	($1,641,547)	($2,401,288)
68	Dec-05	($2,881,437)	($2,501,725)	($3,442,353)	($2,719,835)	($2,265,194)	($3,180,394)	($2,451,511)	($2,016,717)	($2,792,602)
69	Jan-06	($3,259,565)	($2,895,542)	($3,827,695)	($3,096,834)	($2,663,080)	($3,597,220)	($2,811,738)	($2,374,990)	($3,166,344)
70	Feb-06	($3,311,604)	($2,949,117)	($3,881,739)	($3,142,668)	($2,703,899)	($3,677,478)	($2,841,953)	($2,394,788)	($3,200,840)
71	Mar-06	($3,314,269)	($2,952,408)	($3,887,452)	($3,138,916)	($2,680,541)	($3,692,708)	($2,827,417)	($2,375,113)	($3,182,691)
72	Apr-06	($3,261,640)	($2,899,881)	($3,836,994)	($3,082,903)	($2,614,273)	($3,640,782)	($2,767,296)	($2,314,538)	($3,135,097)
73	May-06	($3,214,365)	($2,849,903)	($3,790,122)	($3,033,066)	($2,558,602)	($3,592,646)	($2,714,761)	($2,260,816)	($3,094,888)
74	Jun-06	($3,145,493)	($2,772,022)	($3,721,046)	($2,961,130)	($2,480,281)	($3,517,614)	($2,640,978)	($2,187,876)	($3,033,099)
75	Jul-06	($3,105,771)	($2,726,563)	($3,682,224)	($2,919,714)	($2,435,746)	($3,474,866)	($2,598,167)	($2,144,562)	($2,997,148)
76	Aug-06	($3,081,478)	($2,699,151)	($3,657,741)	($2,894,349)	($2,410,005)	($3,449,241)	($2,571,968)	($2,119,068)	($2,973,814)
77	Sep-06	($3,012,658)	($2,624,844)	($3,591,093)	($2,823,245)	($2,335,172)	($3,375,716)	($2,498,564)	($2,045,442)	($2,910,186)
78	Oct-06	($2,809,523)	($2,411,798)	($3,383,953)	($2,614,044)	($2,111,843)	($3,152,394)	($2,283,503)	($1,831,672)	($2,717,913)
79	Nov-06	($2,692,239)	($2,291,784)	($3,269,254)	($2,488,945)	($1,972,550)	($3,026,111)	($2,147,506)	($1,701,693)	($2,598,895)
80	Dec-06	($2,607,524)	($2,203,872)	($3,194,870)	($2,394,981)	($1,856,438)	($2,953,837)	($2,040,700)	($1,599,752)	($2,504,751)
81	Jan-07	($2,437,059)	($2,003,928)	($3,034,697)	($2,211,658)	($1,639,168)	($2,792,280)	($1,842,107)	($1,401,169)	($2,317,345)
82	Feb-07	($2,295,672)	($1,838,429)	($2,897,475)	($2,057,591)	($1,459,419)	($2,651,614)	($1,675,156)	($1,223,596)	($2,151,246)
83	Mar-07	($2,230,204)	($1,751,094)	($2,833,191)	($1,984,209)	($1,372,153)	($2,589,990)	($1,591,515)	($1,138,128)	($2,067,402)
84	Apr-07	($2,179,303)	($1,687,479)	($2,784,318)	($1,928,394)	($1,308,354)	($2,541,025)	($1,529,240)	($1,073,559)	($2,004,405)
85	May-07	($2,159,959)	($1,662,649)	($2,764,806)	($1,907,147)	($1,283,904)	($2,522,717)	($1,505,080)	($1,047,667)	($1,980,044)
86	Jun-07	($2,141,214)	($1,639,000)	($2,746,281)	($1,887,313)	($1,261,550)	($2,505,368)	($1,483,430)	($1,024,968)	($1,958,252)

Centra Gas Manitoba Inc
2013/14 General Rate Application

PUB/Centra 122 (d)

Time Series of Total Cumulative Risk Margin Profit/Loss Distribution Across All 1, 3 and 5-Year Fixed Price Agreement Terms and Across All SGS and LGS Customer Rate Classes

	SRP	0%			1%			2%		
		Mean	Maximum	Minimum	Mean	Maximum	Minimum	Mean	Maximum	Minimum
87	Jul-07	($2,112,178)	($1,604,705)	($2,718,410)	($1,857,291)	($1,227,597)	($2,478,246)	($1,451,651)	($993,105)	($1,926,892)
88	Aug-07	($2,070,362)	($1,558,386)	($2,678,356)	($1,814,653)	($1,180,031)	($2,439,024)	($1,407,431)	($950,069)	($1,882,448)
89	Sep-07	($1,986,300)	($1,461,245)	($2,597,944)	($1,728,793)	($1,083,380)	($2,361,194)	($1,318,422)	($862,740)	($1,792,407)
90	Oct-07	($1,837,790)	($1,290,319)	($2,455,141)	($1,576,463)	($917,025)	($2,220,970)	($1,159,843)	($703,273)	($1,633,329)
91	Nov-07	($1,621,536)	($1,039,925)	($2,243,718)	($1,352,550)	($667,273)	($2,015,657)	($923,661)	($464,011)	($1,397,105)
92	Dec-07	($1,366,571)	($743,331)	($1,992,533)	($1,086,766)	($359,993)	($1,771,131)	($641,020)	($181,808)	($1,113,438)
93	Jan-08	($1,103,663)	($436,293)	($1,731,512)	($810,955)	($42,696)	($1,516,190)	($347,225)	$107,991	($818,616)
94	Feb-08	($940,376)	($241,751)	($1,564,160)	($636,127)	$156,003	($1,358,306)	($156,659)	$308,922	($631,453)
95	Mar-08	($936,016)	($230,052)	($1,553,642)	($623,235)	$172,937	($1,358,593)	($132,673)	$335,205	($614,418)
96	Apr-08	($975,762)	($271,824)	($1,589,642)	($658,171)	$135,972	($1,400,877)	($161,307)	$305,974	($647,668)
97	May-08	($1,016,894)	($316,688)	($1,628,820)	($696,950)	$92,757	($1,443,017)	($197,456)	$267,995	($686,560)
98	Jun-08	($1,040,193)	($342,326)	($1,650,841)	($718,701)	$68,321	($1,467,201)	($217,428)	$249,236	($708,471)
99	Jul-08	($1,076,219)	($381,973)	($1,686,053)	($753,637)	$28,849	($1,505,173)	($251,447)	$216,679	($744,055)
100	Aug-08	($1,079,210)	($384,962)	($1,688,651)	($755,817)	$26,813	($1,507,105)	($252,384)	$217,579	($745,915)
101	Sep-08	($1,056,321)	($359,754)	($1,665,596)	($731,961)	$54,205	($1,480,857)	($226,498)	$246,973	($721,194)
102	Oct-08	($973,719)	($269,698)	($1,581,937)	($647,116)	$147,745	($1,388,210)	($136,828)	$346,207	($632,710)
103	Nov-08	($821,223)	($105,109)	($1,448,120)	($488,793)	$322,041	($1,212,277)	$32,744	$535,376	($469,482)
104	Dec-08	($678,995)	$49,134	($1,339,562)	($336,217)	$490,711	($1,060,304)	$202,853	$739,132	($311,553)
105	Jan-09	($448,111)	$298,674	($1,141,083)	($94,491)	$762,006	($826,760)	$461,844	$1,032,163	($63,045)
106	Feb-09	($146,638)	$626,186	($864,484)	$214,358	$1,109,403	($519,074)	$783,362	$1,382,791	$254,625
107	Mar-09	$261,731	$1,064,644	($480,887)	$629,348	$1,569,964	($120,376)	$1,210,092	$1,840,062	$672,841
108	Apr-09	$552,028	$1,379,422	($204,115)	$923,030	$1,894,772	$139,862	$1,509,865	$2,163,621	$936,734
109	May-09	$709,552	$1,550,359	($58,020)	$1,082,661	$2,072,717	$285,955	$1,672,625	$2,339,999	$1,085,290
110	Jun-09	$773,920	$1,620,073	$2,389	$1,147,760	$2,145,179	$345,553	$1,739,088	$2,411,262	$1,145,893
111	Jul-09	$837,377	$1,686,902	$63,835	$1,212,028	$2,216,018	$404,856	$1,804,412	$2,481,288	$1,206,940
112	Aug-09	$904,315	$1,760,186	$127,935	$1,279,889	$2,291,069	$468,337	$1,873,380	$2,554,596	$1,272,211
113	Sep-09	$975,759	$1,839,280	$195,650	$1,352,378	$2,370,022	$536,775	$1,947,193	$2,633,223	$1,341,991
114	Oct-09	$1,195,326	$2,078,103	$406,768	$1,575,914	$2,613,330	$743,802	$2,175,528	$2,875,523	$1,560,640
115	Nov-09	$1,421,656	$2,325,984	$619,237	$1,807,635	$2,864,745	$955,363	$2,413,910	$3,123,193	$1,787,532
116	Dec-09	$1,862,505	$2,803,652	$1,032,464	$2,258,192	$3,343,648	$1,378,364	$2,878,259	$3,596,257	$2,229,854
117	Jan-10	$2,209,380	$3,177,520	$1,351,950	$2,613,912	$3,722,018	$1,720,086	$3,246,622	$3,969,679	$2,586,415
118	Feb-10	$2,503,001	$3,495,367	$1,620,515	$2,914,556	$4,038,553	$2,006,283	$3,558,111	$4,279,417	$2,886,167
119	Mar-10	$2,726,413	$3,736,590	$1,820,359	$3,142,814	$4,273,528	$2,221,073	$3,793,243	$4,516,133	$3,115,128
120	Apr-10	$2,866,004	$3,888,351	$1,948,121	$3,285,421	$4,419,747	$2,356,382	$3,939,025	$4,664,834	$3,256,547
121	May-10	$2,978,816	$4,009,450	$2,051,235	$3,400,517	$4,536,346	$2,466,810	$4,056,505	$4,784,171	$3,369,385
122	Jun-10	$3,053,085	$4,088,263	$2,119,636	$3,476,309	$4,613,055	$2,540,600	$4,134,031	$4,862,782	$3,444,210
123	Jul-10	$3,090,093	$4,127,451	$2,153,525	$3,514,137	$4,650,699	$2,577,919	$4,172,765	$4,902,610	$3,481,772
124	Aug-10	$3,142,844	$4,183,158	$2,201,586	$3,568,000	$4,703,770	$2,631,901	$4,227,684	$4,958,907	$3,535,331
125	Sep-10	$3,236,168	$4,282,049	$2,285,411	$3,662,884	$4,798,538	$2,727,739	$4,324,431	$5,057,266	$3,631,145
126	Oct-10	$3,386,148	$4,440,397	$2,422,340	$3,815,477	$4,950,314	$2,883,160	$4,480,116	$5,212,914	$3,773,022
127	Nov-10	$3,636,470	$4,703,700	$2,651,449	$4,070,373	$5,203,769	$3,134,721	$4,740,118	$5,472,842	$4,003,211
128	Dec-10	$3,977,436	$5,061,365	$2,959,669	$4,418,927	$5,554,869	$3,460,032	$5,096,301	$5,856,605	$4,321,825
129	Jan-11	$4,338,184	$5,438,938	$3,287,516	$4,788,007	$5,925,365	$3,798,100	$5,474,157	$6,271,155	$4,659,892
130	Feb-11	$4,624,374	$5,732,899	$3,544,262	$5,081,102	$6,218,262	$4,070,602	$5,774,185	$6,601,338	$4,925,689
131	Mar-11	$4,890,104	$6,005,447	$3,778,596	$5,352,499	$6,490,640	$4,320,584	$6,052,678	$6,905,498	$5,163,876
132										
133	Percentage of Months where Cumulative Monthly Risk Margin > $0	25%	31%	17%	28%	40%	18%	31%	40%	20%
134	Worst Case Interim Cumulative Risk Margin Profit/(Loss)	($3,314,269)	($2,952,408)	($3,887,452)	($3,142,668)	($2,703,899)	($3,692,708)	($2,841,953)	($2,394,788)	($3,200,840)

Centra Gas Manitoba Inc
2013/14 General Rate Application

PUB/Centra 122 (d)

Time Series of Total Cumulative Risk Margin Profit/Loss Distribution Across All 1, 3 and 5-Year Fixed Price Agreement Terms and Across All SGS and LGS Customer Rate Classes

	SRP	3%			4%			5%		
		Mean	Maximum	Minimum	Mean	Maximum	Minimum	Mean	Maximum	Minimum
1	May-00	($267)	($29)	($541)	($254)	$10	($430)	($194)	$20	($383)
2	Jun-00	($2,046)	($1,169)	($3,532)	($2,047)	($991)	($3,209)	($1,877)	($721)	($2,722)
3	Jul-00	($4,448)	($2,689)	($7,533)	($4,432)	($2,265)	($6,695)	($4,143)	($1,619)	($5,933)
4	Aug-00	($5,362)	($2,726)	($9,380)	($5,219)	($2,402)	($8,325)	($4,755)	($1,444)	($7,398)
5	Sep-00	($9,200)	($5,104)	($15,442)	($8,870)	($4,675)	($13,694)	($8,167)	($3,244)	($12,425)
6	Oct-00	($34,110)	($22,850)	($50,729)	($33,672)	($23,473)	($46,188)	($32,523)	($20,411)	($41,830)
7	Nov-00	($84,789)	($58,121)	($122,496)	($84,089)	($61,066)	($114,139)	($81,826)	($55,856)	($102,284)
8	Dec-00	($229,074)	($165,922)	($318,486)	($228,304)	($173,924)	($300,043)	($223,883)	($158,037)	($274,124)
9	Jan-01	($453,885)	($345,020)	($611,026)	($454,171)	($350,727)	($576,402)	($447,969)	($320,002)	($533,237)
10	Feb-01	($598,606)	($458,520)	($803,011)	($598,198)	($457,012)	($759,744)	($589,517)	($415,834)	($701,394)
11	Mar-01	($678,270)	($516,990)	($909,653)	($676,884)	($514,453)	($863,903)	($665,616)	($465,156)	($791,791)
12	Apr-01	($723,279)	($550,349)	($969,727)	($720,920)	($547,209)	($922,185)	($708,192)	($492,030)	($843,704)
13	May-01	($736,752)	($558,152)	($988,030)	($733,745)	($556,721)	($940,722)	($720,352)	($498,504)	($858,476)
14	Jun-01	($729,561)	($549,262)	($981,434)	($726,087)	($549,365)	($934,583)	($712,072)	($489,818)	($850,025)
15	Jul-01	($714,061)	($532,549)	($965,517)	($710,199)	($534,497)	($919,594)	($695,687)	($474,186)	($833,063)
16	Aug-01	($693,949)	($511,525)	($943,881)	($689,711)	($515,798)	($899,328)	($674,798)	($454,710)	($811,674)
17	Sep-01	($665,415)	($481,842)	($913,503)	($660,652)	($488,889)	($870,894)	($645,177)	($427,108)	($781,808)
18	Oct-01	($538,391)	($348,085)	($776,215)	($531,448)	($368,587)	($745,453)	($514,698)	($303,876)	($655,365)
19	Nov-01	($432,616)	($236,551)	($664,360)	($423,261)	($265,207)	($639,904)	($404,752)	($192,984)	($560,206)
20	Dec-01	($295,983)	($92,572)	($525,023)	($283,074)	($113,929)	($507,452)	($261,388)	($3,597)	($435,592)
21	Jan-02	($150,722)	$81,071	($381,888)	($134,038)	$50,257	($364,058)	($108,473)	$200,165	($311,745)
22	Feb-02	($13,288)	$247,108	($244,735)	$6,340	$202,810	($229,609)	$34,964	$380,463	($196,629)
23	Mar-02	$95,405	$377,424	($141,138)	$118,895	$337,630	($119,852)	$150,329	$520,303	($107,330)
24	Apr-02	$130,734	$417,493	($108,264)	$156,463	$383,238	($85,169)	$189,993	$567,246	($79,193)
25	May-02	$150,269	$438,328	($90,667)	$177,492	$408,443	($68,078)	$212,521	$593,174	($63,751)
26	Jun-02	$162,510	$451,731	($78,598)	$190,477	$422,114	($57,363)	$226,010	$608,051	($52,512)
27	Jul-02	$178,910	$470,276	($61,590)	$207,495	$439,278	($41,641)	$243,154	$626,647	($36,969)
28	Aug-02	$208,116	$503,503	($31,178)	$237,531	$469,070	($14,210)	$273,133	$658,763	($9,042)
29	Sep-02	$233,881	$531,634	($4,696)	$264,403	$497,085	$10,797	$300,272	$687,665	$15,905
30	Oct-02	$251,754	$548,627	$11,332	$285,254	$520,395	$24,440	$323,966	$711,899	$34,228
31	Nov-02	$238,965	$530,746	($7,210)	$275,829	$513,894	$6,285	$319,303	$705,861	$22,280
32	Dec-02	$228,000	$514,542	($26,371)	$269,145	$511,690	($11,697)	$318,384	$703,172	$12,346
33	Jan-03	$180,298	$458,301	($83,934)	$227,045	$476,419	($66,863)	$284,072	$659,815	($32,327)
34	Feb-03	$5,303	$279,792	($278,461)	$57,326	$309,830	($250,727)	$123,231	$475,190	($203,239)
35	Mar-03	($384,946)	($82,782)	($697,626)	($330,356)	($54,833)	($650,891)	($254,386)	$52,373	($583,129)
36	Apr-03	($456,946)	($147,464)	($777,149)	($400,348)	($118,249)	($725,799)	($320,653)	($22,862)	($647,226)
37	May-03	($480,386)	($168,593)	($803,011)	($422,861)	($138,225)	($749,756)	($341,762)	($46,708)	($667,565)
38	Jun-03	($493,576)	($181,033)	($817,273)	($435,540)	($149,728)	($762,907)	($353,682)	($59,882)	($678,668)
39	Jul-03	($506,989)	($193,578)	($831,466)	($448,308)	($161,237)	($776,115)	($365,567)	($72,921)	($691,157)
40	Aug-03	($506,396)	($191,830)	($831,135)	($447,201)	($159,861)	($775,634)	($363,847)	($71,527)	($689,923)
41	Sep-03	($509,748)	($193,527)	($834,830)	($449,614)	($161,785)	($778,724)	($365,135)	($73,774)	($692,407)

Centra Gas Manitoba Inc
2013/14 General Rate Application

PUB/Centra 122 (d)

Time Series of Total Cumulative Risk Margin Profit/Loss Distribution Across All 1, 3 and 5-Year Fixed Price Agreement Terms and Across All SGS and LGS Customer Rate Classes

	SRP	3%			4%			5%		
		Mean	Maximum	Minimum	Mean	Maximum	Minimum	Mean	Maximum	Minimum
42	Oct-03	($497,593)	($177,861)	($822,933)	($435,696)	($148,271)	($766,981)	($349,197)	($59,235)	($678,419)
43	Nov-03	($452,599)	($122,069)	($778,067)	($386,005)	($99,707)	($724,487)	($294,459)	$390	($627,535)
44	Dec-03	($458,173)	($119,213)	($785,920)	($386,109)	($95,689)	($728,381)	($288,074)	$14,406	($627,528)
45	Jan-04	($558,724)	($215,601)	($891,901)	($478,548)	($171,006)	($816,980)	($370,538)	($62,097)	($724,642)
46	Feb-04	($626,683)	($280,153)	($964,588)	($540,359)	($220,233)	($874,754)	($425,340)	($113,247)	($788,613)
47	Mar-04	($661,662)	($310,056)	($999,907)	($570,075)	($239,620)	($903,578)	($449,260)	($133,546)	($819,095)
48	Apr-04	($694,841)	($341,868)	($1,037,085)	($599,440)	($262,203)	($937,415)	($474,594)	($157,034)	($850,809)
49	May-04	($745,187)	($392,533)	($1,090,624)	($647,020)	($304,514)	($986,030)	($518,904)	($200,671)	($900,415)
50	Jun-04	($785,295)	($432,976)	($1,132,434)	($685,526)	($338,882)	($1,024,432)	($555,305)	($237,181)	($940,739)
51	Jul-04	($803,956)	($452,082)	($1,152,532)	($703,122)	($353,800)	($1,042,417)	($571,687)	($253,346)	($959,456)
52	Aug-04	($817,832)	($466,625)	($1,168,507)	($715,820)	($364,394)	($1,056,082)	($583,234)	($264,293)	($973,235)
53	Sep-04	($814,740)	($464,823)	($1,169,774)	($711,245)	($357,139)	($1,053,691)	($577,467)	($257,662)	($971,074)
54	Oct-04	($802,787)	($453,232)	($1,166,634)	($695,669)	($335,955)	($1,044,496)	($558,809)	($239,576)	($961,525)
55	Nov-04	($894,953)	($544,813)	($1,264,785)	($782,094)	($410,808)	($1,134,151)	($639,391)	($317,435)	($1,049,970)
56	Dec-04	($1,005,978)	($653,088)	($1,390,918)	($884,828)	($494,910)	($1,246,397)	($732,275)	($407,834)	($1,156,185)
57	Jan-05	($1,058,862)	($705,122)	($1,465,189)	($928,843)	($513,793)	($1,306,269)	($765,238)	($443,796)	($1,210,246)
58	Feb-05	($1,063,632)	($708,000)	($1,491,316)	($927,034)	($495,473)	($1,315,653)	($755,581)	($424,593)	($1,217,110)
59	Mar-05	($1,096,823)	($740,141)	($1,536,952)	($954,383)	($507,891)	($1,348,324)	($775,935)	($434,357)	($1,247,565)
60	Apr-05	($1,147,469)	($792,563)	($1,588,019)	($1,002,109)	($546,051)	($1,396,579)	($819,847)	($472,610)	($1,294,524)
61	May-05	($1,174,139)	($821,096)	($1,614,766)	($1,026,487)	($565,278)	($1,421,202)	($841,644)	($492,308)	($1,317,230)
62	Jun-05	($1,178,315)	($825,225)	($1,618,649)	($1,029,567)	($566,158)	($1,426,449)	($843,209)	($493,179)	($1,318,346)
63	Jul-05	($1,187,930)	($835,622)	($1,627,255)	($1,038,092)	($572,154)	($1,436,352)	($850,257)	($499,738)	($1,324,795)
64	Aug-05	($1,199,704)	($848,323)	($1,638,713)	($1,049,005)	($581,681)	($1,447,088)	($860,357)	($509,064)	($1,334,912)
65	Sep-05	($1,260,513)	($914,950)	($1,694,949)	($1,107,968)	($637,882)	($1,501,717)	($918,076)	($563,603)	($1,391,777)
66	Oct-05	($1,498,900)	($1,158,353)	($1,931,069)	($1,341,062)	($865,472)	($1,714,321)	($1,148,414)	($784,790)	($1,625,614)
67	Nov-05	($1,887,720)	($1,516,017)	($2,344,858)	($1,720,521)	($1,239,983)	($2,105,536)	($1,521,415)	($1,137,001)	($2,006,066)
68	Dec-05	($2,258,144)	($1,846,021)	($2,744,998)	($2,080,337)	($1,591,844)	($2,495,179)	($1,872,215)	($1,457,850)	($2,378,571)
69	Jan-06	($2,613,172)	($2,160,887)	($3,125,979)	($2,424,401)	($1,928,941)	($2,869,430)	($2,207,726)	($1,767,264)	($2,745,525)
70	Feb-06	($2,635,475)	($2,178,941)	($3,181,118)	($2,436,179)	($1,931,599)	($2,891,047)	($2,208,700)	($1,729,758)	($2,777,079)
71	Mar-06	($2,614,291)	($2,160,968)	($3,184,659)	($2,406,965)	($1,891,257)	($2,872,164)	($2,171,224)	($1,662,384)	($2,757,741)
72	Apr-06	($2,551,094)	($2,103,281)	($3,133,666)	($2,340,257)	($1,816,906)	($2,808,564)	($2,100,968)	($1,577,121)	($2,693,306)
73	May-06	($2,496,321)	($2,045,406)	($3,085,883)	($2,283,210)	($1,753,396)	($2,751,968)	($2,041,538)	($1,505,076)	($2,640,876)
74	Jun-06	($2,420,704)	($1,965,984)	($3,016,759)	($2,205,230)	($1,669,063)	($2,673,750)	($1,961,341)	($1,411,496)	($2,568,633)
75	Jul-06	($2,376,828)	($1,918,318)	($2,978,131)	($2,159,655)	($1,619,442)	($2,630,281)	($1,914,452)	($1,354,879)	($2,527,341)
76	Aug-06	($2,349,910)	($1,889,236)	($2,953,861)	($2,131,564)	($1,591,008)	($2,603,441)	($1,885,429)	($1,320,456)	($2,501,550)
77	Sep-06	($2,274,780)	($1,812,472)	($2,887,864)	($2,054,034)	($1,508,307)	($2,533,615)	($1,805,356)	($1,227,953)	($2,430,163)
78	Oct-06	($2,054,795)	($1,580,633)	($2,697,251)	($1,826,870)	($1,267,259)	($2,329,545)	($1,570,964)	($954,510)	($2,212,538)
79	Nov-06	($1,911,353)	($1,430,879)	($2,579,448)	($1,673,269)	($1,097,181)	($2,206,002)	($1,407,087)	($756,638)	($2,061,182)
80	Dec-06	($1,795,715)	($1,311,147)	($2,488,035)	($1,545,166)	($949,742)	($2,108,638)	($1,267,991)	($591,592)	($1,954,570)
81	Jan-07	($1,585,780)	($1,095,783)	($2,298,103)	($1,321,939)	($699,738)	($1,915,579)	($1,029,498)	($314,571)	($1,759,899)
82	Feb-07	($1,408,608)	($904,273)	($2,130,908)	($1,132,014)	($488,843)	($1,740,389)	($826,015)	($85,426)	($1,584,906)
83	Mar-07	($1,317,329)	($802,170)	($2,047,769)	($1,031,827)	($375,555)	($1,645,812)	($716,196)	$44,206	($1,493,458)
84	Apr-07	($1,250,181)	($727,186)	($1,986,773)	($959,108)	($294,126)	($1,575,074)	($637,477)	$135,130	($1,427,216)
85	May-07	($1,224,064)	($699,130)	($1,961,716)	($930,667)	($263,284)	($1,546,445)	($606,602)	$170,871	($1,401,312)
86	Jun-07	($1,201,033)	($675,286)	($1,940,246)	($906,232)	($236,181)	($1,521,683)	($580,732)	$200,683	($1,378,708)

Centra Gas Manitoba Inc
2013/14 General Rate Application

PUB/Centra 122 (d)

Time Series of Total Cumulative Risk Margin Profit/Loss Distribution Across All 1, 3 and 5-Year Fixed Price Agreement Terms and Across All SGS and LGS Customer Rate Classes

	SRP	3%			4%			5%		
		Mean	Maximum	Minimum	Mean	Maximum	Minimum	Mean	Maximum	Minimum
87	Jul-07	($1,167,790)	($640,837)	($1,908,837)	($871,728)	($198,332)	($1,486,483)	($544,902)	$240,655	($1,346,587)
88	Aug-07	($1,122,028)	($593,833)	($1,864,489)	($824,896)	($148,588)	($1,437,529)	($497,036)	$293,771	($1,302,203)
89	Sep-07	($1,029,985)	($498,878)	($1,778,250)	($731,049)	($48,549)	($1,346,648)	($401,176)	$404,823	($1,215,226)
90	Oct-07	($865,771)	($329,520)	($1,622,081)	($563,261)	$131,004	($1,193,916)	($229,417)	$601,187	($1,057,375)
91	Nov-07	($619,199)	($73,715)	($1,385,451)	($309,381)	$403,696	($961,505)	$32,412	$900,016	($818,596)
92	Dec-07	($323,885)	$239,143	($1,105,242)	($2,510)	$729,659	($672,228)	$351,018	$1,273,395	($529,342)
93	Jan-08	($15,627)	$573,572	($814,728)	$318,962	$1,072,192	($371,999)	$685,837	$1,665,145	($222,835)
94	Feb-08	$187,836	$807,036	($622,172)	$534,765	$1,299,538	($182,056)	$913,701	$1,933,621	($22,380)
95	Mar-08	$220,767	$854,185	($590,144)	$577,514	$1,345,486	($151,706)	$965,224	$2,004,962	$11,154
96	Apr-08	$197,389	$837,511	($613,228)	$559,733	$1,327,700	($175,673)	$952,548	$2,000,007	($10,595)
97	May-08	$163,648	$805,388	($646,028)	$528,400	$1,295,899	($212,489)	$923,605	$1,971,100	($42,671)
98	Jun-08	$145,213	$788,190	($664,473)	$511,548	$1,278,672	($232,370)	$908,357	$1,956,106	($60,087)
99	Jul-08	$112,213	$754,872	($696,046)	$479,545	$1,246,306	($266,893)	$877,348	$1,923,056	($91,743)
100	Aug-08	$112,258	$755,616	($696,135)	$480,633	$1,246,925	($266,756)	$879,416	$1,926,106	($91,190)
101	Sep-08	$139,423	$784,741	($670,127)	$509,321	$1,275,731	($238,143)	$909,497	$1,960,378	($62,765)
102	Oct-08	$232,118	$884,541	($581,281)	$605,768	$1,377,514	($141,181)	$1,009,541	$2,073,183	$35,872
103	Nov-08	$409,666	$1,076,145	($406,663)	$792,953	$1,588,138	$47,760	$1,205,151	$2,290,673	$231,287
104	Dec-08	$593,390	$1,279,372	($245,365)	$992,179	$1,817,974	$237,482	$1,417,925	$2,524,232	$448,931
105	Jan-09	$866,945	$1,571,819	$11,718	$1,281,317	$2,136,509	$511,418	$1,720,987	$2,859,717	$762,081
106	Feb-09	$1,200,263	$1,924,971	$343,983	$1,625,801	$2,510,365	$845,582	$2,073,962	$3,249,244	$1,124,682
107	Mar-09	$1,637,860	$2,392,693	$735,845	$2,074,386	$2,985,646	$1,288,034	$2,528,643	$3,739,532	$1,591,783
108	Apr-09	$1,943,923	$2,714,340	$1,012,488	$2,385,739	$3,316,830	$1,590,714	$2,842,351	$4,074,408	$1,920,447
109	May-09	$2,110,171	$2,885,590	$1,162,898	$2,554,707	$3,490,980	$1,740,649	$3,012,203	$4,255,091	$2,077,153
110	Jun-09	$2,177,948	$2,956,250	$1,223,683	$2,623,624	$3,563,960	$1,801,241	$3,081,189	$4,327,818	$2,140,337
111	Jul-09	$2,244,649	$3,026,003	$1,283,533	$2,691,322	$3,633,934	$1,861,171	$3,149,095	$4,398,430	$2,202,383
112	Aug-09	$2,314,779	$3,099,531	$1,348,434	$2,762,591	$3,704,886	$1,923,366	$3,220,590	$4,474,268	$2,265,262
113	Sep-09	$2,389,757	$3,178,965	$1,416,697	$2,838,753	$3,780,533	$1,990,780	$3,296,956	$4,554,261	$2,334,104
114	Oct-09	$2,622,333	$3,423,186	$1,628,171	$3,075,648	$4,033,274	$2,199,671	$3,534,936	$4,803,724	$2,551,742
115	Nov-09	$2,866,608	$3,680,467	$1,850,730	$3,325,847	$4,310,580	$2,413,584	$3,787,374	$5,067,405	$2,778,994
116	Dec-09	$3,342,855	$4,173,758	$2,299,994	$3,813,832	$4,849,021	$2,832,908	$4,280,596	$5,579,760	$3,209,712
117	Jan-10	$3,721,437	$4,583,078	$2,657,244	$4,204,068	$5,283,745	$3,170,307	$4,676,493	$5,989,894	$3,559,856
118	Feb-10	$4,041,953	$4,930,660	$2,958,969	$4,534,304	$5,651,576	$3,457,951	$5,011,117	$6,331,768	$3,853,915
119	Mar-10	$4,284,050	$5,190,022	$3,185,568	$4,782,622	$5,923,217	$3,679,309	$5,262,263	$6,588,513	$4,080,221
120	Apr-10	$4,433,314	$5,350,450	$3,324,619	$4,935,101	$6,088,347	$3,816,931	$5,415,821	$6,744,765	$4,218,739
121	May-10	$4,553,350	$5,478,654	$3,437,062	$5,057,778	$6,219,874	$3,929,330	$5,539,055	$6,870,181	$4,330,592
122	Jun-10	$4,632,603	$5,563,940	$3,512,578	$5,138,818	$6,307,905	$4,003,158	$5,620,427	$6,953,395	$4,405,752
123	Jul-10	$4,672,280	$5,606,924	$3,551,112	$5,179,496	$6,351,891	$4,039,944	$5,661,342	$6,995,303	$4,443,521
124	Aug-10	$4,728,510	$5,667,992	$3,605,224	$5,236,986	$6,414,059	$4,092,143	$5,719,136	$7,053,997	$4,498,066
125	Sep-10	$4,827,536	$5,775,922	$3,699,698	$5,338,377	$6,525,070	$4,186,094	$5,820,387	$7,156,152	$4,590,939
126	Oct-10	$4,987,190	$5,947,520	$3,852,117	$5,501,793	$6,703,707	$4,338,346	$5,983,505	$7,319,500	$4,742,268
127	Nov-10	$5,254,049	$6,233,618	$4,104,343	$5,775,257	$7,004,841	$4,590,170	$6,257,167	$7,592,240	$4,995,849
128	Dec-10	$5,619,588	$6,618,613	$4,447,137	$6,150,509	$7,415,765	$4,931,048	$6,634,168	$7,962,995	$5,348,267
129	Jan-11	$6,007,339	$7,031,823	$4,814,291	$6,549,158	$7,850,088	$5,296,443	$7,034,775	$8,359,680	$5,718,222
130	Feb-11	$6,314,698	$7,368,474	$5,105,487	$6,864,946	$8,196,611	$5,589,391	$7,352,380	$8,686,939	$6,014,009
131	Mar-11	$6,599,254	$7,681,129	$5,379,235	$7,157,393	$8,521,466	$5,860,875	$7,645,717	$9,002,027	$6,286,162
132										
133	Percentage of Months where Cumulative Monthly Risk Margin > $0	38%	41%	21%	40%	44%	24%	41%	51%	27%
134	Worst Case Interim Cumulative Risk Margin Profit/(Loss)	($2,635,475)	($2,178,941)	($3,184,659)	($2,436,179)	($1,931,599)	($2,891,047)	($2,208,700)	($1,767,264)	($2,777,079)

Centra Gas Manitoba Inc
2013/14 General Rate Application

PUB/Centra 122 (d)

Time Series of Total Cumulative Risk Margin Profit/Loss Distribution Across All 1, 3 and 5-Year Fixed Price Agreement Terms and Across All SGS and LGS Customer Rate Classes

	SRP	6%			7%			8%		
		Mean	Maximum	Minimum	Mean	Maximum	Minimum	Mean	Maximum	Minimum
1	May-00	($126)	$87	($311)	($92)	$102	($279)	($29)	$198	($268)
2	Jun-00	($1,766)	($843)	($2,615)	($1,613)	($726)	($2,533)	($1,517)	($837)	($2,363)
3	Jul-00	($3,986)	($1,986)	($5,868)	($3,675)	($1,786)	($5,582)	($3,548)	($2,063)	($5,448)
4	Aug-00	($4,495)	($1,567)	($7,237)	($4,074)	($1,131)	($6,548)	($3,817)	($1,682)	($6,749)
5	Sep-00	($7,694)	($2,796)	($12,158)	($6,958)	($2,378)	($10,774)	($6,529)	($2,815)	($11,291)
6	Oct-00	($31,419)	($18,299)	($44,137)	($29,714)	($20,066)	($38,904)	($29,118)	($20,598)	($40,118)
7	Nov-00	($79,486)	($50,588)	($109,040)	($75,522)	($54,334)	($97,495)	($74,555)	($54,403)	($101,398)
8	Dec-00	($218,756)	($152,562)	($287,989)	($209,393)	($143,998)	($261,078)	($209,126)	($154,004)	($281,658)
9	Jan-01	($440,363)	($321,748)	($570,322)	($424,218)	($288,522)	($515,560)	($427,195)	($316,834)	($568,514)
10	Feb-01	($578,849)	($417,723)	($751,541)	($556,222)	($376,629)	($683,613)	($560,161)	($415,995)	($747,505)
11	Mar-01	($652,426)	($463,209)	($851,048)	($624,999)	($420,536)	($776,331)	($628,793)	($466,270)	($843,824)
12	Apr-01	($693,381)	($488,762)	($907,422)	($663,136)	($444,549)	($826,746)	($666,699)	($494,259)	($896,869)
13	May-01	($704,374)	($493,974)	($923,894)	($672,948)	($448,374)	($841,647)	($676,087)	($500,344)	($913,021)
14	Jun-01	($695,228)	($482,803)	($915,697)	($663,092)	($437,245)	($833,316)	($665,825)	($488,088)	($905,547)
15	Jul-01	($677,926)	($465,108)	($897,770)	($645,284)	($419,676)	($816,055)	($647,597)	($469,037)	($888,744)
16	Aug-01	($655,994)	($444,490)	($874,059)	($622,846)	($397,875)	($793,823)	($624,690)	($445,320)	($866,411)
17	Sep-01	($624,913)	($414,701)	($840,797)	($591,198)	($367,097)	($762,444)	($592,365)	($412,166)	($835,045)
18	Oct-01	($488,467)	($289,872)	($694,317)	($453,239)	($236,972)	($621,707)	($451,837)	($265,343)	($695,651)
19	Nov-01	($372,142)	($177,846)	($573,015)	($334,190)	($123,621)	($501,691)	($330,627)	($131,839)	($580,327)
20	Dec-01	($219,195)	($26,095)	($418,546)	($176,711)	$28,281	($387,917)	($170,373)	$49,893	($433,520)
21	Jan-02	($55,240)	$159,159	($256,701)	($7,878)	$220,867	($282,089)	$2,248	$249,734	($283,322)
22	Feb-02	$97,546	$332,538	($100,352)	$146,543	$390,893	($176,099)	$161,234	$427,839	($130,949)
23	Mar-02	$222,916	$471,604	$23,112	$274,046	$534,331	($87,299)	$292,660	$572,075	($10,013)
24	Apr-02	$266,778	$528,184	$61,607	$319,915	$584,386	($59,122)	$340,585	$626,121	$32,117
25	May-02	$292,267	$559,600	$84,028	$346,572	$611,575	($40,030)	$368,820	$656,903	$56,913
26	Jun-02	$307,003	$576,225	$97,888	$361,833	$627,261	($28,068)	$384,680	$674,306	$72,612
27	Jul-02	$325,168	$595,142	$115,190	$380,379	$646,848	($11,482)	$403,555	$694,337	$91,453
28	Aug-02	$356,752	$627,578	$145,311	$412,331	$679,570	$18,689	$435,842	$728,725	$123,879
29	Sep-02	$385,801	$658,842	$172,218	$441,952	$709,573	$46,187	$466,133	$761,579	$153,806
30	Oct-02	$413,651	$694,291	$197,522	$472,385	$742,504	$70,114	$499,469	$801,460	$183,520
31	Nov-02	$413,463	$703,132	$195,518	$475,718	$749,816	$66,305	$507,238	$816,226	$184,663
32	Dec-02	$418,215	$718,396	$196,663	$484,958	$763,420	$66,742	$522,027	$839,703	$190,172
33	Jan-03	$390,438	$702,651	$164,695	$463,150	$756,014	$32,416	$507,577	$831,464	$161,713
34	Feb-03	$234,166	$547,224	$7,623	$314,157	$622,621	($131,899)	$366,545	$686,619	$5,925
35	Mar-03	($144,198)	$141,154	($372,507)	($55,894)	$263,350	($512,383)	$2,746	$350,757	($370,145)
36	Apr-03	($208,776)	$75,216	($438,538)	($117,468)	$207,596	($579,506)	($55,805)	$303,432	($434,328)
37	May-03	($229,196)	$54,761	($459,194)	($136,711)	$190,309	($600,112)	($73,852)	$289,188	($454,115)
38	Jun-03	($240,767)	$43,132	($470,565)	($147,675)	$180,150	($611,861)	($84,189)	$280,543	($465,304)
39	Jul-03	($252,168)	$31,393	($481,901)	($158,323)	$170,565	($623,265)	($94,074)	$272,522	($476,177)
40	Aug-03	($249,712)	$34,498	($479,366)	($155,430)	$174,616	($620,547)	($90,357)	$277,450	($472,764)
41	Sep-03	($249,819)	$35,229	($479,827)	($154,628)	$177,156	($620,033)	($88,183)	$281,678	($471,468)

Centra Gas Manitoba Inc
2013/14 General Rate Application

PUB/Centra 122 (d)

Time Series of Total Cumulative Risk Margin Profit/Loss Distribution Across All 1, 3 and 5-Year Fixed Price Agreement Terms and Across All SGS and LGS Customer Rate Classes

	SRP	6%			7%			8%		
		Mean	Maximum	Minimum	Mean	Maximum	Minimum	Mean	Maximum	Minimum
42	Oct-03	($231,176)	$57,461	($463,550)	($134,570)	$201,496	($601,339)	($65,129)	$307,976	($449,472)
43	Nov-03	($168,909)	$129,143	($410,504)	($68,911)	$279,378	($537,376)	$8,705	$388,917	($377,570)
44	Dec-03	($155,517)	$150,503	($403,507)	($50,508)	$309,639	($520,565)	$35,487	$424,115	($354,968)
45	Jan-04	($230,832)	$84,204	($480,822)	($117,358)	$257,879	($591,218)	($21,133)	$378,583	($416,249)
46	Feb-04	($280,124)	$40,194	($530,828)	($160,450)	$223,615	($634,991)	($56,396)	$349,562	($454,410)
47	Mar-04	($298,711)	$23,291	($551,542)	($174,034)	$216,919	($648,952)	($63,327)	$347,185	($462,084)
48	Apr-04	($320,696)	$1,834	($575,756)	($192,520)	$202,542	($669,332)	($77,252)	$334,790	($478,496)
49	May-04	($363,226)	($38,908)	($622,212)	($232,007)	$166,811	($710,216)	($113,641)	$298,848	($518,081)
50	Jun-04	($398,832)	($72,577)	($660,048)	($265,652)	$135,534	($744,842)	($145,579)	$268,271	($551,572)
51	Jul-04	($414,484)	($86,308)	($677,175)	($280,084)	$122,881	($760,228)	($158,818)	$256,012	($565,572)
52	Aug-04	($424,993)	($94,747)	($688,859)	($289,396)	$115,426	($771,050)	($166,704)	$248,518	($573,509)
53	Sep-04	($417,695)	($84,712)	($683,222)	($281,000)	$124,976	($763,670)	($156,352)	$257,941	($563,701)
54	Oct-04	($395,365)	($58,083)	($665,451)	($255,548)	$153,404	($740,678)	($126,333)	$285,929	($537,587)
55	Nov-04	($471,280)	($124,687)	($751,017)	($325,910)	$90,488	($813,206)	($189,915)	$222,969	($611,064)
56	Dec-04	($554,814)	($194,593)	($851,077)	($400,145)	$23,768	($894,371)	($252,539)	$163,312	($680,950)
57	Jan-05	($576,975)	($200,328)	($893,038)	($411,323)	$22,735	($916,543)	($250,720)	$166,227	($686,374)
58	Feb-05	($559,234)	($172,680)	($891,466)	($385,321)	$62,386	($899,551)	($215,167)	$201,920	($655,608)
59	Mar-05	($572,718)	($177,010)	($914,817)	($391,519)	$72,216	($912,847)	($213,238)	$203,230	($661,178)
60	Apr-05	($613,637)	($212,509)	($960,318)	($428,687)	$42,282	($954,430)	($246,655)	$170,959	($698,690)
61	May-05	($633,287)	($226,919)	($983,188)	($445,582)	$30,888	($972,857)	($260,901)	$158,190	($716,053)
62	Jun-05	($633,556)	($222,739)	($986,210)	($444,379)	$34,735	($972,627)	($258,203)	$160,322	($713,980)
63	Jul-05	($639,473)	($225,057)	($993,481)	($448,848)	$32,010	($978,701)	($261,371)	$156,467	($719,364)
64	Aug-05	($648,716)	($232,987)	($1,003,607)	($457,200)	$24,820	($987,200)	($268,760)	$149,175	($728,479)
65	Sep-05	($705,214)	($288,835)	($1,062,379)	($512,053)	($28,246)	($1,041,485)	($322,274)	$98,729	($785,876)
66	Oct-05	($932,528)	($522,543)	($1,295,860)	($734,837)	($246,696)	($1,266,070)	($542,159)	($111,837)	($1,017,223)
67	Nov-05	($1,298,613)	($886,794)	($1,674,453)	($1,091,999)	($605,207)	($1,623,473)	($892,678)	($452,626)	($1,389,157)
68	Dec-05	($1,639,524)	($1,224,247)	($2,032,162)	($1,421,675)	($940,495)	($1,953,879)	($1,213,764)	($766,355)	($1,731,080)
69	Jan-06	($1,965,856)	($1,536,278)	($2,376,557)	($1,736,995)	($1,261,118)	($2,268,386)	($1,520,799)	($1,057,405)	($2,054,747)
70	Feb-06	($1,954,281)	($1,495,932)	($2,394,321)	($1,716,929)	($1,248,369)	($2,276,983)	($1,487,466)	($1,007,617)	($2,039,720)
71	Mar-06	($1,907,194)	($1,425,909)	($2,361,314)	($1,663,703)	($1,189,852)	($2,249,719)	($1,423,893)	($928,088)	($1,984,557)
72	Apr-06	($1,832,579)	($1,339,623)	($2,288,167)	($1,586,926)	($1,114,718)	($2,179,999)	($1,342,420)	($839,509)	($1,904,064)
73	May-06	($1,770,155)	($1,270,259)	($2,224,621)	($1,522,978)	($1,050,768)	($2,122,987)	($1,275,470)	($767,869)	($1,837,087)
74	Jun-06	($1,687,918)	($1,184,092)	($2,139,726)	($1,439,095)	($967,811)	($2,043,024)	($1,188,592)	($671,321)	($1,745,940)
75	Jul-06	($1,639,645)	($1,134,057)	($2,090,618)	($1,389,659)	($916,256)	($1,997,236)	($1,137,150)	($613,593)	($1,691,469)
76	Aug-06	($1,609,750)	($1,102,820)	($2,061,840)	($1,359,074)	($884,328)	($1,969,877)	($1,105,239)	($580,252)	($1,657,779)
77	Sep-06	($1,528,053)	($1,021,711)	($1,975,675)	($1,275,653)	($803,891)	($1,891,154)	($1,018,480)	($484,103)	($1,565,725)
78	Oct-06	($1,289,997)	($777,416)	($1,723,311)	($1,032,901)	($573,188)	($1,663,593)	($766,814)	($208,414)	($1,289,828)
79	Nov-06	($1,119,165)	($603,562)	($1,540,225)	($854,620)	($376,839)	($1,507,279)	($576,230)	$2,670	($1,129,415)
80	Dec-06	($971,505)	($442,593)	($1,379,410)	($697,039)	($194,821)	($1,365,860)	($405,570)	$188,900	($997,647)
81	Jan-07	($723,471)	($182,772)	($1,137,638)	($437,151)	$92,923	($1,112,148)	($129,637)	$488,747	($767,239)
82	Feb-07	($510,596)	$45,821	($941,950)	($212,340)	$335,990	($892,747)	$108,698	$745,917	($559,284)
83	Mar-07	($393,304)	$173,161	($830,038)	($86,451)	$477,087	($774,700)	$244,698	$896,644	($443,674)
84	Apr-07	($310,094)	$261,046	($752,289)	$2,062	$575,438	($692,849)	$339,547	$999,941	($359,853)
85	May-07	($277,313)	$298,762	($721,433)	$36,902	$615,279	($659,420)	$377,060	$1,039,343	($327,120)
86	Jun-07	($250,265)	$328,975	($695,823)	$65,271	$646,715	($631,806)	$407,022	$1,070,444	($300,046)

Centra Gas Manitoba Inc
2013/14 General Rate Application

PUB/Centra 122 (d)

Time Series of Total Cumulative Risk Margin Profit/Loss Distribution Across All 1, 3 and 5-Year Fixed Price Agreement Terms and Across All SGS and LGS Customer Rate Classes

	SRP	6%			7%			8%		
		Mean	Maximum	Minimum	Mean	Maximum	Minimum	Mean	Maximum	Minimum
87	Jul-07	($213,428)	$369,132	($660,759)	$103,346	$687,895	($595,308)	$446,408	$1,110,678	($262,474)
88	Aug-07	($164,646)	$419,978	($613,846)	$153,261	$740,360	($546,574)	$497,490	$1,164,681	($212,205)
89	Sep-07	($67,340)	$524,809	($520,605)	$252,949	$848,230	($448,436)	$599,229	$1,269,711	($112,721)
90	Oct-07	$107,885	$713,365	($355,924)	$432,304	$1,041,301	($269,719)	$783,270	$1,455,899	$69,905
91	Nov-07	$377,300	$1,004,155	($105,041)	$710,154	$1,347,339	$3,483	$1,070,641	$1,742,829	$342,536
92	Dec-07	$706,812	$1,364,076	$205,476	$1,051,354	$1,721,126	$332,594	$1,426,025	$2,094,367	$646,568
93	Jan-08	$1,052,844	$1,749,564	$526,630	$1,411,588	$2,111,429	$681,847	$1,801,716	$2,459,610	$967,956
94	Feb-08	$1,291,912	$2,018,894	$747,536	$1,662,732	$2,387,379	$916,647	$2,067,226	$2,722,198	$1,192,140
95	Mar-08	$1,352,321	$2,094,769	$796,462	$1,732,147	$2,469,355	$970,278	$2,147,097	$2,802,836	$1,253,469
96	Apr-08	$1,345,039	$2,094,090	$782,522	$1,730,066	$2,472,101	$964,489	$2,151,011	$2,809,221	$1,250,137
97	May-08	$1,318,652	$2,068,680	$752,905	$1,705,866	$2,449,018	$940,415	$2,129,595	$2,790,825	$1,228,435
98	Jun-08	$1,305,097	$2,055,755	$737,387	$1,693,743	$2,438,146	$928,015	$2,119,308	$2,782,230	$1,217,259
99	Jul-08	$1,275,288	$2,024,224	$706,028	$1,664,759	$2,408,404	$899,909	$2,091,434	$2,756,537	$1,190,547
100	Aug-08	$1,278,256	$2,028,344	$706,705	$1,668,764	$2,412,945	$902,975	$2,096,652	$2,760,925	$1,194,312
101	Sep-08	$1,309,471	$2,063,362	$734,253	$1,701,558	$2,447,124	$931,933	$2,131,280	$2,792,831	$1,225,844
102	Oct-08	$1,411,851	$2,174,664	$826,831	$1,807,986	$2,557,720	$1,027,543	$2,241,806	$2,893,962	$1,329,719
103	Nov-08	$1,613,682	$2,393,006	$1,010,534	$2,019,821	$2,778,825	$1,218,186	$2,463,706	$3,090,787	$1,537,293
104	Dec-08	$1,838,435	$2,636,881	$1,210,053	$2,259,824	$3,032,496	$1,433,209	$2,720,293	$3,316,660	$1,776,884
105	Jan-09	$2,153,107	$2,980,443	$1,497,191	$2,591,112	$3,376,541	$1,722,871	$3,067,769	$3,667,517	$2,107,060
106	Feb-09	$2,515,355	$3,369,454	$1,834,282	$2,967,005	$3,768,252	$2,055,639	$3,453,526	$4,085,466	$2,477,496
107	Mar-09	$2,979,419	$3,857,489	$2,242,350	$3,444,349	$4,264,446	$2,487,134	$3,940,239	$4,613,964	$2,951,344
108	Apr-09	$3,298,958	$4,189,225	$2,519,918	$3,771,641	$4,604,170	$2,781,356	$4,272,384	$4,972,397	$3,276,465
109	May-09	$3,471,990	$4,366,811	$2,674,258	$3,948,529	$4,788,372	$2,942,844	$4,451,339	$5,169,660	$3,449,769
110	Jun-09	$3,542,333	$4,439,548	$2,737,034	$4,020,625	$4,862,850	$3,007,648	$4,524,237	$5,251,045	$3,522,625
111	Jul-09	$3,611,514	$4,510,270	$2,801,992	$4,091,251	$4,937,721	$3,072,595	$4,595,913	$5,329,879	$3,592,475
112	Aug-09	$3,684,340	$4,583,413	$2,872,004	$4,165,536	$5,016,247	$3,141,146	$4,671,081	$5,411,260	$3,661,404
113	Sep-09	$3,761,885	$4,662,212	$2,947,447	$4,244,711	$5,101,027	$3,216,563	$4,751,188	$5,497,426	$3,733,598
114	Oct-09	$4,003,732	$4,911,023	$3,182,974	$4,492,020	$5,364,683	$3,453,437	$5,002,233	$5,766,296	$3,965,971
115	Nov-09	$4,262,089	$5,178,753	$3,434,151	$4,757,615	$5,645,987	$3,705,173	$5,272,820	$6,061,597	$4,219,150
116	Dec-09	$4,766,973	$5,700,814	$3,927,891	$5,276,157	$6,183,135	$4,206,064	$5,800,596	$6,652,143	$4,713,213
117	Jan-10	$5,173,678	$6,121,983	$4,322,663	$5,694,630	$6,606,733	$4,619,268	$6,228,418	$7,130,819	$5,106,238
118	Feb-10	$5,517,221	$6,471,371	$4,657,162	$6,048,508	$6,961,566	$4,971,814	$6,589,515	$7,526,810	$5,440,316
119	Mar-10	$5,774,246	$6,739,539	$4,911,274	$6,313,192	$7,224,749	$5,229,963	$6,858,557	$7,821,432	$5,687,770
120	Apr-10	$5,930,740	$6,904,429	$5,067,553	$6,473,475	$7,382,455	$5,383,849	$7,021,109	$7,997,730	$5,836,331
121	May-10	$6,056,139	$7,036,673	$5,192,917	$6,601,835	$7,506,806	$5,505,837	$7,151,149	$8,138,176	$5,956,439
122	Jun-10	$6,138,981	$7,123,574	$5,276,252	$6,686,817	$7,589,532	$5,586,774	$7,237,241	$8,232,266	$6,034,767
123	Jul-10	$6,180,729	$7,167,068	$5,318,213	$6,729,642	$7,631,253	$5,627,696	$7,280,734	$8,279,341	$6,075,230
124	Aug-10	$6,239,646	$7,227,433	$5,377,017	$6,789,811	$7,690,073	$5,684,986	$7,341,686	$8,345,265	$6,132,673
125	Sep-10	$6,343,139	$7,334,686	$5,480,316	$6,895,403	$7,793,822	$5,785,262	$7,448,611	$8,462,670	$6,233,071
126	Oct-10	$6,510,215	$7,503,612	$5,647,582	$7,065,865	$7,960,874	$5,946,776	$7,621,070	$8,649,783	$6,395,475
127	Nov-10	$6,790,619	$7,790,432	$5,930,505	$7,352,065	$8,240,608	$6,221,712	$7,911,176	$8,961,900	$6,668,897
128	Dec-10	$7,176,902	$8,179,878	$6,323,484	$7,747,359	$8,660,092	$6,597,256	$8,313,028	$9,392,647	$7,047,263
129	Jan-11	$7,587,732	$8,589,695	$6,743,309	$8,168,130	$9,125,644	$6,997,481	$8,740,844	$9,848,599	$7,449,572
130	Feb-11	$7,913,185	$8,918,136	$7,076,747	$8,501,470	$9,491,156	$7,315,822	$9,080,016	$10,213,499	$7,761,172
131	Mar-11	$8,213,680	$9,247,425	$7,382,575	$8,808,903	$9,821,329	$7,607,627	$9,393,203	$10,550,173	$8,054,600
132										
133	Percentage of Months where Cumulative Monthly Risk Margin > $0	42%	60%	40%	47%	74%	36%	51%	76%	40%
134	Worst Case Interim Cumulative Risk Margin Profit/(Loss)	($1,965,856)	($1,536,278)	($2,394,321)	($1,736,995)	($1,261,118)	($2,276,983)	($1,520,799)	($1,057,405)	($2,054,747)

Centra Gas Manitoba Inc
2013/14 General Rate Application

PUB/Centra 122 (d)

Time Series of Total Cumulative Risk
Margin Profit/Loss Distribution Across All
1, 3 and 5-Year Fixed Price Agreement
Terms and Across All SGS and LGS
Customer Rate Classes

	SRP	9%			10%			11%		
		Mean	Maximum	Minimum	Mean	Maximum	Minimum	Mean	Maximum	Minimum
1	May-00	($3)	$207	($199)	$44	$242	($191)	$100	$348	($109)
2	Jun-00	($1,369)	($797)	($2,036)	($1,211)	($596)	($1,727)	($1,143)	($444)	($1,777)
3	Jul-00	($3,226)	($1,794)	($4,804)	($2,960)	($1,517)	($3,916)	($2,869)	($935)	($4,370)
4	Aug-00	($3,323)	($1,114)	($5,125)	($2,894)	($365)	($4,790)	($2,742)	$73	($4,604)
5	Sep-00	($5,659)	($1,892)	($8,972)	($4,964)	($595)	($8,381)	($4,670)	($344)	($7,496)
6	Oct-00	($26,947)	($16,391)	($36,734)	($25,656)	($17,183)	($33,124)	($25,149)	($13,850)	($35,566)
7	Nov-00	($69,559)	($45,470)	($92,163)	($66,746)	($47,449)	($86,073)	($65,561)	($41,281)	($89,271)
8	Dec-00	($198,107)	($149,253)	($250,579)	($192,008)	($144,250)	($245,242)	($189,880)	($136,276)	($248,741)
9	Jan-01	($409,409)	($322,363)	($504,016)	($399,284)	($313,952)	($507,689)	($397,936)	($297,505)	($512,456)
10	Feb-01	($536,091)	($424,407)	($663,772)	($522,870)	($412,346)	($671,811)	($520,163)	($384,325)	($664,462)
11	Mar-01	($600,179)	($475,201)	($750,347)	($585,017)	($460,891)	($757,904)	($580,314)	($420,666)	($740,107)
12	Apr-01	($635,453)	($503,769)	($798,604)	($618,848)	($487,187)	($804,848)	($613,040)	($440,920)	($781,393)
13	May-01	($643,599)	($510,463)	($813,472)	($626,407)	($492,904)	($817,481)	($619,680)	($443,246)	($789,949)
14	Jun-01	($632,543)	($497,499)	($804,631)	($615,135)	($482,366)	($808,256)	($607,566)	($430,892)	($774,603)
15	Jul-01	($613,634)	($477,051)	($786,536)	($596,151)	($464,592)	($790,506)	($587,691)	($411,205)	($749,037)
16	Aug-01	($590,077)	($452,962)	($763,279)	($572,638)	($440,423)	($768,301)	($563,189)	($387,607)	($717,635)
17	Sep-01	($556,862)	($419,007)	($730,518)	($539,501)	($403,821)	($737,785)	($528,756)	($354,770)	($674,297)
18	Oct-01	($413,368)	($272,534)	($586,533)	($396,288)	($245,924)	($607,409)	($380,905)	($215,516)	($532,710)
19	Nov-01	($288,408)	($139,851)	($469,938)	($271,252)	($103,236)	($497,633)	($251,096)	($93,255)	($422,491)
20	Dec-01	($122,267)	$56,586	($326,401)	($104,558)	$89,597	($350,910)	($76,972)	$92,417	($277,507)
21	Jan-02	$55,910	$268,153	($170,055)	$75,875	$305,660	($193,641)	$111,001	$304,547	($127,588)
22	Feb-02	$219,168	$462,581	($15,344)	$241,945	$500,299	($43,591)	$283,173	$491,411	$27,952
23	Mar-02	$355,682	$626,820	$112,024	$382,234	$658,835	$51,055	$429,883	$646,405	$151,230
24	Apr-02	$406,738	$690,603	$159,102	$435,103	$716,062	$84,974	$486,343	$706,682	$195,693
25	May-02	$436,880	$725,921	$188,791	$466,346	$748,685	$106,186	$519,538	$740,643	$224,444
26	Jun-02	$453,579	$744,419	$204,974	$483,322	$766,695	$119,677	$537,480	$759,401	$240,751
27	Jul-02	$473,045	$764,170	$224,494	$502,897	$787,838	$137,216	$557,857	$780,671	$260,697
28	Aug-02	$506,303	$797,789	$257,405	$536,125	$822,807	$168,343	$592,112	$817,383	$295,682
29	Sep-02	$537,852	$830,590	$288,214	$567,922	$856,011	$197,008	$625,146	$852,801	$329,318
30	Oct-02	$574,805	$872,716	$324,359	$607,007	$898,890	$224,155	$667,225	$903,091	$368,431
31	Nov-02	$586,489	$892,101	$335,171	$622,462	$917,677	$225,330	$686,025	$931,331	$378,882
32	Dec-02	$606,342	$922,076	$353,640	$646,801	$947,861	$231,021	$714,872	$972,059	$398,420
33	Jan-03	$598,317	$923,375	$342,197	$644,546	$951,163	$206,740	$718,634	$984,368	$391,820
34	Feb-03	$462,902	$798,905	$193,680	$516,651	$817,620	$65,144	$596,476	$863,131	$251,790
35	Mar-03	$99,922	$444,341	($181,751)	$164,355	$445,824	($279,355)	$248,150	$510,809	($132,432)
36	Apr-03	$43,690	$392,856	($241,075)	$111,364	$391,893	($332,870)	$197,897	$467,524	($192,457)
37	May-03	$26,569	$377,681	($259,006)	$95,477	$376,063	($349,352)	$183,165	$454,657	($210,992)
38	Jun-03	$16,734	$369,090	($269,151)	$86,288	$367,107	($358,630)	$174,588	$446,742	($221,532)
39	Jul-03	$7,487	$361,306	($278,728)	$77,852	$358,967	($366,690)	$166,908	$439,714	($231,210)
40	Aug-03	$11,870	$366,974	($274,316)	$82,822	$364,096	($362,472)	$172,502	$445,434	($226,350)
41	Sep-03	$15,200	$372,420	($271,115)	$87,257	$369,205	($358,784)	$178,060	$451,510	($222,779)

Centra Gas Manitoba Inc
2013/14 General Rate Application

PUB/Centra 122 (d)

Time Series of Total Cumulative Risk Margin Profit/Loss Distribution Across All 1, 3 and 5-Year Fixed Price Agreement Terms and Across All SGS and LGS Customer Rate Classes

	SRP	9%			10%			11%		
		Mean	Maximum	Minimum	Mean	Maximum	Minimum	Mean	Maximum	Minimum
42	Oct-03	$40,592	$402,486	($245,301)	$114,723	$397,572	($334,756)	$207,740	$481,939	($195,042)
43	Nov-03	$120,362	$494,015	($165,340)	$199,782	$484,568	($259,008)	$298,790	$576,164	($108,988)
44	Dec-03	$153,801	$539,115	($132,547)	$239,608	$526,720	($224,831)	$345,219	$626,376	($72,142)
45	Jan-04	$106,213	$504,115	($177,896)	$201,127	$491,576	($264,876)	$315,483	$600,963	($117,701)
46	Feb-04	$77,852	$483,025	($202,982)	$179,667	$470,129	($286,577)	$300,673	$591,859	($141,037)
47	Mar-04	$76,989	$487,445	($202,997)	$184,846	$474,174	($282,393)	$311,550	$607,691	($137,720)
48	Apr-04	$66,869	$482,527	($212,679)	$178,955	$467,882	($287,774)	$309,208	$605,037	($146,185)
49	May-04	$33,342	$453,249	($245,163)	$148,278	$437,922	($316,947)	$281,173	$577,949	($178,882)
50	Jun-04	$3,105	$425,426	($274,008)	$119,811	$410,101	($343,739)	$254,160	$551,402	($208,682)
51	Jul-04	($9,034)	$415,073	($287,798)	$108,888	$398,937	($354,296)	$244,157	$541,394	($220,116)
52	Aug-04	($15,812)	$410,029	($297,216)	$103,357	$392,877	($359,961)	$239,739	$537,380	($225,586)
53	Sep-04	($4,107)	$423,954	($287,450)	$116,333	$403,478	($348,779)	$254,162	$553,451	($209,966)
54	Oct-04	$29,166	$462,542	($257,274)	$153,033	$433,420	($316,334)	$294,493	$595,289	($165,543)
55	Nov-04	($28,818)	$409,670	($331,804)	$100,710	$380,769	($366,286)	$247,039	$550,573	($213,673)
56	Dec-04	($81,953)	$364,490	($411,758)	$57,837	$332,838	($413,842)	$211,887	$516,557	($236,552)
57	Jan-05	($69,169)	$384,907	($425,540)	$81,787	$360,012	($399,130)	$244,824	$552,998	($183,200)
58	Feb-05	($25,592)	$433,412	($400,902)	$133,852	$428,815	($354,547)	$303,201	$617,786	($108,385)
59	Mar-05	($17,230)	$445,760	($408,142)	$150,119	$454,069	($344,428)	$325,153	$645,756	($79,813)
60	Apr-05	($47,298)	$418,715	($445,501)	$123,598	$429,788	($373,212)	$301,669	$623,211	($110,208)
61	May-05	($58,977)	$409,693	($462,553)	$114,307	$422,150	($382,657)	$294,253	$617,452	($121,430)
62	Jun-05	($54,727)	$415,946	($461,315)	$119,883	$430,513	($376,353)	$300,930	$626,006	($117,122)
63	Jul-05	($56,362)	$416,123	($465,504)	$119,503	$432,054	($376,855)	$301,623	$627,853	($117,593)
64	Aug-05	($62,872)	$410,346	($473,493)	$113,795	$426,509	($382,778)	$296,691	$623,182	($123,173)
65	Sep-05	($114,842)	$358,730	($529,398)	$62,902	$370,767	($436,905)	$247,324	$571,950	($172,785)
66	Oct-05	($330,658)	$138,863	($753,782)	($151,195)	$145,911	($663,887)	$37,655	$354,214	($380,119)
67	Nov-05	($673,477)	($210,612)	($1,107,565)	($489,858)	($148,513)	($1,025,749)	($292,817)	$14,571	($705,666)
68	Dec-05	($983,611)	($530,313)	($1,426,396)	($794,190)	($401,830)	($1,347,497)	($587,399)	($291,873)	($998,046)
69	Jan-06	($1,280,124)	($833,842)	($1,730,970)	($1,086,110)	($640,492)	($1,650,839)	($869,499)	($587,310)	($1,320,066)
70	Feb-06	($1,235,120)	($791,495)	($1,682,713)	($1,031,607)	($534,329)	($1,607,469)	($806,656)	($519,572)	($1,273,670)
71	Mar-06	($1,162,767)	($719,660)	($1,627,326)	($951,157)	($413,811)	($1,535,414)	($720,271)	($398,600)	($1,197,456)
72	Apr-06	($1,077,952)	($635,961)	($1,547,026)	($861,735)	($305,280)	($1,452,021)	($629,162)	($288,835)	($1,103,839)
73	May-06	($1,008,955)	($565,895)	($1,478,860)	($789,349)	($222,592)	($1,383,522)	($555,385)	($202,932)	($1,026,452)
74	Jun-06	($921,289)	($479,638)	($1,394,837)	($697,561)	($123,485)	($1,296,937)	($462,775)	($98,380)	($928,205)
75	Jul-06	($869,383)	($428,458)	($1,343,363)	($642,980)	($63,944)	($1,245,440)	($407,928)	($36,824)	($870,718)
76	Aug-06	($836,976)	($396,569)	($1,310,480)	($609,084)	($27,744)	($1,213,990)	($373,678)	$181	($835,048)
77	Sep-06	($749,139)	($311,249)	($1,225,192)	($517,896)	$71,947	($1,128,476)	($281,956)	$105,958	($740,202)
78	Oct-06	($496,291)	($67,502)	($1,001,813)	($254,693)	$351,546	($867,567)	($16,798)	$398,360	($461,929)
79	Nov-06	($300,914)	$115,865	($837,301)	($46,778)	$573,220	($664,271)	$196,137	$635,762	($240,982)
80	Dec-06	($122,416)	$319,409	($686,952)	$144,857	$769,573	($479,766)	$394,683	$859,513	($52,327)
81	Jan-07	$162,067	$653,089	($453,142)	$447,950	$1,059,437	($164,931)	$704,200	$1,219,479	$235,819
82	Feb-07	$409,932	$941,327	($245,538)	$711,567	$1,319,735	$103,117	$974,419	$1,531,086	$493,999
83	Mar-07	$553,408	$1,106,170	($130,609)	$864,834	$1,470,144	$251,092	$1,133,552	$1,715,805	$638,188
84	Apr-07	$652,854	$1,218,209	($46,151)	$970,761	$1,568,416	$344,918	$1,243,359	$1,838,232	$740,635
85	May-07	$692,392	$1,262,270	($12,530)	$1,012,812	$1,607,458	$382,773	$1,286,953	$1,888,459	$781,498
86	Jun-07	$723,507	$1,296,185	$14,337	$1,045,643	$1,636,984	$411,509	$1,320,613	$1,927,112	$812,927

Centra Gas Manitoba Inc
2013/14 General Rate Application

PUB/Centra 122 (d)

Time Series of Total Cumulative Risk Margin Profit/Loss Distribution Across All 1, 3 and 5-Year Fixed Price Agreement Terms and Across All SGS and LGS Customer Rate Classes

	SRP	9%			10%			11%		
		Mean	Maximum	Minimum	Mean	Maximum	Minimum	Mean	Maximum	Minimum
87	Jul-07	$764,174	$1,339,126	$51,399	$1,087,944	$1,675,313	$448,985	$1,363,619	$1,975,050	$853,374
88	Aug-07	$816,385	$1,394,574	$100,375	$1,141,743	$1,723,202	$497,157	$1,417,970	$2,035,693	$903,890
89	Sep-07	$920,136	$1,502,444	$193,160	$1,249,066	$1,818,599	$594,891	$1,526,409	$2,159,562	$1,001,887
90	Oct-07	$1,108,625	$1,694,250	$361,842	$1,443,796	$2,017,145	$771,841	$1,723,724	$2,383,332	$1,180,837
91	Nov-07	$1,404,844	$1,990,835	$619,755	$1,751,599	$2,350,362	$1,047,179	$2,037,671	$2,742,252	$1,459,776
92	Dec-07	$1,772,020	$2,354,238	$934,920	$2,132,919	$2,765,935	$1,371,292	$2,429,933	$3,191,276	$1,807,687
93	Jan-08	$2,161,277	$2,731,120	$1,274,772	$2,537,739	$3,201,476	$1,719,626	$2,846,461	$3,665,280	$2,174,092
94	Feb-08	$2,439,333	$3,023,892	$1,510,631	$2,828,320	$3,517,815	$1,969,242	$3,148,647	$4,010,192	$2,435,501
95	Mar-08	$2,528,362	$3,126,968	$1,585,919	$2,926,771	$3,633,407	$2,050,721	$3,255,921	$4,138,125	$2,522,157
96	Apr-08	$2,537,641	$3,143,457	$1,592,467	$2,941,629	$3,655,871	$2,060,185	$3,275,636	$4,168,920	$2,531,498
97	May-08	$2,518,572	$3,125,993	$1,575,121	$2,925,042	$3,640,613	$2,043,675	$3,261,338	$4,156,481	$2,514,600
98	Jun-08	$2,509,759	$3,118,169	$1,567,500	$2,917,975	$3,634,487	$2,037,038	$3,255,646	$4,152,410	$2,506,905
99	Jul-08	$2,482,926	$3,091,002	$1,543,618	$2,892,248	$3,606,887	$2,012,581	$3,230,849	$4,126,319	$2,483,551
100	Aug-08	$2,489,083	$3,098,863	$1,549,639	$2,899,438	$3,615,379	$2,018,622	$3,238,894	$4,134,988	$2,490,966
101	Sep-08	$2,524,896	$3,139,208	$1,581,943	$2,936,671	$3,657,205	$2,052,054	$3,277,211	$4,176,084	$2,527,824
102	Oct-08	$2,638,663	$3,262,965	$1,687,529	$3,053,438	$3,786,077	$2,159,042	$3,396,274	$4,301,249	$2,635,509
103	Nov-08	$2,868,778	$3,509,047	$1,902,149	$3,291,122	$4,051,145	$2,381,322	$3,639,970	$4,554,671	$2,848,336
104	Dec-08	$3,138,701	$3,793,101	$2,154,035	$3,574,898	$4,364,503	$2,637,944	$3,934,138	$4,860,435	$3,106,296
105	Jan-09	$3,500,405	$4,166,572	$2,493,606	$3,949,680	$4,766,893	$2,956,938	$4,320,173	$5,256,590	$3,446,166
106	Feb-09	$3,898,246	$4,572,151	$2,861,669	$4,356,716	$5,205,808	$3,318,759	$4,734,551	$5,685,167	$3,810,598
107	Mar-09	$4,396,539	$5,084,007	$3,315,999	$4,863,309	$5,751,730	$3,780,450	$5,246,989	$6,210,247	$4,266,627
108	Apr-09	$4,734,628	$5,427,418	$3,621,561	$5,205,639	$6,121,308	$4,093,527	$5,593,100	$6,562,457	$4,577,655
109	May-09	$4,917,014	$5,613,453	$3,785,620	$5,390,781	$6,319,057	$4,263,452	$5,780,073	$6,752,613	$4,745,972
110	Jun-09	$4,991,475	$5,689,776	$3,851,987	$5,466,113	$6,399,700	$4,334,681	$5,856,361	$6,829,657	$4,812,563
111	Jul-09	$5,064,552	$5,762,946	$3,919,102	$5,539,940	$6,477,590	$4,403,922	$5,931,191	$6,904,505	$4,878,038
112	Aug-09	$5,141,308	$5,840,271	$3,990,751	$5,617,381	$6,561,138	$4,478,268	$6,009,589	$6,983,420	$4,946,255
113	Sep-09	$5,223,024	$5,921,676	$4,068,542	$5,699,834	$6,649,650	$4,558,953	$6,093,101	$7,066,396	$5,017,745
114	Oct-09	$5,480,180	$6,177,849	$4,314,544	$5,959,265	$6,922,931	$4,812,866	$6,356,836	$7,327,577	$5,243,481
115	Nov-09	$5,759,347	$6,460,849	$4,574,504	$6,241,286	$7,216,639	$5,087,365	$6,645,440	$7,610,029	$5,488,577
116	Dec-09	$6,305,495	$7,003,709	$5,094,889	$6,792,372	$7,784,731	$5,634,160	$7,209,985	$8,169,159	$5,968,925
117	Jan-10	$6,749,336	$7,471,810	$5,521,064	$7,241,524	$8,244,581	$6,085,444	$7,671,305	$8,620,063	$6,365,916
118	Feb-10	$7,124,176	$7,881,252	$5,885,628	$7,621,101	$8,628,788	$6,468,998	$8,061,086	$8,997,030	$6,702,057
119	Mar-10	$7,403,051	$8,187,407	$6,156,341	$7,903,542	$8,913,460	$6,747,551	$8,350,669	$9,276,626	$6,949,990
120	Apr-10	$7,570,787	$8,369,107	$6,322,749	$8,072,795	$9,082,951	$6,917,595	$8,523,462	$9,443,634	$7,097,277
121	May-10	$7,705,006	$8,515,544	$6,456,485	$8,208,159	$9,216,773	$7,056,147	$8,661,456	$9,577,307	$7,213,262
122	Jun-10	$7,794,017	$8,611,782	$6,544,543	$8,297,887	$9,310,032	$7,147,617	$8,752,975	$9,665,656	$7,290,385
123	Jul-10	$7,838,891	$8,659,994	$6,588,812	$8,343,254	$9,359,050	$7,193,884	$8,799,310	$9,710,379	$7,330,966
124	Aug-10	$7,901,600	$8,726,080	$6,651,610	$8,406,626	$9,427,254	$7,258,479	$8,863,846	$9,772,471	$7,388,244
125	Sep-10	$8,011,636	$8,841,987	$6,762,314	$8,517,622	$9,547,659	$7,371,476	$8,976,555	$9,879,976	$7,486,320
126	Oct-10	$8,189,409	$9,028,257	$6,942,097	$8,696,898	$9,740,118	$7,554,584	$9,158,704	$10,056,823	$7,642,787
127	Nov-10	$8,488,679	$9,342,082	$7,246,340	$8,998,986	$10,065,643	$7,864,754	$9,465,588	$10,357,652	$7,909,029
128	Dec-10	$8,903,303	$9,775,809	$7,672,088	$9,417,757	$10,505,969	$8,292,942	$9,891,699	$10,776,532	$8,283,380
129	Jan-11	$9,345,125	$10,240,532	$8,123,154	$9,864,169	$10,970,150	$8,749,683	$10,346,137	$11,228,491	$8,680,280
130	Feb-11	$9,695,445	$10,613,926	$8,481,449	$10,218,533	$11,364,711	$9,103,269	$10,707,113	$11,608,654	$9,000,705
131	Mar-11	$10,019,345	$10,963,578	$8,808,413	$10,545,717	$11,738,703	$9,428,807	$11,039,924	$11,970,754	$9,296,699
132										
133	Percentage of Months where Cumulative Monthly Risk Margin > $0	63%	77%	44%	75%	79%	47%	76%	81%	49%
134	Worst Case Interim Cumulative Risk Margin Profit/(Loss)	($1,280,124)	($833,842)	($1,730,970)	($1,086,110)	($640,492)	($1,650,839)	($869,499)	($587,310)	($1,320,066)

Centra Gas Manitoba Inc
2013/14 General Rate Application

PUB/Centra 122 (d)

Time Series of Total Cumulative Risk
Margin Profit/Loss Distribution Across All
1, 3 and 5-Year Fixed Price Agreement
Terms and Across All SGS and LGS
Customer Rate Classes

	SRP	12%			13%			14%		
		Mean	Maximum	Minimum	Mean	Maximum	Minimum	Mean	Maximum	Minimum
1	May-00	$153	$401	($91)	$200	$453	($63)	$245	$499	($29)
2	Jun-00	($1,028)	($550)	($1,567)	($838)	($375)	($1,320)	($765)	($257)	($1,280)
3	Jul-00	($2,672)	($1,535)	($4,265)	($2,304)	($1,357)	($3,714)	($2,160)	($753)	($3,350)
4	Aug-00	($2,364)	($682)	($4,449)	($1,797)	($53)	($4,201)	($1,538)	$731	($3,368)
5	Sep-00	($4,005)	($1,165)	($7,503)	($3,040)	$157	($6,794)	($2,579)	$1,053	($5,496)
6	Oct-00	($24,075)	($16,774)	($32,784)	($21,935)	($15,487)	($30,450)	($20,957)	($10,179)	($29,584)
7	Nov-00	($63,490)	($43,776)	($81,656)	($58,927)	($41,668)	($81,834)	($56,795)	($31,730)	($79,515)
8	Dec-00	($185,271)	($129,984)	($232,412)	($176,229)	($127,215)	($236,717)	($171,613)	($116,574)	($225,868)
9	Jan-01	($389,491)	($277,473)	($482,805)	($377,501)	($271,634)	($488,665)	($370,144)	($272,454)	($467,377)
10	Feb-01	($508,394)	($353,770)	($632,386)	($492,378)	($349,241)	($638,376)	($482,283)	($359,156)	($613,465)
11	Mar-01	($566,117)	($384,216)	($708,169)	($546,762)	($383,572)	($716,081)	($534,594)	($393,578)	($685,462)
12	Apr-01	($597,337)	($400,490)	($748,880)	($575,922)	($401,898)	($758,879)	($562,363)	($410,614)	($724,402)
13	May-01	($603,386)	($400,885)	($758,004)	($580,834)	($402,499)	($769,401)	($566,484)	($411,237)	($732,930)
14	Jun-01	($591,056)	($387,043)	($746,306)	($567,615)	($389,505)	($758,673)	($552,644)	($396,310)	($720,333)
15	Jul-01	($571,189)	($366,242)	($725,355)	($546,884)	($370,349)	($739,852)	($531,330)	($373,221)	($699,925)
16	Aug-01	($546,844)	($341,228)	($700,796)	($521,656)	($347,507)	($716,745)	($505,477)	($346,117)	($674,750)
17	Sep-01	($512,593)	($306,120)	($666,938)	($486,278)	($315,239)	($683,975)	($469,178)	($307,202)	($640,285)
18	Oct-01	($365,746)	($157,661)	($524,163)	($334,960)	($179,512)	($542,631)	($315,436)	($142,835)	($495,271)
19	Nov-01	($236,167)	($21,424)	($412,168)	($200,905)	($36,833)	($419,194)	($178,029)	$2,215	($367,203)
20	Dec-01	($61,276)	$164,015	($270,870)	($19,844)	$157,280	($263,010)	$8,627	$204,707	($207,461)
21	Jan-02	$127,776	$368,149	($115,203)	$175,127	$358,874	($113,702)	$212,121	$443,615	($25,160)
22	Feb-02	$300,645	$552,191	$37,607	$354,182	$548,109	$32,567	$396,752	$654,548	$143,969
23	Mar-02	$448,495	$714,521	$172,582	$508,741	$717,449	$157,905	$558,563	$839,714	$290,574
24	Apr-02	$506,425	$779,944	$216,995	$569,889	$798,820	$208,476	$623,406	$914,306	$345,302
25	May-02	$541,285	$818,808	$245,123	$606,740	$847,646	$239,886	$662,552	$957,247	$380,014
26	Jun-02	$559,779	$840,470	$262,246	$626,023	$871,466	$257,283	$682,715	$979,330	$399,077
27	Jul-02	$580,525	$863,716	$281,844	$647,330	$895,883	$276,919	$704,468	$1,003,275	$419,025
28	Aug-02	$615,375	$902,645	$315,792	$682,997	$935,525	$309,200	$740,622	$1,042,924	$452,169
29	Sep-02	$649,317	$940,396	$347,920	$718,091	$975,693	$341,563	$776,579	$1,082,438	$485,204
30	Oct-02	$694,488	$996,427	$386,003	$767,200	$1,038,025	$388,557	$829,177	$1,139,976	$535,526
31	Nov-02	$717,126	$1,031,661	$399,503	$794,956	$1,081,758	$417,743	$861,604	$1,177,311	$569,834
32	Dec-02	$750,592	$1,079,411	$421,314	$834,896	$1,141,830	$458,124	$907,323	$1,229,679	$614,957
33	Jan-03	$760,013	$1,105,520	$420,151	$853,057	$1,180,683	$474,121	$932,604	$1,264,368	$629,354
34	Feb-03	$644,179	$1,002,874	$299,417	$745,310	$1,087,628	$368,899	$832,708	$1,162,729	$511,576
35	Mar-03	$300,160	$663,014	($40,987)	$407,991	$742,007	$46,998	$502,650	$826,742	$163,669
36	Apr-03	$251,888	$621,474	($94,406)	$362,992	$698,401	$3,222	$460,650	$791,446	$111,977
37	May-03	$237,938	$610,383	($110,394)	$350,310	$686,756	($9,164)	$449,149	$782,798	$97,013
38	Jun-03	$229,827	$603,721	($119,708)	$342,815	$679,746	($16,486)	$442,335	$777,393	$88,487
39	Jul-03	$222,733	$598,226	($128,438)	$336,529	$673,815	($23,129)	$436,807	$773,617	$81,135
40	Aug-03	$228,835	$605,645	($124,380)	$343,400	$681,658	($16,726)	$444,273	$782,591	$86,667
41	Sep-03	$235,337	$614,200	($121,139)	$351,206	$690,894	($9,284)	$453,238	$794,205	$92,740

Centra Gas Manitoba Inc
2013/14 General Rate Application

PUB/Centra 122 (d)

Time Series of Total Cumulative Risk Margin Profit/Loss Distribution Across All 1, 3 and 5-Year Fixed Price Agreement Terms and Across All SGS and LGS Customer Rate Classes

	SRP	12%			13%			14%		
		Mean	Maximum	Minimum	Mean	Maximum	Minimum	Mean	Maximum	Minimum
42	Oct-03	$266,691	$650,131	($98,372)	$385,268	$727,018	$24,155	$489,407	$837,387	$122,805
43	Nov-03	$362,393	$757,505	($26,450)	$487,936	$836,746	$124,570	$597,425	$964,177	$217,259
44	Dec-03	$414,356	$821,681	$4,111	$547,520	$901,616	$172,386	$663,444	$1,047,690	$268,966
45	Jan-04	$392,686	$813,882	($36,288)	$535,826	$907,889	$153,585	$661,364	$1,060,498	$249,149
46	Feb-04	$383,713	$811,210	($60,189)	$534,130	$925,057	$150,299	$666,887	$1,076,728	$243,917
47	Mar-04	$399,481	$832,006	($55,413)	$556,061	$961,078	$168,013	$694,903	$1,112,747	$264,171
48	Apr-04	$400,542	$836,417	($58,576)	$561,567	$973,714	$171,906	$704,844	$1,126,695	$271,068
49	May-04	$375,062	$812,941	($86,854)	$539,169	$954,651	$147,181	$685,932	$1,109,003	$248,163
50	Jun-04	$349,577	$788,504	($113,188)	$515,596	$932,443	$123,371	$664,366	$1,087,269	$223,794
51	Jul-04	$340,512	$779,760	($123,272)	$507,909	$925,680	$114,256	$657,978	$1,081,162	$215,693
52	Aug-04	$337,090	$776,646	($127,740)	$506,021	$924,416	$111,556	$657,386	$1,080,805	$212,827
53	Sep-04	$352,694	$791,466	($113,441)	$523,540	$942,349	$128,830	$676,290	$1,100,493	$229,165
54	Oct-04	$395,868	$831,129	($71,671)	$571,582	$993,841	$178,281	$727,815	$1,151,050	$275,947
55	Nov-04	$354,167	$794,454	($121,207)	$536,491	$962,936	$141,727	$698,333	$1,118,353	$241,163
56	Dec-04	$328,996	$782,180	($161,176)	$523,484	$949,005	$112,645	$694,953	$1,109,097	$227,022
57	Jan-05	$372,207	$841,719	($140,671)	$581,578	$1,006,003	$151,455	$763,252	$1,172,366	$287,112
58	Feb-05	$437,887	$922,261	($92,297)	$658,705	$1,080,045	$215,138	$847,681	$1,256,024	$366,602
59	Mar-05	$466,587	$962,701	($77,035)	$696,770	$1,117,794	$243,597	$892,205	$1,306,309	$404,133
60	Apr-05	$446,920	$947,397	($105,660)	$681,182	$1,100,376	$223,079	$879,819	$1,296,989	$390,936
61	May-05	$442,379	$945,407	($117,041)	$679,405	$1,099,045	$216,721	$880,699	$1,298,828	$393,269
62	Jun-05	$450,626	$956,152	($112,355)	$689,245	$1,108,779	$223,307	$892,110	$1,309,084	$405,440
63	Jul-05	$452,939	$960,645	($113,113)	$692,829	$1,111,321	$225,187	$897,170	$1,313,860	$410,526
64	Aug-05	$449,005	$957,542	($118,685)	$689,747	$1,108,571	$221,487	$895,027	$1,311,201	$408,223
65	Sep-05	$401,366	$908,656	($168,566)	$643,217	$1,061,195	$174,351	$850,199	$1,268,222	$363,692
66	Oct-05	$196,131	$698,932	($376,200)	$440,876	$853,101	($25,265)	$651,941	$1,083,750	$167,319
67	Nov-05	($124,786)	$361,221	($698,943)	$126,212	$528,036	($342,349)	$343,963	$791,378	($133,254)
68	Dec-05	($407,687)	$88,367	($983,157)	($147,148)	$246,104	($621,638)	$78,612	$536,340	($387,530)
69	Jan-06	($679,766)	($163,527)	($1,256,347)	($409,595)	($31,196)	($891,432)	($176,426)	$295,685	($630,471)
70	Feb-06	($606,777)	($83,870)	($1,190,026)	($322,532)	$34,204	($822,090)	($84,815)	$383,735	($517,616)
71	Mar-06	($511,997)	$20,006	($1,100,828)	($217,770)	$116,196	($727,770)	$24,071	$485,542	($397,342)
72	Apr-06	($417,035)	$119,750	($1,008,433)	($118,678)	$203,267	($633,553)	$124,530	$576,051	($296,529)
73	May-06	($340,850)	$197,210	($930,956)	($39,512)	$280,086	($554,870)	$204,392	$649,117	($223,953)
74	Jun-06	($246,164)	$294,059	($833,613)	$57,685	$379,052	($461,168)	$301,562	$738,738	($131,861)
75	Jul-06	($189,849)	$351,221	($775,370)	$115,501	$438,419	($406,257)	$359,862	$797,799	($77,240)
76	Aug-06	($154,637)	$387,343	($739,901)	$151,637	$476,299	($372,677)	$396,461	$836,172	($44,566)
77	Sep-06	($60,240)	$484,634	($641,772)	$248,260	$577,030	($286,217)	$493,771	$941,692	$43,928
78	Oct-06	$211,635	$767,146	($349,505)	$526,432	$865,154	($43,215)	$773,451	$1,241,861	$293,931
79	Nov-06	$433,578	$994,771	($111,940)	$758,040	$1,099,881	$157,333	$1,011,067	$1,496,152	$510,301
80	Dec-06	$643,432	$1,214,785	$107,462	$978,745	$1,355,950	$349,407	$1,239,058	$1,746,334	$716,873
81	Jan-07	$967,290	$1,562,402	$452,632	$1,314,611	$1,732,107	$663,148	$1,584,343	$2,105,760	$1,034,231
82	Feb-07	$1,251,981	$1,880,828	$699,705	$1,610,048	$2,051,099	$944,759	$1,889,915	$2,426,444	$1,312,585
83	Mar-07	$1,421,862	$2,067,422	$846,098	$1,788,008	$2,251,876	$1,113,049	$2,075,033	$2,617,442	$1,479,052
84	Apr-07	$1,537,917	$2,193,183	$947,303	$1,909,139	$2,388,981	$1,227,087	$2,200,394	$2,750,935	$1,592,856
85	May-07	$1,584,189	$2,243,863	$985,568	$1,957,586	$2,445,522	$1,271,491	$2,250,251	$2,802,554	$1,637,400
86	Jun-07	$1,619,504	$2,282,171	$1,015,039	$1,994,424	$2,487,925	$1,305,292	$2,287,836	$2,840,707	$1,671,446

Centra Gas Manitoba Inc
2013/14 General Rate Application

PUB/Centra 122 (d)

Time Series of Total Cumulative Risk Margin Profit/Loss Distribution Across All 1, 3 and 5-Year Fixed Price Agreement Terms and Across All SGS and LGS Customer Rate Classes

	SRP	12%			13%			14%		
		Mean	Maximum	Minimum	Mean	Maximum	Minimum	Mean	Maximum	Minimum
87	Jul-07	$1,664,115	$2,329,383	$1,052,589	$2,040,614	$2,540,295	$1,347,341	$2,334,452	$2,887,646	$1,714,393
88	Aug-07	$1,719,830	$2,387,456	$1,101,709	$2,097,893	$2,605,741	$1,400,060	$2,391,826	$2,946,514	$1,766,103
89	Sep-07	$1,830,315	$2,500,643	$1,199,150	$2,211,293	$2,737,285	$1,503,838	$2,505,188	$3,065,701	$1,874,851
90	Oct-07	$2,032,068	$2,709,267	$1,383,055	$2,418,248	$2,973,231	$1,689,544	$2,712,878	$3,280,276	$2,070,899
91	Nov-07	$2,354,412	$3,042,019	$1,678,586	$2,750,782	$3,352,188	$1,988,077	$3,048,768	$3,632,770	$2,396,673
92	Dec-07	$2,758,914	$3,460,521	$2,051,246	$3,168,260	$3,834,681	$2,378,209	$3,473,068	$4,077,573	$2,809,085
93	Jan-08	$3,189,812	$3,897,766	$2,455,233	$3,614,460	$4,352,553	$2,787,440	$3,926,481	$4,558,809	$3,249,725
94	Feb-08	$3,505,441	$4,241,059	$2,749,211	$3,943,659	$4,738,112	$3,093,172	$4,263,180	$4,938,010	$3,570,100
95	Mar-08	$3,622,546	$4,373,949	$2,847,347	$4,071,061	$4,890,373	$3,208,745	$4,396,950	$5,101,069	$3,670,923
96	Apr-08	$3,648,094	$4,403,806	$2,862,717	$4,102,538	$4,931,693	$3,237,690	$4,432,584	$5,149,688	$3,691,188
97	May-08	$3,636,329	$4,392,201	$2,846,472	$4,093,307	$4,923,972	$3,227,663	$4,425,618	$5,145,215	$3,681,056
98	Jun-08	$3,632,434	$4,389,547	$2,839,589	$4,091,018	$4,923,013	$3,225,573	$4,424,802	$5,147,201	$3,678,638
99	Jul-08	$3,608,624	$4,363,868	$2,812,136	$4,068,228	$4,899,021	$3,203,048	$4,403,110	$5,124,319	$3,657,535
100	Aug-08	$3,617,867	$4,373,186	$2,819,713	$4,078,379	$4,909,498	$3,212,497	$4,414,201	$5,137,490	$3,666,861
101	Sep-08	$3,658,128	$4,414,667	$2,858,194	$4,120,077	$4,952,573	$3,253,617	$4,456,989	$5,187,444	$3,705,847
102	Oct-08	$3,782,088	$4,541,262	$2,980,676	$4,247,646	$5,085,301	$3,379,937	$4,587,232	$5,337,417	$3,826,380
103	Nov-08	$4,037,370	$4,799,798	$3,232,491	$4,511,485	$5,361,702	$3,643,983	$4,858,467	$5,649,781	$4,084,759
104	Dec-08	$4,349,777	$5,109,201	$3,537,270	$4,837,185	$5,700,719	$3,966,672	$5,197,689	$6,039,009	$4,408,849
105	Jan-09	$4,754,279	$5,516,268	$3,941,238	$5,255,123	$6,128,609	$4,353,373	$5,630,250	$6,527,343	$4,820,599
106	Feb-09	$5,182,031	$5,966,388	$4,341,857	$5,694,208	$6,575,114	$4,766,887	$6,079,621	$7,037,290	$5,246,715
107	Mar-09	$5,707,354	$6,512,871	$4,818,322	$6,230,456	$7,119,694	$5,270,401	$6,625,362	$7,655,381	$5,765,364
108	Apr-09	$6,060,572	$6,878,389	$5,132,322	$6,589,694	$7,494,363	$5,606,744	$6,990,196	$8,065,496	$6,112,441
109	May-09	$6,250,534	$7,078,281	$5,304,416	$6,783,713	$7,693,308	$5,785,519	$7,186,278	$8,284,590	$6,292,718
110	Jun-09	$6,327,609	$7,159,324	$5,371,887	$6,862,606	$7,774,719	$5,859,521	$7,266,037	$8,372,550	$6,365,828
111	Jul-09	$6,403,323	$7,240,595	$5,440,992	$6,940,092	$7,855,594	$5,934,679	$7,344,315	$8,459,024	$6,439,603
112	Aug-09	$6,482,748	$7,328,852	$5,515,412	$7,021,249	$7,938,395	$6,012,658	$7,426,112	$8,549,356	$6,516,255
113	Sep-09	$6,567,334	$7,421,936	$5,594,555	$7,107,366	$8,024,112	$6,095,980	$7,513,017	$8,643,032	$6,596,993
114	Oct-09	$6,834,950	$7,711,863	$5,851,824	$7,380,679	$8,299,027	$6,366,478	$7,789,003	$8,939,665	$6,849,927
115	Nov-09	$7,128,957	$8,025,246	$6,133,072	$7,681,824	$8,597,344	$6,663,262	$8,094,522	$9,263,981	$7,132,940
116	Dec-09	$7,704,598	$8,640,012	$6,672,203	$8,270,808	$9,180,265	$7,240,766	$8,691,649	$9,909,944	$7,687,447
117	Jan-10	$8,177,237	$9,145,386	$7,115,961	$8,754,597	$9,664,444	$7,718,329	$9,182,430	$10,435,864	$8,154,997
118	Feb-10	$8,576,655	$9,576,231	$7,489,811	$9,163,220	$10,122,954	$8,117,272	$9,596,435	$10,885,605	$8,557,298
119	Mar-10	$8,872,488	$9,886,562	$7,771,809	$9,465,682	$10,458,717	$8,411,915	$9,901,749	$11,211,510	$8,855,547
120	Apr-10	$9,048,438	$10,073,673	$7,942,029	$9,645,079	$10,656,385	$8,585,724	$10,082,331	$11,405,426	$9,034,528
121	May-10	$9,188,874	$10,220,719	$8,079,474	$9,788,055	$10,813,655	$8,725,846	$10,226,353	$11,559,067	$9,178,941
122	Jun-10	$9,282,142	$10,317,831	$8,171,351	$9,882,910	$10,917,786	$8,818,976	$10,322,082	$11,659,759	$9,275,292
123	Jul-10	$9,329,431	$10,366,425	$8,217,961	$9,931,093	$10,971,192	$8,866,221	$10,370,741	$11,711,004	$9,324,231
124	Aug-10	$9,395,404	$10,435,321	$8,282,972	$9,998,080	$11,044,278	$8,932,210	$10,438,326	$11,782,086	$9,391,418
125	Sep-10	$9,510,779	$10,558,687	$8,396,673	$10,115,144	$11,172,669	$9,048,696	$10,556,099	$11,904,860	$9,510,781
126	Oct-10	$9,697,700	$10,757,052	$8,580,280	$10,304,701	$11,382,194	$9,236,852	$10,746,732	$12,104,463	$9,693,329
127	Nov-10	$10,013,514	$11,097,157	$8,891,316	$10,625,150	$11,737,329	$9,559,165	$11,069,236	$12,442,392	$9,996,814
128	Dec-10	$10,452,367	$11,571,408	$9,320,397	$11,070,892	$12,227,237	$9,960,485	$11,518,885	$12,901,958	$10,421,438
129	Jan-11	$10,920,218	$12,077,120	$9,775,059	$11,546,683	$12,754,823	$10,376,282	$11,999,462	$13,388,954	$10,875,052
130	Feb-11	$11,291,109	$12,475,655	$10,139,658	$11,923,501	$13,179,058	$10,708,498	$12,380,860	$13,775,222	$11,237,135
131	Mar-11	$11,631,944	$12,839,229	$10,473,717	$12,270,319	$13,568,483	$11,017,363	$12,732,182	$14,139,867	$11,565,109
132										
133	Percentage of Months where Cumulative Monthly Risk Margin > $0	77%	85%	50%	81%	86%	70%	85%	89%	76%
134	Worst Case Interim Cumulative Risk Margin Profit/(Loss)	($679,766)	($400,885)	($1,256,347)	($580,834)	($402,499)	($891,432)	($566,484)	($411,237)	($732,930)

Centra Gas Manitoba Inc
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PUB/Centra 122 (d)

Time Series of Total Cumulative Risk Margin Profit/Loss Distribution Across All 1, 3 and 5-Year Fixed Price Agreement Terms and Across All SGS and LGS Customer Rate Classes

	SRP	15%		
		Mean	Maximum	Minimum
1	May-00	$309	$605	($11)
2	Jun-00	($626)	($93)	($1,156)
3	Jul-00	($1,971)	($870)	($3,284)
4	Aug-00	($1,255)	$767	($3,016)
5	Sep-00	($2,134)	$1,440	($4,875)
6	Oct-00	($20,113)	($13,185)	($27,750)
7	Nov-00	($54,841)	($38,681)	($71,101)
8	Dec-00	($167,904)	($125,286)	($216,958)
9	Jan-01	($365,191)	($280,991)	($466,425)
10	Feb-01	($474,278)	($356,542)	($611,785)
11	Mar-01	($523,648)	($381,936)	($680,269)
12	Apr-01	($549,659)	($394,391)	($716,611)
13	May-01	($552,770)	($391,884)	($723,203)
14	Jun-01	($538,252)	($373,277)	($709,777)
15	Jul-01	($516,336)	($347,590)	($687,925)
16	Aug-01	($489,889)	($317,482)	($660,274)
17	Sep-01	($452,859)	($275,077)	($621,730)
18	Oct-01	($296,678)	($96,840)	($461,631)
19	Nov-01	($156,550)	$65,004	($337,358)
20	Dec-01	$34,553	$291,857	($176,099)
21	Jan-02	$242,582	$528,690	$700
22	Feb-02	$429,905	$727,971	$171,640
23	Mar-02	$594,236	$913,888	$313,153
24	Apr-02	$660,869	$998,856	$370,995
25	May-02	$701,124	$1,046,693	$407,106
26	Jun-02	$721,840	$1,070,427	$426,076
27	Jul-02	$743,997	$1,094,389	$447,480
28	Aug-02	$780,547	$1,133,676	$483,654
29	Sep-02	$817,242	$1,172,615	$519,690
30	Oct-02	$872,220	$1,233,803	$570,707
31	Nov-02	$907,750	$1,276,716	$598,868
32	Dec-02	$957,552	$1,334,349	$640,910
33	Jan-03	$988,476	$1,380,313	$663,770
34	Feb-03	$895,298	$1,302,930	$556,632
35	Mar-03	$571,084	$976,296	$198,975
36	Apr-03	$532,157	$940,103	$152,992
37	May-03	$521,846	$930,852	$140,485
38	Jun-03	$515,638	$925,392	$132,919
39	Jul-03	$510,888	$921,696	$126,651
40	Aug-03	$518,963	$930,948	$133,794
41	Sep-03	$529,038	$942,820	$142,404

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Time Series of Total Cumulative Risk Margin Profit/Loss Distribution Across All 1, 3 and 5-Year Fixed Price Agreement Terms and Across All SGS and LGS Customer Rate Classes

	SRP	15%		
		Mean	Maximum	Minimum
42	Oct-03	$567,230	$985,885	$178,591
43	Nov-03	$680,596	$1,115,274	$287,434
44	Dec-03	$752,869	$1,200,924	$351,357
45	Jan-04	$759,616	$1,218,935	$347,560
46	Feb-04	$771,458	$1,238,663	$351,607
47	Mar-04	$804,715	$1,277,324	$374,810
48	Apr-04	$817,836	$1,296,736	$379,745
49	May-04	$801,417	$1,283,560	$358,422
50	Jun-04	$781,477	$1,264,979	$337,085
51	Jul-04	$776,061	$1,260,767	$331,094
52	Aug-04	$776,512	$1,262,949	$330,840
53	Sep-04	$796,513	$1,285,242	$349,832
54	Oct-04	$851,079	$1,341,757	$399,720
55	Nov-04	$828,011	$1,320,460	$377,548
56	Dec-04	$835,319	$1,332,277	$392,220
57	Jan-05	$915,782	$1,412,285	$484,611
58	Feb-05	$1,009,472	$1,504,002	$589,508
59	Mar-05	$1,061,959	$1,557,885	$656,280
60	Apr-05	$1,053,471	$1,548,016	$655,771
61	May-05	$1,056,859	$1,551,281	$664,093
62	Jun-05	$1,069,716	$1,563,418	$680,228
63	Jul-05	$1,076,182	$1,570,770	$688,569
64	Aug-05	$1,074,875	$1,569,419	$689,088
65	Sep-05	$1,031,054	$1,525,271	$645,783
66	Oct-05	$834,773	$1,331,140	$447,624
67	Nov-05	$532,009	$1,029,353	$153,146
68	Dec-05	$274,124	$768,672	($87,898)
69	Jan-06	$26,845	$520,178	($345,294)
70	Feb-06	$131,814	$605,636	($260,372)
71	Mar-06	$249,888	$701,409	($184,719)
72	Apr-06	$354,891	$790,589	($104,098)
73	May-06	$437,902	$861,657	($33,594)
74	Jun-06	$538,616	$947,022	$54,461
75	Jul-06	$598,857	$996,046	$109,138
76	Aug-06	$636,654	$1,030,558	$144,082
77	Sep-06	$737,126	$1,121,190	$237,677
78	Oct-06	$1,026,515	$1,426,654	$513,534
79	Nov-06	$1,274,977	$1,706,266	$749,059
80	Dec-06	$1,515,994	$1,973,658	$978,630
81	Jan-07	$1,877,493	$2,360,529	$1,299,982
82	Feb-07	$2,195,765	$2,709,308	$1,580,728
83	Mar-07	$2,390,842	$2,935,892	$1,749,505
84	Apr-07	$2,522,630	$3,089,504	$1,862,818
85	May-07	$2,575,582	$3,149,091	$1,910,526
86	Jun-07	$2,614,954	$3,192,863	$1,946,549

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Time Series of Total Cumulative Risk Margin Profit/Loss Distribution Across All 1, 3 and 5-Year Fixed Price Agreement Terms and Across All SGS and LGS Customer Rate Classes

	SRP	15%		
		Mean	Maximum	Minimum
87	Jul-07	$2,663,321	$3,245,742	$1,989,665
88	Aug-07	$2,722,441	$3,308,648	$2,044,261
89	Sep-07	$2,839,147	$3,432,295	$2,150,954
90	Oct-07	$3,052,974	$3,655,932	$2,349,678
91	Nov-07	$3,400,469	$4,027,279	$2,668,372
92	Dec-07	$3,839,983	$4,531,636	$3,074,675
93	Jan-08	$4,309,312	$5,064,139	$3,504,826
94	Feb-08	$4,659,426	$5,458,515	$3,822,365
95	Mar-08	$4,803,653	$5,623,780	$3,948,890
96	Apr-08	$4,845,272	$5,675,051	$3,983,469
97	May-08	$4,840,853	$5,673,103	$3,976,586
98	Jun-08	$4,841,718	$5,675,990	$3,975,938
99	Jul-08	$4,821,166	$5,655,185	$3,955,168
100	Aug-08	$4,833,412	$5,668,257	$3,967,728
101	Sep-08	$4,877,742	$5,713,906	$4,012,171
102	Oct-08	$5,011,190	$5,850,217	$4,146,048
103	Nov-08	$5,290,636	$6,130,514	$4,430,775
104	Dec-08	$5,644,314	$6,484,353	$4,737,364
105	Jan-09	$6,089,985	$6,922,700	$5,127,521
106	Feb-09	$6,548,845	$7,373,955	$5,535,180
107	Mar-09	$7,102,646	$7,906,910	$6,021,883
108	Apr-09	$7,471,213	$8,306,524	$6,346,607
109	May-09	$7,669,417	$8,520,922	$6,525,519
110	Jun-09	$7,750,028	$8,606,210	$6,600,312
111	Jul-09	$7,829,137	$8,688,641	$6,674,977
112	Aug-09	$7,911,816	$8,773,790	$6,755,130
113	Sep-09	$7,999,678	$8,866,345	$6,840,651
114	Oct-09	$8,279,843	$9,159,913	$7,118,409
115	Nov-09	$8,591,399	$9,492,947	$7,424,047
116	Dec-09	$9,202,612	$10,153,022	$8,027,708
117	Jan-10	$9,706,994	$10,688,817	$8,518,237
118	Feb-10	$10,133,618	$11,142,001	$8,934,625
119	Mar-10	$10,448,307	$11,473,910	$9,244,662
120	Apr-10	$10,633,454	$11,674,106	$9,427,309
121	May-10	$10,780,929	$11,832,075	$9,573,985
122	Jun-10	$10,879,061	$11,937,292	$9,672,575
123	Jul-10	$10,929,037	$11,991,370	$9,723,020
124	Aug-10	$10,998,227	$12,066,347	$9,791,854
125	Sep-10	$11,119,112	$12,195,851	$9,913,586
126	Oct-10	$11,314,934	$12,405,261	$10,107,972
127	Nov-10	$11,645,607	$12,759,276	$10,433,888
128	Dec-10	$12,107,493	$13,254,178	$10,849,857
129	Jan-11	$12,600,988	$13,778,590	$11,289,049
130	Feb-11	$12,992,559	$14,201,332	$11,638,808
131	Mar-11	$13,352,563	$14,580,601	$11,948,558
132				
133	Percentage of Months where Cumulative Monthly Risk Margin > $0	86%	89%	80%
134	Worst Case Interim Cumulative Risk Margin Profit/(Loss)	($552,770)	($394,391)	($723,203)

PUB/CENTRA I-122

Subject: **Tab 13 FRPGS**

Reference: **Tab 13 Pages 8 and 9 of 11 – SRP**

e) Please confirm whether Centra modeled potential SRPs using hypothetical future gas price increases, and if so, please provide the results.

ANSWER:

Because of the extraordinarily challenging market circumstances inherent in the historical period from August 1, 2000 through March 31, 2011 used to test the robustness of the SRP approach, Centra did not model hypothetically derived future gas price increases. The historical period chosen to model and test potential SRP's represented the most volatile period for natural gas prices that have been experienced in the history of the natural gas market. During this period market prices ranged from a low of approximately $1/GJ to a high of$17/GJ. Over that period, actual monthly index prices would have varied greatly relative to the forecast prices embedded in FRPGS offerings.

PUB/CENTRA I-123

Subject: **Tab 13 FRPGS**

Reference: **Tab 13 Page 10 of 11 - Thresholds**

a) **Please explain how Centra determined the four target thresholds and how the four thresholds impacted modeled operating results based on the Self-insurance Risk Premiums modeled.**

ANSWER:

Explanations as to the derivation of the four target thresholds are provided below. These thresholds are intended to supplement the protection provided by the Self-Insurance Risk Premium and were not applied in the modeling of those premiums.

Program Review When Net Migration to the FRPGS Reaches 0.5% of Overall Annual Sales Volume in any Individual Gas Quarter

Quarterly net migration to fixed-rate Primary Gas products (marketers and Centra combined) as a percentage of Centra's overall annual sales volume averaged approximately 0.5% over the period from the inception of fixed-rate products in Manitoba on May 1, 2000, through March 31, 2011 inclusive. Centra chose this quarterly program review threshold as it limits FRPGS program risk under Self-Insurance by triggering a review of program risk exposure in cases where much higher than normal demand for the FRPGS in a single gas quarter could result in a high percentage of Centra's fixed-rate customers under contract being clustered in a single set of offerings that ultimately may generate losses for the program.

Program Review When Cumulative Total FRPGS Customers Under Contract Reaches 2.5% of Overall Annual Sales Volume, Combined with a 5% Cap on Total Customer Participation at any One Time

The 2.5% review threshold was chosen as it will trigger a review of program risk exposure, and provide the opportunity to take remedial action(s) if necessary, when cumulative total customers under FRPGS contract reach a level that is half of Centra's intended program customer participation cap of 5% of overall annual sales volumes. A cap on total active customers under FRPGS contract of 5% of overall annual sales volumes serves to limit Centra's overall financial risk associated with the FRPGS to manageable levels.

Program Review When Cumulative Settled Risk Margin Losses Under Self-Insurance Exceed $1 Million

Given the potentially increased financial risk associated with foregoing the use of derivative instruments in favour of Self-Insurance, this review threshold is intended to provide a backward-looking measure to supplement the SRP and provide the opportunity to take remedial action(s) if necessary in order to limit continued growth in program financial losses.

Program Review When Unsettled Forward Mark-to-Market Risk Margin Losses Under Self-Insurance Exceed $1 Million

As is the case with the previously described threshold, there is a potentially increased financial risk associated with foregoing the use of derivative instruments in favour of Self-Insurance. This review threshold is intended to provide a forward-looking measure to supplement the SRP and provide the opportunity to take remedial action(s) if necessary in order to limit the continued growth in the program's potential financial losses.

<u>PUB/CENTRA I-123</u>

Subject: **Tab 13 FRPGS**

Reference: **Tab 13 Page 10 of 11 - Thresholds**

b) **Please confirm whether the percentage of annual sales volume refers to the Primary Gas sales by Centra or some other sales volume.**

<u>ANSWER</u>:

All references to annual sales volumes are intended to mean total weather-normalized forecast annual gas volumes provided to customers either by Centra under system supply arrangements or by marketers under the Western Transportation Service. These do not include volumes delivered to Transportation Service customers by Centra that are transported solely on Centra's distribution system.

PUB/CENTRA I-123

Subject: **Tab 13 FRPGS**

Reference: **Tab 13 Page 10 of 11 - Thresholds**

c) Please provide corresponding customer numbers (assuming the current customer mix and average use) that would trigger the customer migration threshold of 0.5% of overall annual sales volumes per quarter or 2.5% of Centra's annual sales volume.

ANSWER:

The following table outlines the number of customers that would trigger the customer migration threshold of 0.5% of overall annual sales volumes per quarter and 2.5% of Centra's annual sales volume, based on the current customer mix and average annual usage.

Current Customer Mix *(active contracts as of March 4, 2013)*			
	SGS Res	**SGS Com**	**LGS**
Current Customer Mix	343	10	44
Percentage of Customer Mix	86%	3%	11%

Migration Threshold Number of Customers			
	SGS Res	**SGS Com**	**LGS**
Net Quarterly FRPGS Migration Limit - 0.5% of Overall SGS & LGS Annual Sales Volumes	2,578	31	13
FRPGS Program Review Threshold - 2.5% of Overall SGS & LGS Annual Sales Volumes	12,890	157	63

PUB/CENTRA I-123

Subject: **Tab 13 FRPGS**

Reference: **Tab 13 Page 10 of 11 - Thresholds**

d) Please provide the current sales volume thresholds of 0.5%, 2.5%, and 5% in cubic metres as well as the 2012/13 FRPGS volumes as a percentage of total sales volumes.

ANSWER:

Please see the attachment to this response detailing FRPGS program thresholds and the associated customer uptake percentages.

		Volume (m^3) - as per 2012/13 Fiscal Year Forecast	
1		Volume (m^3) - as per 2012/13 Fiscal Year Forecast	
2	Total Annual Forecast Sales Volume	1,420,000,000	
3	Net Quarterly FRPGS Migration Limit - 0.5% of Total Annual Forecast Sales Volume	7,080,000	
4	FRPGS Program Review Threshold - 2.5% of Total Annual Forecast Sales Volume	35,420,000	
5	FRPGS Program Limit Threshold - 5.0% of Total Annual Forecast Sales Volume	70,830,000	
6			
7	Quarterly FRPGS Enrolment Uptake (Total of 1, 3 & 5-Year Contract Terms)	Forecast Volume (m^3) - as at Close of Enrolment	Actual Customer Uptake as a % of Total Annual Forecast Sales Volume
8	May 1, 2012	1,184,370	0.0834%
9	August 1, 2012	36,132	0.0025%
10	November 1, 2012	15,749	0.0011%
11	February 1, 2013	9,615	0.0007%
12			
13		Forecast Volume (m^3) - Active Contracts as at March 18, 2013	Active Customers Under Contract as a % of Total Annual Forecast Sales Volume
14	Total Annualized Forecast of FRPGS Subscribed Volumes (FRPGS Enrolment Periods 1 through 15, Active Contracts as at March 18, 2013)	4,980,219	0.3507%

PUB/CENTRA I-123

Subject: **Tab 13 FRPGS**

Reference: **Tab 13 Page 10 of 11 - Thresholds**

e) Please describe the courses of action Centra intends to pursue in the event that the enrolment thresholds (0.5% per quarter, 2.5% total sales, $1 million risk margin losses) are reached.

ANSWER:

In the event that one or more of the thresholds stated in Tab 13, section 13.2.5 are reached, Centra will notify the PUB of the situation and will review the FRPGS program. After such a review, the risk analysis and recommendation resulting from that analysis will be presented to the Corporation's Executive Committee. Centra will advise the PUB of the results of the review, and if necessary, will make an application to the PUB.

PUB/CENTRA I-123

Subject: **Tab 13 FRPGS**

Reference: **Tab 13 Page 10 of 11 - Thresholds**

f) Please confirm whether Centra intends to cap the number of FRPGS enrolments, and thus refuse additional applications, in the event the 0.5% of overall sales volumes per quarter limit is reached.

ANSWER:

Centra intends to review the FRPGS program when any of the thresholds stated in Tab 13, section 13.2.5 are reached. Centra may cap the number of FRPGS enrolments and close the offering to additional applications, if it is determined that, because one or more of the thresholds have been reached, risk exposure is significant and the Rate Setting Methodology needs to be adjusted.

PUB/CENTRA I-123

Subject: **Tab 13 FRPGS**

Reference: **Tab 13 Page 10 of 11 - Thresholds**

g) Please confirm whether Centra intends to cap the number of FRPGS enrolments, and thus refuse additional applications, in the event the 5% of overall sales volumes limit is reached.

ANSWER:

Please see Centra's response to PUB/Centra I-123(f).

PUB/CENTRA I-123

Subject: **Tab 13 FRPGS**

Reference: **Tab 13 Page 10 of 11 - Thresholds**

h) Please explain how a "review" of the FRPGS program when cumulative settled risk margin losses or unsettled mark-to-market losses reach $1 million will restrict future losses, since FRPGS contracts will already be in place which may extend and increase the total losses in the future.

ANSWER:

Centra acknowledges that existing contracts may continue to incur losses. However, it is Centra's intention to consider the appropriateness of further risk exposure by adding incremental contracts.

PUB/CENTRA I-124

Subject: **Tab 13 FRPGS**

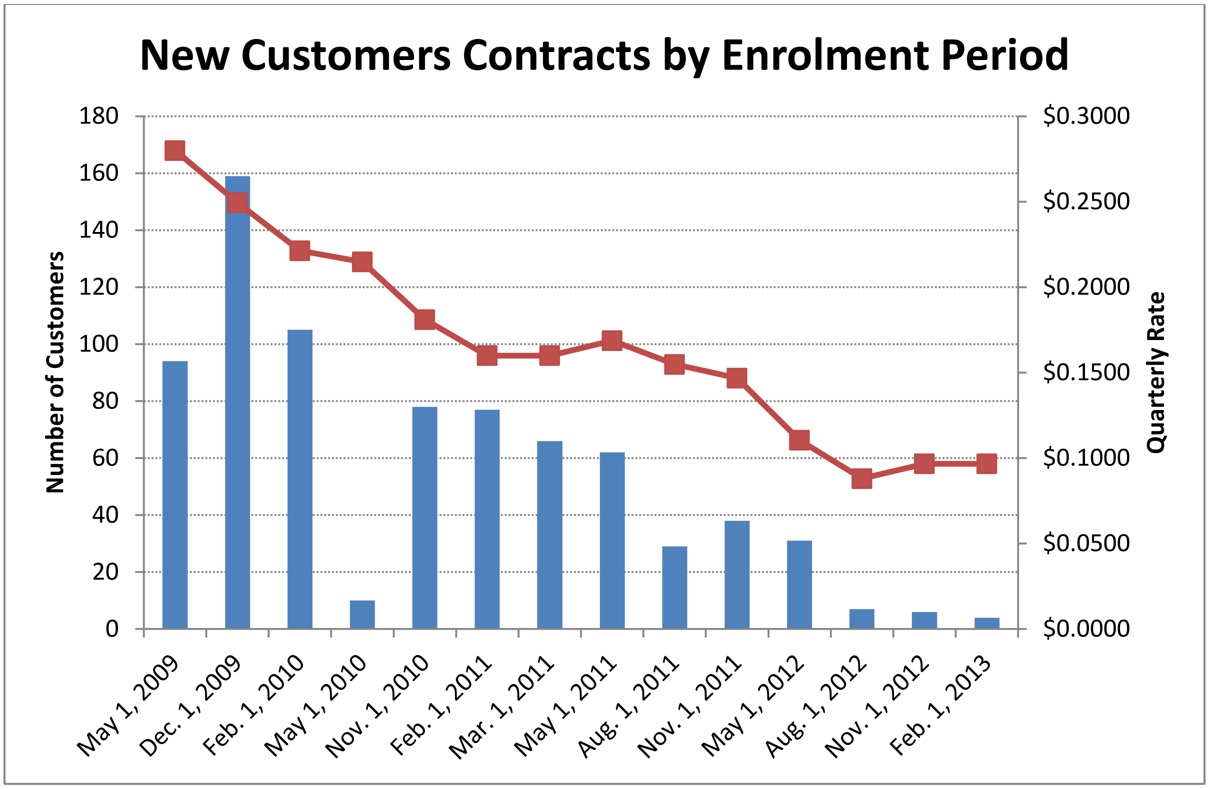
Reference: **Tab 13 Pages 8 to 11 of 11**

Please provide Centra's views on customer participation in the FRPGS compared to the currently forecasted participation in a rising gas price environment (i.e. gas prices rise more than currently forecasted).

ANSWER:

Centra has been offering fixed rate primary gas products since 2009. Program history has shown that customers are more likely to sign up for a Fixed Rate when primary gas prices are higher. The following chart shows the number of new customers enrolled during each of Centra's fixed rate offer periods compared to the corresponding Quarterly Rate at the time of the offering. As illustrated, in recent quarters when natural gas prices have been low, few customers signed up for Fixed Rate contracts.

It is anticipated that consumer demand for Fixed Rate products may increase slightly if natural gas prices rise. However, a significant increase in demand, regardless of natural gas price fluctuations, is not expected.


New Customers Contracts by Enrolment Period
Number of Customers
Quarterly Rate
180
160
140
120
100
80
60
40
20
0
$0.3000
$0.2500
$0.2000
$0.1500
$0.1000
$0.0500
$0.0000
May 1, 2009
Dec. 1, 2009
Feb. 1, 2010
May 1, 2010
Nov. 1, 2010
Feb. 1, 2011
Mar. 1, 2011
May 1, 2011
Aug. 1, 2011
Nov. 1, 2011
May 1, 2012
Aug. 1, 2012
Nov. 1, 2012
Feb. 1, 2013

PUB/CENTRA I-125

Subject: **Tab 13 FRPGS**

Reference: **Tab 13 Appendix 13.2 Page 4 of 9 - FRPGS**

Please update the schedule of FRPGS program operating costs on page 4 for 2012/13 with budgeted and actual numbers.

ANSWER:

The following table includes the FRPGS program operating budget for Fiscal Year 2012/13. Actual results for 2012/13 are not yet available.

Results reported in 000's	FY 2012/13 Budget	FY 2011/12 Actual	FY 2010/11 Actual	FY 2009/10 Actual
Labour				
Marketing	$30	$37	$42	$65
Gas Supply	$9	$17	$51	$47
Business Communications	$0	$0.5	$2	$14
Load Forecast	$0	$0.5	$12	$18
Call Centre	$3	$2	$4	$4
Billing	$0	$0	$1	$5
Accounting	$0	$0.5	$3	$7
Rate Department	$0	$6	$17	$6
Legal	$0	$0.5	$1	$1
Other	$0	$0	$0	$0
Overhead	$11	$11	$22	$43
Marketing				
Advertising	$50	$28	$64	$144
Materials & Administration	$1	$1	$0	$0
Promotional Items	$4	$0	$0	$0
Other				
Computer Software	$0	$5	$0	$0
Total Costs	**$107**	**$109**	**$219**	**$354**

PUB/CENTRA I-126

Subject: **Tab 13 FRPGS**

Reference: **Tab 13 Appendix 13.2 Page 7 of 9 - PCR**

a) **Please provide the program administrative and start-up costs that were recovered through the Program Cost Rate and the percentage recovery of the total allocated program costs and start-up costs for the years 2008/09 through to 2012/13.**

ANSWER:

For rate setting purposes, an initial estimate of the FRPGS Program administration cost was established at the outset of the Program in 2009. That initial cost estimate, including the amortization of program start up costs, was used to establish the level of the Program Cost Rate that was embedded in the calculation of rates for each FRPGS offering. Revenues were collected from participating FRPGS customers based upon that Program Cost Rate The PCR will be updated as part of each GRA to reflect current cost estimates. The current PCR of \$26.2 per 10^3 m^3 was approved in Order 128/09 and is proposed as part of this Application to change to \$31.4 per 10^3 m^3 (Schedule 11.1.2 line 49).

Actual operating costs have generally been less than that originally estimated at the outset of the Program. Centra has incurred those actual operating costs in each fiscal year, and has obtained actual revenues from FRPGS customers based upon the volumes of gas sold.

As customer subscription rates and actual volumes sold have been less than forecast, there have been insufficient revenues to offset all of the expenses incurred in each year. As with all of Centra's costs of operation that are recovered through the volumetric rates, their recovery is subject to volatility due to variances in actual consumption compared to forecast consumption. Shortfalls that occur as a result of lower than forecasted volumes are reflected in Centra's annual net income.

The table below identifies the actual operating costs of the Fixed Rate Primary Gas Program compared to the actual costs recovered through the Program Cost Rate with the residual flowing to Net Income:

	2008/09	2009/10	2010/11	2011/12	Total
Program Operating Expense	$ 66,000	$ 354,000	$ 219,000	$ 109,000	$ 748,000
Amortization of Start Up Costs	$ -	$ 100,000	$ 100,000	$ 100,000	$ 300,000
Total Program Administrative & Start Up Costs	$ 66,000	$ 454,000	$ 319,000	$ 209,000	$ 1,048,000
Program Costs Recovered through the PCR	$ - [1]	$ 42,000	$ 76,000	$ 110,000	$ 375,000
Residual	$ 66,000	$ 412,000	$ 243,000	$ 99,000	$ 816,000
% of Program Costs recovered through the PCR		9%	24%	53%	31%

1 FRPGS contracts commenced on May 1, 2009

PUB/CENTRA I-126

Subject: **Tab 13 FRPGS**

Reference: **Tab 13 Appendix 13.2 Page 7 of 9 - PCR**

b) **Please determine the FRPGS Program Cost Rate necessary to recover the current balance of unrecovered program costs since program inception in addition to the currently forecasted program costs.**

ANSWER:

The only unrecovered program costs pertain to the unamortized Start Up Costs. The annual amortized amount of these costs ($100,000) is reflected in the proposed Program Cost Rate ($31.4 per 10^3m^3).

PUB/CENTRA I-127

Subject: **Tab 13 FRPGS**

Reference: **Tab 13 Appendix 13.4 - FRPGS Mark to Market Results**

Please provide an update to the mark to market results as at March 31, 2013.

ANSWER:

Please see the table below.

Centra Gas Manitoba Inc. **PUB/Centra I-127**
2013/14 Cost of Gas Application **April 1, 2013**
FRPGS Settled and Mark-to-Market Projections (Hedging Instruments Only)

SETTLED RESULTS to March 31, 2013		**Total**
May 1, 2009 (1 year offering)	$	(18 792)
May 1, 2009 (3 year offering)	$	(104 879)
May 1, 2009 (5 year offering)	$	(200 425)
December 1, 2009 (1 year offering)	$	(42 958)
December 1, 2009 (3 year offering)	$	(14 687)
December 1, 2009 (5 year offering)	$	(61 231)
February 1, 2010 (1 year offering)	$	(155 883)
February 1, 2010 (3 year offering)	$	(83 411)
February 1, 2010 (5 year offering)	$	(129 222)
May 1, 2010 (1 year offering)	$	(9 339)
May 1, 2010 (3 year offering)	$	(32 047)
May 1, 2010 (5 year offering)	$	(116 911)
November 1, 2010 (1 year offering)	$	(2 647)
November 1, 2010 (3 year offering)	$	(16 115)
November 1, 2010 (5 year offering)	$	(66 186)
February 1, 2011 (1 year offering)	$	(1 782)
February 1, 2011 (3 year offering)	$	(138 363)
February 1, 2011 (5 year offering)	$	(71 716)
March 1, 2011 (1 year offering)	$	(1 729)
March 1, 2011 (3 year offering)	$	(52 460)
March 1, 2011 (5 year offering)	$	(77 835)
May 1, 2011 (1 year offering)	$	(2 223)
May 1, 2011 (3 year offering)	$	(69 733)
May 1, 2011 (5 year offering)	$	(10 787)
August 1, 2011 (3 year offering)	$	(24 304)
August 1, 2011 (5 year offering)	$	(7 280)
Total Settled Results	$	(1 512 945)
MARK-TO-MARKET PROJECTION (March 31, 2013 forward)		
May 1, 2009 (5 year offering)		(39 282)
December 1, 2009 (5 year offering)		(15 789)
February 1, 2010 (5 year offering)		(46 410)
May 1, 2010 (3 year offering)		(575)
May 1, 2010 (5 year offering)		(52 634)
November 1, 2010 (3 year offering)		(1 011)
November 1, 2010 (5 year offering)		(29 342)
February 1, 2011 (3 year offering)		(20 595)
February 1, 2011 (5 year offering)		(37 618)
March 1, 2011 (3 year offering)		(10 286)
March 1, 2011 (5 year offering)		(48 471)
May 1, 2011 (3 year offering)		(17 068)
May 1, 2011 (5 year offering)		(6 691)
August 1, 2011 (3 year offering)		(6 061)
August 1, 2011 (5 year offering)		(4 256)
Total Mark-to-Market Projection	$	(336 089)
Total Impact on Retained Earnings Since Inception:	**$**	**(1 849 034)**

PUB/CENTRA I-128

Subject: Tab 13 FRPGS

Reference: Tab 13 Appendix 13.5

a) Please elaborate on the methodology for generating the Risk Margin Distribution.

ANSWER:

For each gas quarter throughout the May 1, 2000 through March 31, 2011 period, Centra's market simulation model first calculates the FRPGS rates that would have been offered to customers based on actual futures market prices as at each quarter, forecast weather-normalized Primary Gas consumption for each small volume customer class that would have been assumed at each historical point in time, and the particular SRP being studied.

For each individual model trial the number of customers in each of the SGS Residential, SGS Commercial and Large General Service customer classes assumed to have signed FRPGS contracts for each of the available contract terms in each gas quarter throughout the eleven-year period are allowed to float randomly and independently between zero and an upper bound parameter for each product term and each gas quarter. The upper bound customer subscription parameters were set to be equivalent to the average customer participation figures contained in the first eleven years of Centra's twenty-year base case FRPGS customer demand forecast.

As each model trial is executed, detailed settled monthly financial results are calculated for each customer class and product offering throughout the entire eleven-year period based on actual system average consumption per customer for each small volume customer class under the actual weather conditions, the FRPGS billed rates that would have been offered each quarter under the particular SRP being studied, and the actual underlying weighted average cost of Primary Gas that would have been incurred monthly in support of each FRPGS offering.

As each model trial is executed, a detailed time series of monthly financial results generated by that trial, along with other descriptive statistics, are captured, recorded and exported to an output file before running each of the successive independent trials constituting the full simulation.

Once all trials are completed for a particular simulation, summary statistics such as mean, maximum and minimum time series of monthly financial results across all trials executed for each simulation are generated by the model for analysis.

PUB/CENTRA I-128

Subject: **Tab 13 FRPGS**

Reference: **Tab 13 Appendix 13.5**

b) Please identify the parameters that change to generate the different cases (mean, best, worst).

ANSWER:

Please see Centra's response to PUB/Centra I-128(a).

PUB/CENTRA I-128

Subject: **Tab 13 FRPGS**

Reference: **Tab 13 Appendix 13.5**

c) Please provide the volumes or percentage of Centra's volumes that were assumed in this analysis.

ANSWER:

FRPGS Base Case Small Volume Customer Demand Forecast as a % of Total Forecast Sales Volume	
Forecast Year	**% of Total Annual Sales Volume**
1	0.2%
2	0.9%
3	1.7%
4	1.7%
5	1.7%
6	1.7%
7	1.6%
8	1.6%
9	1.6%
10	1.6%
11	1.6%

PUB/CENTRA I-128

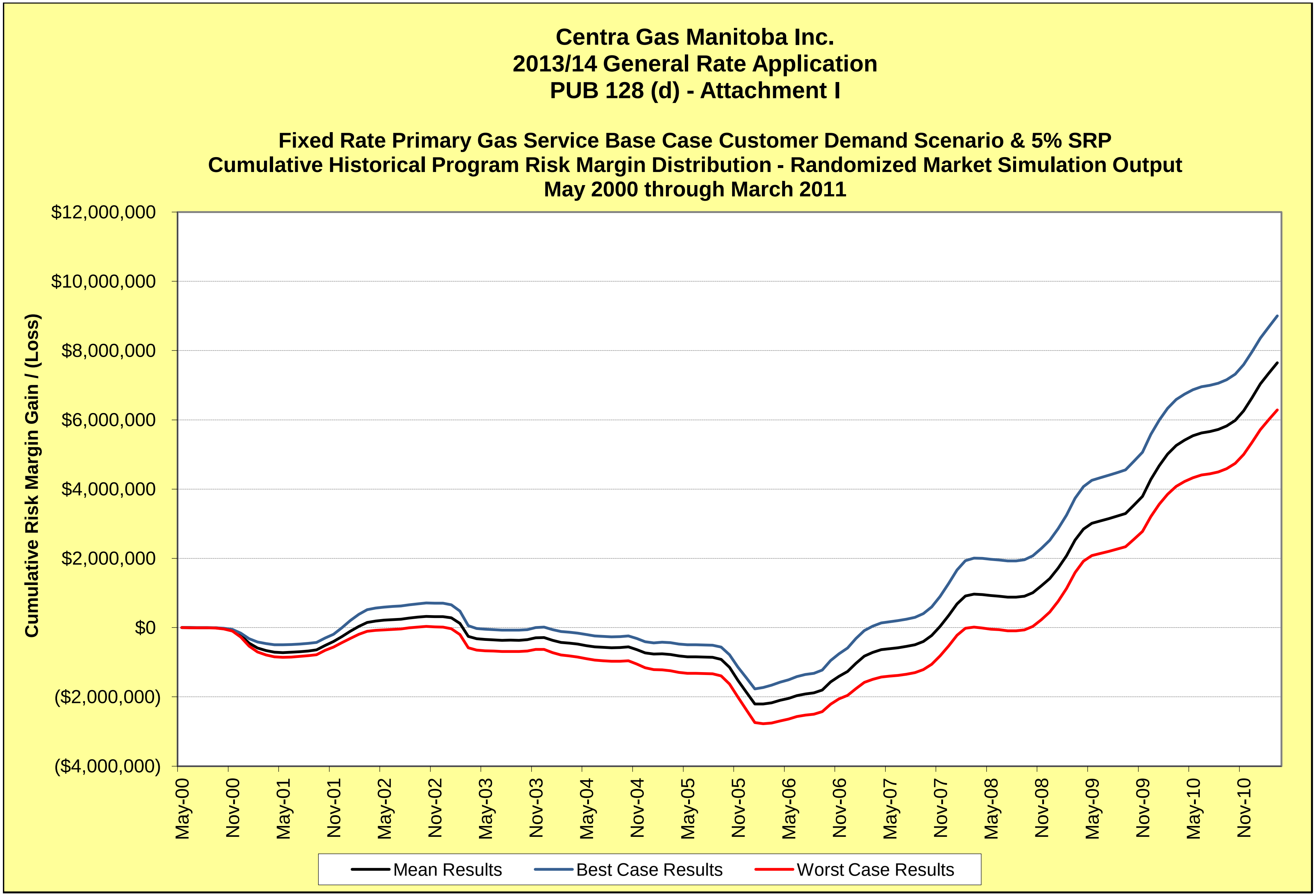
Subject: **Tab 13 FRPGS**

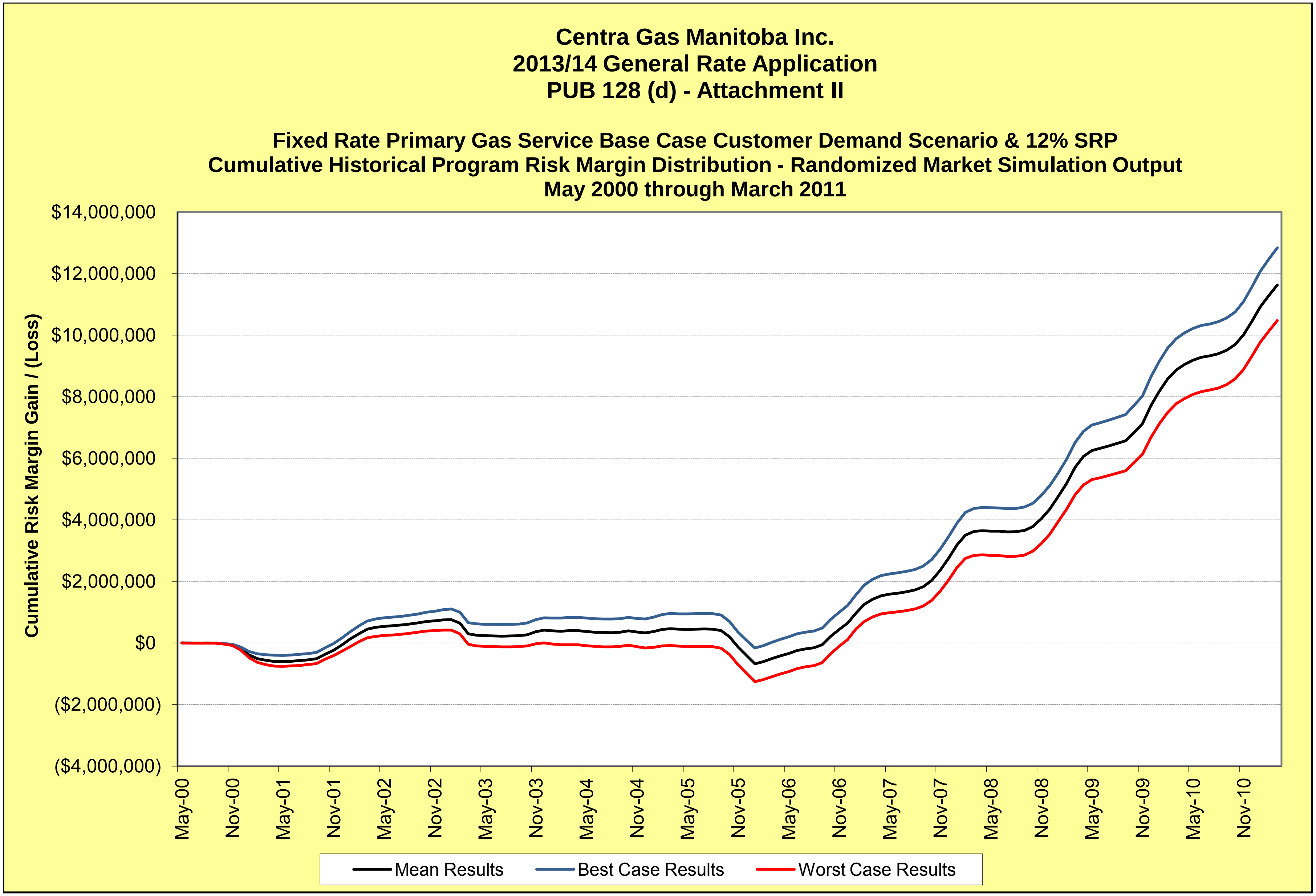
Reference: **Tab 13 Appendix 13.5**

d) Please prepare Risk Margin Distributions with SRPs of 5% and with 12%.

ANSWER:

Please see attachments I and II regarding the Cumulative Historical Risk Margin Distributions utilizing SRPs of 5% and 12% respectively.


Centra Gas Manitoba Inc.
2013/14 General Rate Application
PUB 128 (d) - Attachment I
Fixed Rate Primary Gas Service Base Case Customer Demand Scenario & 5% SRP
Cumulative Historical Program Risk Margin Distribution - Randomized Market Simulation Output
May 2000 through March 2011
Cumulative Risk Margin Gain / (Loss)
$12,000,000
$10,000,000
$8,000,000
$6,000,000
$4,000,000
$2,000,000
$0
($2,000,000)
($4,000,000)
May-00
Nov-00
May-01
Nov-01
May-02
Nov-02
May-03
Nov-03
May-04
Nov-04
May-05
Nov-05
May-06
Nov-06
May-07
Nov-07
May-08
Nov-08
May-09
Nov-09
May-10
Nov-10
Mean Results
Best Case Results
Worst Case Results


Centra Gas Manitoba Inc.
2013/14 General Rate Application
PUB 128 (d) - Attachment II
Fixed Rate Primary Gas Service Base Case Customer Demand Scenario & 12% SRP
Cumulative Historical Program Risk Margin Distribution - Randomized Market Simulation Output
May 2000 through March 2011
Cumulative Risk Margin Gain / (Loss)
$14,000,000
$12,000,000
$10,000,000
$8,000,000
$6,000,000
$4,000,000
$2,000,000
$0
($2,000,000)
($4,000,000)
May-00
Nov-00
May-01
Nov-01
May-02
Nov-02
May-03
Nov-03
May-04
Nov-04
May-05
Nov-05
May-06
Nov-06
May-07
Nov-07
May-08
Nov-08
May-09
Nov-09
May-10
Nov-10
Mean Results
Best Case Results
Worst Case Results

PUB/CENTRA I-129

Subject: **Tab 14 Terms and Conditions**

Reference: **Tab 14 Page 2 of 7; Appendix 14.3 - New Activity Rates**

a) For the past five years, please provide a table listing, on an annual basis:

- **a. The total number of below grade damages for each of the four categories shown on page 2 of 7 of Tab 14;**
- **b. The average and median cost of repair per incident in each of the four categories;**
- **c. The average and median cost of gas lost in each of the four categories;**
- **d. The average and median cost of incident investigation and customer appliance relights in each of the four categories; and**
- **e. The nominal activity rates used by Centra in each of the past five years to calculate the cost of incident investigation and customer appliance relights.**

ANSWER:

a. The total number of below grade damages for the last five years for each of the four categories shown on page 2 of 7 of Tab 14 is:

Fiscal Year*	2008	2009	2010	2011	2012
Total Below Grade Damages*	87	78	106	110	78
Gas Attributes*	2008	2009	2010	2011	2012
Number of locates	38103	39034	40461	41271	41556
Number of Customers (Based on calendar year)	259202	265814	265814	264301	267909
Number of km of main	8962	9072	9151	9181	9290
Number of km main and services	19727	20390	20498	20913	21175
Below Grade Damage Averages by Category*	2008	2009	2010	2011	2012
Below Grade Damages per 1000 locates	2.28	2.00	2.62	2.67	1.88
Below Grade Damages per 1000 customers	0.34	0.29	0.40	0.42	0.29
Below Grade Damages per 1000 km of main	9.71	8.60	11.58	11.98	8.40
Below Grade Damages per 1000 km of main and services	4.41	3.83	5.17	5.26	3.68
*To end of Q3 (Dec 31/2012) in 2012 fiscal year					

b. The average and median cost of repair per incident in each of the four categories is:

Above & Below Grade Billable Incidents**	2008	2009	2010	2011	*2012
Total Number of Billable Incidents	77	79	98	106	82
Total Cost of Billable Incidents	$ 159,821	$ 233,952	$317,691	$372,993	$139,757
Average Cost per Billable Incident	$ 2,076	$ 2,961	$ 3,242	$ 3,519	$ 1,704
Median Cost per Billable Incident	$ 986	$ 864	$ 1,188	$ 1,342	$ 1,172
Average Cost by Category (Billable Incidents)					
Average Cost per 1000 locates	$ 4,194	$ 5,994	$ 7,852	$ 9,038	$ 3,363
Average Cost per 1000 customers	$ 617	$ 880	$ 1,195	$ 1,411	$ 522
Average Cost per 1000 km of main	$ 17,833	$ 25,788	$ 34,717	$ 40,627	$ 15,044
Average Cost per 1000 km of main and services	$ 8,102	$ 11,474	$ 15,499	$ 17,835	$ 6,600
Median Cost by Category (Billable Incidents)					
Median Cost per 1000 locates	N/A	N/A	N/A	N/A	N/A
Median Cost per 1000 customers	N/A	N/A	N/A	N/A	N/A
Median Cost per 1000 km of main	N/A	N/A	N/A	N/A	N/A
Median Cost per 1000 km of main and services	N/A	N/A	N/A	N/A	N/A
*To end of Q3 (Dec 31/2012) in 2012 fiscal year					
**Damages are included in the year they were billed - above & below grade damages are not separately tracked					

c. The average and median cost of gas lost in each of the four categories is:

Above & Below Grade Billable Damages with Gas Lost**	2008	2009	2010	2011	*2012
(Gas Lost Per Incident not separately tracked prior to 2011)					
Total Billable Incidents with Gas Lost				23	26
Total Cost of Gas Lost				$ 44,339	$ 17,707
Average Cost of Gas Lost per Billable Incident				$ 1,928	$ 681
Median Cost of Gas Lost per Billable Incident				$ 799	$ 167
Average Cost of Gas Lost by Category (Billable Incidents)					
Average Cost of Gas Lost per 1000 locates				$ 1,074	$ 426
Average Cost of Gas Lost per 1000 customers				$ 168	$ 66
Average Cost of Gas Lost per 1000 km of main				$ 4,829	$ 1,906
Average Cost of Gas Lost per 1000 km of main and services				$ 2,120	$ 836
Median Cost of Gas Lost by Category (Billable Incidents)					
Median Cost of Gas Lost per 1000 locates				N/A	N/A
Median Cost of Gas Lost per 1000 customers				N/A	N/A
Median Cost of Gas Lost per 1000 km of main				N/A	N/A
Median Cost of Gas Lost per 1000 km of main and services				N/A	N/A

*To end of Q3 (Dec 31/2012) fiscal year
**Damages are included in the year they were billed - above & below grade damages are not separately tracked

d. & e. Since Centra was not seeking recovery of incident investigation costs or appliance relight costs, these costs were not tracked or billed. These costs were not itemized by incident and were included in Centra's operating costs.

PUB/CENTRA I-129

Subject: **Tab 14 Terms and Conditions**

Reference: **Tab 14 Page 2 of 7; Appendix 14.3 - New Activity Rates**

b) Provide a description of the significant cost factors involved in incident investigation and appliance relights.

ANSWER:

The severity, nature and location of the event will influence the costs associated with incident investigation. Significant cost factors involved in incident investigation include: the cost to reallocate resources to incident investigation (i.e. to conduct interviews with all involved parties and witnesses; examine equipment and facilities; photograph and take measurements; coordinate with internal and external departments); and the time required to complete and review incident investigation reports internally and with provincial departments as required (i.e. Workplace Safety & Health and Manitoba Conservation).

Significant cost factors involved in appliance relights include: direct labor costs, the cost of reallocating resources, the number of services requiring relight, accessibility and location of equipment, type and number of appliances.

PUB/CENTRA I-129

Subject: **Tab 14 Terms and Conditions**

Reference: **Tab 14 Page 2 of 7; Appendix 14.3 - New Activity Rates**

c) **To what extent do third parties who will be charged the proposed new activity rates be able to determine the number of staff devoted to the task and whether overtime rates become payable?**

ANSWER:

Third parties invoiced for activities related to incident investigation and customer appliance relights related to damages will, upon request to Centra, be provided a detailed breakdown of the labour time deployed to these work activities and the labour rates applied, inclusive of overtime rates where applicable.

PUB/CENTRA I-130

Subject: **Tab 14 Terms and Conditions**

Reference: **Tab 14 Pages 4 and 5 of 7 - Modifications to Customer Equipment Problems Program**

a) For each of the past five years, please provide a breakdown of the total number of service calls, the total cost of service calls, and the average cost per service call broken down into the following categories:

a. Commercial

i. Space heating
ii. Water heating
iii. Other

b. Residential

i. Space heating
ii. Water heating
ii. Other

ANSWER:

The following tables illustrate a breakdown of the total number of service calls, total cost of service calls and the average cost of service calls broken down by Space Heating, Water Heating and Other categories for each of commercial and residential work orders:

a) Commercial

Commercial		Number of Calls			Average time per call in minutes			Average Cost per call		
	Fiscal Year	Other	Space Heating	Water Heating	Other	Space Heating	Water Heating	Other	Space Heating	Water Heating
	2007-08	-	3	-	-	79.7	-	-	$ 100.91	-
	2008-09	-	4	-	-	38.0	-	-	$ 48.13	-
	2009-10	-	2	-	-	85.5	-	-	$ 108.30	-
	2010-11	-	-	-	-	-	-	-	-	-
	2011-12	-	-	-	-	-	-	-	-	-
	2012-13	-	-	-	-	-	-	-	-	-

Note: No calls were recorded in years 2010-11 to 2012-13.

Centra does not keep specific records of costs incurred for each service call related to commercial Space Heating, Water Heating or Other. Total costs can be inferred by the product of number of calls completed and the average cost per call. Using this calculation the total cost of commercial service calls related to space heating for each of 2007/08, 2008/09 and 2009/10 is estimated to be $303, $193 and $217 respectively.

b) Residential

Residential		Number of Calls			Average time per call in minutes			Average Cost per call		
	Fiscal Year	Other	Space Heating	Water Heating	Other	Space Heating	Water Heating	Other	Space Heating	Water Heating
	2007-08	2072	16561	2310	59.2	50.0	49.3	$ 74.94	$ 63.38	$ 62.44
	2008-09	1573	15890	2199	61.1	54.0	51.8	$ 79.44	$ 70.26	$ 67.34
	2009-10	1379	12869	2290	61.5	54.8	53.6	$ 91.23	$ 81.29	$ 79.50
	2010-11	1522	13616	2258	61.7	57.0	56.0	$ 77.11	$ 71.25	$ 70.06
	2011-12	1248	13161	2479	59.1	56.8	54.5	$ 87.73	$ 84.28	$ 80.80
	2012-13	1132	12655	2201	62.6	55.8	55.3	$ 78.21	$ 69.78	$ 69.08

Centra does not keep specific records of costs incurred for each service call related to residential Space Heating, Water Heating or Other. Total costs can be inferred by the product of number of calls completed and the average cost per call.

		Total Costs of Service Calls		
	Fiscal Year	Other	Space Heating	Water Heating
Residential	2007-08	$155,000	$1,050,000	$144,000
	2008-09	$125,000	$1,116,000	$148,000
	2009-10	$126,000	$1,046,000	$182,000
	2010-11	$117,000	$970,000	$158,000
	2011-12	$109,000	$1,109,000	$200,000
	2012-13	$88,000	$883,000	$152,000

PUB/CENTRA I-130

Subject: **Tab 14 Terms and Conditions**

Reference: **Tab 14 Pages 4 and 5 of 7 - Modifications to Customer Equipment Problems Program**

b) Please provide Centra's understanding of the distinction between "primary" space heating and water heating appliances as opposed to non-primary space heating and water heating appliances.

ANSWER:

Centra's understanding of the distinction between "primary" space and water heating appliances as opposed to non-primary space and water heating appliances is that "primary" means those natural gas fired appliances that provide the central source of heat or hot water used for a building. Non-primary space and water heating appliances would apply to other natural gas appliances such as clothes dryers, ranges, cook tops, fireplaces, fireplace inserts, lamps, barbeques, pool or hot tub heaters, patio heaters, unit heaters, etc.

PUB/CENTRA I-130

Subject: **Tab 14 Terms and Conditions**

Reference: **Tab 14 Pages 4 and 5 of 7 - Modifications to Customer Equipment Problems Program**

c) For each of the past five years, please provide an estimate of the Centra staff FTE (full-time equivalent) devoted to service calls on "Other" commercial or residential appliances.

ANSWER:

Centra does not have staff solely dedicated to service calls categorized as "Other" commercial or residential appliances. This type of work is assigned to qualified staff as customer appointments where the staff normally perform multiple tasks in any given work shift, and may or may not include "Other" commercial or residential appliance service calls.

The cumulative total amount of work required to complete "Other" commercial and residential appliance calls can be equated to an approximate number of EFTs on an annual basis. The EFT equivalent assigned to service calls on "Other" commercial and residential over each of the past five years is:

2008/09: 0.8 EFT

2009/10: 0.7 EFT

2010/11: 0.8 EFT

2011/12: 0.6 EFT

2012/13: 0.6 EFT

PUB/CENTRA I-130

Subject: **Tab 14 Terms and Conditions**

Reference: **Tab 14 Pages 4 and 5 of 7 - Modifications to Customer Equipment Problems Program**

d) Please confirm whether Centra expects to change its staffing levels as a result of no longer responding to service calls for “Other” equipment. If, so, please provide details.

ANSWER:

Staffing levels are continually monitored to ensure appropriate staffing levels are in place. Centra does not dedicate staff specifically to respond to service calls for “Other” equipment. It is expected that any labour savings will be deployed to perform other outstanding core utility work.

PUB/CENTRA I-131

Subject: **Tab 14 Terms and Conditions**

Reference: **Tab 14 Appendix 14.3 - Proposed Labour Rates**

a) Please file Centra's labour rates for each of the five categories set out in Appendix 14.3 as approved in 2007/08 and in 2009/10.

ANSWER:

Please see the attachment to this response.

Service Type	Location	Regular Hourly Rate	Overtime Hourly Rate
Service Line Alterations	All Areas	$98.00	$136.00
Damage Repairs	Winnipeg East	$95.00	$134.00
	Parkland	$120.00	$161.00
	WestMan	$120.00	$161.00
	EastMan	$120.00	$161.00
	Interlake	$110.00	$146.00
Metering Services	All Areas	$86.00	$125.00
Gas Pipeline Operational Services	EastMan	$128.00	n/a

Approved by Manitoba Public Utilities Board Order: 99/07
Supercedes Rates in Manitoba Public Utilities Board Order 174/05
Effective from: August 1, 2007
Date Implemented: August 1, 2007

Centra Gas Manitoba Inc. **September 16, 2009**
Appendix B - Schedule of Sales and Transportation Services and Rates
Company Labour Rates Effective September 16, 2009 **Page 1 of 1**

Service Type	Location	Regular Hourly Rate	Overtime Hourly Rate
Service Line Alterations	All Areas	$103.00	$147.00
Damage Repairs	Winnipeg East	$110.00	$159.00
	Parkland	$128.00	$170.00
	WestMan	$128.00	$170.00
	EastMan	$128.00	$170.00
	Interlake	$128.00	$170.00
Metering Services	All Areas	$99.00	$148.00
Gas Pipeline Operational Services	EastMan	$128.00	$170.00

Approved by PUB Order No.: **128/09**
Date of Board Order: **Sept 16/2009**

PUB/CENTRA I-131

Subject: **Tab 14 Terms and Conditions**

Reference: **Tab 14 Appendix 14.3 - Proposed Labour Rates**

b) For each of the proposed labour rates set out in Appendix 14.3, please provide the actual hourly cost, to Centra, of regular staffing and overtime pay, broken down into components to the extent possible, and advise which components have changed as a result of changes to Centra's overhead capitalization practice.

ANSWER:

Please see the table below reflecting the breakdown of the proposed labour rates for the service types set out in Appendix 14.3.

	Service Line Alterations	Damage Repairs	Damage Investigation	Appliance Relights	Metering Services	Gas Pipeline Operational Services	"As Built" Plans
Activity Rate	79	79	86	79	89	86	87
Overhead	20	20	21	20	22	21	22
Third Party Provision	22	22	24	22	25	24	24
Regular Hourly Rate	**121**	**121**	**131**	**121**	**136**	**131**	**134**
Overtime Hourly Rate (Regular plus 40%)	**169**	**169**	**184**	**169**	**191**	**184**	**187**

Centra has used internal activity & overhead rates to calculate Company Labour Rates for third party billings. Changes in costing methodology have resulted in the reallocation of departmental support costs previously included in activity rates to the common overhead rate. The overhead line item reflects the reallocation of department support costs previously included in activity rates.

In addition, changes in overhead capitalization practices have resulted in some cost components being eliminated from common overhead. As a result, the application of overhead would not recover all of the costs associated with the provision of the chargeable customer service. To appropriately recover the costs incurred in providing the service, the utility has included a provision in the calculation of the company Labour Rates to reflect the same costs that were included in previously approved rates. The third party line item reflects cost components eliminated from common overhead including interest on equipment and facilities, building depreciation and operating costs, IT infrastructure and related support, as well as various corporate department costs.

PUB/CENTRA I-131

Subject: **Tab 14 Terms and Conditions**

Reference: **Tab 14 Appendix 14.3 - Proposed Labour Rates**

c) **Please elaborate on the reasons for proposing different hourly rates for different activities.**

ANSWER:

The hourly rates for the different service types were calculated using the average activity rate of employees that provide such services**.**

PUB/CENTRA I-131

Subject: **Tab 14 Terms and Conditions**

Reference: **Tab 14 Appendix 14.3 - Proposed Labour Rates**

d) Please provide copies of all submissions made to the Executive Committee dealing with labour overhead rates, benefit rates, and material overhead rates for each of the years from 2007/08 to 2012/13. Please provide the minutes of the determination by the Executive Committee.

ANSWER:

Please see Centra's attachment to this response.

No submission was made to the Executive Committee for 2011/12 as there were no material changes from the prior year.

EXECUTIVE COMMITTEE

MINUTES OF MEETING

Held 2008 05 14 at 7:30 a.m. in Executive Conference Room No. 3

Present: R.B. Brennan
K.R.F. Adams
E.R. Kristjanson
G.W. Rose
A.M. Snyder
K.M. Tennenhouse
V.A. Warden

1215.05 W. Derkson, P. Martin and D. Rainkie entered the meeting and reviewed a submission dated 2008 04 03 dealing with rates for Overhead, Benefits and Material. ***Overhead Rates***

Following discussion, the following rates were approved for operating and capital costing purposes effective as of April 1, 2008:

Common Overhead Rate	27%
Wuskwatim Generation Overhead Rate	22% (blended)
Employee Benefit Rate - ST:	24%
Employee Benefit Rate - OT:	3%
General Material Issues:	18%
Serialized Equipment Issues:	11%

Secretary of the Meeting
2008 05 14
c: Distribution List

EXECUTIVE COMMITTEE RECOMMENDATION

SUBJECT:

Overhead Rates, Benefit Rates and Material Overhead Rates for 2008/09 and 2009/10.

RECOMMENDATION:

The following overhead and benefit rates to be approved for operating and capital costing purposes for the fiscal years 2008/09 and 2009/10:

	Proposed	Approved
Common Overhead Rate:	27%	29%
Wuskwatim Generation Overhead Rate	22% (blended rate)	21% (on-site)
Employee Benefit Rate - ST:	24%	24%
Employee Benefit Rate - OT:	3%	3%
Materials Overhead Rates:		
General Material Issues	18%	21%
Serialized Equipment Issues	11%	11%

BACKGROUND:

Common overhead costs are those administrative and general costs that cannot be associated with the direct operating and capital activities of the utility. Common overhead costs are applied to the direct operating programs and capital projects to provide the full cost of such work. These costs primarily include administrative department costs such as executive, human resources and finance; and computer system and infrastructure costs.

The Wuskwatim generation overhead rate excludes the common overhead costs of administrative facilities and personal computer depreciation and interest as the direct costs associated with these items are charged to the project. This rate is to be used only for the Wuskwatim generating station project.

The blended Wuskwatim generation overhead rate is based on the weighting between on-site and off-site resources. The blended rate allows for understandability and ease of use as all Wuskwatim generation activity will use this rate.

Employee benefit costs, including pensions, disability insurance, medical benefits, workmen's compensation and unemployment insurance are charged to cost centres based upon a percentage add-on applied to wages and salaries.

FOR EXECUTIVE COMMITTEE MEETING ON MAY 1 4 2008

Materials overhead represents the costs and salvage rates for materials managed by the stores department. These costs include the facilities costs, operating costs and salvage recovery credits. Serialized (or capitalized) equipment includes such items like large oil-filled equipment and switches that can be tracked by serial number. They are purchased to assets accounts resulting in a different costing structure from general materials. Therefore, a separate material rate is maintained for serialized equipment.

Overhead and benefits studies are performed annually to recalculate the various rates based on current expectations. The rates are reviewed with previous years and year-to-date actual results. The studies are performed to ensure that the costs will be fully allocated. Rate calculations also consider upcoming accounting changes and Manitoba Hydro internal policies.

Additionally, the results from the studies are continuously tested throughout the remainder of the fiscal year. By reviewing absorption monthly, further understanding is achieved of current trends, which may result in changes in the recommendations.

JUSTIFICATION:

It is essential that common overhead costs, employee benefit costs, and material handling costs be allocated to operating and capital activities so that the appropriate share of these costs are charged to the income and capital assets of each utility. Further, these fully loaded costs are necessary to derive appropriate cost apportionment for rate design calculations.

Attachments
Finance and Administration
April 3, 2008

EXECUTIVE COMMITTEE

MINUTES OF MEETING

Held 2009 05 06 at 7:30 a.m. in Executive Conference Room No. 3

Present:

R.B. Brennan	A.M. Snyder
K.R.F. Adams	K.M. Tennenhouse
E.R. Kristjanson	V.A. Warden
G.B. Reed	C.E. Wray
G.W. Rose	

1262.04 V.A. Warden reviewed a submission dated 2009 04 29 dealing with Overhead Rates, Benefit Rates and Material Overhead Rates. ***Overhead Rates***

Following discussion, the Committee approved the following for operating and capital costing purposes for the fiscal year 2009/10:

Common Overhead Rate:	24%
Wuskwatim Generation Overhead Rate:	19%
Employee Benefit Rate - ST:	24%
Employee Benefit Rate - OT:	3%
Materials Overhead Rates:	
General Material Issues:	11%
Serialized Equipment Issues:	7%

Secretary of the Meeting
2009 05 06
c: Distribution List

EXECUTIVE COMMITTEE RECOMMENDATION

SUBJECT:

Overhead Rates, Benefit Rates and Material Overhead Rates for 2009/10.

RECOMMENDATION:

The following overhead and benefit rates to be approved for operating and capital costing purposes for the fiscal year 2009/10:

	Proposed	Approved
Common Overhead Rate:	24%	27%
Wuskwatim Generation Overhead Rate	19%	22%
Employee Benefit Rate - ST:	24%	24%
Employee Benefit Rate - OT:	3%	3%
Materials Overhead Rates:		
General Material Issues	11%	18%
Serialized Equipment Issues	7%	11%

BACKGROUND:

Common overhead costs are those administrative and general costs that cannot be associated with a specific operating and capital program/project of the utility. Common overhead costs are applied to the direct operating programs and capital projects to provide the full cost of such work. These costs primarily include administrative department costs such as human resources and finance; and computer system and infrastructure costs.

The Wuskwatim generation overhead rate excludes the common overhead costs of administrative facilities and personal computer depreciation and interest as the direct costs associated with these items are charged to the project. This rate is to be used only for the Wuskwatim generating station project.

Employee benefit costs, including pensions, disability insurance, medical benefits, workmen's compensation and unemployment insurance are charged to cost centres based upon a percentage add-on applied to wages and salaries.

Materials overhead represents the costs and salvage rates for materials managed by the stores department. These costs include operating costs and salvage recovery credits.

FOR EXECUTIVE COMMITTEE MEETING ON MAY - 6 2009

Serialized (or capitalized) equipment includes such items like large oil-filled equipment and switches that can be tracked by serial number. They are purchased to assets accounts resulting in a different costing structure from general materials. Therefore, a separate material rate is maintained for serialized equipment.

Overhead and benefits studies are performed annually to recalculate the various rates based on current expectations. The rates are reviewed with previous years and year-to-date actual results. The studies are performed to ensure that the costs will be fully allocated. Rate calculations also consider upcoming accounting changes and Manitoba Hydro internal policies.

Additionally, the results from the studies are continuously tested throughout the remainder of the fiscal year. By reviewing absorption monthly, further understanding is achieved of current trends, which may result in changes in the recommendations.

JUSTIFICATION:

It is essential that common overhead costs, employee benefit costs, and material handling costs be allocated to operating and capital activities so that the appropriate share of these costs are charged to the income and capital assets of each utility. Further, these fully loaded costs are necessary to derive appropriate cost apportionment for rate design calculations.

Attachment
Finance and Administration
2009 04 29

EXECUTIVE COMMITTEE

MINUTES OF MEETING

Held 2010 03 23 at 7:30 a.m.
in the President's Meeting Room, 360 Portage Avenue

Present:

R.B. Brennan	K.M. Tennenhouse
K.R.F. Adams	T.E. Tymofichuk
E.R. Kristjanson	V.A Warden
G.W. Rose	C.E. Wray

1301.06 V.A. Warden reviewed a submission dated 2010 03 15 dealing with Corporate Overhead Rates. ***Corporate Overhead Rates***

Following discussion, the Committee approved the following Corporate Overhead Rates for fiscal year 2010/11:

	Previous	Approved 2010/11
Common Overhead Rate:	24%	17%
New Generating Station Overhead Rate:	19%	15%
Materials Overhead Rates:		
General Material Issues	11%	10%
Serialized Equipment Issues	7%	6%

Secretary of the Meeting
2010 03 24
rev. 2010 03 30
c: Distribution List

EXECUTIVE COMMITTEE RECOMMENDATION

SUBJECT:

Corporate Overhead Rates

RECOMMENDATION:

That the following Corporate Overhead rates be approved for the fiscal year 2010/11:

	Current Approved	Proposed
Common Overhead Rate:	24%	17%
New Generating Station Overhead Rate:	19%	15%
Materials Overhead Rates:		
General Material Issues	11%	10%
Serialized Equipment Issues	7%	6%

BACKGROUND:

Overhead costs are those administrative and general costs that cannot be associated with a specific operating or capital program/project (electric or gas) of Manitoba Hydro. Common overhead costs are applied to the direct operating programs and capital projects to provide the appropriate cost of such work. These costs primarily include administrative department costs such as human resources, finance, computer system and infrastructure costs.

The new generating station overhead rate excludes the common overhead costs of administrative facilities and personal computer depreciation and interest as the costs associated with these items are charged directly to the project. This rate is to be used only for the Generating Station projects.

Materials overhead represents the costs and salvage rates for materials managed by the stores department. These costs include operating costs and salvage recovery credits. Serialized (or capitalized) equipment includes such items like large oil-filled equipment and switches that can be tracked by serial number. They are purchased to asset accounts resulting in a different costing structure from general materials. Therefore, a separate material rate is maintained for serialized equipment.

Overhead studies are performed annually to recalculate the various rates based on current expectations. The rates are reviewed with previous years and year-to-date actual results. The studies are performed to ensure that the costs will be allocated appropriately. Rate

FOR EXECUTIVE COMMITTEE MEETING ON
MAR 23 2010

calculations also consider upcoming accounting changes and Manitoba Hydro internal policies.

Additionally, the results from the studies are continuously tested throughout the remainder of the fiscal year. By reviewing absorption monthly, further understanding is achieved of current trends, which may result in changes in the recommendations.

Further information is provided in the attached schedules.

JUSTIFICATION:

Preliminary to the implementation of IFRS in 2011/12, and considering industry trends to move away from full cost accounting, Manitoba Hydro has been reviewing its existing cost capitalization practices. Based on this review, Manitoba Hydro has eliminated, or is planning to eliminate the following cost components from its capitalized overhead (in millions)

2008/09:	
Interest and facilities overhead on stores materials	$5.0
2009/10:	
Executive costs	$2.0
Property taxes on facilities	$2.0
2010/11:	
Interest on common assets (facilities & equipment)	$12.0
General and administrative department costs	$5.0

Removing these costs from the overhead pool has resulted in the proposed changes to the corporate overhead rates.

RISK:

Implementation of this recommendation will cause an increase in operating costs of approximately $14 million in 2010/11 making it difficult to achieve the previous approved OM&A targets.

EXECUTIVE COMMITTEE

MINUTES OF MEETING

Held 2012 08 07 at 8:30 a.m. and 2012 08 09 at 8:30 a.m.
in the President's Meeting Room, 360 Portage Avenue

Present:

K.R.F. Adams	K.M. Tennenhouse
E.R. Kristjanson	T.E. Tymofichuk
L.J. Kuczek	V.A. Warden
G.B. Reed	

1406.03 V.A. Warden reviewed a submission dated 2012 07 30 dealing with Corporate Overhead, Material and Employee Benefit Rates.

Overhead, Material & Benefit Rates

Following discussion, the Committee approved revisions to the above rates, effective April 1, 2012, as described in detail in the above submission.

Secretary of the Meeting
2012 08 09
c: Distribution List

1906 #4

EXECUTIVE COMMITTEE RECOMMENDATION

SUBJECT:

Corporate Overhead, Material and Employee Benefit Rates.

RECOMMENDATION:

That the following revisions to Corporate Overhead, Material and Employee Benefit Rates be approved effective April 1, 2012:

	Previous Rate	Proposed
Corporate Overhead:		
Common Overhead	17%	20%
New Generating Station Overhead	15%	n/a
Tool & Procurement Add-On	n/a	5%
Third Party Billing Overhead	28%	28%
Material Overhead:		
General Material Add-On	10%	10%
Serialized Equipment Add-On	6%	4%
Employee Benefits:		
Straight-Time Benefit Rate	24%	26%
Overtime Benefit Rate	3%	3%

BACKGROUND:

Manitoba Hydro has historically applied a full absorption approach to costing its capital, operating and maintenance programs. Under this approach, general and administrative costs such as corporate governance, corporate infrastructure, corporate services and departmental support were allocated to capital and operating projects/programs either through activity or overhead rates.

In preparation for the implementation of IFRS, the Corporation began moving away from the full cost approach to capitalized overhead in 2008/09. In 2012/13 costs associated with building depreciation and operating costs, as well as IT infrastructure and related support costs have been removed from capitalized overhead.

A listing of the 2012/13 changes are summarized below:

FOR EXECUTIVE COMMITTEE MEETING ON
AUG - 7 2012

Common Overhead

The increase in the rate from 17% to 20% is primarily due to the fact that department support costs deemed ineligible for capitalization under IFRS have been removed from activity rates and will be allocated to programs/ projects through the common overhead rate. This change will simplify the transition to IFRS and assist with comparative year reporting by placing the majority of ineligible costs in the common overhead pool.

New Generating Station Overhead

The new generation station overhead rate was previously used to allocate common overhead costs except for those associated with administrative facilities or personal computer depreciation. With the changes noted in the common overhead pool the difference between the new generating station overhead and the common overhead is no longer significant. Therefore, the new generating station rate is proposed to be eliminated.

Tool & Procurement Rate Add-On

Tool and procurement costs deemed eligible for capitalization under IFRS have been removed from common overhead and will now be allocated to operating programs and capital projects through a new add-on rate initially calculated to be 5%. This change will also assist in simplifying the transition to IFRS and assist with comparative year reporting.

Third Party Billing Overhead

Over the past few years Manitoba Hydro has eliminated a number of cost components from common overhead. As a result, these costs are no longer allocated to the operating orders and capital projects that are used to record the costs for billing work for outside parties. It is therefore necessary to apply a billing overhead to these work order costs in order to recover a reasonable portion of costs from third parties. For existing contracts, with special billing arrangements, historical rates will be applied. For any new contracts, the third party billing overhead rate of 28% will be applied.

Material costs

Stores costs and material issues have been updated for this rate calculation applying previous year actual data adjusted for escalation in material costs. Based on this analysis, the general material rate will not change however the serialized equipment rate has been reduced due to an increase in material issues.

Employee Benefits

The increase in the employee benefit rate is due primarily to the increase in Past Service Pension costs as a result of the amortization of investment losses experienced since 2008 as well as higher current service pension costs due to higher pensionable earnings resulting from escalating wages & salaries.

JUSTIFICATION:

The changes recommended for 2012/13 are consistent with IFRS requirements for capitalization of overheads.

Please refer to the attached Appendices for further details of recommended Overhead, Material and Employee Benefit Rates:

Appendix A:	Common Overhead Rates
Appendix B:	Material Overhead Rates
Appendix C:	Employee Benefit Rates

Attachments
Finance & Administration
2012 07 30

PUB/CENTRA I-132

Subject: **Tab 14 Terms and Conditions**

Reference: **Tab 14 - Evaluation of Changes Made after 2009/10 & 2010/11 GRA**

a) In respect of the changes to the terms and conditions for interruptible sales service and interruptible delivery services:

a. For each year since the changes to the Terms & Conditions came into effect, please provide the number of interruptible sales service and interruptible delivery services customers.

ANSWER:

Please see below.

Interruptible Annual Customers by Class

Fiscal Year	System Supply	WTS	T-Service	Total
2008/09	33	8	4	45
2009/10	32	9	4	45
2010/11	32	9	3	44
2011/12	30	7	3	40

PUB/CENTRA I-132

Subject: **Tab 14 Terms and Conditions**

Reference: **Tab 14 - Evaluation of Changes Made after 2009/10 & 2010/11 GRA**

a) **In respect of the changes to the terms and conditions for interruptible sales service and interruptible delivery services:**

b. **Please advise how many interruptible customers that did not have a suitable stand-by fuel source have now installed a stand-by fuel source subsequent to or as a result of the amendment.**

ANSWER:

No customers have installed stand-by fuel sources as a result of the amendment. However, as noted in Centra's response to PUB/Centra I-132(b), three customers have elected to switch from Interruptible service to firm service.

PUB/CENTRA I-132

Subject: **Tab 14 Terms and Conditions**

Reference: **Tab 14 - Evaluation of Changes Made after 2009/10 & 2010/11 GRA**

a) **In respect of the changes to the terms and conditions for interruptible sales service and interruptible delivery services:**

c. **Provide the number of interruptible customers against which over-run charges were levied in each year since 2007, and the average amount of the over-run charge.**

ANSWER:

The number of customers with over-run charges is as follows:

2008: No penalties

2009: January 14th – 24 customers at $0.2625/m^3$

7219 mcf x 28.32784 x $0.2625 ÷ 24 = $2,236.70 each

2010: No penalties

2011: May 1st & 2nd – 3 customers at $0.3102/m^3$

24 mcf x 28.32784 x $0.3102÷ 3 = $70.30 each

2012: No penalties

2013: No penalties

PUB/CENTRA I-132

Subject: **Tab 14 Terms and Conditions**

Reference: **Tab 14 - Evaluation of Changes Made after 2009/10 & 2010/11 GRA**

a) In respect of the changes to the terms and conditions for interruptible sales service and interruptible delivery services:

d. Advise whether the number of over-runs has decreased since the amendment to the terms and conditions and, if so, quantify the reduction.

ANSWER:

Please see Centra's response to PUB/Centra I-132(ac).

PUB/CENTRA I-132

Subject: **Tab 14 Terms and Conditions**

Reference: **Tab 14 - Evaluation of Changes Made after 2009/10 & 2010/11 GRA**

b) In respect of the creation of rules for the transfer of customers between classes or services:

a. Please advise how many customers have switched from High Volume Firm Status to Interruptible Class in each year since the changes came into effect, and vice versa.

b. Please confirm whether Centra has withheld consent to a switch from High Volume Firm to Interruptible Class on any occasions. If so, elaborate.

ANSWER:

a. No customers have changed from High Volume Firm Status to Interruptible Class. One customer changed from Interruptible service to Large General service and two customers changed from Interruptible class to High Volume Firm classification.

b. Centra has not withheld consent or refused any request to switch to Interruptible Class.

PUB/CENTRA I-132

Subject: **Tab 14 Terms and Conditions**

Reference: **Tab 14 - Evaluation of Changes Made after 2009/10 & 2010/11 GRA**

c) **Please advise how many customers have switched between Sales Service and Transportation Service in each year since the changes came into effect.**

ANSWER:

No customers have switched from Sales Service to Transportation Service for the Interruptible Class. There also have not been any firm customers that elected to take Transportation Service.

PUB/CENTRA I-133

Subject: **Tab 15 - Directives**

Reference: **Tab 15 Page 2 of 8 - Rural Expansion True-Ups**

a) Please file the true-ups referenced in section 15.1.2.

ANSWER:

Please see attachment to this response.

Manitoba Hydro

PO Box 815 • Winnipeg Manitoba Canada • R3C 2P4
Street Location for DELIVERY: 22nd floor – 360 Portage Avenue
Telephone / N° de téléphone : (204) 360-3468 • Fax / N° de télécopieur : (204) 360-6147
mmurphy@hydro.mb.ca

December 4, 2009

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

ATTENTION: Mr. Gerry Gaudreau, Executive Director

Dear Mr. Gaudreau:

RE: Centra Gas Manitoba Inc. ("Centra")
Final True up Calculations of Financial Feasibility Tests for
RM of Hamiota and RM of Woodlands - Natural Gas Expansion Projects

Centra is hereby enclosing the final true up calculations for the feasibility tests in support of the natural gas system expansion projects, as directed by the Manitoba Public Utilities Board ("PUB"), in the following referenced Orders:

1. RM of Woodlands - Car and Truck Wash (PUB Order No. 79/03). The effective date of the final recalculation is December 31, 2008, and;

2. RM of Hamiota (PUB Order No. 121/03). The effective date of the final recalculation is December 31, 2008.

With respect to the true up of the RM of Woodlands expansion project, it was determined that a refund was due to the single customer in the amount of $13,828 plus GST (totalling $14,795.96). A cheque in this amount was issued to the customer on September 9, 2009. This amount represents the total contribution paid.

With respect to the true up of the RM of Hamiota expansion project, it was determined that a refund was due to the single customer in the amount of $18,773 plus GST (totalling $20,087.11). This amount represents the total contribution paid.

When Centra filed the RM of Hamiota Application on July 3, 2003, it had collected an initial contribution of $10,000 (plus GST). As per Order 121/03, Centra collected the balance of the contribution prior to construction. Order 121/03 also required that Centra provide the PUB with the particulars of the treatment of any subsequent customers that may attach to this expansion. No other customers have attached.

Centra has determined that the customer that provided the original contribution is no longer in existance. This customer's assets were the subject of a receivership in 2004 and were subsequently sold. Centra contacted the receiver appointed by the Manitoba Court of Queen's Bench, and was advised that the receiver was discharged in 2006.

In accordance with Section IV. C) 1) c) of the Schedule of Sales and Transportation Services and Rates, Centra applied the sum of $1,431.27 against an outstanding debt associated with the inactive account in this customer's name. The balance of $17,341.73 will be retained by Centra and transferred from the refundable contributions account to the non-refundable contributions account.

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

Yours truly,
MANITOBA HYDRO LAW DEPARTMENT
Per:

M Murphy

MARLA D. MURPHY,
Barrister and Solicitor
Att.

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

Centra Gas Manitoba Inc.
Financial Feasibility Test

Attachment 1
December 4, 2009

1 **R.M. of Woodlands - Car and Truck Wash Site Expansion Project Final True Up (PUB Order #79/03)**

2		TIME 0	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8	YEAR 9	YEAR 10
3		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
4	OPERATING ASSUMPTIONS											
5	Number of Customers		1	1	1	1	1	1	1	1	1	1
6	Annual Volume (Mcf)		754	747	707	735	977	977	977	977	977	977
7	Annual Volume (10^3m^3)		21	21	20	21	28	28	28	28	28	28
8	Projected Revenues		$9,362	$9,276	$8,788	$9,130	$12,084	$12,084	$12,084	$12,084	$12,084	$12,084
9	RATE BASE											
10	Gross Fixed Assets	$17,878	$17,878	$17,878	$17,878	$17,878	$17,907	$17,907	$17,907	$17,907	$17,907	$17,907
11	Accumulated Depreciation		$350	$701	$1,051	$1,402	$1,753	$2,104	$2,455	$2,806	$3,156	$3,507
12	Contributions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Working Capital Allowance		$366	$342	$324	$358	$468	$468	$468	$468	$468	$468
14	Rate Base		$18,069	$17,694	$17,326	$17,010	$16,783	$16,446	$16,095	$15,744	$15,393	$15,042
15	REVENUE DEFICIENCY											
16												
17	Cost of Gas		$7,201	$7,134	$6,752	$7,019	$9,331	$9,331	$9,331	$9,331	$9,331	$9,331
18	Operating & Maintenance Expenses		$100	$100	$100	$100	$100	$100	$100	$100	$100	$100
19	Depreciation Expense		$350	$350	$350	$350	$351	$351	$351	$351	$351	$351
20	Amortization of Contributions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
21	Municipal Tax & Corp.Cap. Tax		$441	$456	$452	$464	$471	$469	$468	$466	$464	$462
22	Income Taxes		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	Overall Return		$1,463	$1,432	$1,331	$1,229	$1,213	$1,188	$1,163	$1,138	$1,112	$1,087
24	Total Revenue Requirement		$9,555	$9,473	$8,985	$9,163	$11,466	$11,439	$11,412	$11,385	$11,358	$11,331
25	Projected Revenues		$9,362	$9,276	$8,788	$9,130	$12,084	$12,084	$12,084	$12,084	$12,084	$12,084
26	Revenue Deficiency (Annual)		($194)	($197)	($198)	($34)	$619	$645	$672	$699	$726	$753
27	Revenue to Cost Ratio		98.0%	97.9%	97.8%	99.6%	105.4%	105.6%	105.9%	106.1%	106.4%	106.6%
28	NPV of Revenue Deficiency	$6,967										
29	CONTRIBUTION REQUIREMENT											
30	Total Contribution Required	$0										

Centra Gas Manitoba Inc.
Financial Feasibility Test

Attachment 1
December 4, 2009

1 **R.M. of Woodlands - Car and Truck Wash Site Expansion Project Final True Up (PUB Order #79/03)**

Line		YEAR 11	YEAR 12	YEAR 13	YEAR 14	YEAR 15	YEAR 16	YEAR 17	YEAR 18	YEAR 19	YEAR 20
3		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
4	OPERATING ASSUMPTIONS										
5	Number of Customers	1	1	1	1	1	1	1	1	1	1
6	Annual Volume (Mcf)	977	977	977	977	977	977	977	977	977	977
7	Annual Volume (10^3m^3)	28	28	28	28	28	28	28	28	28	28
8	Projected Revenues	$12,084	$12,084	$12,084	$12,084	$12,084	$12,084	$12,084	$12,084	$12,084	$12,084
9	RATE BASE										
10	Gross Fixed Assets	$17,907	$17,907	$17,907	$17,907	$17,907	$17,907	$17,907	$17,907	$17,907	$17,907
11	Accumulated Depreciation	$3,858	$4,209	$4,560	$4,911	$5,262	$5,613	$5,964	$6,315	$6,666	$7,017
12	Contributions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Working Capital Allowance	$467	$467	$467	$467	$467	$467	$467	$467	$467	$467
14	Rate Base	$14,691	$14,340	$13,989	$13,638	$13,287	$12,936	$12,585	$12,234	$11,883	$11,532
15	REVENUE DEFICIENCY										
16											
17	Cost of Gas	$9,331	$9,331	$9,331	$9,331	$9,331	$9,331	$9,331	$9,331	$9,331	$9,331
18	Operating & Maintenance Expenses	$100	$100	$100	$100	$100	$100	$100	$100	$100	$100
19	Depreciation Expense	$351	$351	$351	$351	$351	$351	$351	$351	$351	$351
20	Amortization of Contributions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
21	Municipal Tax & Corp.Cap. Tax	$461	$459	$457	$455	$454	$452	$450	$448	$447	$445
22	Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	Overall Return	$1,062	$1,036	$1,011	$985	$960	$935	$909	$884	$859	$833
24	Total Revenue Requirement	$11,304	$11,277	$11,250	$11,222	$11,195	$11,168	$11,141	$11,114	$11,087	$11,060
25	Projected Revenues	$12,084	$12,084	$12,084	$12,084	$12,084	$12,084	$12,084	$12,084	$12,084	$12,084
26	Revenue Deficiency (Annual)	$780	$807	$835	$862	$889	$916	$943	$970	$997	$1,024
27	Revenue to Cost Ratio	106.9%	107.2%	107.4%	107.7%	107.9%	108.2%	108.5%	108.7%	109.0%	109.3%

Centra Gas Manitoba Inc.
Financial Feasibility Test

Attachment 1
December 4, 2009

1	**R.M. of Woodlands - Car and Truck Wash Site Expansion Project Final True Up (PUB Order #79/03)**										
2		YEAR 21	YEAR 22	YEAR 23	YEAR 24	YEAR 25	YEAR 26	YEAR 27	YEAR 28	YEAR 29	YEAR 30
3		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
4	OPERATING ASSUMPTIONS										
5	Number of Customers	1	1	1	1	1	1	1	1	1	1
6	Annual Volume (Mcf)	977	977	977	977	977	977	977	977	977	977
7	Annual Volume (10^3m^3)	28	28	28	28	28	28	28	28	28	28
8	Projected Revenues	$12,084	$12,084	$12,084	$12,084	$12,084	$12,084	$12,084	$12,084	$12,084	$12,084
9	RATE BASE										
10	Gross Fixed Assets	$17,907	$17,907	$17,907	$17,907	$17,907	$17,907	$17,907	$17,907	$17,907	$17,907
11	Accumulated Depreciation	$7,368	$7,719	$8,070	$8,421	$8,772	$9,123	$9,474	$9,825	$10,176	$10,527
12	Contributions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Working Capital Allowance	$467	$467	$466	$466	$466	$466	$466	$466	$466	$466
14	Rate Base	$11,181	$10,830	$10,479	$10,128	$9,776	$9,425	$9,074	$8,723	$8,372	$8,021
15	REVENUE DEFICIENCY										
16											
17	Cost of Gas	$9,331	$9,331	$9,331	$9,331	$9,331	$9,331	$9,331	$9,331	$9,331	$9,331
18	Operating & Maintenance Expenses	$100	$100	$100	$100	$100	$100	$100	$100	$100	$100
19	Depreciation Expense	$351	$351	$351	$351	$351	$351	$351	$351	$351	$351
20	Amortization of Contributions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
21	Municipal Tax & Corp.Cap. Tax	$443	$441	$440	$438	$436	$434	$433	$431	$429	$427
22	Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	Overall Return	$808	$783	$757	$732	$706	$681	$656	$630	$605	$580
24	Total Revenue Requirement	$11,033	$11,006	$10,978	$10,951	$10,924	$10,897	$10,870	$10,843	$10,816	$10,789
25	Projected Revenues	$12,084	$12,084	$12,084	$12,084	$12,084	$12,084	$12,084	$12,084	$12,084	$12,084
26	Revenue Deficiency (Annual)	$1,052	$1,079	$1,106	$1,133	$1,160	$1,187	$1,214	$1,241	$1,268	$1,296
27	Revenue to Cost Ratio	109.5%	109.8%	110.1%	110.3%	110.6%	110.9%	111.2%	111.4%	111.7%	112.0%

Centra Gas Manitoba Inc.
Financial Feasibility Test

Attachment 2
December 4, 2009

1 **R.M. of Hamiota - Expansion Project Final True Up (PUB Order #121/03)**

2		TIME 0	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8	YEAR 9	YEAR 10
3		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
4	OPERATING ASSUMPTIONS											
5	Number of Customers		1	1	1	1	1	1	1	1	1	1
6	Annual Volume (Mcf)		2,510	1,897	1,500	2,352	2,432	2,432	2,432	2,432	2,432	2,432
7	Annual Volume (10^3m^3)		71	54	42	67	69	69	69	69	69	69
8	Projected Revenues		$27,851	$21,254	$16,982	$26,151	$27,012	$27,012	$27,012	$27,012	$27,012	$27,012
9	RATE BASE											
10	Gross Fixed Assets	$23,940	$23,940	$23,940	$23,940	$23,940	$23,940	$23,940	$23,940	$23,940	$23,940	$23,940
11	Accumulated Depreciation		$709	$1,417	$2,126	$2,835	$3,543	$4,252	$4,960	$5,669	$6,378	$7,086
12	Contributions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Working Capital Allowance		$1,159	$830	$662	$1,088	$1,125	$1,125	$1,125	$1,124	$1,124	$1,124
14	Rate Base		$24,745	$23,707	$22,831	$22,548	$21,876	$21,168	$20,459	$19,750	$19,041	$18,332
15	REVENUE DEFICIENCY											
16												
17	Cost of Gas		$23,943	$18,095	$14,308	$22,436	$23,199	$23,199	$23,199	$23,199	$23,199	$23,199
18	Operating & Maintenance Expenses		$100	$100	$100	$100	$100	$100	$100	$100	$100	$100
19	Depreciation Expense		$709	$709	$709	$709	$709	$709	$709	$709	$709	$709
20	Amortization of Contributions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
21	Municipal Tax & Corp.Cap. Tax		$481	$485	$489	$493	$504	$500	$497	$493	$489	$486
22	Income Taxes		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	Overall Return		$2,003	$1,919	$1,754	$1,629	$1,581	$1,530	$1,478	$1,427	$1,376	$1,325
24	Total Revenue Requirement		$27,236	$21,308	$17,360	$25,367	$26,092	$26,037	$25,982	$25,928	$25,873	$25,818
25	Projected Revenues		$27,851	$21,254	$16,982	$26,151	$27,012	$27,012	$27,012	$27,012	$27,012	$27,012
26	Revenue Deficiency (Annual)		$615	($54)	($378)	$784	$920	$975	$1,029	$1,084	$1,139	$1,194
27	Revenue to Cost Ratio		102.3%	99.7%	97.8%	103.1%	103.5%	103.7%	104.0%	104.2%	104.4%	104.6%
28	NPV of Revenue Deficiency	$13,085										
29	CONTRIBUTION REQUIREMENT											
30	Total Contribution Required	$0										

Centra Gas Manitoba Inc.
Financial Feasibility Test

Attachment 2
December 4, 2009

1 **R.M. of Hamiota - Expansion Project Final True Up (PUB Order #121/03)**

Line		YEAR 11	YEAR 12	YEAR 13	YEAR 14	YEAR 15	YEAR 16	YEAR 17	YEAR 18	YEAR 19	YEAR 20
3		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
4	OPERATING ASSUMPTIONS										
5	Number of Customers	1	1	1	1	1	1	1	1	1	1
6	Annual Volume (Mcf)	2,432	2,432	2,432	2,432	2,432	2,432	2,432	2,432	2,432	2,432
7	Annual Volume (10^3m^3)	69	69	69	69	69	69	69	69	69	69
8	Projected Revenues	$27,012	$27,012	$27,012	$27,012	$27,012	$27,012	$27,012	$27,012	$27,012	$27,012
9	RATE BASE										
10	Gross Fixed Assets	$23,940	$23,940	$23,940	$23,940	$23,940	$23,940	$23,940	$23,940	$23,940	$23,940
11	Accumulated Depreciation	$7,795	$8,504	$9,212	$9,921	$10,630	$11,338	$12,047	$12,755	$13,464	$14,173
12	Contributions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Working Capital Allowance	$1,124	$1,124	$1,124	$1,123	$1,123	$1,123	$1,123	$1,123	$1,123	$1,122
14	Rate Base	$17,624	$16,915	$16,206	$15,497	$14,788	$14,080	$13,371	$12,662	$11,953	$11,244
15	REVENUE DEFICIENCY										
16											
17	Cost of Gas	$23,199	$23,199	$23,199	$23,199	$23,199	$23,199	$23,199	$23,199	$23,199	$23,199
18	Operating & Maintenance Expenses	$100	$100	$100	$100	$100	$100	$100	$100	$100	$100
19	Depreciation Expense	$709	$709	$709	$709	$709	$709	$709	$709	$709	$709
20	Amortization of Contributions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
21	Municipal Tax & Corp.Cap. Tax	$482	$479	$475	$472	$468	$465	$461	$458	$454	$450
22	Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	Overall Return	$1,273	$1,222	$1,171	$1,120	$1,069	$1,017	$966	$915	$864	$813
24	Total Revenue Requirement	$25,763	$25,708	$25,654	$25,599	$25,544	$25,489	$25,435	$25,380	$25,325	$25,270
25	Projected Revenues	$27,012	$27,012	$27,012	$27,012	$27,012	$27,012	$27,012	$27,012	$27,012	$27,012
26	Revenue Deficiency (Annual)	$1,248	$1,303	$1,358	$1,413	$1,467	$1,522	$1,577	$1,632	$1,687	$1,741
27	Revenue to Cost Ratio	104.8%	105.1%	105.3%	105.5%	105.7%	106.0%	106.2%	106.4%	106.7%	106.9%

Centra Gas Manitoba Inc.
Financial Feasibility Test

Attachment 2
December 4, 2009

1	**R.M. of Hamiota - Expansion Project Final True Up (PUB Order #121/03)**										
2		YEAR 21	YEAR 22	YEAR 23	YEAR 24	YEAR 25	YEAR 26	YEAR 27	YEAR 28	YEAR 29	YEAR 30
3		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
4	OPERATING ASSUMPTIONS										
5	Number of Customers	1	1	1	1	1	1	1	1	1	1
6	Annual Volume (Mcf)	2,432	2,432	2,432	2,432	2,432	2,432	2,432	2,432	2,432	2,432
7	Annual Volume (10^3m^3)	69	69	69	69	69	69	69	69	69	69
8	Projected Revenues	$27,012	$27,012	$27,012	$27,012	$27,012	$27,012	$27,012	$27,012	$27,012	$27,012
9	RATE BASE										
10	Gross Fixed Assets	$23,940	$23,940	$23,940	$23,940	$23,940	$23,940	$23,940	$23,940	$23,940	$23,940
11	Accumulated Depreciation	$14,881	$15,590	$16,299	$17,007	$17,716	$18,425	$19,133	$19,842	$20,550	$21,259
12	Contributions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Working Capital Allowance	$1,122	$1,122	$1,122	$1,122	$1,122	$1,121	$1,121	$1,121	$1,121	$1,121
14	Rate Base	$10,536	$9,827	$9,118	$8,409	$7,700	$6,992	$6,283	$5,574	$4,865	$4,156
15	REVENUE DEFICIENCY										
16											
17	Cost of Gas	$23,199	$23,199	$23,199	$23,199	$23,199	$23,199	$23,199	$23,199	$23,199	$23,199
18	Operating & Maintenance Expenses	$100	$100	$100	$100	$100	$100	$100	$100	$100	$100
19	Depreciation Expense	$709	$709	$709	$709	$709	$709	$709	$709	$709	$709
20	Amortization of Contributions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
21	Municipal Tax & Corp.Cap. Tax	$447	$443	$440	$436	$433	$429	$426	$422	$419	$415
22	Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	Overall Return	$761	$710	$659	$608	$556	$505	$454	$403	$352	$300
24	Total Revenue Requirement	$25,216	$25,161	$25,106	$25,051	$24,997	$24,942	$24,887	$24,832	$24,778	$24,723
25	Projected Revenues	$27,012	$27,012	$27,012	$27,012	$27,012	$27,012	$27,012	$27,012	$27,012	$27,012
26	Revenue Deficiency (Annual)	$1,796	$1,851	$1,906	$1,960	$2,015	$2,070	$2,125	$2,179	$2,234	$2,289
27	Revenue to Cost Ratio	107.1%	107.4%	107.6%	107.8%	108.1%	108.3%	108.5%	108.8%	109.0%	109.3%

Manitoba Hydro

PO Box 815 • Winnipeg Manitoba Canada • R3C 2P4
Street Location for DELIVERY: 22nd floor – 360 Portage Avenue
Telephone / N° de téléphone : (204) 360-3468 • Fax / N° de télécopieur : (204) 360-6147 • mboyd@hydro.mb.ca

October 20, 2011

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

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

Dear Mr. Singh:

RE: FINAL TRUE-UP CALCULATION - FINANCIAL FEASIBILITY TEST RURAL MUNICIPALITY OF ROCKWOOD NATURAL GAS EXPANSION PROJECT (2005)

Enclosed is the final true-up calculation of the feasibility test for the natural gas system extension in the Rural Municipality of Rockwood, as required by the Manitoba Public Utilities Board ("PUB") in Directive 3 of Order 132/05. The true-up calculation is based upon the five year period ending December 31, 2010.

The true-up for this system extension indicates a financial shortfall of $138,356, which is greater than the original shortfall of $134,298. This difference is due to lower than forecast customer volumes.

Although the recalculated shortfall is greater than the original forecasted shortfall, one additional commercial customer attached and paid a contribution on the same basis as the original contributing customers. Contributions totaling $154,393 were collected and therefore a refund of $16,037 is due. This refund amount has been allocated among the contributing customers on a volumetric basis. Each of the five customers have received their refunds.

If you require clarification of this true-up report, please do not hesitate to call the writer (360-3468) or Greg Barnlund (360-5243).

Yours truly,
MANITOBA HYDRO LAW DEPARTMENT
Per:

M Boyd

Marla D. Boyd
Barrister & Solicitor

att

Centra Gas Manitoba Inc.
RM of Rockwood
Financial Feasibility Test

Attachment
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October 20, 2011

RM of Rockwood Expansion Project Final True-up PUB Order 132/05

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
	TIME 0	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8	YEAR 9	YEAR 10
OPERATING ASSUMPTIONS											
Number of Customers		5	5	5	5	5	5	5	5	5	5
Annual Volume (Mcf)		3,819	9,929	11,109	9,637	8,457	8,457	8,457	8,457	8,457	8,457
Annual Volume (10^3m^3)		108	281	315	273	240	240	240	240	240	240
Projected Revenues		$29,993	$71,846	$79,918	$69,859	$61,791	$61,791	$61,791	$61,791	$61,791	$61,791
RATE BASE											
Gross Fixed Assets	$231,658	$239,067	$239,067	$239,067	$239,067	$239,067	$239,067	$239,067	$239,067	$239,067	$239,067
Accumulated Depreciation		$5,188	$10,376	$15,563	$20,751	$25,939	$31,127	$36,314	$41,502	$46,690	$51,878
Net Plant Closing	$231,658	$233,880	$228,692	$223,504	$218,316	$213,129	$207,941	$202,753	$197,565	$192,377	$187,190
Net Plant at Mid-Year		$232,769	$231,286	$226,098	$220,910	$215,722	$210,535	$205,347	$200,159	$194,971	$189,784
Contributions	$138,356	$135,354	$132,351	$129,349	$126,347	$123,344	$120,342	$117,340	$114,337	$111,335	$108,333
Contribution at Mid-Year		$136,855	$133,852	$130,850	$127,848	$124,845	$121,843	$118,841	$115,838	$112,836	$109,834
Working Capital Allowance		$1,267	$2,973	$3,285	$2,894	$2,549	$2,547	$2,546	$2,545	$2,544	$2,542
Rate Base at Mid-Year		$97,181	$100,407	$98,533	$95,956	$93,426	$91,239	$89,052	$86,866	$84,679	$82,492
REVENUE DEFICIENCY CALCULATION											
Cost of Gas		$21,412	$55,670	$62,286	$54,033	$47,417	$47,417	$47,417	$47,417	$47,417	$47,417
Operating & Maintenance Expenses		$500	$500	$500	$500	$500	$500	$500	$500	$500	$500
Depreciation Expense		$5,188	$5,188	$5,188	$5,188	$5,188	$5,188	$5,188	$5,188	$5,188	$5,188
Amortization of Contributions		($3,002)	($3,002)	($3,002)	($3,002)	($3,002)	($3,002)	($3,002)	($3,002)	($3,002)	($3,002)
Municipal Tax & Corp. Cap. Tax		$6,613	$6,747	$6,719	$6,702	$6,008	$5,982	$5,956	$5,930	$5,904	$5,878
Income Taxes		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Overall Return		$7,465	$7,255	$7,120	$6,934	$5,681	$5,548	$5,415	$5,282	$5,149	$5,016
Total Revenue Requirement		$38,175	$72,358	$78,810	$70,354	$61,791	$61,632	$61,473	$61,314	$61,155	$60,996
Projected Revenues		$29,993	$71,846	$79,918	$69,859	$61,791	$61,791	$61,791	$61,791	$61,791	$61,791
Revenue Deficiency (Annual)		($8,182)	($512)	$1,108	($495)	$0	$159	$318	$477	$636	$794
Revenue to Cost Ratio		78.6%	99.3%	101.4%	99.3%	100.0%	100.3%	100.5%	100.8%	101.0%	101.3%
NPV of Revenue Deficiency	$7,542										
CONTRIBUTION REQUIREMENT											
Total Contribution Required	$138,356										

Attachment
Page 1 of 3

Centra Gas Manitoba Inc.
RM of Rockwood
Financial Feasibility Test

Attachment
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October 20, 2011

RM of Rockwood Expansion Project Final True-up PUB Order 132/05

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	YEAR 11	YEAR 12	YEAR 13	YEAR 14	YEAR 15	YEAR 16	YEAR 17	YEAR 18	YEAR 19	YEAR 20
OPERATING ASSUMPTIONS										
Number of Customers	5	5	5	5	5	5	5	5	5	5
Annual Volume (Mcf)	8,457	8,457	8,457	8,457	8,457	8,457	8,457	8,457	8,457	8,457
Annual Volume (10^3m^3)	240	240	240	240	240	240	240	240	240	240
Projected Revenues	$61,791	$61,791	$61,791	$61,791	$61,791	$61,791	$61,791	$61,791	$61,791	$61,791
RATE BASE										
Gross Fixed Assets	$239,067	$239,067	$239,067	$239,067	$239,067	$239,067	$239,067	$239,067	$239,067	$239,067
Accumulated Depreciation	$57,065	$62,253	$67,441	$72,629	$77,816	$83,004	$88,192	$93,380	$98,567	$103,755
Net Plant Closing	$182,002	$176,814	$171,626	$166,439	$161,251	$156,063	$150,875	$145,688	$140,500	$135,312
Net Plant at Mid-Year	$184,596	$179,408	$174,220	$169,033	$163,845	$158,657	$153,469	$148,282	$143,094	$137,906
Contributions	$105,330	$102,328	$99,326	$96,323	$93,321	$90,319	$87,316	$84,314	$81,312	$78,309
Contribution at Mid-Year	$106,831	$103,829	$100,827	$97,825	$94,822	$91,820	$88,818	$85,815	$82,813	$79,811
Working Capital Allowance	$2,541	$2,540	$2,539	$2,537	$2,536	$2,535	$2,534	$2,533	$2,531	$2,530
Rate Base at Mid-Year	$80,306	$78,119	$75,932	$73,746	$71,559	$69,372	$67,186	$64,999	$62,812	$60,626
REVENUE DEFICIENCY CALCULATION										
Cost of Gas	$47,417	$47,417	$47,417	$47,417	$47,417	$47,417	$47,417	$47,417	$47,417	$47,417
Operating & Maintenance Expenses	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500
Depreciation Expense	$5,188	$5,188	$5,188	$5,188	$5,188	$5,188	$5,188	$5,188	$5,188	$5,188
Amortization of Contributions	($3,002)	($3,002)	($3,002)	($3,002)	($3,002)	($3,002)	($3,002)	($3,002)	($3,002)	($3,002)
Municipal Tax & Corp. Cap. Tax	$5,852	$5,826	$5,800	$5,774	$5,748	$5,722	$5,696	$5,670	$5,644	$5,618
Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Overall Return	$4,883	$4,750	$4,617	$4,484	$4,351	$4,218	$4,085	$3,952	$3,819	$3,686
Total Revenue Requirement	$60,838	$60,679	$60,520	$60,361	$60,202	$60,043	$59,884	$59,725	$59,566	$59,407
Projected Revenues	$61,791	$61,791	$61,791	$61,791	$61,791	$61,791	$61,791	$61,791	$61,791	$61,791
Revenue Deficiency (Annual)	$953	$1,112	$1,271	$1,430	$1,589	$1,748	$1,907	$2,066	$2,225	$2,383
Revenue to Cost Ratio	101.6%	101.8%	102.1%	102.4%	102.6%	102.9%	103.2%	103.5%	103.7%	104.0%

Attachment
Page 2 of 3

Centra Gas Manitoba Inc.
RM of Rockwood
Financial Feasibility Test

1	**RM of Rockwood Expansion Project Final True-up PUB Order 132/05**										
2											
3		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
4		YEAR 21	YEAR 22	YEAR 23	YEAR 24	YEAR 25	YEAR 26	YEAR 27	YEAR 28	YEAR 29	YEAR 30
5	OPERATING ASSUMPTIONS										
6	Number of Customers	5	5	5	5	5	5	5	5	5	5
7	Annual Volume (Mcf)	8,457	8,457	8,457	8,457	8,457	8,457	8,457	8,457	8,457	8,457
8	Annual Volume (10^3m^3)	240	240	240	240	240	240	240	240	240	240
9	Projected Revenues	$61,791	$61,791	$61,791	$61,791	$61,791	$61,791	$61,791	$61,791	$61,791	$61,791
10											
11	RATE BASE										
12	Gross Fixed Assets	$239,067	$239,067	$239,067	$239,067	$239,067	$239,067	$239,067	$239,067	$239,067	$239,067
13	Accumulated Depreciation	$108,943	$114,131	$119,319	$124,506	$129,694	$134,882	$140,070	$145,257	$150,445	$155,633
14	Net Plant Closing	$130,124	$124,937	$119,749	$114,561	$109,373	$104,186	$98,998	$93,810	$88,622	$83,435
15	Net Plant at Mid-Year	$132,718	$127,530	$122,343	$117,155	$111,967	$106,779	$101,592	$96,404	$91,216	$86,028
16	Contributions	$75,307	$72,305	$69,302	$66,300	$63,298	$60,295	$57,293	$54,291	$51,289	$48,286
17	Contribution at Mid-Year	$76,808	$73,806	$70,804	$67,801	$64,799	$61,797	$58,794	$55,792	$52,790	$49,787
18	Working Capital Allowance	$2,529	$2,528	$2,526	$2,525	$2,524	$2,523	$2,522	$2,520	$2,519	$2,518
19	Rate Base at Mid-Year	$58,439	$56,252	$54,066	$51,879	$49,692	$47,506	$45,319	$43,132	$40,946	$38,759
20											
21	REVENUE DEFICIENCY CALCULATION										
22	Cost of Gas	$47,417	$47,417	$47,417	$47,417	$47,417	$47,417	$47,417	$47,417	$47,417	$47,417
23	Operating & Maintenance Expenses	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500
24	Depreciation Expense	$5,188	$5,188	$5,188	$5,188	$5,188	$5,188	$5,188	$5,188	$5,188	$5,188
25	Amortization of Contributions	($3,002)	($3,002)	($3,002)	($3,002)	($3,002)	($3,002)	($3,002)	($3,002)	($3,002)	($3,002)
26	Municipal Tax & Corp. Cap. Tax	$5,593	$5,567	$5,541	$5,515	$5,489	$5,463	$5,437	$5,411	$5,385	$5,359
27	Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	Overall Return	$3,553	$3,420	$3,287	$3,154	$3,022	$2,889	$2,756	$2,623	$2,490	$2,357
29	Total Revenue Requirement	$59,249	$59,090	$58,931	$58,772	$58,613	$58,454	$58,295	$58,136	$57,977	$57,818
30	Projected Revenues	$61,791	$61,791	$61,791	$61,791	$61,791	$61,791	$61,791	$61,791	$61,791	$61,791
31	Revenue Deficiency (Annual)	$2,542	$2,701	$2,860	$3,019	$3,178	$3,337	$3,496	$3,655	$3,814	$3,972
32	Revenue to Cost Ratio	104.3%	104.6%	104.9%	105.1%	105.4%	105.7%	106.0%	106.3%	106.6%	106.9%

Attachment
Page 3 of 3

Manitoba Hydro

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October 20, 2011

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

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

Dear Mr. Singh:

RE: FINAL TRUE-UP CALCULATION - FINANCIAL FEASIBILITY TEST RURAL MUNICIPALITY OF ROSSER NATURAL GAS EXPANSION PROJECT (2005)

Enclosed is the final true-up calculation for the feasibility test for the extension to one commercial customer in the Rural Municipality of Rosser, as required by the Manitoba Public Utilities Board ("PUB") in Directive 5 of Order 54/05. This true-up calculation is based upon the five year period ending December 31, 2010.

The true-up calculation for this system extension indicates a financial shortfall of $115,649 which is greater than the original shortfall of $71,514. This difference is due to higher than estimated construction costs and lower than forecasted customer volumes. As a result, there is no refund due to the customer at the end of the five year period.

In addition to providing the final true-up calculation of the feasibility test, Order 54/05 also included the following directives:

> Directive 3: "Centra obtain the balance of the required customer contribution prior to commencing any construction related to this project."
>
> Centra confirms that the balance of the required customer contribution was collected prior to commencing construction of the project.
>
> Directive 4: "Centra submit a report to the Board detailing the treatment of customer contributions related to any future customers that are attached to the expanded distribution system."

Centra reports that one additional residential customer requested natural gas service prior to start of construction for this main extension. To determine the required contribution, the original feasibility test was recalculated to include the capital costs and revenue associated with serving this residential customer. The residential customer paid the incremental shortfall of $365.

Directive 6: "Centra treat all costs associated with the 4" pipe as Construction Work in Progress and not include said costs in Rate Base until such time as additional capacity is required."

Centra inadvertently recorded all of the costs associated with this project in rate base when the project was placed into service in February 2006. For the purposes of the true-up calculation, Centra has removed the incremental costs of the larger 4" plant from the feasibility test in order to provide a contribution analysis on the same basis as used to derive the original customer contribution.

If you require clarification of this true-up report, please do not hesitate to call the writer (360-3468) or Greg Barnlund (360-5243).

Yours truly,
MANITOBA HYDRO LAW DEPARTMENT
Per:

M Boyd

Marla D. Boyd
Barrister & Solicitor

att

Centra Gas Manitoba Inc.
RM of Rosser
Financial Feasibility Test

RM of Rosser (Commercial Project Site) Expansion Project Final True-up PUB Order 54/05

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
	TIME 0	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8	YEAR 9	YEAR 10
OPERATING ASSUMPTIONS											
Number of Customers		3	3	3	3	3	3	3	3	3	3
Annual Volume (Mcf)		4,721	4,096	4,351	3,628	3,420	3,420	3,420	3,420	3,420	3,420
Annual Volume (10^3m^3)		134	116	123	103	97	97	97	97	97	97
Projected Revenues		$34,343	$30,079	$31,810	$26,887	$25,463	$25,463	$25,463	$25,463	$25,463	$25,463
RATE BASE											
Gross Fixed Assets	$156,259	$156,259	$156,259	$156,259	$156,259	$156,259	$156,259	$156,259	$156,259	$156,259	$156,259
Accumulated Depreciation		$3,094	$6,188	$9,282	$12,376	$15,470	$18,564	$21,658	$24,751	$27,845	$30,939
Net Plant Closing	$156,259	$153,165	$150,071	$146,977	$143,883	$140,789	$137,696	$134,602	$131,508	$128,414	$125,320
Net Plant at Mid-Year		$154,712	$151,618	$148,524	$145,430	$142,336	$139,242	$136,149	$133,055	$129,961	$126,867
Contributions	$115,649	$113,359	$111,069	$108,780	$106,490	$104,200	$101,910	$99,620	$97,330	$95,040	$92,751
Contribution at Mid-Year		$114,504	$112,214	$109,924	$107,635	$105,345	$103,055	$100,765	$98,475	$96,185	$93,895
Working Capital Allowance		$1,329	$1,249	$1,316	$1,124	$1,056	$1,055	$1,055	$1,054	$1,053	$1,052
Rate Base at Mid-Year		$41,537	$40,653	$39,915	$38,920	$38,048	$37,243	$36,438	$35,633	$34,829	$34,024
REVENUE DEFICIENCY CALCULATION											
Cost of Gas		$26,467	$22,963	$24,393	$20,340	$19,174	$19,174	$19,174	$19,174	$19,174	$19,174
Operating & Maintenance Expenses		$300	$300	$300	$300	$300	$300	$300	$300	$300	$300
Depreciation Expense		$3,094	$3,094	$3,094	$3,094	$3,094	$3,094	$3,094	$3,094	$3,094	$3,094
Amortization of Contributions		($2,290)	($2,290)	($2,290)	($2,290)	($2,290)	($2,290)	($2,290)	($2,290)	($2,290)	($2,290)
Municipal Tax & Corp. Cap. Tax		$3,148	$3,160	$3,144	$3,141	$2,872	$2,856	$2,841	$2,825	$2,810	$2,795
Income Taxes		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Overall Return		$3,191	$2,938	$2,884	$2,812	$2,313	$2,265	$2,216	$2,167	$2,118	$2,069
Total Revenue Requirement		$33,910	$30,165	$31,525	$27,397	$25,463	$25,399	$25,334	$25,270	$25,205	$25,141
Projected Revenues		$34,343	$30,079	$31,810	$26,887	$25,463	$25,463	$25,463	$25,463	$25,463	$25,463
Revenue Deficiency (Annual)		$433	($86)	$285	($510)	$0	$64	$129	$193	$258	$322
Revenue to Cost Ratio		101.3%	99.7%	100.9%	98.1%	100.0%	100.3%	100.5%	100.8%	101.0%	101.3%
NPV of Revenue Deficiency	$6,278										
CONTRIBUTION REQUIREMENT											
Total Contribution Required	$115,649										

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Centra Gas Manitoba Inc.
RM of Rosser
Financial Feasibility Test

1	**RM of Rosser (Commercial Project Site) Expansion Project Final True-up PUB Order 54/05**										
2											
3		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
4		YEAR 11	YEAR 12	YEAR 13	YEAR 14	YEAR 15	YEAR 16	YEAR 17	YEAR 18	YEAR 19	YEAR 20
5	OPERATING ASSUMPTIONS										
6	Number of Customers	3	3	3	3	3	3	3	3	3	3
7	Annual Volume (Mcf)	3,420	3,420	3,420	3,420	3,420	3,420	3,420	3,420	3,420	3,420
8	Annual Volume (10^3m^3)	97	97	97	97	97	97	97	97	97	97
9	Projected Revenues	$25,463	$25,463	$25,463	$25,463	$25,463	$25,463	$25,463	$25,463	$25,463	$25,463
10											
11	RATE BASE										
12	Gross Fixed Assets	$156,259	$156,259	$156,259	$156,259	$156,259	$156,259	$156,259	$156,259	$156,259	$156,259
13	Accumulated Depreciation	$34,033	$37,127	$40,221	$43,315	$46,409	$49,503	$52,597	$55,691	$58,785	$61,879
14	Net Plant Closing	$122,226	$119,132	$116,038	$112,944	$109,850	$106,756	$103,662	$100,568	$97,474	$94,381
15	Net Plant at Mid-Year	$123,773	$120,679	$117,585	$114,491	$111,397	$108,303	$105,209	$102,115	$99,021	$95,927
16	Contributions	$90,461	$88,171	$85,881	$83,591	$81,301	$79,011	$76,722	$74,432	$72,142	$69,852
17	Contribution at Mid-Year	$91,606	$89,316	$87,026	$84,736	$82,446	$80,156	$77,867	$75,577	$73,287	$70,997
18	Working Capital Allowance	$1,052	$1,051	$1,050	$1,049	$1,049	$1,048	$1,047	$1,047	$1,046	$1,045
19	Rate Base at Mid-Year	$33,219	$32,414	$31,609	$30,804	$30,000	$29,195	$28,390	$27,585	$26,780	$25,976
20											
21	REVENUE DEFICIENCY CALCULATION										
22	Cost of Gas	$19,174	$19,174	$19,174	$19,174	$19,174	$19,174	$19,174	$19,174	$19,174	$19,174
23	Operating & Maintenance Expenses	$300	$300	$300	$300	$300	$300	$300	$300	$300	$300
24	Depreciation Expense	$3,094	$3,094	$3,094	$3,094	$3,094	$3,094	$3,094	$3,094	$3,094	$3,094
25	Amortization of Contributions	($2,290)	($2,290)	($2,290)	($2,290)	($2,290)	($2,290)	($2,290)	($2,290)	($2,290)	($2,290)
26	Municipal Tax & Corp. Cap. Tax	$2,779	$2,764	$2,748	$2,733	$2,717	$2,702	$2,686	$2,671	$2,655	$2,640
27	Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	Overall Return	$2,020	$1,971	$1,922	$1,873	$1,824	$1,775	$1,726	$1,677	$1,628	$1,579
29	Total Revenue Requirement	$25,077	$25,012	$24,948	$24,883	$24,819	$24,755	$24,690	$24,626	$24,561	$24,497
30	Projected Revenues	$25,463	$25,463	$25,463	$25,463	$25,463	$25,463	$25,463	$25,463	$25,463	$25,463
31	Revenue Deficiency (Annual)	$386	$451	$515	$580	$644	$708	$773	$837	$902	$966
32	Revenue to Cost Ratio	101.5%	101.8%	102.1%	102.3%	102.6%	102.9%	103.1%	103.4%	103.7%	103.9%

Attachment
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Centra Gas Manitoba Inc.
RM of Rosser
Financial Feasibility Test

Attachment
Page 3 of 3
October 20, 2011

1	**RM of Rosser (Commercial Project Site) Expansion Project Final True-up PUB Order 54/05**										
2											
3		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
4		YEAR 21	YEAR 22	YEAR 23	YEAR 24	YEAR 25	YEAR 26	YEAR 27	YEAR 28	YEAR 29	YEAR 30
5	OPERATING ASSUMPTIONS										
6	Number of Customers	3	3	3	3	3	3	3	3	3	3
7	Annual Volume (Mcf)	3,420	3,420	3,420	3,420	3,420	3,420	3,420	3,420	3,420	3,420
8	Annual Volume (10^3m^3)	97	97	97	97	97	97	97	97	97	97
9	Projected Revenues	$25,463	$25,463	$25,463	$25,463	$25,463	$25,463	$25,463	$25,463	$25,463	$25,463
10											
11	RATE BASE										
12	Gross Fixed Assets	$156,259	$156,259	$156,259	$156,259	$156,259	$156,259	$156,259	$156,259	$156,259	$156,259
13	Accumulated Depreciation	$64,973	$68,066	$71,160	$74,254	$77,348	$80,442	$83,536	$86,630	$89,724	$92,818
14	Net Plant Closing	$91,287	$88,193	$85,099	$82,005	$78,911	$75,817	$72,723	$69,629	$66,535	$63,441
15	Net Plant at Mid-Year	$92,834	$89,740	$86,646	$83,552	$80,458	$77,364	$74,270	$71,176	$68,082	$64,988
16	Contributions	$67,562	$65,272	$62,982	$60,693	$58,403	$56,113	$53,823	$51,533	$49,243	$46,954
17	Contribution at Mid-Year	$68,707	$66,417	$64,127	$61,838	$59,548	$57,258	$54,968	$52,678	$50,388	$48,098
18	Working Capital Allowance	$1,044	$1,044	$1,043	$1,042	$1,041	$1,041	$1,040	$1,039	$1,039	$1,038
19	Rate Base at Mid-Year	$25,171	$24,366	$23,561	$22,756	$21,952	$21,147	$20,342	$19,537	$18,732	$17,928
20											
21	REVENUE DEFICIENCY CALCULATION										
22	Cost of Gas	$19,174	$19,174	$19,174	$19,174	$19,174	$19,174	$19,174	$19,174	$19,174	$19,174
23	Operating & Maintenance Expenses	$300	$300	$300	$300	$300	$300	$300	$300	$300	$300
24	Depreciation Expense	$3,094	$3,094	$3,094	$3,094	$3,094	$3,094	$3,094	$3,094	$3,094	$3,094
25	Amortization of Contributions	($2,290)	($2,290)	($2,290)	($2,290)	($2,290)	($2,290)	($2,290)	($2,290)	($2,290)	($2,290)
26	Municipal Tax & Corp. Cap. Tax	$2,624	$2,609	$2,593	$2,578	$2,563	$2,547	$2,532	$2,516	$2,501	$2,485
27	Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	Overall Return	$1,531	$1,482	$1,433	$1,384	$1,335	$1,286	$1,237	$1,188	$1,139	$1,090
29	Total Revenue Requirement	$24,433	$24,368	$24,304	$24,239	$24,175	$24,111	$24,046	$23,982	$23,917	$23,853
30	Projected Revenues	$25,463	$25,463	$25,463	$25,463	$25,463	$25,463	$25,463	$25,463	$25,463	$25,463
31	Revenue Deficiency (Annual)	$1,030	$1,095	$1,159	$1,224	$1,288	$1,353	$1,417	$1,481	$1,546	$1,610
32	Revenue to Cost Ratio	104.2%	104.5%	104.8%	105.0%	105.3%	105.6%	105.9%	106.2%	106.5%	106.8%

Attachment
Page 3 of 3

Manitoba Hydro

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Telephone / N° de téléphone : (204) 360-3468 • Fax / N° de télécopieur : (204) 360-6147 • mboyd@hydro.mb.ca

February 5, 2013

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

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

Dear Mr. Singh:

**RE: CENTRA GAS MANITOBA INC. ("CENTRA")
FINAL TRUE-UP CALCULATION - FINANCIAL FEASIBILITY TEST
RURAL MUNICIPALITY OF ROCKWOOD
NATURAL GAS EXPANSION PROJECT (2006)**

Enclosed is the final true-up calculation of the feasibility test for the natural gas system extension in the Rural Municipality of Rockwood, as required by The Public Utilities Board of Manitoba ("PUB") in Directive 4 of Order 102/06. The true-up calculation is based upon the five year period ending December 31, 2011.

The true-up calculation for this system extension indicates a financial shortfall of $197,659 which is less than the original shortfall of $267,129. This difference is primarily due to higher than forecast customer volumes. As a result, a refund of $69,470 (plus GST) is due to the eight contributing commercial customers and has been allocated on a volumetric basis. Centra has issued these refunds to the contributing customers.

Order 102/06 also directed Centra to collect the remainder of all required customer contributions prior to the start of construction. Centra confirms that the balance of the required customer contribution was collected prior to commencing construction of the project.

If you require clarification of this true-up report, please call the writer (204-360-3468) or Greg Barnlund (204-360-5243).

Yours truly,
MANITOBA HYDRO LAW DEPARTMENT
Per:
M Boyd

Marla D. Boyd
Barrister & Solicitor

Att.

Centra Gas Manitoba Inc.
RM of Rockwood
Financial Feasibility Test

1	**RM of Rockwood Expansion Project Final True-up PUB Order 102/06**											
2		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
3		YEAR 0	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8	YEAR 9	YEAR 10
4	**OPERATING ASSUMPTIONS**											
5	Number of Customers		8	8	8	8	8	8	8	8	8	8
6	Annual Volume (Mcf)		25,466	25,191	18,763	13,317	14,400	14,400	14,400	14,400	14,400	14,400
7	Annual Volume (10^3m^3)		721	714	532	377	408	408	408	408	408	408
8	Projected Revenues		$170,098	$168,128	$126,960	$92,252	$99,251	$99,251	$99,251	$99,251	$99,251	$99,251
9	**RATE BASE**											
10	Gross Fixed Assets	$240,490	$399,200	$399,200	$399,200	$399,200	$399,200	$399,200	$399,200	$399,200	$399,200	$399,200
11	Accumulated Depreciation		$8,180	$16,359	$24,539	$32,719	$40,899	$49,078	$57,258	$65,438	$73,617	$81,797
12	Net Plant Closing	$240,490	$391,020	$382,840	$374,661	$366,481	$358,301	$350,122	$341,942	$333,762	$325,582	$317,403
13	Net Plant at Mid-Year		$315,755	$386,930	$378,751	$370,571	$362,391	$354,211	$346,032	$337,852	$329,672	$321,493
14	Contributions	$197,659	$193,609	$189,559	$185,509	$181,459	$177,409	$173,359	$169,309	$165,258	$161,208	$157,158
15	Contribution at Mid-Year		$195,634	$191,584	$187,534	$183,484	$179,434	$175,384	$171,334	$167,284	$163,233	$159,183
16	Working Capital Allowance		$6,678	$6,609	$5,041	$3,691	$3,958	$3,956	$3,954	$3,953	$3,951	$3,949
17	Rate Base at Mid-Year		$126,800	$201,955	$196,258	$190,778	$186,916	$182,784	$178,653	$174,521	$170,390	$166,258
18	**REVENUE DEFICIENCY CALCULATION**											
19												
20	Cost of Gas		$131,337	$129,914	$96,765	$68,683	$74,270	$74,270	$74,270	$74,270	$74,270	$74,270
21	Operating & Maintenance Expenses		$800	$800	$800	$800	$800	$800	$800	$800	$800	$800
22	Depreciation Expense		$8,180	$8,180	$8,180	$8,180	$8,180	$8,180	$8,180	$8,180	$8,180	$8,180
23	Amortization of Contributions		($4,050)	($4,050)	($4,050)	($4,050)	($4,050)	($4,050)	($4,050)	($4,050)	($4,050)	($4,050)
24	Municipal Tax & Corp.Cap. Tax		$9,175	$9,131	$9,101	$8,608	$8,686	$8,645	$8,604	$8,563	$8,522	$8,481
25	Income Taxes		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Overall Return		$9,162	$12,280	$11,933	$11,600	$11,365	$11,114	$10,863	$10,612	$10,360	$10,109
27	Total Revenue Requirement		$154,604	$156,255	$122,729	$93,821	$99,251	$98,958	$98,666	$98,374	$98,082	$97,790
28	Projected Revenues		$170,098	$168,128	$126,960	$92,252	$99,251	$99,251	$99,251	$99,251	$99,251	$99,251
29	Revenue Deficiency (Annual)		$15,494	$11,873	$4,231	($1,569)	($0)	$292	$584	$876	$1,168	$1,461
30	Revenue to Cost Ratio		110.0%	107.6%	103.4%	98.3%	100.0%	100.3%	100.6%	100.9%	101.2%	101.5%
31	NPV of Revenue Deficiency	$54,998										
32	**CONTRIBUTION REQUIREMENT**											
33	Total Contribution Required	$197,659										

Centra Gas Manitoba Inc.
RM of Rockwood
Financial Feasibility Test

1 **RM of Rockwood Expansion Project Final True-up PUB Order 102/06**

2			2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
3			YEAR 11	YEAR 12	YEAR 13	YEAR 14	YEAR 15	YEAR 16	YEAR 17	YEAR 18	YEAR 19	YEAR 20
4	**OPERATING ASSUMPTIONS**											
5	Number of Customers		8	8	8	8	8	8	8	8	8	8
6	Annual Volume (Mcf)		14,400	14,400	14,400	14,400	14,400	14,400	14,400	14,400	14,400	14,400
7	Annual Volume (10^3m^3)		408	408	408	408	408	408	408	408	408	408
8	Projected Revenues		$99,251	$99,251	$99,251	$99,251	$99,251	$99,251	$99,251	$99,251	$99,251	$99,251
9	**RATE BASE**											
10	Gross Fixed Assets		$399,200	$399,200	$399,200	$399,200	$399,200	$399,200	$399,200	$399,200	$399,200	$399,200
11	Accumulated Depreciation		$89,977	$98,157	$106,336	$114,516	$122,696	$130,875	$139,055	$147,235	$155,415	$163,594
12	Net Plant Closing	$317,403	$309,223	$301,043	$292,864	$284,684	$276,504	$268,325	$260,145	$251,965	$243,785	$235,606
13	Net Plant at Mid-Year		$313,313	$305,133	$296,954	$288,774	$280,594	$272,414	$264,235	$256,055	$247,875	$239,696
14	Contributions	$157,158	$153,108	$149,058	$145,008	$140,958	$136,908	$132,858	$128,808	$124,758	$120,707	$116,657
15	Contribution at Mid-Year		$155,133	$151,083	$147,033	$142,983	$138,933	$134,883	$130,833	$126,783	$122,733	$118,682
16	Working Capital Allowance		$3,947	$3,945	$3,943	$3,941	$3,939	$3,937	$3,935	$3,933	$3,931	$3,929
17	Rate Base at Mid-Year		$162,126	$157,995	$153,863	$149,732	$145,600	$141,469	$137,337	$133,206	$129,074	$124,942
18	**REVENUE DEFICIENCY CALCULATION**											
19												
20	Cost of Gas		$74,270	$74,270	$74,270	$74,270	$74,270	$74,270	$74,270	$74,270	$74,270	$74,270
21	Operating & Maintenance Expenses		$800	$800	$800	$800	$800	$800	$800	$800	$800	$800
22	Depreciation Expense		$8,180	$8,180	$8,180	$8,180	$8,180	$8,180	$8,180	$8,180	$8,180	$8,180
23	Amortization of Contributions		($4,050)	($4,050)	($4,050)	($4,050)	($4,050)	($4,050)	($4,050)	($4,050)	($4,050)	($4,050)
24	Municipal Tax & Corp.Cap. Tax		$8,441	$8,400	$8,359	$8,318	$8,277	$8,236	$8,195	$8,154	$8,113	$8,072
25	Income Taxes		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Overall Return		$9,858	$9,607	$9,356	$9,104	$8,853	$8,602	$8,351	$8,100	$7,848	$7,597
27	Total Revenue Requirement		$97,498	$97,206	$96,914	$96,622	$96,329	$96,037	$95,745	$95,453	$95,161	$94,869
28	Projected Revenues		$99,251	$99,251	$99,251	$99,251	$99,251	$99,251	$99,251	$99,251	$99,251	$99,251
29	Revenue Deficiency (Annual)		$1,753	$2,045	$2,337	$2,629	$2,921	$3,213	$3,505	$3,798	$4,090	$4,382
30	Revenue to Cost Ratio		101.8%	102.1%	102.4%	102.7%	103.0%	103.3%	103.7%	104.0%	104.3%	104.6%

Centra Gas Manitoba Inc.
RM of Rockwood
Financial Feasibility Test

1	**RM of Rockwood Expansion Project Final True-up PUB Order 102/06**											
2			2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
3			YEAR 21	YEAR 22	YEAR 23	YEAR 24	YEAR 25	YEAR 26	YEAR 27	YEAR 28	YEAR 29	YEAR 30
4	**OPERATING ASSUMPTIONS**											
5	Number of Customers		8	8	8	8	8	8	8	8	8	8
6	Annual Volume (Mcf)		14,400	14,400	14,400	14,400	14,400	14,400	14,400	14,400	14,400	14,400
7	Annual Volume (10^3m^3)		408	408	408	408	408	408	408	408	408	408
8	Projected Revenues		$99,251	$99,251	$99,251	$99,251	$99,251	$99,251	$99,251	$99,251	$99,251	$99,251
9	**RATE BASE**											
10	Gross Fixed Assets		$399,200	$399,200	$399,200	$399,200	$399,200	$399,200	$399,200	$399,200	$399,200	$399,200
11	Accumulated Depreciation		$171,774	$179,954	$188,133	$196,313	$204,493	$212,672	$220,852	$229,032	$237,212	$245,391
12	Net Plant Closing	$235,606	$227,426	$219,246	$211,067	$202,887	$194,707	$186,527	$178,348	$170,168	$161,988	$153,809
13	Net Plant at Mid-Year		$231,516	$223,336	$215,156	$206,977	$198,797	$190,617	$182,438	$174,258	$166,078	$157,898
14	Contributions	$116,657	$112,607	$108,557	$104,507	$100,457	$96,407	$92,357	$88,307	$84,257	$80,207	$76,157
15	Contribution at Mid-Year		$114,632	$110,582	$106,532	$102,482	$98,432	$94,382	$90,332	$86,282	$82,232	$78,182
16	Working Capital Allowance		$3,927	$3,925	$3,924	$3,922	$3,920	$3,918	$3,916	$3,914	$3,912	$3,910
17	Rate Base at Mid-Year		$120,811	$116,679	$112,548	$108,416	$104,285	$100,153	$96,022	$91,890	$87,758	$83,627
18	**REVENUE DEFICIENCY CALCULATION**											
19												
20	Cost of Gas		$74,270	$74,270	$74,270	$74,270	$74,270	$74,270	$74,270	$74,270	$74,270	$74,270
21	Operating & Maintenance Expenses		$800	$800	$800	$800	$800	$800	$800	$800	$800	$800
22	Depreciation Expense		$8,180	$8,180	$8,180	$8,180	$8,180	$8,180	$8,180	$8,180	$8,180	$8,180
23	Amortization of Contributions		($4,050)	($4,050)	($4,050)	($4,050)	($4,050)	($4,050)	($4,050)	($4,050)	($4,050)	($4,050)
24	Municipal Tax & Corp.Cap. Tax		$8,032	$7,991	$7,950	$7,909	$7,868	$7,827	$7,786	$7,745	$7,704	$7,663
25	Income Taxes		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Overall Return		$7,346	$7,095	$6,843	$6,592	$6,341	$6,090	$5,839	$5,587	$5,336	$5,085
27	Total Revenue Requirement		$94,577	$94,285	$93,993	$93,700	$93,408	$93,116	$92,824	$92,532	$92,240	$91,948
28	Projected Revenues		$99,251	$99,251	$99,251	$99,251	$99,251	$99,251	$99,251	$99,251	$99,251	$99,251
29	Revenue Deficiency (Annual)		$4,674	$4,966	$5,258	$5,550	$5,842	$6,134	$6,427	$6,719	$7,011	$7,303
30	Revenue to Cost Ratio		104.9%	105.3%	105.6%	105.9%	106.3%	106.6%	106.9%	107.3%	107.6%	107.9%

Manitoba Hydro

PO Box 815 • Winnipeg Manitoba Canada • R3C 2P4
Street Location for DELIVERY: 22rd floor – 360 Portage Avenue
Telephone / N° de téléphone : (204) 360-3468 • Fax / N° de télécopieur : (204) 360-6147 • mboyd@hydro.mb.ca

March 13, 2013

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

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

Dear Mr. Singh:

**RE: CENTRA GAS MANITOBA INC.
REVISED FINAL TRUE-UP CALCULATION - FINANCIAL FEASIBILITY TEST
TOWN OF SHOAL LAKE AND RURAL MUNICIPALITY OF SHOAL LAKE
NATURAL GAS EXPANSION PROJECT (2006)**

On February 5, 2013, Centra Gas Manitoba Inc. ("Centra") filed the final true-up calculation of the feasibility test for the natural gas system extension in the Town of Shoal Lake and Rural Municipality ("RM") of Shoal Lake, as required by the Public Utilities Board of Manitoba in Directive 3 of Order 72/06. Centra has calculated a revised final true-up for the Town of Shoal Lake and RM of Shoal Lake adjusting the rate used to determine the overall return on rate base for 2008 and 2009 to be consistent with rate used by Centra for these years in previous feasibility tests and true-up calculations. The revised final true-up calculation is enclosed.

The revised true-up calculation indicates a financial shortfall of $1,511,115, compared to $1,511,801 in the original true-up calculation. As noted in Centra's letter of February 5, 2013, contributions from the Shoal Lake Regional Community Development Corporation totaled $1,600,000 (plus GST) pursuant to the funding agreement. A total refund of $88,199 (plus GST) has already been refunded to the customer. Based on the revised true-up calculation, an additional $686 (plus GST) will be refunded to the customer.

Centra notes that it also recalculated the final true-up of the feasibility test for the natural gas system extension in the RM of Rockwood, as originally filed on February 5, 2013, with the adjusted overall rate of return for 2008 and 2009. However, there is no change in the customer contribution or refund for Rockwood due to the requirement that the revenue-to-cost ratio equal 1.0 by the end of the fifth year of the calculation.

If you require clarification of this true-up report, please call the writer at 204-360-3468 or Greg Barnlund at 204-360-5243.

Yours truly,
MANITOBA HYDRO LAW DEPARTMENT
Per:

M Boyd

Marla D. Boyd
Barrister & Solicitor

Att.

Centra Gas Manitoba Inc. | Attachment
Town of Shoal Lake and RM of Shoal Lake | Page 1 of 3
Financial Feasibility Test | March 13, 2013

1 Revised Town of Shoal Lake and RM of Shoal Lake Expansion Project Final True-up PUB Order 72/06

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Line		2006 YEAR 0	2007 YEAR 1	2008 YEAR 2	2009 YEAR 3	2010 YEAR 4	2011 YEAR 5	2012 YEAR 6	2013 YEAR 7	2014 YEAR 8	2015 YEAR 9	2016 YEAR 10
3												
4												
	OPERATING ASSUMPTIONS											
5	Number of Customers		36	38	38	38	38	38	38	38	38	38
6	Annual Volume (Mcf)		6,363	16,191	22,593	19,004	15,835	15,835	15,835	15,835	15,835	15,835
7	Annual Volume (103m3)		180	459	640	538	449	449	449	449	449	449
8	Projected Revenues		$55,642	$121,525	$162,060	$138,405	$119,306	$119,306	$119,306	$119,306	$119,306	$119,306
9	RATE BASE											
10	Gross Fixed Assets	$1,439,907	$1,459,002	$1,468,633	$1,469,959	$1,469,959	$1,469,959	$1,469,959	$1,469,959	$1,469,959	$1,469,959	$1,469,959
11	Accumulated Depreciation		$27,120	$54,419	$81,742	$109,066	$136,389	$163,713	$191,036	$218,360	$245,684	$273,007
12	Net Plant Closing	$1,439,907	$1,431,882	$1,414,214	$1,388,217	$1,360,893	$1,333,570	$1,306,246	$1,278,922	$1,251,599	$1,224,275	$1,196,952
13	Net Plant at Mid-Year		$1,435,894	$1,423,048	$1,401,215	$1,374,555	$1,347,231	$1,319,908	$1,292,584	$1,265,261	$1,237,937	$1,210,613
14	Contributions	$1,511,115	$1,483,008	$1,454,901	$1,426,795	$1,398,688	$1,370,581	$1,342,474	$1,314,368	$1,286,261	$1,258,154	$1,230,047
15	Contribution at Mid-Year		$1,497,061	$1,468,955	$1,440,848	$1,412,741	$1,384,634	$1,356,528	$1,328,421	$1,300,314	$1,272,208	$1,244,101
16	Working Capital Allowance		$3,588	$6,021	$7,595	$6,626	$5,752	$5,745	$5,739	$5,732	$5,726	$5,719
17	Rate Base at Mid-Year		($57,579)	($39,886)	($32,038)	($31,560)	($31,652)	($30,875)	($30,098)	($29,321)	($28,545)	($27,768)
18	REVENUE DEFICIENCY CALCULATION											
19												
20	Cost of Gas		$32,874	$83,612	$116,613	$98,095	$81,778	$81,778	$81,778	$81,778	$81,778	$81,778
21	Operating & Maintenance Expenses		$3,600	$3,800	$3,800	$3,800	$3,800	$3,800	$3,800	$3,800	$3,800	$3,800
22	Depreciation Expense		$27,120	$27,299	$27,324	$27,324	$27,324	$27,324	$27,324	$27,324	$27,324	$27,324
23	Amortization of Contributions		($28,107)	($28,107)	($28,107)	($28,107)	($28,107)	($28,107)	($28,107)	($28,107)	($28,107)	($28,107)
24	Municipal Tax & Corp.Cap. Tax		$39,450	$39,984	$40,283	$38,311	$36,122	$35,985	$35,848	$35,712	$35,575	$35,438
25	Income Taxes		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Overall Return		($4,161)	($2,882)	($2,315)	($1,919)	($1,925)	($1,877)	($1,830)	($1,783)	($1,736)	($1,688)
27	Total Revenue Requirement		$70,776	$123,706	$157,598	$137,503	$118,992	$118,902	$118,813	$118,723	$118,634	$118,545
28	Projected Revenues		$55,642	$121,525	$162,060	$138,405	$119,306	$119,306	$119,306	$119,306	$119,306	$119,306
29	Revenue Deficiency (Annual)		($15,134)	($2,182)	$4,462	$902	$315	$404	$494	$583	$672	$762
30	Revenue to Cost Ratio		78.6%	98.2%	102.8%	100.7%	100.3%	100.3%	100.4%	100.5%	100.6%	100.6%
31	NPV of Revenue Deficiency	$1										
32	CONTRIBUTION REQUIREMENT											
33	Total Contribution Required	$1,511,115										

Centra Gas Manitoba Inc.
Town of Shoal Lake and RM of Shoal Lake
Financial Feasibility Test

Attachment
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March 13, 2013

1 Revised Town of Shoal Lake and RM of Shoal Lake Expansion Project Final True-up PUB Order 72/06

Line			2017 YEAR 11	2018 YEAR 12	2019 YEAR 13	2020 YEAR 14	2021 YEAR 15	2022 YEAR 16	2023 YEAR 17	2024 YEAR 18	2025 YEAR 19	2026 YEAR 20
	OPERATING ASSUMPTIONS											
5	Number of Customers		38	38	38	38	38	38	38	38	38	38
6	Annual Volume (Mcf)		15,835	15,835	15,835	15,835	15,835	15,835	15,835	15,835	15,835	15,835
7	Annual Volume (103m3)		449	449	449	449	449	449	449	449	449	449
8	Projected Revenues		$119,306	$119,306	$119,306	$119,306	$119,306	$119,306	$119,306	$119,306	$119,306	$119,306
9	RATE BASE											
10	Gross Fixed Assets		$1,469,959	$1,469,959	$1,469,959	$1,469,959	$1,469,959	$1,469,959	$1,469,959	$1,469,959	$1,469,959	$1,469,959
11	Accumulated Depreciation		$300,331	$327,654	$354,978	$382,301	$409,625	$436,949	$464,272	$491,596	$518,919	$546,243
12	Net Plant Closing	$1,196,952	$1,169,628	$1,142,305	$1,114,981	$1,087,657	$1,060,334	$1,033,010	$1,005,687	$978,363	$951,040	$923,716
13	Net Plant at Mid-Year		$1,183,290	$1,155,966	$1,128,643	$1,101,319	$1,073,996	$1,046,672	$1,019,349	$992,025	$964,701	$937,378
14	Contributions	$1,230,047	$1,201,941	$1,173,834	$1,145,727	$1,117,620	$1,089,514	$1,061,407	$1,033,300	$1,005,194	$977,087	$948,980
15	Contribution at Mid-Year		$1,215,994	$1,187,887	$1,159,781	$1,131,674	$1,103,567	$1,075,460	$1,047,354	$1,019,247	$991,140	$963,033
16	Working Capital Allowance		$5,713	$5,706	$5,700	$5,693	$5,687	$5,681	$5,674	$5,668	$5,661	$5,655
17	Rate Base at Mid-Year		($26,991)	($26,215)	($25,438)	($24,661)	($23,884)	($23,108)	($22,331)	($21,554)	($20,778)	($20,001)
18	REVENUE DEFICIENCY CALCULATION											
20	Cost of Gas		$81,778	$81,778	$81,778	$81,778	$81,778	$81,778	$81,778	$81,778	$81,778	$81,778
21	Operating & Maintenance Expenses		$3,800	$3,800	$3,800	$3,800	$3,800	$3,800	$3,800	$3,800	$3,800	$3,800
22	Depreciation Expense		$27,324	$27,324	$27,324	$27,324	$27,324	$27,324	$27,324	$27,324	$27,324	$27,324
23	Amortization of Contributions		($28,107)	($28,107)	($28,107)	($28,107)	($28,107)	($28,107)	($28,107)	($28,107)	($28,107)	($28,107)
24	Municipal Tax & Corp.Cap. Tax		$35,302	$35,165	$35,029	$34,892	$34,755	$34,619	$34,482	$34,346	$34,209	$34,072
25	Income Taxes		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Overall Return		($1,641)	($1,594)	($1,547)	($1,500)	($1,452)	($1,405)	($1,358)	($1,311)	($1,263)	($1,216)
27	Total Revenue Requirement		$118,455	$118,366	$118,276	$118,187	$118,098	$118,008	$117,919	$117,829	$117,740	$117,651
28	Projected Revenues		$119,306	$119,306	$119,306	$119,306	$119,306	$119,306	$119,306	$119,306	$119,306	$119,306
29	Revenue Deficiency (Annual)		$851	$941	$1,030	$1,119	$1,209	$1,298	$1,387	$1,477	$1,566	$1,656
30	Revenue to Cost Ratio		100.7%	100.8%	100.9%	100.9%	101.0%	101.1%	101.2%	101.3%	101.3%	101.4%

Centra Gas Manitoba Inc.
Town of Shoal Lake and RM of Shoal Lake
Financial Feasibility Test

1 Revised Town of Shoal Lake and RM of Shoal Lake Expansion Project Final True-up PUB Order 72/06

2

			2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
3			YEAR 21	YEAR 22	YEAR 23	YEAR 24	YEAR 25	YEAR 26	YEAR 27	YEAR 28	YEAR 29	YEAR 30
4												
	OPERATING ASSUMPTIONS											
5	Number of Customers		38	38	38	38	38	38	38	38	38	38
6	Annual Volume (Mcf)		15,835	15,835	15,835	15,835	15,835	15,835	15,835	15,835	15,835	15,835
7	Annual Volume (103m3)		449	449	449	449	449	449	449	449	449	449
8	Projected Revenues		$119,306	$119,306	$119,306	$119,306	$119,306	$119,306	$119,306	$119,306	$119,306	$119,306
9	RATE BASE											
10	Gross Fixed Assets		$1,469,959	$1,469,959	$1,469,959	$1,469,959	$1,469,959	$1,469,959	$1,469,959	$1,469,959	$1,469,959	$1,469,959
11	Accumulated Depreciation		$573,566	$600,890	$628,214	$655,537	$682,861	$710,184	$737,508	$764,831	$792,155	$819,478
12	Net Plant Closing	$923,716	$896,392	$869,069	$841,745	$814,422	$787,098	$759,775	$732,451	$705,128	$677,804	$650,480
13	Net Plant at Mid-Year		$910,054	$882,731	$855,407	$828,084	$800,760	$773,436	$746,113	$718,789	$691,466	$664,142
14	Contributions	$948,980	$920,873	$892,767	$864,660	$836,553	$808,446	$780,340	$752,233	$724,126	$696,019	$667,913
15	Contribution at Mid-Year		$934,927	$906,820	$878,713	$850,606	$822,500	$794,393	$766,286	$738,180	$710,073	$681,966
16	Working Capital Allowance		$5,648	$5,642	$5,635	$5,629	$5,622	$5,616	$5,609	$5,603	$5,597	$5,590
17	Rate Base at Mid-Year		($19,224)	($18,447)	($17,671)	($16,894)	($16,117)	($15,341)	($14,564)	($13,787)	($13,011)	($12,234)
18	REVENUE DEFICIENCY CALCULATION											
19												
20	Cost of Gas		$81,778	$81,778	$81,778	$81,778	$81,778	$81,778	$81,778	$81,778	$81,778	$81,778
21	Operating & Maintenance Expenses		$3,800	$3,800	$3,800	$3,800	$3,800	$3,800	$3,800	$3,800	$3,800	$3,800
22	Depreciation Expense		$27,324	$27,324	$27,324	$27,324	$27,324	$27,324	$27,324	$27,324	$27,324	$27,324
23	Amortization of Contributions		($28,107)	($28,107)	($28,107)	($28,107)	($28,107)	($28,107)	($28,107)	($28,107)	($28,107)	($28,107)
24	Municipal Tax & Corp.Cap. Tax		$33,936	$33,799	$33,662	$33,526	$33,389	$33,253	$33,116	$32,979	$32,843	$32,706
25	Income Taxes		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Overall Return		($1,169)	($1,122)	($1,074)	($1,027)	($980)	($933)	($886)	($838)	($791)	($744)
27	Total Revenue Requirement		$117,561	$117,472	$117,383	$117,293	$117,204	$117,114	$117,025	$116,936	$116,846	$116,757
28	Projected Revenues		$119,306	$119,306	$119,306	$119,306	$119,306	$119,306	$119,306	$119,306	$119,306	$119,306
29	Revenue Deficiency (Annual)		$1,745	$1,834	$1,924	$2,013	$2,103	$2,192	$2,281	$2,371	$2,460	$2,550
30	Revenue to Cost Ratio		101.5%	101.6%	101.6%	101.7%	101.8%	101.9%	101.9%	102.0%	102.1%	102.2%

PUB/CENTRA I-134

Subject: **Tab 15 - Directives**

Reference: **Tab 15 Appendix 15.1**

a) Please confirm whether Centra is estimating capital costs for main extensions according to the specific construction technique used for each extension, either four party trenching or conventional installation.

ANSWER:

Centra confirms that since January, 2010, it has been estimating capital costs for main extension requests based on the specific construction technique that will be used. Main extensions that will be installed as four party trench are estimated using costs established specifically for four party installations. Capital costs for all other main extension requests are estimated based on conventional methods.

PUB/CENTRA I-134

Subject: Tab 15 - Directives

Reference: Tab 15 Appendix 15.1

b) If Centra is estimating the capital costs for all main extensions assuming conventional installation techniques, please explain why it is not estimating the capital costs of four party trench installations using that construction technique.

ANSWER:

Please see Centra's response to PUB/Centra I-134(a).

PUB/CENTRA I-134

Subject: **Tab 15 - Directives**

Reference: **Tab 15 Appendix 15.1**

c) Please explain why MER 2008-00027 in the RM of Rockwood has no customers.

ANSWER:

MER 2008-00027 in the RM of Rockwood was a main extension request to pre-service a light industrial park where no committed customers had been identified at the time of the request.

PUB/CENTRA I-134

Subject: **Tab 15 - Directives**

Reference: **Tab 15 Appendix 15.1**

d) Please file the feasibility tests for the following main extensions:

- **a. 2008-00026 Arrowwood - Wpg**
- **b. 2009-00011 Municipal Road 38N - Hanover**
- **c. 2010-00111 Bergen Road - Rosser**
- **d. 2011-00005 Portage La Prairie**
- **e. 2012-00139 Pine Drive - La Broquerie**

ANSWER:

The requested feasibility tests are attached to this response.

Financial Feasibility Test

1	**MER 2008-00026 Arrowwood - Winnipeg**											
2		YEAR 0	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8	YEAR 9	YEAR 10
3		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
4	**OPERATING ASSUMPTIONS**											
5	Number of Customers		5	10	15	20	25	25	25	25	25	25
6	Annual Volume (Mcf)		500	1000	1500	2000	2500	2500	2500	2500	2500	2500
7	Annual Volume (10^3m^3)		14	28	42	57	71	71	71	71	71	71
8	Projected Revenues		$6,479	$12,958	$19,437	$25,916	$32,395	$32,395	$32,395	$32,395	$32,395	$32,395
9	**RATE BASE**											
10	Gross Fixed Assets	$11,592	$17,031	$22,579	$28,237	$34,009	$39,896	$39,896	$39,896	$39,896	$39,896	$39,896
11	Accumulated Depreciation		$485	$1,127	$1,931	$2,899	$4,034	$5,170	$6,305	$7,441	$8,576	$9,712
12	Net Plant Closing	$11,592	$16,546	$21,451	$26,306	$31,110	$35,861	$34,726	$33,590	$32,455	$31,319	$30,184
13	Net Plant at Mid-Year		$14,069	$18,999	$23,879	$28,708	$33,486	$35,294	$34,158	$33,023	$31,887	$30,752
14	Contributions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	Contribution at Mid-Year		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16	Working Capital Allowance		$245	$474	$703	$931	$1,160	$1,160	$1,159	$1,159	$1,159	$1,159
17	Rate Base at Mid-Year		$14,315	$19,473	$24,581	$29,639	$34,646	$36,453	$35,318	$34,182	$33,046	$31,910
18	**REVENUE DEFICIENCY CALCULATION**											
19												
20	Cost of Gas		$4,452	$8,903	$13,355	$17,807	$22,259	$22,259	$22,259	$22,259	$22,259	$22,259
21	Operating & Maintenance Expenses		$200	$400	$600	$800	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000
22	Depreciation Expense		$485	$643	$804	$968	$1,135	$1,135	$1,135	$1,135	$1,135	$1,135
23	Amortization of Contributions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	Municipal Tax & Corp.Cap. Tax		$539	$726	$913	$1,100	$1,286	$1,281	$1,275	$1,269	$1,264	$1,258
25	Income Taxes		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Overall Return		$1,034	$1,407	$1,776	$2,142	$2,503	$2,634	$2,552	$2,470	$2,388	$2,306
27	Total Revenue Requirement		$6,709	$12,079	$17,448	$22,816	$28,184	$28,309	$28,221	$28,133	$28,046	$27,958
28	Projected Revenues		$6,479	$12,958	$19,437	$25,916	$32,395	$32,395	$32,395	$32,395	$32,395	$32,395
29	Revenue Sufficiency (Deficiency)		($230)	$879	$1,989	$3,100	$4,211	$4,087	$4,174	$4,262	$4,350	$4,438
30	Revenue to Cost Ratio		96.6%	107.3%	111.4%	113.6%	114.9%	114.4%	114.8%	115.1%	115.5%	115.9%
31	Net Present Value	$46,445										
32	**CONTRIBUTION REQUIREMENT**											
33	Total Contribution Required	$0										

Financial Feasibility Test

1	**MER 2008-00026 Arrowwood - Winnipeg**										
2		YEAR 11	YEAR 12	YEAR 13	YEAR 14	YEAR 15	YEAR 16	YEAR 17	YEAR 18	YEAR 19	YEAR 20
3		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
4	**OPERATING ASSUMPTIONS**										
5	Number of Customers	25	25	25	25	25	25	25	25	25	25
6	Annual Volume (Mcf)	2500	2500	2500	2500	2500	2500	2500	2500	2500	2500
7	Annual Volume ($10^3 m^3$)	71	71	71	71	71	71	71	71	71	71
8	Projected Revenues	$32,395	$32,395	$32,395	$32,395	$32,395	$32,395	$32,395	$32,395	$32,395	$32,395
9	**RATE BASE**										
10	Gross Fixed Assets	$39,896	$39,896	$39,896	$39,896	$39,896	$39,896	$39,896	$39,896	$39,896	$39,896
11	Accumulated Depreciation	$10,847	$11,983	$13,118	$14,254	$15,389	$16,525	$17,660	$18,796	$19,931	$21,067
12	Net Plant Closing	$29,048	$27,913	$26,777	$25,642	$24,507	$23,371	$22,236	$21,100	$19,965	$18,829
13	Net Plant at Mid-Year	$29,616	$28,481	$27,345	$26,210	$25,074	$23,939	$22,803	$21,668	$20,532	$19,397
14	Contributions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	Contribution at Mid-Year	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16	Working Capital Allowance	$1,158	$1,158	$1,158	$1,158	$1,157	$1,157	$1,157	$1,157	$1,156	$1,156
17	Rate Base at Mid-Year	$30,775	$29,639	$28,503	$27,367	$26,232	$25,096	$23,960	$22,824	$21,689	$20,553
18	**REVENUE DEFICIENCY CALCULATION**										
19											
20	Cost of Gas	$22,259	$22,259	$22,259	$22,259	$22,259	$22,259	$22,259	$22,259	$22,259	$22,259
21	Operating & Maintenance Expenses	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000
22	Depreciation Expense	$1,135	$1,135	$1,135	$1,135	$1,135	$1,135	$1,135	$1,135	$1,135	$1,135
23	Amortization of Contributions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	Municipal Tax & Corp.Cap. Tax	$1,252	$1,247	$1,241	$1,235	$1,229	$1,224	$1,218	$1,212	$1,207	$1,201
25	Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Overall Return	$2,224	$2,142	$2,060	$1,978	$1,895	$1,813	$1,731	$1,649	$1,567	$1,485
27	Total Revenue Requirement	$27,870	$27,782	$27,695	$27,607	$27,519	$27,431	$27,344	$27,256	$27,168	$27,080
28	Projected Revenues	$32,395	$32,395	$32,395	$32,395	$32,395	$32,395	$32,395	$32,395	$32,395	$32,395
29	Revenue Sufficiency (Deficiency)	$4,525	$4,613	$4,701	$4,788	$4,876	$4,964	$5,052	$5,139	$5,227	$5,315
30	Revenue to Cost Ratio	116.2%	116.6%	117.0%	117.3%	117.7%	118.1%	118.5%	118.9%	119.2%	119.6%

Financial Feasibility Test

1	**MER 2008-00026 Arrowwood - Winnipeg**										
2		YEAR 21	YEAR 22	YEAR 23	YEAR 24	YEAR 25	YEAR 26	YEAR 27	YEAR 28	YEAR 29	YEAR 30
3		2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
4	**OPERATING ASSUMPTIONS**										
5	Number of Customers	25	25	25	25	25	25	25	25	25	25
6	Annual Volume (Mcf)	2500	2500	2500	2500	2500	2500	2500	2500	2500	2500
7	Annual Volume (10^3m^3)	71	71	71	71	71	71	71	71	71	71
8	Projected Revenues	$32,395	$32,395	$32,395	$32,395	$32,395	$32,395	$32,395	$32,395	$32,395	$32,395
9	**RATE BASE**										
10	Gross Fixed Assets	$39,896	$39,896	$39,896	$39,896	$39,896	$39,896	$39,896	$39,896	$39,896	$39,896
11	Accumulated Depreciation	$22,202	$23,338	$24,473	$25,609	$26,744	$27,880	$29,015	$30,151	$31,286	$32,422
12	Net Plant Closing	$17,694	$16,558	$15,423	$14,287	$13,152	$12,016	$10,881	$9,745	$8,610	$7,474
13	Net Plant at Mid-Year	$18,261	$17,126	$15,990	$14,855	$13,719	$12,584	$11,448	$10,313	$9,177	$8,042
14	Contributions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	Contribution at Mid-Year	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16	Working Capital Allowance	$1,156	$1,155	$1,155	$1,155	$1,155	$1,154	$1,154	$1,154	$1,154	$1,153
17	Rate Base at Mid-Year	$19,417	$18,281	$17,146	$16,010	$14,874	$13,738	$12,603	$11,467	$10,331	$9,195
18	**REVENUE DEFICIENCY CALCULATION**										
19											
20	Cost of Gas	$22,259	$22,259	$22,259	$22,259	$22,259	$22,259	$22,259	$22,259	$22,259	$22,259
21	Operating & Maintenance Expenses	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000
22	Depreciation Expense	$1,135	$1,135	$1,135	$1,135	$1,135	$1,135	$1,135	$1,135	$1,135	$1,135
23	Amortization of Contributions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	Municipal Tax & Corp.Cap. Tax	$1,195	$1,190	$1,184	$1,178	$1,173	$1,167	$1,161	$1,156	$1,150	$1,144
25	Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Overall Return	$1,403	$1,321	$1,239	$1,157	$1,075	$993	$911	$829	$747	$664
27	Total Revenue Requirement	$26,993	$26,905	$26,817	$26,729	$26,642	$26,554	$26,466	$26,378	$26,291	$26,203
28	Projected Revenues	$32,395	$32,395	$32,395	$32,395	$32,395	$32,395	$32,395	$32,395	$32,395	$32,395
29	Revenue Sufficiency (Deficiency)	$5,403	$5,490	$5,578	$5,666	$5,754	$5,841	$5,929	$6,017	$6,105	$6,192
30	Revenue to Cost Ratio	120.0%	120.4%	120.8%	121.2%	121.6%	122.0%	122.4%	122.8%	123.2%	123.6%

Financial Feasibility Test

1	**MER 2009-00011 Municipal Road 38N - Hanover**											
2		YEAR 0	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8	YEAR 9	YEAR 10
3		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
4	**OPERATING ASSUMPTIONS**											
5	Number of Customers		1	1	1	1	1	1	1	1	1	1
6	Annual Volume (Mcf)		996	996	996	996	996	996	996	996	996	996
7	Annual Volume (10^3m^3)		28	28	28	28	28	28	28	28	28	28
8	Projected Revenues		$11,449	$11,449	$11,449	$11,449	$11,449	$11,449	$11,449	$11,449	$11,449	$11,449
9	**RATE BASE**											
10	Gross Fixed Assets	$72,018	$77,244	$77,244	$77,244	$77,244	$77,244	$77,244	$77,244	$77,244	$77,244	$77,244
11	Accumulated Depreciation		$2,201	$4,403	$6,604	$8,806	$11,007	$13,209	$15,410	$17,612	$19,813	$22,014
12	Net Plant Closing	$72,018	$75,042	$72,841	$70,639	$68,438	$66,236	$64,035	$61,834	$59,632	$57,431	$55,229
13	Net Plant at Mid-Year		$73,530	$73,941	$71,740	$69,539	$67,337	$65,136	$62,934	$60,733	$58,531	$56,330
14	Contributions	$59,177	$57,490	$55,804	$54,117	$52,430	$50,744	$49,057	$47,371	$45,684	$43,998	$42,311
15	Contributions at Mid-Year		$58,333	$56,647	$54,960	$53,274	$51,587	$49,901	$48,214	$46,528	$44,841	$43,155
16	Working Capital Allowance		$463	$463	$462	$462	$461	$461	$460	$460	$459	$459
17	Rate Base at Mid-Year		$15,660	$17,758	$17,242	$16,727	$16,211	$15,696	$15,180	$14,665	$14,150	$13,634
18	**REVENUE DEFICIENCY CALCULATION**											
19												
20	Cost of Gas		$9,391	$9,391	$9,391	$9,391	$9,391	$9,391	$9,391	$9,391	$9,391	$9,391
21	Operating & Maintenance Expenses		$40	$40	$40	$40	$40	$40	$40	$40	$40	$40
22	Depreciation Expense		$2,201	$2,201	$2,201	$2,201	$2,201	$2,201	$2,201	$2,201	$2,201	$2,201
23	Amortization of Contributions		($1,687)	($1,687)	($1,687)	($1,687)	($1,687)	($1,687)	($1,687)	($1,687)	($1,687)	($1,687)
24	Municipal Tax & Corp.Cap. Tax		$375	$364	$353	$342	$331	$320	$309	$298	$287	$276
25	Income Taxes		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Overall Return		$1,132	$1,283	$1,246	$1,209	$1,171	$1,134	$1,097	$1,060	$1,022	$985
27	Total Revenue Requirement		$11,453	$11,594	$11,545	$11,497	$11,449	$11,401	$11,352	$11,304	$11,256	$11,208
28	Projected Revenues		$11,449	$11,449	$11,449	$11,449	$11,449	$11,449	$11,449	$11,449	$11,449	$11,449
29	Revenue Sufficiency (Deficiency)		($4)	($145)	($97)	($48)	$0	$48	$97	$145	$193	$241
30	Revenue to Cost Ratio		100.0%	98.8%	99.2%	99.6%	100.0%	100.4%	100.9%	101.3%	101.7%	102.2%
31	Net Present Value	$3,466										
32	**CONTRIBUTION REQUIREMENT**											
33	Total Contribution Required	$59,177										

Financial Feasibility Test

1	**MER 2009-00011 Municipal Road 38N - Hanover**										
2		YEAR 11	YEAR 12	YEAR 13	YEAR 14	YEAR 15	YEAR 16	YEAR 17	YEAR 18	YEAR 19	YEAR 20
3		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
4	**OPERATING ASSUMPTIONS**										
5	Number of Customers	1	1	1	1	1	1	1	1	1	1
6	Annual Volume (Mcf)	996	996	996	996	996	996	996	996	996	996
7	Annual Volume (10^3m^3)	28	28	28	28	28	28	28	28	28	28
8	Projected Revenues	$11,449	$11,449	$11,449	$11,449	$11,449	$11,449	$11,449	$11,449	$11,449	$11,449
9	**RATE BASE**										
10	Gross Fixed Assets	$77,244	$77,244	$77,244	$77,244	$77,244	$77,244	$77,244	$77,244	$77,244	$77,244
11	Accumulated Depreciation	$24,216	$26,417	$28,619	$30,820	$33,022	$35,223	$37,425	$39,626	$41,827	$44,029
12	Net Plant Closing	$53,028	$50,826	$48,625	$46,423	$44,222	$42,021	$39,819	$37,618	$35,416	$33,215
13	Net Plant at Mid-Year	$54,128	$51,927	$49,726	$47,524	$45,323	$43,121	$40,920	$38,718	$36,517	$34,315
14	Contributions	$40,625	$38,938	$37,252	$35,565	$33,879	$32,192	$30,506	$28,819	$27,132	$25,446
15	Contributions at Mid-Year	$41,468	$39,781	$38,095	$36,408	$34,722	$33,035	$31,349	$29,662	$27,976	$26,289
16	Working Capital Allowance	$458	$458	$457	$457	$456	$456	$455	$455	$454	$454
17	Rate Base at Mid-Year	$13,119	$12,603	$12,088	$11,572	$11,057	$10,542	$10,026	$9,511	$8,995	$8,480
18	**REVENUE DEFICIENCY CALCULATION**										
19											
20	Cost of Gas	$9,391	$9,391	$9,391	$9,391	$9,391	$9,391	$9,391	$9,391	$9,391	$9,391
21	Operating & Maintenance Expenses	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40
22	Depreciation Expense	$2,201	$2,201	$2,201	$2,201	$2,201	$2,201	$2,201	$2,201	$2,201	$2,201
23	Amortization of Contributions	($1,687)	($1,687)	($1,687)	($1,687)	($1,687)	($1,687)	($1,687)	($1,687)	($1,687)	($1,687)
24	Municipal Tax & Corp.Cap. Tax	$265	$254	$243	$232	$221	$210	$199	$188	$177	$166
25	Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Overall Return	$948	$911	$873	$836	$799	$762	$724	$687	$650	$613
27	Total Revenue Requirement	$11,159	$11,111	$11,063	$11,015	$10,966	$10,918	$10,870	$10,822	$10,773	$10,725
28	Projected Revenues	$11,449	$11,449	$11,449	$11,449	$11,449	$11,449	$11,449	$11,449	$11,449	$11,449
29	Revenue Sufficiency (Deficiency)	$290	$338	$386	$434	$483	$531	$579	$627	$676	$724
30	Revenue to Cost Ratio	102.6%	103.0%	103.5%	103.9%	104.4%	104.9%	105.3%	105.8%	106.3%	106.7%

Financial Feasibility Test

1	**MER 2009-00011 Municipal Road 38N - Hanover**										
2		YEAR 21	YEAR 22	YEAR 23	YEAR 24	YEAR 25	YEAR 26	YEAR 27	YEAR 28	YEAR 29	YEAR 30
3		2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
4	**OPERATING ASSUMPTIONS**										
5	Number of Customers	1	1	1	1	1	1	1	1	1	1
6	Annual Volume (Mcf)	996	996	996	996	996	996	996	996	996	996
7	Annual Volume (10^3m^3)	28	28	28	28	28	28	28	28	28	28
8	Projected Revenues	$11,449	$11,449	$11,449	$11,449	$11,449	$11,449	$11,449	$11,449	$11,449	$11,449
9	**RATE BASE**										
10	Gross Fixed Assets	$77,244	$77,244	$77,244	$77,244	$77,244	$77,244	$77,244	$77,244	$77,244	$77,244
11	Accumulated Depreciation	$46,230	$48,432	$50,633	$52,835	$55,036	$57,238	$59,439	$61,640	$63,842	$66,043
12	Net Plant Closing	$31,013	$28,812	$26,610	$24,409	$22,208	$20,006	$17,805	$15,603	$13,402	$11,200
13	Net Plant at Mid-Year	$32,114	$29,913	$27,711	$25,510	$23,308	$21,107	$18,905	$16,704	$14,502	$12,301
14	Contributions	$23,759	$22,073	$20,386	$18,700	$17,013	$15,327	$13,640	$11,954	$10,267	$8,581
15	Contributions at Mid-Year	$24,603	$22,916	$21,230	$19,543	$17,857	$16,170	$14,483	$12,797	$11,110	$9,424
16	Working Capital Allowance	$453	$453	$452	$451	$451	$450	$450	$449	$449	$448
17	Rate Base at Mid-Year	$7,964	$7,449	$6,934	$6,418	$5,903	$5,387	$4,872	$4,356	$3,841	$3,326
18	**REVENUE DEFICIENCY CALCULATION**										
19											
20	Cost of Gas	$9,391	$9,391	$9,391	$9,391	$9,391	$9,391	$9,391	$9,391	$9,391	$9,391
21	Operating & Maintenance Expenses	$40	$40	$40	$40	$40	$40	$40	$40	$40	$40
22	Depreciation Expense	$2,201	$2,201	$2,201	$2,201	$2,201	$2,201	$2,201	$2,201	$2,201	$2,201
23	Amortization of Contributions	($1,687)	($1,687)	($1,687)	($1,687)	($1,687)	($1,687)	($1,687)	($1,687)	($1,687)	($1,687)
24	Municipal Tax & Corp.Cap. Tax	$155	$144	$133	$122	$111	$100	$89	$78	$67	$56
25	Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Overall Return	$576	$538	$501	$464	$427	$389	$352	$315	$278	$240
27	Total Revenue Requirement	$10,677	$10,629	$10,580	$10,532	$10,484	$10,436	$10,387	$10,339	$10,291	$10,243
28	Projected Revenues	$11,449	$11,449	$11,449	$11,449	$11,449	$11,449	$11,449	$11,449	$11,449	$11,449
29	Revenue Sufficiency (Deficiency)	$772	$820	$869	$917	$965	$1,013	$1,062	$1,110	$1,158	$1,206
30	Revenue to Cost Ratio	107.2%	107.7%	108.2%	108.7%	109.2%	109.7%	110.2%	110.7%	111.3%	111.8%

Financial Feasibility Test

1 **MER 2010-00111 Bergen Road - Rosser**

		YEAR 0	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8	YEAR 9	YEAR 10
3		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
4	**OPERATING ASSUMPTIONS**											
5	Number of Customers		2	2	2	2	2	2	2	2	2	2
6	Annual Volume (Mcf)		3700	3700	3700	3700	3700	3700	3700	3700	3700	3700
7	Annual Volume (10^3m^3)		105	105	105	105	105	105	105	105	105	105
8	Projected Revenues		$28,965	$28,965	$28,965	$28,965	$28,965	$28,965	$28,965	$28,965	$28,965	$28,965
9	**RATE BASE**											
10	Gross Fixed Assets	$47,067	$70,376	$70,376	$70,376	$70,376	$70,376	$70,376	$70,376	$70,376	$70,376	$70,376
11	Accumulated Depreciation		$2,027	$4,054	$6,081	$8,107	$10,134	$12,161	$14,188	$16,215	$18,241	$20,268
12	Net Plant Closing	$47,067	$68,349	$66,322	$64,295	$62,269	$60,242	$58,215	$56,188	$54,161	$52,134	$50,108
13	Net Plant at Mid-Year		$57,708	$67,336	$65,309	$63,282	$61,255	$59,228	$57,202	$55,175	$53,148	$51,121
14	Contributions	$5,076	$4,930	$4,783	$4,637	$4,491	$4,345	$4,199	$4,053	$3,906	$3,760	$3,614
15	Contributions at Mid-Year		$5,003	$4,857	$4,710	$4,564	$4,418	$4,272	$4,126	$3,979	$3,833	$3,687
16	Working Capital Allowance		$1,115	$1,115	$1,114	$1,114	$1,113	$1,113	$1,113	$1,112	$1,112	$1,111
17	Rate Base at Mid-Year		$53,821	$63,594	$61,713	$59,832	$57,951	$56,070	$54,188	$52,307	$50,426	$48,545
18	**REVENUE DEFICIENCY CALCULATION**											
19												
20	Cost of Gas		$22,592	$22,592	$22,592	$22,592	$22,592	$22,592	$22,592	$22,592	$22,592	$22,592
21	Operating & Maintenance Expenses		$80	$80	$80	$80	$80	$80	$80	$80	$80	$80
22	Depreciation Expense		$2,027	$2,027	$2,027	$2,027	$2,027	$2,027	$2,027	$2,027	$2,027	$2,027
23	Amortization of Contributions		($146)	($146)	($146)	($146)	($146)	($146)	($146)	($146)	($146)	($146)
24	Municipal Tax & Corp.Cap. Tax		$929	$919	$909	$898	$888	$878	$868	$858	$848	$838
25	Income Taxes		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Overall Return		$3,889	$3,867	$3,752	$3,638	$3,524	$3,409	$3,295	$3,181	$3,066	$2,952
27	Total Revenue Requirement		$29,371	$29,338	$29,214	$29,089	$28,965	$28,840	$28,716	$28,591	$28,467	$28,342
28	Projected Revenues		$28,965	$28,965	$28,965	$28,965	$28,965	$28,965	$28,965	$28,965	$28,965	$28,965
29	Revenue Sufficiency (Deficiency)		($406)	($374)	($249)	($125)	($0)	$125	$249	$374	$498	$623
30	Revenue to Cost Ratio		98.6%	98.7%	99.1%	99.6%	100.0%	100.4%	100.9%	101.3%	101.7%	102.2%
31	Net Present Value	$8,575										
32	**CONTRIBUTION REQUIREMENT**											
33	Total Contribution Required	$5,076										

Financial Feasibility Test

1	**MER 2010-00111 Bergen Road - Rosser**										
2		YEAR 11	YEAR 12	YEAR 13	YEAR 14	YEAR 15	YEAR 16	YEAR 17	YEAR 18	YEAR 19	YEAR 20
3		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
4	**OPERATING ASSUMPTIONS**										
5	Number of Customers	2	2	2	2	2	2	2	2	2	2
6	Annual Volume (Mcf)	3700	3700	3700	3700	3700	3700	3700	3700	3700	3700
7	Annual Volume (10^3m^3)	105	105	105	105	105	105	105	105	105	105
8	Projected Revenues	$28,965	$28,965	$28,965	$28,965	$28,965	$28,965	$28,965	$28,965	$28,965	$28,965
9	**RATE BASE**										
10	Gross Fixed Assets	$70,376	$70,376	$70,376	$70,376	$70,376	$70,376	$70,376	$70,376	$70,376	$70,376
11	Accumulated Depreciation	$22,295	$24,322	$26,349	$28,376	$30,402	$32,429	$34,456	$36,483	$38,510	$40,537
12	Net Plant Closing	$48,081	$46,054	$44,027	$42,000	$39,974	$37,947	$35,920	$33,893	$31,866	$29,839
13	Net Plant at Mid-Year	$49,094	$47,067	$45,041	$43,014	$40,987	$38,960	$36,933	$34,906	$32,880	$30,853
14	Contributions	$3,468	$3,322	$3,175	$3,029	$2,883	$2,737	$2,591	$2,445	$2,298	$2,152
15	Contributions at Mid-Year	$3,541	$3,395	$3,249	$3,102	$2,956	$2,810	$2,664	$2,518	$2,371	$2,225
16	Working Capital Allowance	$1,111	$1,110	$1,110	$1,109	$1,109	$1,108	$1,108	$1,107	$1,107	$1,106
17	Rate Base at Mid-Year	$46,664	$44,783	$42,902	$41,021	$39,139	$37,258	$35,377	$33,496	$31,615	$29,734
18	**REVENUE DEFICIENCY CALCULATION**										
19											
20	Cost of Gas	$22,592	$22,592	$22,592	$22,592	$22,592	$22,592	$22,592	$22,592	$22,592	$22,592
21	Operating & Maintenance Expenses	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80
22	Depreciation Expense	$2,027	$2,027	$2,027	$2,027	$2,027	$2,027	$2,027	$2,027	$2,027	$2,027
23	Amortization of Contributions	($146)	($146)	($146)	($146)	($146)	($146)	($146)	($146)	($146)	($146)
24	Municipal Tax & Corp.Cap. Tax	$827	$817	$807	$797	$787	$777	$767	$757	$746	$736
25	Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Overall Return	$2,837	$2,723	$2,609	$2,494	$2,380	$2,265	$2,151	$2,037	$1,922	$1,808
27	Total Revenue Requirement	$28,218	$28,093	$27,969	$27,844	$27,720	$27,595	$27,471	$27,346	$27,222	$27,097
28	Projected Revenues	$28,965	$28,965	$28,965	$28,965	$28,965	$28,965	$28,965	$28,965	$28,965	$28,965
29	Revenue Sufficiency (Deficiency)	$747	$872	$996	$1,121	$1,245	$1,370	$1,494	$1,619	$1,743	$1,868
30	Revenue to Cost Ratio	102.6%	103.1%	103.6%	104.0%	104.5%	105.0%	105.4%	105.9%	106.4%	106.9%

Financial Feasibility Test

1	**MER 2010-00111 Bergen Road - Rosser**										
2		YEAR 21	YEAR 22	YEAR 23	YEAR 24	YEAR 25	YEAR 26	YEAR 27	YEAR 28	YEAR 29	YEAR 30
3		2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
4	**OPERATING ASSUMPTIONS**										
5	Number of Customers	2	2	2	2	2	2	2	2	2	2
6	Annual Volume (Mcf)	3700	3700	3700	3700	3700	3700	3700	3700	3700	3700
7	Annual Volume (10^3m^3)	105	105	105	105	105	105	105	105	105	105
8	Projected Revenues	$28,965	$28,965	$28,965	$28,965	$28,965	$28,965	$28,965	$28,965	$28,965	$28,965
9	**RATE BASE**										
10	Gross Fixed Assets	$70,376	$70,376	$70,376	$70,376	$70,376	$70,376	$70,376	$70,376	$70,376	$70,376
11	Accumulated Depreciation	$42,563	$44,590	$46,617	$48,644	$50,671	$52,698	$54,724	$56,751	$58,778	$60,805
12	Net Plant Closing	$27,813	$25,786	$23,759	$21,732	$19,705	$17,678	$15,652	$13,625	$11,598	$9,571
13	Net Plant at Mid-Year	$28,826	$26,799	$24,772	$22,745	$20,719	$18,692	$16,665	$14,638	$12,611	$10,585
14	Contributions	$2,006	$1,860	$1,714	$1,567	$1,421	$1,275	$1,129	$983	$836	$690
15	Contributions at Mid-Year	$2,079	$1,933	$1,787	$1,641	$1,494	$1,348	$1,202	$1,056	$910	$763
16	Working Capital Allowance	$1,106	$1,105	$1,105	$1,104	$1,104	$1,103	$1,103	$1,102	$1,102	$1,102
17	Rate Base at Mid-Year	$27,853	$25,972	$24,090	$22,209	$20,328	$18,447	$16,566	$14,685	$12,804	$10,923
18	**REVENUE DEFICIENCY CALCULATION**										
19											
20	Cost of Gas	$22,592	$22,592	$22,592	$22,592	$22,592	$22,592	$22,592	$22,592	$22,592	$22,592
21	Operating & Maintenance Expenses	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80
22	Depreciation Expense	$2,027	$2,027	$2,027	$2,027	$2,027	$2,027	$2,027	$2,027	$2,027	$2,027
23	Amortization of Contributions	($146)	($146)	($146)	($146)	($146)	($146)	($146)	($146)	($146)	($146)
24	Municipal Tax & Corp.Cap. Tax	$726	$716	$706	$696	$686	$675	$665	$655	$645	$635
25	Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Overall Return	$1,694	$1,579	$1,465	$1,350	$1,236	$1,122	$1,007	$893	$779	$664
27	Total Revenue Requirement	$26,973	$26,848	$26,724	$26,599	$26,475	$26,350	$26,225	$26,101	$25,976	$25,852
28	Projected Revenues	$28,965	$28,965	$28,965	$28,965	$28,965	$28,965	$28,965	$28,965	$28,965	$28,965
29	Revenue Sufficiency (Deficiency)	$1,992	$2,117	$2,241	$2,366	$2,490	$2,615	$2,739	$2,864	$2,988	$3,113
30	Revenue to Cost Ratio	107.4%	107.9%	108.4%	108.9%	109.4%	109.9%	110.4%	111.0%	111.5%	112.0%

Financial Feasibility Test

		YEAR 0	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8	YEAR 9	YEAR 10
1	**MER 2011- 00005 Portage la Prairie**											
2		YEAR 0	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8	YEAR 9	YEAR 10
3		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
4	**OPERATING ASSUMPTIONS**											
5	Number of Customers		1	1	1	1	1	1	1	1	1	1
6	Annual Volume (Mcf)		8123	8123	8123	8123	8123	8123	8123	8123	8123	8123
7	Annual Volume (10^3m^3)		230	230	230	230	230	230	230	230	230	230
8	Projected Revenues		$54,994	$54,994	$54,994	$54,994	$54,994	$54,994	$54,994	$54,994	$54,994	$54,994
9	**RATE BASE**											
10	Gross Fixed Assets	$411,455	$411,455	$411,455	$411,455	$411,455	$411,455	$411,455	$411,455	$411,455	$411,455	$411,455
11	Accumulated Depreciation		$11,850	$23,700	$35,550	$47,400	$59,250	$71,099	$82,949	$94,799	$106,649	$118,499
12	Net Plant Closing	$411,455	$399,605	$387,755	$375,905	$364,055	$352,205	$340,356	$328,506	$316,656	$304,806	$292,956
13	Net Plant at Mid-Year		$405,530	$393,680	$381,830	$369,980	$358,130	$346,281	$334,431	$322,581	$310,731	$298,881
14	Contributions	$389,087	$377,881	$366,675	$355,470	$344,264	$333,058	$321,852	$310,647	$299,441	$288,235	$277,030
15	Contribution at Mid-Year		$383,484	$372,278	$361,072	$349,867	$338,661	$327,455	$316,250	$305,044	$293,838	$282,632
16	Working Capital Allowance		$2,517	$2,514	$2,511	$2,508	$2,505	$2,503	$2,500	$2,497	$2,494	$2,491
17	Rate Base at Mid-Year		$24,563	$23,916	$23,269	$22,622	$21,975	$21,328	$20,681	$20,034	$19,387	$18,740
18	**REVENUE DEFICIENCY CALCULATION**											
19												
20	Cost of Gas		$44,164	$44,164	$44,164	$44,164	$44,164	$44,164	$44,164	$44,164	$44,164	$44,164
21	Operating & Maintenance Expenses		$380	$380	$380	$380	$380	$380	$380	$380	$380	$380
22	Depreciation Expense		$11,850	$11,850	$11,850	$11,850	$11,850	$11,850	$11,850	$11,850	$11,850	$11,850
23	Amortization of Contributions		($11,206)	($11,206)	($11,206)	($11,206)	($11,206)	($11,206)	($11,206)	($11,206)	($11,206)	($11,206)
24	Municipal Tax & Corp.Cap. Tax		$8,706	$8,647	$8,588	$8,529	$8,469	$8,410	$8,351	$8,292	$8,232	$8,173
25	Income Taxes		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Overall Return		$1,494	$1,454	$1,415	$1,376	$1,336	$1,297	$1,257	$1,218	$1,179	$1,139
27	Total Revenue Requirement		$55,388	$55,290	$55,191	$55,093	$54,994	$54,896	$54,797	$54,698	$54,600	$54,501
28	Projected Revenues		$54,994	$54,994	$54,994	$54,994	$54,994	$54,994	$54,994	$54,994	$54,994	$54,994
29	Revenue Sufficiency (Deficiency)		($394)	($296)	($197)	($99)	($0)	$99	$197	$296	$394	$493
30	Revenue to Cost Ratio		99.3%	99.5%	99.6%	99.8%	100.0%	100.2%	100.4%	100.5%	100.7%	100.9%
31	Net Present Value	$8,468										
32	**CONTRIBUTION REQUIREMENT**											
33	Total Contribution Required	$389,087										

Financial Feasibility Test

1	**MER 2011- 00005 Portage la Prairie**										
2		YEAR 11	YEAR 12	YEAR 13	YEAR 14	YEAR 15	YEAR 16	YEAR 17	YEAR 18	YEAR 19	YEAR 20
3		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
4	**OPERATING ASSUMPTIONS**										
5	Number of Customers	1	1	1	1	1	1	1	1	1	1
6	Annual Volume (Mcf)	8123	8123	8123	8123	8123	8123	8123	8123	8123	8123
7	Annual Volume (10^3m^3)	230	230	230	230	230	230	230	230	230	230
8	Projected Revenues	$54,994	$54,994	$54,994	$54,994	$54,994	$54,994	$54,994	$54,994	$54,994	$54,994
9	**RATE BASE**										
10	Gross Fixed Assets	$411,455	$411,455	$411,455	$411,455	$411,455	$411,455	$411,455	$411,455	$411,455	$411,455
11	Accumulated Depreciation	$130,349	$142,199	$154,049	$165,899	$177,749	$189,598	$201,448	$213,298	$225,148	$236,998
12	Net Plant Closing	$281,106	$269,256	$257,406	$245,556	$233,706	$221,857	$210,007	$198,157	$186,307	$174,457
13	Net Plant at Mid-Year	$287,031	$275,181	$263,331	$251,481	$239,631	$227,781	$215,932	$204,082	$192,232	$180,382
14	Contributions	$265,824	$254,618	$243,413	$232,207	$221,001	$209,795	$198,590	$187,384	$176,178	$164,973
15	Contribution at Mid-Year	$271,427	$260,221	$249,015	$237,810	$226,604	$215,398	$204,193	$192,987	$181,781	$170,576
16	Working Capital Allowance	$2,489	$2,486	$2,483	$2,480	$2,477	$2,475	$2,472	$2,469	$2,466	$2,463
17	Rate Base at Mid-Year	$18,093	$17,446	$16,799	$16,152	$15,505	$14,858	$14,211	$13,564	$12,917	$12,270
18	**REVENUE DEFICIENCY CALCULATION**										
19											
20	Cost of Gas	$44,164	$44,164	$44,164	$44,164	$44,164	$44,164	$44,164	$44,164	$44,164	$44,164
21	Operating & Maintenance Expenses	$380	$380	$380	$380	$380	$380	$380	$380	$380	$380
22	Depreciation Expense	$11,850	$11,850	$11,850	$11,850	$11,850	$11,850	$11,850	$11,850	$11,850	$11,850
23	Amortization of Contributions	($11,206)	($11,206)	($11,206)	($11,206)	($11,206)	($11,206)	($11,206)	($11,206)	($11,206)	($11,206)
24	Municipal Tax & Corp.Cap. Tax	$8,114	$8,055	$7,995	$7,936	$7,877	$7,818	$7,758	$7,699	$7,640	$7,581
25	Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Overall Return	$1,100	$1,061	$1,021	$982	$943	$903	$864	$825	$785	$746
27	Total Revenue Requirement	$54,403	$54,304	$54,205	$54,107	$54,008	$53,910	$53,811	$53,712	$53,614	$53,515
28	Projected Revenues	$54,994	$54,994	$54,994	$54,994	$54,994	$54,994	$54,994	$54,994	$54,994	$54,994
29	Revenue Sufficiency (Deficiency)	$592	$690	$789	$887	$986	$1,084	$1,183	$1,282	$1,380	$1,479
30	Revenue to Cost Ratio	101.1%	101.3%	101.5%	101.6%	101.8%	102.0%	102.2%	102.4%	102.6%	102.8%

Financial Feasibility Test

1	**MER 2011- 00005 Portage la Prairie**										
2		YEAR 21	YEAR 22	YEAR 23	YEAR 24	YEAR 25	YEAR 26	YEAR 27	YEAR 28	YEAR 29	YEAR 30
3		2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
4	**OPERATING ASSUMPTIONS**										
5	Number of Customers	1	1	1	1	1	1	1	1	1	1
6	Annual Volume (Mcf)	8123	8123	8123	8123	8123	8123	8123	8123	8123	8123
7	Annual Volume (10^3m^3)	230	230	230	230	230	230	230	230	230	230
8	Projected Revenues	$54,994	$54,994	$54,994	$54,994	$54,994	$54,994	$54,994	$54,994	$54,994	$54,994
9	**RATE BASE**										
10	Gross Fixed Assets	$411,455	$411,455	$411,455	$411,455	$411,455	$411,455	$411,455	$411,455	$411,455	$411,455
11	Accumulated Depreciation	$248,848	$260,698	$272,548	$284,398	$296,248	$308,098	$319,947	$331,797	$343,647	$355,497
12	Net Plant Closing	$162,607	$150,757	$138,907	$127,057	$115,207	$103,357	$91,508	$79,658	$67,808	$55,958
13	Net Plant at Mid-Year	$168,532	$156,682	$144,832	$132,982	$121,132	$109,282	$97,433	$85,583	$73,733	$61,883
14	Contributions	$153,767	$142,561	$131,356	$120,150	$108,944	$97,739	$86,533	$75,327	$64,121	$52,916
15	Contribution at Mid-Year	$159,370	$148,164	$136,958	$125,753	$114,547	$103,341	$92,136	$80,930	$69,724	$58,519
16	Working Capital Allowance	$2,461	$2,458	$2,455	$2,452	$2,449	$2,447	$2,444	$2,441	$2,438	$2,435
17	Rate Base at Mid-Year	$11,623	$10,976	$10,329	$9,682	$9,035	$8,388	$7,741	$7,094	$6,447	$5,800
18	**REVENUE DEFICIENCY CALCULATION**										
19											
20	Cost of Gas	$44,164	$44,164	$44,164	$44,164	$44,164	$44,164	$44,164	$44,164	$44,164	$44,164
21	Operating & Maintenance Expenses	$380	$380	$380	$380	$380	$380	$380	$380	$380	$380
22	Depreciation Expense	$11,850	$11,850	$11,850	$11,850	$11,850	$11,850	$11,850	$11,850	$11,850	$11,850
23	Amortization of Contributions	($11,206)	($11,206)	($11,206)	($11,206)	($11,206)	($11,206)	($11,206)	($11,206)	($11,206)	($11,206)
24	Municipal Tax & Corp.Cap. Tax	$7,521	$7,462	$7,403	$7,344	$7,284	$7,225	$7,166	$7,107	$7,047	$6,988
25	Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Overall Return	$707	$667	$628	$589	$549	$510	$471	$431	$392	$353
27	Total Revenue Requirement	$53,417	$53,318	$53,219	$53,121	$53,022	$52,924	$52,825	$52,727	$52,628	$52,529
28	Projected Revenues	$54,994	$54,994	$54,994	$54,994	$54,994	$54,994	$54,994	$54,994	$54,994	$54,994
29	Revenue Sufficiency (Deficiency)	$1,577	$1,676	$1,775	$1,873	$1,972	$2,070	$2,169	$2,268	$2,366	$2,465
30	Revenue to Cost Ratio	103.0%	103.1%	103.3%	103.5%	103.7%	103.9%	104.1%	104.3%	104.5%	104.7%

Financial Feasibility Test

1	**MER 2012-00139 Pine Drive - La Broquerie**											
2		YEAR 0	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8	YEAR 9	YEAR 10
3		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
4	**OPERATING ASSUMPTIONS**											
5	Number of Customers		3	6	9	12	14	14	14	14	14	14
6	Annual Volume (Mcf)		300	600	900	1200	1400	1400	1400	1400	1400	1400
7	Annual Volume (10^3m^3)		8	17	25	34	40	40	40	40	40	40
8	Projected Revenues		$2,575	$5,149	$7,724	$10,298	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014
9	**RATE BASE**											
10	Gross Fixed Assets	$43,315	$46,962	$50,681	$54,475	$58,345	$60,977	$60,977	$60,977	$60,977	$60,977	$60,977
11	Accumulated Depreciation		$1,353	$2,812	$4,381	$6,061	$7,818	$9,574	$11,330	$13,086	$14,842	$16,598
12	Net Plant Closing	$43,315	$45,609	$47,869	$50,094	$52,284	$53,159	$51,403	$49,647	$47,891	$46,135	$44,379
13	Net Plant at Mid-Year		$44,462	$46,739	$48,982	$51,189	$52,721	$52,281	$50,525	$48,769	$47,013	$45,257
14	Contributions	$9,240	$8,974	$8,708	$8,442	$8,176	$7,910	$7,644	$7,378	$7,111	$6,845	$6,579
15	Contributions at Mid-Year		$9,107	$8,841	$8,575	$8,309	$8,043	$7,777	$7,511	$7,244	$6,978	$6,712
16	Working Capital Allowance		$117	$186	$254	$322	$368	$368	$367	$367	$366	$366
17	Rate Base at Mid-Year		$35,472	$38,084	$40,661	$43,203	$45,047	$44,872	$43,381	$41,891	$40,401	$38,910
18	**REVENUE DEFICIENCY CALCULATION**											
19												
20	Cost of Gas		$1,273	$2,545	$3,818	$5,091	$5,939	$5,939	$5,939	$5,939	$5,939	$5,939
21	Operating & Maintenance Expenses		$120	$240	$360	$480	$560	$560	$560	$560	$560	$560
22	Depreciation Expense		$1,353	$1,460	$1,569	$1,680	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756
23	Amortization of Contributions		($266)	($266)	($266)	($266)	($266)	($266)	($266)	($266)	($266)	($266)
24	Municipal Tax & Corp.Cap. Tax		$1,084	$1,140	$1,196	$1,252	$1,286	$1,277	$1,268	$1,260	$1,251	$1,242
25	Income Taxes		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Overall Return		$2,157	$2,316	$2,472	$2,627	$2,739	$2,728	$2,638	$2,547	$2,457	$2,366
27	Total Revenue Requirement		$5,720	$7,435	$9,149	$10,864	$12,014	$11,995	$11,896	$11,796	$11,697	$11,597
28	Projected Revenues		$2,575	$5,149	$7,724	$10,298	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014
29	Revenue Sufficiency (Deficiency)		($3,146)	($2,286)	($1,426)	($566)	$0	$19	$119	$218	$318	$417
30	Revenue to Cost Ratio		45.0%	69.3%	84.4%	94.8%	100.0%	100.2%	101.0%	101.8%	102.7%	103.6%
31	Net Present Value	$2,029										
32	**CONTRIBUTION REQUIREMENT**											
33	Total Contribution Required	$9,240										

Financial Feasibility Test

1	**MER 2012-00139 Pine Drive - La Broquerie**										
2		YEAR 11	YEAR 12	YEAR 13	YEAR 14	YEAR 15	YEAR 16	YEAR 17	YEAR 18	YEAR 19	YEAR 20
3		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
4	**OPERATING ASSUMPTIONS**										
5	Number of Customers	14	14	14	14	14	14	14	14	14	14
6	Annual Volume (Mcf)	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400
7	Annual Volume (10^3m^3)	40	40	40	40	40	40	40	40	40	40
8	Projected Revenues	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014
9	**RATE BASE**										
10	Gross Fixed Assets	$60,977	$60,977	$60,977	$60,977	$60,977	$60,977	$60,977	$60,977	$60,977	$60,977
11	Accumulated Depreciation	$18,354	$20,110	$21,867	$23,623	$25,379	$27,135	$28,891	$30,647	$32,403	$34,159
12	Net Plant Closing	$42,622	$40,866	$39,110	$37,354	$35,598	$33,842	$32,086	$30,329	$28,573	$26,817
13	Net Plant at Mid-Year	$43,500	$41,744	$39,988	$38,232	$36,476	$34,720	$32,964	$31,208	$29,451	$27,695
14	Contributions	$6,313	$6,047	$5,781	$5,515	$5,249	$4,982	$4,716	$4,450	$4,184	$3,918
15	Contributions at Mid-Year	$6,446	$6,180	$5,914	$5,648	$5,382	$5,116	$4,849	$4,583	$4,317	$4,051
16	Working Capital Allowance	$365	$365	$365	$364	$364	$363	$363	$363	$362	$362
17	Rate Base at Mid-Year	$37,420	$35,929	$34,439	$32,949	$31,458	$29,968	$28,477	$26,987	$25,496	$24,006
18	**REVENUE DEFICIENCY CALCULATION**										
19											
20	Cost of Gas	$5,939	$5,939	$5,939	$5,939	$5,939	$5,939	$5,939	$5,939	$5,939	$5,939
21	Operating & Maintenance Expenses	$560	$560	$560	$560	$560	$560	$560	$560	$560	$560
22	Depreciation Expense	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756
23	Amortization of Contributions	($266)	($266)	($266)	($266)	($266)	($266)	($266)	($266)	($266)	($266)
24	Municipal Tax & Corp.Cap. Tax	$1,233	$1,225	$1,216	$1,207	$1,198	$1,189	$1,181	$1,172	$1,163	$1,154
25	Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Overall Return	$2,275	$2,185	$2,094	$2,003	$1,913	$1,822	$1,732	$1,641	$1,550	$1,460
27	Total Revenue Requirement	$11,498	$11,399	$11,299	$11,200	$11,100	$11,001	$10,902	$10,802	$10,703	$10,603
28	Projected Revenues	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014
29	Revenue Sufficiency (Deficiency)	$516	$616	$715	$815	$914	$1,013	$1,113	$1,212	$1,312	$1,411
30	Revenue to Cost Ratio	104.5%	105.4%	106.3%	107.3%	108.2%	109.2%	110.2%	111.2%	112.3%	113.3%

Financial Feasibility Test

1	**MER 2012-00139 Pine Drive - La Broquerie**										
2		YEAR 21	YEAR 22	YEAR 23	YEAR 24	YEAR 25	YEAR 26	YEAR 27	YEAR 28	YEAR 29	YEAR 30
3		2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
4	**OPERATING ASSUMPTIONS**										
5	Number of Customers	14	14	14	14	14	14	14	14	14	14
6	Annual Volume (Mcf)	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400
7	Annual Volume (10^3m^3)	40	40	40	40	40	40	40	40	40	40
8	Projected Revenues	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014
9	**RATE BASE**										
10	Gross Fixed Assets	$60,977	$60,977	$60,977	$60,977	$60,977	$60,977	$60,977	$60,977	$60,977	$60,977
11	Accumulated Depreciation	$35,916	$37,672	$39,428	$41,184	$42,940	$44,696	$46,452	$48,208	$49,965	$51,721
12	Net Plant Closing	$25,061	$23,305	$21,549	$19,793	$18,037	$16,280	$14,524	$12,768	$11,012	$9,256
13	Net Plant at Mid-Year	$25,939	$24,183	$22,427	$20,671	$18,915	$17,159	$15,402	$13,646	$11,890	$10,134
14	Contributions	$3,652	$3,386	$3,120	$2,853	$2,587	$2,321	$2,055	$1,789	$1,523	$1,257
15	Contributions at Mid-Year	$3,785	$3,519	$3,253	$2,987	$2,720	$2,454	$2,188	$1,922	$1,656	$1,390
16	Working Capital Allowance	$361	$361	$360	$360	$360	$359	$359	$358	$358	$358
17	Rate Base at Mid-Year	$22,516	$21,025	$19,535	$18,044	$16,554	$15,063	$13,573	$12,083	$10,592	$9,102
18	**REVENUE DEFICIENCY CALCULATION**										
19											
20	Cost of Gas	$5,939	$5,939	$5,939	$5,939	$5,939	$5,939	$5,939	$5,939	$5,939	$5,939
21	Operating & Maintenance Expenses	$560	$560	$560	$560	$560	$560	$560	$560	$560	$560
22	Depreciation Expense	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756
23	Amortization of Contributions	($266)	($266)	($266)	($266)	($266)	($266)	($266)	($266)	($266)	($266)
24	Municipal Tax & Corp.Cap. Tax	$1,145	$1,137	$1,128	$1,119	$1,110	$1,102	$1,093	$1,084	$1,075	$1,066
25	Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Overall Return	$1,369	$1,278	$1,188	$1,097	$1,007	$916	$825	$735	$644	$553
27	Total Revenue Requirement	$10,504	$10,405	$10,305	$10,206	$10,106	$10,007	$9,908	$9,808	$9,709	$9,609
28	Projected Revenues	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014
29	Revenue Sufficiency (Deficiency)	$1,510	$1,610	$1,709	$1,809	$1,908	$2,008	$2,107	$2,206	$2,306	$2,405
30	Revenue to Cost Ratio	114.4%	115.5%	116.6%	117.7%	118.9%	120.1%	121.3%	122.5%	123.7%	125.0%

PUB/CENTRA I-134

Subject: Tab 15 - Directives

Reference: Tab 15 Appendix 15.1

e) Please clarify the details in Appendix 15.1 for the following MERs, which conflict with other information previously provided by Centra:

a. MER 2011-00025 for South Pointe, which is in the City of Winnipeg not the RM of De Salaberry, and is approximately 3500m, not 9360m as listed.

b. MER 2011-00076 for a main in the RM of Gilbert Plains, not Springfield, and is approximately 1800m, not 870m.

c. MER 2011-00096 for service to the Blue Clay colony in De Salaberry, not West St. Paul, and is approximately 9200m, not 3368m nor 0.8 miles.

ANSWER:

Details for the abovementioned MERs have been corrected in the revised Appendix 15.1 which has been filed along with responses to Round 1 Information Requests. Centra found other data entry errors in Appendix 15.1 table which have also been corrected.

PUB/CENTRA I-134

Subject: **Tab 15 - Directives**

Reference: **Tab 15 Appendix 15.1**

f) **Please provide all the inputs used in the feasibility test, as well as when each input was last updated or approved by the PUB. Please briefly explain the rationale for each input.**

ANSWER:

Please see the table below.

INPUTS	**UPDATE**	**RATIONALE**
Operating Assumption Inputs		
Number of Customers	Input at time of feasibility Updated for actual at true-up	Projection of the number of customers that will attach over the life of the project. Used to forecast Basic Monthly Charge (BMC) revenues and volumes.
Annual Volume	Input at time of feasibility Updated for actual at True-up	Estimated annual consumption used to calculate projected revenues.
Base Sales Rates & BMC	Most recently approved PUB rates Updated for current rates at the time of true-up	Base Sales rates and BMC used to calculate projected revenues.
Rate Base Inputs		
Capital Costs	Input at time of feasibility Updated for actual at true-up	Includes all estimated capital costs associated with the proposed expansion. Used as the input to Gross Fixed Assets.
Inflation Rate	Assumed at 2% in initial feasibility study. Not applicable at time of true-up as actual construction costs are used.	Inflation rate only applied to escalate service capital added after year 1. Meant to recognize additional construction cost risks in future periods.
Working Capital Allowance	Assumes 15-day lag applied to gas costs, O&M and taxes Rate is maintained in true-up	The lead lags days are used to calculate the incremental working capital allowance required to serve the proposed extension.
Revenue Deficiency Calculation Inputs		
WACOG Rates	Most recently approved PUB rates Updated for current rates at the time of true-up	WACOG Rates are used to calculate the projected annual Cost of Gas.
Operating & Maintenance	Reviewed depending upon the scope and scale of project Original estimate included in true-up (not updated for actual)	Represents a reasonable estimate of the incremental costs to serve the proposed extension.

INPUTS	UPDATE	RATIONALE
Depreciation Rate	Orders 128/09 & 41/10 Updated for current rates at the time of true-up	Used to calculate the depreciation expense of the Fixed Assets. Weighted average calculation based on the most recently approved test year (2010/11).
Amortization Rate	Orders 128/09 & 41/10 Updated for current rates at the time of True-up	Used to calculate the amortization of customer contributions. Weighted average calculation based on the most recently approved test year (2010/11)
Property Tax Mill Rates	September, 2012 Updated for current rates at the time of true-up	Used to calculate the projected taxes owed on the gross plant.
Property Tax Assessment Rates	2012 Updated for current rates at the time of true-up	Used to calculate the projected taxes owed on the gross plant.
Corporate Capital Tax	August 1, 2003 Most recent tax rate was established in 2003.	Provincial requirement to pay corporate tax.
Overall Rate of Return	Orders 128/09 & 41/10 True-up reflects most recently approved second test year rate of return	Used to calculate Centra's Overall Return as part of the revenue deficiency calculation. Weighted average calculation based on the most recently approved test year (2010/11).
Discount Rate	Orders 128/09 & 41/10 Updated for current rates at the time of true-up	Used to calculate the Net Present Value of future revenue deficiency cash flows. Discounting at the weighted average cost of capital based on the most recently approved test year (2010/11).

PUB/CENTRA I-134

Subject: **Tab 15 - Directives**

Reference: **Tab 15 Appendix 15.1**

g) Please identify the inputs into the feasibility test that are updated when calculating the true-ups, typically after five years. If there are inputs that are not updated with current information in the calculation of the true-up, please explain why those particular inputs are not updated.

ANSWER:

Please see Centra's response to PUB/Centra I-134(f).

PUB/CENTRA I-134

Subject: **Tab 15 - Directives**

Reference: **Tab 15 Appendix 15.1**

h) Please provide the study initiated by Centra in 2008 to determine the most appropriate consumption assumptions for the feasibility test, as referenced in 2009/10 GRA PUB/Centra 2-185(b).

ANSWER:

The study is anticipated to be completed by the end of 2013.

PUB/CENTRA I-136

Subject: **Tab 15 - Directives**

Reference: **Tab 15 - Order 159/11 Directive 5 (Generic Franchise Agreement)**

Please provide a listing of the municipalities that have applied to amend their franchise agreements, and the dates that the new agreements were signed.

ANSWER:

The following municipalities applied for and adopted the Franchise Agreement as approved in Order 159/11 in conjunction with the granting of new franchise areas to accommodate extending natural gas service to new customers:

Municipality	Order Number	Date New Agreement Signed
RM of Portage la Prairie	67/12	June 28, 2012
RM of Grey	70/12	July 31, 2012
RM of Ste. Anne	85/12	August 22, 2012

The following franchise granting municipalities have applied to adopt the Franchise Agreement as approved in Order 159/11:

- RM of North Norfolk;
- RM of Woodlands;
- City of Portage la Prairie;
- RM of Elton;
- RM of Langford;
- RM of Shellmouth-Boulton; and
- RM of Stanley

On January 25, 2013, Centra filed an application with the PUB for approval of these franchise agreements.

PUB/CENTRA I-137

Subject: Tab 15 - Directives

Reference: Tab 15 Appendix 15.3

Please confirm whether Centra plans to extend its FRPGS offerings to customers in the High Volume Firm, Interruptible, or Main Line classes and whether it would be necessary to hedge these offerings.

ANSWER:

Under Centra's existing FRPGS program High Volume Firm, Interruptible and Main Line customers are not eligible. Centra does not intend to extend FRPGS offerings to higher volume customers at this time.