IN THE MATTER OF:

CENTRA GAS MANITOBA INC.
2013/14
GENERAL RATE APPLICATION

HEARING BEFORE
THE PUBLIC UTILITIES BOARD

Board Counsel's Book of Documents

Volume 1 of 2

June 13, 2013

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Centra Gas Manitoba Inc.
2013/14 General Rate Application - Cost of Gas Update
Purchase Cost of Gas Supplied to Load
2012/13 Gas Year
Supply prices for 2012/13 Gas Year per forward strip as of: **April 2, 2013**

Updated Schedule 10.12.3(b)
May 10, 2013

			Total
	Fixed Costs		
1	TCPL Firm Service - Man Zone	CDN $	$21,000,168
2	TCPL Firm Service - Sask Zone	CDN $	$156,642
3	TCPL STFT to Man Zone	CDN $	$11,445,045
4	TCPL Firm Service - Emerson to Man Zone	CDN $	$1,129,240
5	TCPL STS	CDN $	$2,891,292
6	ANR Storage Capacity	CDN $	$2,439,499
7	ANR Storage Deliverability	CDN $	$1,931,021
8	ANR Oklahoma Winter	CDN $	$209,910
9	ANR Crystal Falls from Storage	CDN $	$298,421
10	GLGT Winter	CDN $	$1,040,369
11	Seasonal Storage Capacity	CDN $	$1,338,963
12	Seasonal Storage Deliverability	CDN $	$991,267
13	Annual Storage Capacity	CDN $	$1,265,780
14	Annual Storage Deliverability	CDN $	$1,297,296
15	ANR Joliet Summer	CDN $	$190,402
16	ANR Crystal Falls to Storage	CDN $	$1,365,453
17	GLGT Summer	CDN $	$1,064,594
18			
19	**Total Fixed Costs**	CDN $	$50,055,362
20			
21	**Variable Transportation Costs**		
22			
23	TCPL Firm Service - Man Zone	CDN $	$1,551,282
24	TCPL Firm Service - Sask Zone	CDN $	$11,016
25	TCPL Firm Service - Emerson to Man Zone	CDN $	$13,825
26	ANR Oklahoma to Crystal Falls	CDN $	$19,807
27	ANR Storage Withdrawl	CDN $	$148,284
28	ANR Storage Transportation	CDN $	$93,913
29	Storage Gas - Transportation & Delivery Cost (Centra)	CDN $	$2,179,962
30	Compressor Fuel -Emerson	CDN $	$7,032
31	Compressor Fuel -Oklahoma	CDN $	$148,624
32	Compressor Fuel -Storage	CDN $	$103,950
33	Compressor Fuel -MDA	CDN $	$573,654
34	Compressor Fuel -SSDA	CDN $	$4,694
35			
36	**Total Variable Transportation Costs**	CDN $	$4,856,044
37			
38	**Supply Costs**		
39			
40	Primary Supply Direct to System Supply Load	CDN $	$102,842,503
41	Storage Gas - Primary Supply to System Supply	CDN $	$24,754,674
42	Emerson Supply	CDN $	$6,860,360
43	Oklahoma Supply	CDN $	$3,672,042
44	Storage Gas - Supplemental Supply	CDN $	$12,632,218
45	Chicago Supply	CDN $	$0
46			
47	**Total Supply Costs**	CDN $	$150,761,797
48			
49	**Other**		
50	Minell Charges	CDN $	$198,444
51	Load Balancing Charges	CDN $	$200,000
52			
53	**Total Other Costs**	CDN $	$398,444
54			
55	**Total Cost of Gas**	CDN $	$206,071,646
56	Five Year Average Capacity Management Revenues	CDN $	($6,300,000)
57	**Net Cost of Gas**	CDN $	$199,771,646

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Centra Gas Manitoba Inc. **Updated Schedule 10.12.4 (a)**
2013/14 General Rate Application - Cost of Gas Update **May 10, 2013**
Difference Between Forecasted Non-Primary Gas Costs
and Non-Primary Gas Costs Recoverable With Existing Base Rates
Supply prices for 2012/13 Gas Year per forward strip as of: **April 2, 2013**

		(1) Recoverable at Existing Base Rates	(2) Forecast for 2012/13	(3) Difference
1	Primary Gas	$126,515,283	$126,260,276	($255,007)
2	Supplemental Gas	$19,089,719	$22,865,989	$3,776,270
3	Transportation[1]	$52,168,031	$48,233,057	($3,934,974)
4	Distribution	$3,127,437	$2,412,324	($715,114)
5				
6				
7	**Totals**	**$200,900,471**	**$199,771,646**	**($1,128,825)**
8				
9				
10	**Non-Primary Gas Cost Totals**	**$74,385,188**	**$73,511,370**	**($873,818)**
11				
12	Note 1: Transportation costs including $6.3 mm Capacity Management forecast.			

Updated Schedule 10.12.4 (b)
May 10, 2013

Centra Gas Manitoba Inc.
2013/14 General Rate Application - Cost of Gas Update
Difference Between 2010/11 Gas Year Approved and 2012/13 Gas Year Non-Primary Forecasts
Supply prices for 2012/13 Gas Year per forward strip as of: April 2, 2013

		(1)	(2)	(3)
		Approved for 2010/11	Forecast for 2012/13	Difference
1	Primary Gas	$155,081,267	$126,260,276	($28,820,991)
2	Supplemental Gas	$37,755,692	$22,865,989	($14,889,703)
3	Transportation	$52,140,493	$48,233,057	($3,907,435)
4	Distribution	$3,032,337	$2,412,324	($620,013)
5				
6				
7	**Totals**	**$248,009,789**	**$199,771,646**	**($48,238,142)**
8				
9				
10	**Non-Primary Gas Cost Totals**	**$92,928,522**	**$73,511,370**	**($19,417,151)**
11				
12				

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Centra Gas Manitoba Inc.
2010/11 Gas Year Capacity Management Deferral Account
2010/11 Gas Year Actual

Schedule 10.6.2
February 22, 2013

		Actual Nov 2010	Actual Dec 2010	Actual Jan 2011	Actual Feb 2011	Actual Mar 2011	Actual Apr 2011	Actual May 2011	Actual Jun 2011	Actual Jul 2011	Actual Aug 2011	Actual Sep 2011	Actual Oct 2011	TOTAL
1	Capacity Management Revenue	($286,392)	($115,195)	($373,445)	($170,010)	($131,660)	($262,159)	($694,224)	($711,759)	($621,963)	($556,530)	($603,071)	($804,624)	**($5,331,031)**
2														
3	Carrying Costs	($140)	($350)	($600)	($983)	(1,241)	($1,236)	($6,959)	($4,337)	($5,737)	($6,832)	($7,683)	($9,277)	($45,375)
4														
5	**Net Inflow**	**($286,532)**	**($115,545)**	**($374,045)**	**($170,993)**	**($132,901)**	**($263,395)**	**($701,183)**	**($716,096)**	**($627,700)**	**($563,362)**	**($610,754)**	**($813,901)**	**($5,376,406)**
6														
7	**Net Balance**	**($286,532)**	**($402,077)**	**($776,122)**	**($947,115)**	**($1,080,016)**	**($1,343,411)**	**($2,044,594)**	**($2,760,690)**	**($3,388,390)**	**($3,951,752)**	**($4,562,505)**	**($5,376,406)**	

Centra Gas Manitoba Inc.
2011/12 Gas Year Capacity Management Deferral Account

Schedule 10.9.2
February 22, 2013

		Actual Nov 2011	Actual Dec 2011	Actual Jan 2012	Actual Feb 2012	Actual Mar 2012	Actual Apr 2012	Actual May 2012	Actual Jun 2012	Actual Jul 2012	Actual Aug 2012	Actual Sep 2012	Actual Oct 2012	TOTAL
1	Capacity Management Revenue	($308,300)	($135,559)	($58,440)	($74,996)	($501,989)	($771,837)	($971,223)	($823,482)	($936,883)	($725,600)	($573,130)	($505,463)	**($6,386,903)**
2														
3	Carrying Costs	($279)	($703)	($1,128)	($1,133)	(891)	($2,406)	($4,004)	($5,075)	($6,701)	($8,517)	($9,324)	($10,407)	**($50,568)**
4														
5	**Net Inflow**	**($308,579)**	**($136,262)**	**($59,568)**	**($76,129)**	**($502,880)**	**($774,243)**	**($975,227)**	**($828,557)**	**($943,584)**	**($734,117)**	**($582,454)**	**($515,870)**	**($6,437,471)**
6														
7	**Net Balance**	**($308,579)**	**($444,841)**	**($504,409)**	**($580,538)**	**($1,083,418)**	**($1,857,661)**	**($2,832,889)**	**($3,661,446)**	**($4,605,030)**	**($5,339,147)**	**($5,921,601)**	**($6,437,471)**	

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Centra Gas Manitoba Inc.
2013/14 General Rate Application
Summary of Gas Costs
Actual vs. Approved

Schedule 10.4.0
February 22, 2013

		2010/11 Gas Year Actual	2010/11 Gas Year Approved	Actual vs. Approved
1	**Fixed Costs**			
2				
3	TCPL Firm Service Demand - Man Zone	$28,737,660	$31,168,268	($2,430,608)
4	TCPL Firm Service Demand - Sask Zone	$262,132	$262,132	($0)
5	TCPL STS Demand	$2,611,347	$2,611,347	$0
6	Storage Capacity Chg.	$5,723,585	$5,860,677	($137,093)
7	Storage Deliverability Chg	$4,534,602	$4,647,323	($112,720)
8	ANR Oklahoma Demand	$492,930	$505,183	($12,253)
9	ANR Louisianna Demand	$1,405,564	$1,464,557	($58,993)
10	ANR Storage to and From Crystal Falls Demand	$1,656,060	$1,714,461	($58,400)
11	GLGT Emerson to Crys. Falls Dmd	$1,834,151	$1,912,834	($78,683)
12	GLGT Backhaul Demand	$1,027,444	$1,027,446	($2)
13				
14	**Total Fixed Costs**	$48,285,476	$51,174,228	($2,888,753)
15				
16	**Variable Transportation Costs**			
17				
18	TCPL Firm Service - Man Zone	$872,259	$999,429	($127,170)
19	TCPL Firm Service - Sask Zone	$8,263	$7,043	$1,220
20	TCPL Park & Loan Service	$2,200	$0	$2,200
21	GLGT Park & Loan Service	$1,452	$0	$1,452
22	GLGT Storage Gas Backhaul	$9,844	$0	$9,844
23	Supplemental Gas Peaking Delivered Service Imputed Transportation Cost	$4,809,287	$4,057,954	$751,333
24	Primary Gas Delivered Service Transportation Cost	$2,376,162	$0	$2,376,162
25	ANR Oklahoma to Crystall Falls	$4,083	$20,015	($15,932)
26	ANR Storage Transportation	$78,274	$69,848	$8,426
27	ANR Storage Withdrawl Chg	$128,774	$177,451	($48,678)
28	Storage Gas - Transportation and Delivery	$2,447,562	$1,963,970	$483,591
29	Compressor Fuel - TCPL to MDA	$638,370	$659,389	($21,020)
30	- TCPL to SSDA	$6,392	$5,669	$724
31	- Oklahoma	$22,672	$133,171	($110,499)
32	- Storage	$274,500	$237,382	$37,118
33	Miscellaneous Transportation Charges	$56,116	$0	$56,116
34				
35	**Total Variable Transport Costs**	$11,736,210	$8,331,323	$3,404,887
36				
37	**Supply Costs**			
38				
39	Primary Supply	$88,476,419	$101,052,620	($12,576,201)
40	Primary Gas Delivered Service	$11,545,146	$0	$11,545,146
41	Primary Gas from Storage	$18,181,155	$35,055,825	($16,874,670)
42	Primary Gas from Storage for Exchanges With Counterparties	$20,322,049	$0	$20,322,049
43	LBA & T-Service Imbalances - Primary Supply	($21,312)	$0	($21,312)
44	LBA & T-Service Imbalances - Supplemental Supply	$2,852	$0	$2,852
45	Oklahoma Supply	$3,849,270	$4,050,090	($200,820)
46	Supplemental Gas from Storage	$4,050,407	$174,581	$3,875,825
47	Supplemental Gas from Storage for Exchanges With Counterparties	$2,176,424	$0	$2,176,424
48	Supplemental Gas Peaking Delivered Service	$28,142,536	$34,049,340	($5,906,804)
49	Delivered Service - Alternate Service For Curtailed Interruptibles	$569,254	$0	$569,254
50				
51				
52	**Total Supply Costs**	$177,294,201	$174,382,457	$2,911,744
53				
54	**Other**			
55				
56	TCPL Load Balancing Charges	$178,716	$200,000	($21,284)
57	Miscellaneous Supplemental Charges	$3,783	$0	$3,783
58	Capacity Management	($5,331,031)	($6,900,000)	$1,568,969
59	Minell Charges	$198,444	$198,444	$0
60	Hedging Impact	$18,931,814	$20,623,337	($1,691,524)
61				
62	**Total Inflows to PGVA**	$251,297,613	$248,009,789	$3,287,824
63				
64				
65	**Purchased Volumes Excluding Primary WTS Supply (GJ)**			
66				
67	Primary Gas	37,357,056	37,035,437	321,619
68	Supplemental Gas (Excluding Alternate Service for Curtailed Interruptibles)	10,569,423	11,127,455	(558,033)
69	Alternate Service for Curtailed Interruptibles	147,431	0	147,431
70				
71	**Total Volumes Excluding Primary WTS Supply (GJ)**	48,073,910	48,162,893	(88,983)

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Centra Gas Manitoba Inc.
2010/11 Gas Year Capacity Management
Activity by Transaction Type

Schedule 10.6.1
February 22, 2013

			Total
1	**November 1, 2010 to October 31, 2011**		
2	Capacity Release Revenues	$5,159,829	
3	Capacity Release Costs	($551,793)	
4			$4,608,036
5			
6	Exchange Revenues	$722,995	
7	Exchange Costs	$0	
8			$722,995
9			
10	**Total Capacity Management Results November 1, 2010 to October 31, 2011**		$5,331,031
11			
12	Carrying Costs		$45,375
13			
14	**October 31, 2011 Ending Balance**		**$5,376,406**

Centra Gas Manitoba Inc.
2011/12 Gas Year Capacity Management
Activity by Transaction Type

Schedule 10.9.1
February 22, 2013

			TOTAL
1			
2	Capacity Release Revenues	$6,773,423	
3	Capacity Release Costs	($578,011)	
4			$6,195,412
5			
6	Exchange Revenues	$191,491	
7	Exchange Costs	$0	
8			$191,491
9			
10	**Capacity Management Results**		**$6,386,903**
11			
12	Carrying Costs		$50,568
13			
14	**Capacity Management Results to October 31, 2012**		**$6,437,471**

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Centra Gas Manitoba Inc.
2013/14 General Rate Application
Summary of Gas Costs
Actual vs. Approved

Schedule 10.8.0
February 22, 2013

		2011/12 Gas Year Actuals	2010/11 Gas Year Approved	Actual vs. Approved
1	**Fixed Costs**			
2				
3	TCPL Firm Service Demand - Man Zone	$24,761,780	$31,168,268	($6,406,489)
4	TCPL Firm Service Demand - Sask Zone	$156,642	$262,132	($105,490)
5	TCPL STS Demand	$2,891,292	$2,611,347	$279,945
6	Storage Capacity Chg	$5,833,711	$5,860,677	($26,967)
7	Storage Deliverability Chg	$4,621,263	$4,647,323	($26,060)
8	ANR Oklahoma Demand	$502,351	$505,183	($2,833)
9	ANR Louisianna Demand	$1,438,799	$1,464,557	($25,759)
10	ANR Storage to and From Crystal Falls Demand	$1,692,769	$1,714,461	($21,692)
11	GLGT Emerson to Crys. Falls Dmd	$1,878,918	$1,912,834	($33,917)
12	GLGT Backhaul Demand	$1,039,582	$1,027,446	$12,136
13				
14	**Total Fixed Costs**	$44,817,104	$51,174,228	($6,357,124)
15				
16	**Variable Transportation Costs**			
17				
18	TCPL Firm Service - Man Zone	$972,803	$999,429	($26,626)
19	TCPL Firm Service - Sask Zone	$7,008	$7,043	($36)
20	TCPL Park & Loan Service	$11,805	$0	$11,805
21	GLGT Park & Loan Service	$0	$0	$0
22	GLGT Storage Gas Backhaul	$8,545	$0	$8,545
23	Supplemental Gas Peaking Delivered Service Imputed Transportation Cost	$0	$4,057,954	($4,057,954)
24	Primary Gas Delivered Service Imputed Transportation Cost	$10,662,680	$0	$10,662,680
25	ANR Oklahoma to Crystall Falls	$8,319	$20,015	($11,696)
26	ANR Storage Transportation	$46,089	$69,848	($23,759)
27	ANR Storage Withdrawl Chg	$71,493	$177,451	($105,959)
28	Storage Gas - Transportation and Delivery	$1,193,857	$1,963,970	($770,113)
29	Compressor Fuel - TCPL to MDA	$614,687	$659,389	($44,702)
30	- TCPL to SSDA	$3,110	$5,669	($2,559)
31	- Oklahoma	$71,336	$133,171	($61,835)
32	- Storage	$188,558	$237,382	($48,825)
33	ANR Storage Gas Cycling Charge	$218,733	$0	$218,733
34				
35	**Total Variable Transport Costs**	$14,079,022	$8,331,323	$5,747,700
36				
37	**Supply Costs**			
38				
39	Primary Supply	$44,444,069	$101,052,620	($56,608,551)
40	Primary Gas Delivered Service	$34,978,193	$0	$34,978,193
41	Primary Gas from Storage	$17,296,137	$35,055,825	($17,759,688)
42	Primary Gas from Storage for Exchanges With Counterparties	$5,509,564	$0	$5,509,564
43	LBA & T-Service Imbalances - Primary Supply	$38,255	$0	$38,255
44	LBA & T-Service Imbalances - Supplemental Supply	$0	$0	$0
45	Oklahoma Supply	$2,152,509	$4,050,090	($1,897,581)
46	Supplemental Gas from Storage	$0	$174,581	($174,581)
47	Supplemental Gas from Storage for Exchanges With Counterparties	$0	$0	$0
48	Supplemental Gas Peaking Delivered Service	$2,193,275	$34,049,340	($31,856,065)
49	Delivered Service - Alternate Service For Curtailed Interruptibles	$526,765	$0	$526,765
50				
51	**Total Supply Costs**	$107,138,769	$174,382,457	($67,243,688)
52				
53	**Other**			
54				
55	TCPL Load Balancing Charges	$203,599	$200,000	$3,599
59	Capacity Management	($6,386,903)	($6,900,000)	$513,097
60	Minell Charges	$198,444	$198,444	$0
61	Hedging Impact	$0	$20,623,337	($20,623,337)
62				
63	**Total Inflows to PGVA**	$160,050,035	$248,009,789	($87,959,754)
64				
65				
66	**Purchased Volumes Excluding Primary WTS Supply (GJ)**			
67				
68	Primary Gas	39,316,838	37,035,437	2,281,401
69	Supplemental Gas (Excluding Alternate Service for Curtailed Interruptibles)	1,566,660	11,127,455	(9,560,795)
70	Alternate Service for Curtailed Interruptibles	181,032	0	181,032
71				
72	**Total Volumes Excluding Primary WTS Supply (GJ)**	41,064,530	48,162,893	(7,098,363)

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PUB/CENTRA I-88

Subject: **Tab 10 – Gas Costs**

Reference: **Tab 10 Page 5 of 63**

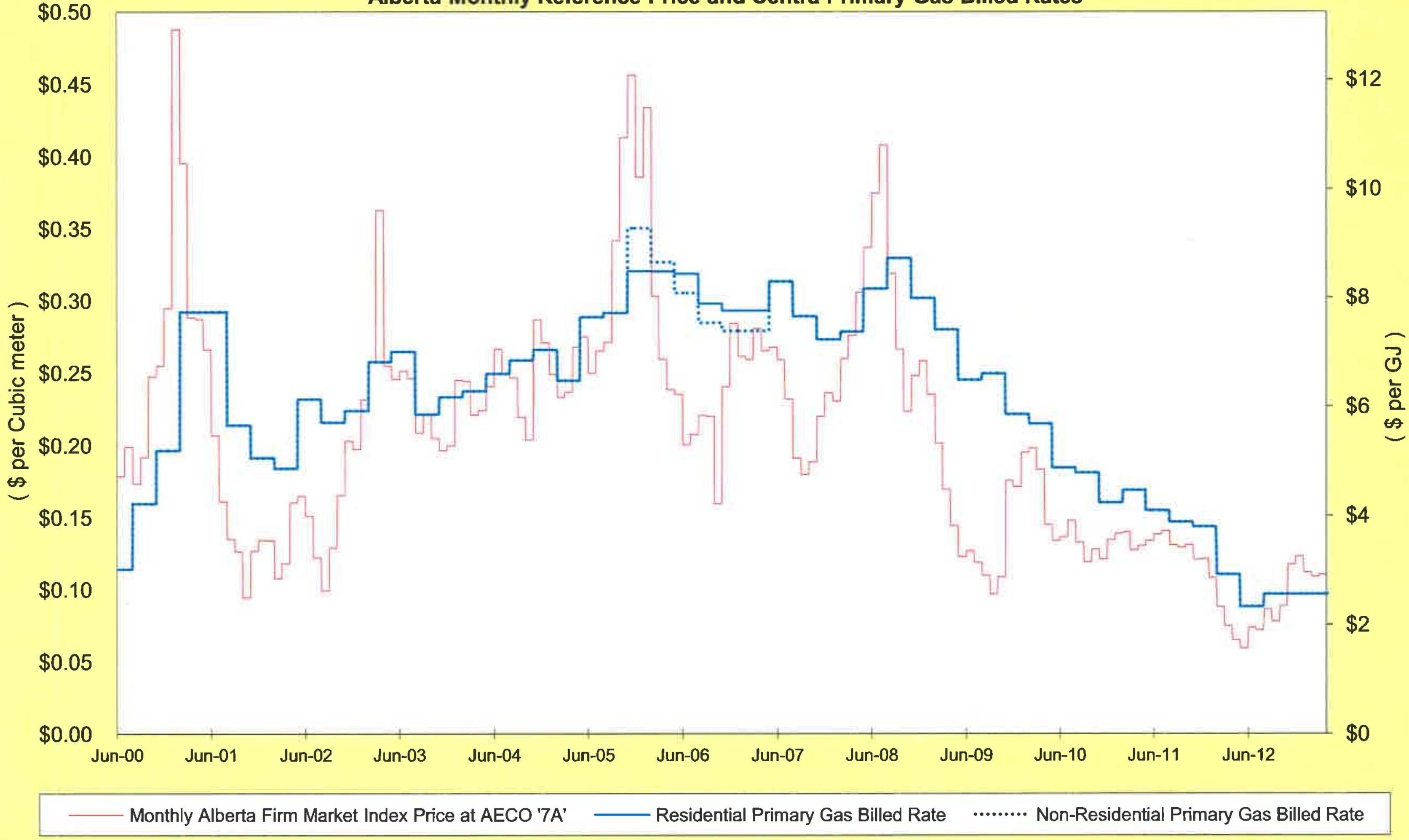
Please provide a graph showing the AECO monthly reference price and Centra's Primary Gas rates (both residential and non-residential) since 2000.

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



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Centra Gas Manitoba Inc.
Purchase Gas Variance Account - Primary Gas
2010/11 Gas Year Actual

Schedule 10.4.1
February 22, 2013

		Actual Oct. 31, 2010	Actual Nov 2010	Actual Dec 2010	Actual Jan 2011	Actual Feb 2011	Actual Mar 2011	Actual Apr 2011	Actual May 2011	Actual Jun 2011	Actual Jul 2011	Actual Aug 2011	Actual Sep 2011	Actual Oct 2011	TOTAL
1	Inflows														
2	Primary Gas		$10,076,195	$12,732,816	$12,382,304	$10,960,518	$11,994,926	$7,681,157	$4,148,772	$2,796,806	$3,527,828	$3,433,075	$2,876,327	$5,865,693	$88,476,419
3	Primary Gas Delivered Service		$0	$0	$0	$0	$0	$3,483,291	$2,579,005	$1,577,963	$0	$0	$1,431,338	$2,473,550	$11,545,146
4	Primary Gas from Storage		$2,223,417	$4,208,300	$2,886,795	$6,981,577	$1,881,067	$0	$0	$0	$0	$0	$0	$0	$18,181,156
5	Primary Gas from Storage for Exchanges With Counterparties		$2,569,728	$4,149,802	$9,631,671	$2,969,507	$1,001,341	$0	$0	$0	$0	$0	$0	$0	$20,322,049
6	LBA & T-Service Imbalances - Primary Supply		$14,446	$20,648	($18,903)	$43,002	($16,109)	$7,758	$92,438	($115,558)	($16,553)	$10,567	$18,139	($61,188)	($21,312)
7	TCPL Fuel to MDA & SSDA		$55,967	$94,050	$142,258	$114,817	$60,293	$75,790	$36,345	$13,533	$14,787	$14,974	$6,830	$15,119	$644,762
8	Hedging Impact		$3,661,123	$5,526,849	$6,304,814	$965,552	$1,138,919	$700,806	$244,780	$203,610	$185,360	$0	$0	$0	$18,931,814
9															
10	Total Inflows		$18,600,877	$26,732,465	$31,328,939	$22,034,973	$16,060,437	$11,848,803	$7,101,339	$4,476,366	$3,711,423	$3,458,615	$4,332,633	$8,293,173	$158,080,034
11	Less: UFG Component to Distribution PGVA		($255,193)	($332,862)	($389,903)	($276,985)	($211,429)	($187,421)	($146,266)	($102,160)	($106,177)	($98,614)	($104,606)	($146,629)	($2,358,245)
12	Less: UFG True-up Transferred To Distribution PGVA									($322,026)					($322,026)
13	Less: FRPGS Cost of Gas		($48,134)	($41,568)	($45,835)	($43,902)	($72,986)	($33,911)	($27,024)	($7,916)	($11,165)	($6,980)	($10,382)	($22,563)	($372,386)
14	Net Inflow		$18,297,550	$26,358,035	$30,893,201	$21,714,086	$15,776,022	$11,727,471	$6,928,050	$4,044,254	$3,594,081	$3,353,021	$4,217,645	$8,123,961	$155,027,377
15															
16	Outflows														
17	WACOG Outflows		$16,834,484	$26,318,974	$29,338,724	$24,092,051	$21,365,874	$10,641,654	$6,685,715	$3,495,615	$2,945,376	$2,876,201	$3,813,730	$7,714,802	$156,123,200
18	Primary Gas PGVA Rider Amortization		($32,212)	($48,461)	($55,333)	$829,598	$700,483	$340,669	($190,859)	($85,959)	($67,838)	($67,188)	($86,843)	($172,666)	$1,071,390
19	Total Outflows		$16,802,272	$26,269,514	$29,283,391	$24,921,649	$22,066,357	$10,981,324	$6,494,856	$3,409,656	$2,877,538	$2,809,012	$3,726,887	$7,542,137	$157,194,591
20															
21	Carrying Costs		$726	$1,562	$2,431	$1,465	($3,220)	($5,996)	($12,553)	($8,118)	($7,120)	($5,941)	($4,746)	($4,250)	($45,760)
22															
23	Net Inflow		$1,496,004	$90,083	$1,612,242	($3,206,098)	($6,293,555)	$730,152	$420,641	$626,480	$709,423	$538,068	$486,012	$577,574	($2,212,973)
24															
25	Net Balance	($3,527)	$1,492,477	$1,582,560	$3,194,802	($11,296)	($6,304,851)	($5,574,699)	($5,154,058)	($4,527,578)	($3,818,155)	($3,280,086)	($2,794,074)	($2,216,511)	
26															
27	Primary GJ's (includes UFG)		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
28	Primary Gas Avg. Cost - $/GJ		$4.530	$4.849	$4.866	$4.002	$3.949	$3.801	$3.740	$3.936	$4.101	$3.636	$3.453	$3.405	

15

Centra Gas Manitoba Inc.
Purchase Gas Variance Account - Primary Gas
2011/12 Gas Year Actual

Schedule 10.8.1
February 22, 2013

		Oct 31/2011	Actual Nov 2011	Actual Dec 2011	Actual Jan 2012	Actual Feb 2012	Actual Mar 2012	Actual Apr 2012	Actual May 2012	Actual Jun 2012	Actual Jul 2012	Actual Aug 2012	Actual Sep 2012	Actual Oct 2012	TOTAL
1	Inflows														
2	Primary Gas		$7,123,291	$7,813,465	$4,937,792	$3,769,240	$2,052,118	$2,314,331	$1,349,259	$1,999,671	$1,768,766	$2,234,337	$2,488,820	$6,592,979	$44,444,069
3	Primary Gas Delivered Service		$4,705,965	$7,007,240	$7,305,367	$5,494,572	$3,844,155	$1,889,101	$1,307,115	$0	$0	$0	$689,393	$2,735,266	$34,978,193
4	Primary Gas from Storage		$1,092,809	$2,441,409	$7,248,024	$4,912,393	$1,601,503	$0	$0	$0	$0	$0	$0	$0	$17,296,137
5	Primary Gas from Storage for Exchanges With Counterparties		$1,572,519	$2,491,582	$304,087	$218,241	$923,135	$0	$0	$0	$0	$0	$0	$0	$5,509,564
6	LBA & T-Service Imbalances - Primary Supply		$59,238	($22,400)	$31,659	($22,146)	$25,631	($42,677)	$377	$14,235	($5,609)	$11,450	($4,442)	($7,061)	$38,255
7	TCPL Fuel to MDA & SSDA		$64,740	$139,179	$164,500	$126,441	$40,754	$15,511	$8,480	$2,030	$3,985	$7,106	$7,062	$38,028	$817,797
8															
9	Total Inflows		$14,618,562	$19,870,475	$19,991,429	$14,488,742	$8,487,296	$4,176,266	$2,665,231	$2,015,936	$1,767,142	$2,252,892	$3,180,833	$9,359,212	$102,884,016
10	Less: UFG Component to Distribution PGVA		($206,003)	($261,271)	($261,015)	($192,406)	($126,738)	($68,095)	($57,941)	($54,823)	($51,052)	($59,551)	($48,704)	($142,044)	($1,529,644)
11	Less: UFG True-up Transferred From Distribution PGVA									$740,754					$740,754
12	Less: FRPGS Cost of Gas		($65,824)	($79,130)	($66,352)	($52,826)	($37,790)	($19,687)	($14,140)	($11,992)	($6,143)	($8,897)	($13,180)	($3,257)	($399,222)
13	Net Inflow After UFG Transfer		$14,346,734	$19,630,073	$19,664,063	$14,243,509	$8,322,768	$4,088,484	$2,593,150	$2,689,875	$1,709,947	$2,184,443	$3,118,948	$9,213,911	$101,695,904
14															
15	Outflows														
16	WACOG Outflows		$17,210,420	$23,493,609	$26,043,072	$19,191,838	$12,586,437	$8,816,053	$4,244,584	$3,365,202	$2,284,652	$2,603,950	$3,994,892	$10,185,505	$134,020,214
17	Primary Gas PGVA Rider Amortization		($86,199)	($98,084)	($110,071)	($1,891,402)	($1,186,995)	($833,880)	($866,508)	($701,080)	($469,507)	($517,639)	($783,524)	($1,992,882)	($9,537,770)
18	Total Outflows		$17,124,221	$23,395,525	$25,933,001	$17,300,436	$11,399,442	$7,982,173	$3,378,076	$2,664,122	$1,815,145	$2,086,312	$3,211,368	$8,192,623	$124,482,444
19															
20	Carrying Costs		($6,515)	($12,950)	($32,456)	($28,199)	($16,322)	($38,164)	($43,881)	($40,835)	($42,487)	($44,976)	($43,548)	($43,576)	($383,909)
21															
22	Net Inflow		($2,784,002)	($3,878,402)	($6,301,394)	($3,085,127)	($3,092,996)	($3,931,853)	($828,807)	($15,082)	($147,685)	$53,156	($135,968)	$977,711	($23,170,449)
23															
24	Net Balance	($2,216,511)	($5,000,613)	($8,878,914)	($15,180,308)	($18,265,435)	($21,358,431)	($25,290,285)	($26,119,092)	($26,134,174)	($26,281,858)	($26,228,703)	($26,364,671)	($25,386,960)	
25															
26	Primary GJ's (includes UFG)		4,563,700	6,280,581	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
27	Primary Gas Avg. Cost - $/GJ		$3.203	$3.164	$2.923	$2.444	$2.118	$1.567	$1.666	$2.040	$2.060	$2.409	$2.268	$2.884	

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

Centra Gas Manitoba Inc.
2013/14 General Rate Application
Primary Gas Inflow Volumes - 2010/11 & 2011/12 Gas Years

PUB/Centra I-102 (b)
Attachment
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 II-179

Reference: PUB/Centra I-102(b); Tab 10 Page 36 of 63; Schedules 10.4.1, 10.8.1

f) Please provide the monthly Primary Gas baseload volumes from Empress, the monthly Primary Gas swing volumes from Empress, the average AECO daily price for each month, the AECO to Empress Nova tolls, the AECO to Empress Transportation Basis Differentials, and the monthly Primary Gas sales volumes for the period November 2010 to October 2012. If Centra claims any portions of this information to be commercially sensitive information, such portions may be filed in confidence, with a redacted response being filed on the public record.

ANSWER:

Please see attachment to this response.

Centra Gas Manitoba Inc.
2013/14 General Rate Application
Primary Baseload & Swing Volumes, Daily and Monthly Pricing Components

PUB/Centra II-179 (f)
Attachment
May 7, 2013

		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
1	Primary Gas Baseload Volumes from Empress (ConocoPhillips)[1]	1,619,700	2,047,550	2,425,750	1,867,600	1,556,820	1,396,800	1,194,430	1,408,500	2,224,870	2,171,860	1,411,200	855,600	**20,180,680**
2	Monthly Primary Gas Swing Volumes from Empress (ConocoPhillips)[1]	1,397,879	1,523,960	1,135,280	1,355,930	1,960,132	1,636,526	880,784	429,254	61,209	169,921	504,681	1,179,343	**12,234,899**
3	Centra Primary Gas Sales Volumes	3,984,318	6,221,736	6,937,572	5,593,938	4,971,003	2,477,526	1,591,395	831,886	707,571	721,409	972,462	1,957,990	**36,968,805**
4														
5	Average AECO Daily Spot Price (NGX)	$3.4786	$3.6995	$3.7845	$3.4132	$3.5259	$3.5414	$3.7006	$3.7944	$3.5108	$3.4502	$3.4420	$3.2019	
6	AECO to Empress Nova Tolls (NGTL)	$0.1982	$0.1982	$0.1982	$0.1982	$0.1982	$0.1982	$0.1982	$0.1982	$0.1982	$0.1982	$0.1982	$0.1930	
7	AECO to Empress Monthly Basis Differential Index (CGPR)	($0.1152)	($0.1509)	($0.1134)	($0.1209)	($0.1000)	($0.1603)	($0.1816)	($0.1729)	($0.1630)	($0.2029)	($0.2384)	($0.2776)	
8														
9														
10		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
11														
12	Primary Gas Baseload Volumes from Empress (ConocoPhillips)[1]	526,200	1,529,230	1,478,700	625,240	431,830	-	-	309,900	1,484,280	1,487,380	742,500	156,240	**8,771,500**
13	Monthly Primary Gas Swing Volumes from Empress (ConocoPhillips)[1]	1,716,330	1,151,756	727,568	1,429,612	1,063,463	1,517,395	575,994	711,744	92,132	165,829	531,994	2,134,626	**11,818,443**
14	Centra Primary Gas Sales Volumes	4,556,616	6,209,236	6,895,718	6,059,689	3,950,897	2,771,343	1,494,099	1,187,267	798,461	835,266	1,274,481	3,252,975	**39,286,048**
15														
16	Average AECO Daily Spot Price (NGX)	$3.0872	$2.8112	$2.4204	$2.0493	$1.6983	$1.5937	$1.9452	$1.8586	$2.2235	$2.0847	$2.1848	$2.9222	
17	AECO to Empress Nova Tolls (NGTL)	$0.1930	$0.1930	$0.1740	$0.1740	$0.1740	$0.1740	$0.1740	$0.1740	$0.1740	$0.1740	$0.1740	$0.1740	
18	AECO to Empress Monthly Basis Differential Index (CGPR)	($0.3393)	($0.3807)	($0.3811)	($0.3278)	($0.2017)	($0.3347)	($0.1531)	$0.0245	$0.1183	$0.0161	$0.1123	$0.1196	
19														
20	**Note 1: Primary Gas Storage purchases are included.**													
21														

CENTRA GAS MANITOBA INC.

Schedule 1.1.3

Interim Primary Gas Rates Effective Aug 1, 2011

Primary Gas PGVA

(based on forward market strip as at July 1, 2011 close)

		(1)	(2)	(3)	(4)
		April	**May**	**June**	**July**
	Primary Gas PGVA	Actual	Actual	Outlook	Outlook
1	Inflows				
2	Primary Gas Direct to Load		$4,172,204	$4,070,537	$3,959,649
3	Primary Gas from Storage		$0	$0	$0
4	TCPL Fuel to MDA & SSDA		$36,345	$26,735	$26,004
5	Exchanges With Counterparties (excluding stg. Withd.)		$0	$0	$0
6	TCPL Line Pack/Draft Nomination & T-Service Imbalances		$92,438	$0	$0
7	Other Primary		$2,739,935	$0	$0
8	Miscellaneous Primary		$0	$0	$0
9	Hedging (System Supply)		$244,780	$203,610	$185,360
10	**Total Inflows**		**$7,285,701**	**$4,300,882**	**$4,171,013**
11	Less: UFG Component to Trans Accnt.		($149,580)	($107,308)	($100,699)
12	**Inflow After UFG Transfer**		**$7,136,121**	**$4,193,573**	**$4,070,314**
13					
14	WACOG Outflows		($6,685,715)	($3,369,788)	($3,390,643)
15	Primary Gas Rate Rider Amortizations		$190,859	$73,163	$73,615
16	**Total Outflows**		**($6,494,856)**	**($3,296,626)**	**($3,317,027)**
17					
18	Carrying Costs		($5,233)	($9,450)	($7,683)
19					
20	**Net Balance**	**($5,446,176)**	**($4,810,144)**	**($3,922,647)**	**($3,177,043)**

CENTRA GAS MANITOBA INC.
Interim Primary Gas Rates Effective November 1, 2011
Primary Gas PGVA
(based on forward market strip as at October 3, 2011 close)

Schedule 1.1.3

		(1) July Actual	(2) August Actual	(3) September Outlook	(4) October Outlook
	Primary Gas PGVA				
1	Inflows				
2	Primary Gas Direct to Load		$3,426,094	$5,197,172	$9,465,967
3	Primary Gas from Storage		$0	$0	$0
4	TCPL Fuel to MDA & SSDA		$14,974	$34,178	$62,335
5	Exchanges With Counterparties (excluding stg. Withd.)		$0	$0	$0
6	TCPL Line Pack/Draft Nomination & T-Service Imbalances		$10,567	$0	$0
7	Other Primary		$0	$0	$2,145,262
8	Miscellaneous Primary		$0	$0	$0
9	Hedging (System Supply)		$0	$0	$0
10	**Total Inflows**		**$3,451,635**	**$5,231,351**	**$11,673,564**
11	Less: UFG Component to Trans Accnt.		($98,614)	($112,280)	($190,343)
12	**Inflow After UFG Transfer**		**$3,353,021**	**$5,119,070**	**$11,483,221**
13					
14	WACOG Outflows		($2,876,201)	($4,461,788)	($10,253,278)
15	Primary Gas Rate Rider Amortizations		$67,189	$99,151	$227,851
16	**Total Outflows**		**($2,809,012)**	**($4,362,637)**	**($10,025,427)**
17					
18	Carrying Costs		($5,941)	($5,725)	($3,247)
19					
20	**Net Balance**	**($3,460,659)**	**($2,922,591)**	**($2,171,883)**	**($717,335)**

9

Centra Gas Manitoba Inc.
Summary of All Gas Cost Deferral Balances
To July 31, 2013

Schedule 10.11.0
February 22, 2013

	Gas Cost Deferral Balances as at October 31, 2012	
2009/10 Gas Year Balances		
April 30, 2011 Prior Period Gas Deferrals	$746,147	
		$746,147
2010/11 Gas Year Balances		
Supplemental Gas PGVA	($9,750,857)	
Transportation PGVA[1]	$7,612,899	
Distribution PGVA	($505,729)	
Heating Value Margin Deferral	($786,854)	
Sub-Total Non Primary Accounts 2010/2011		**($3,430,541)**
2011/12 Gas Year Balances		
Supplemental Gas PGVA	($697,860)	
Transportation PGVA[2]	$5,600,955	
Distribution PGVA	($1,706,117)	
Heating Value Margin Deferral	($499,057)	
Sub-Total Non Primary Accounts 2011/2012		**$2,697,921**
Total All Non-Primary Account Forecast Balances at October 31, 2012		**$13,526**
November 2012 through July 2013 Carrying Costs of all Gas Deferral Accounts		$218
Total All Non-Primary Account Forecast Balances at July 31, 2013		**$13,744**

Note 1: Includes embedded credit of ($5.376 million) for 2010/2011 Gas Year Capacity Management results including carrying costs
Note 2: Includes embedded credit of ($6.437 million) for 2011/2012 Gas Year Capacity Management results including carrying costs

10

CENTRA GAS MANITOBA INC.

2010/11 COST OF GAS APPLICATION

RESPONSE TO INFORMATION REQUESTS OF THE PUBLIC UTILITIES BOARD OF MANITOBA

PUB/CENTRA 16

Reference: Tab 5 Page 2 of 10 – Gas Supply Contract

(a) Please file the redacted evaluation matrix used by Centra to select its new Primary Gas supplier which was previously filed with the Board on October 16, 2009.

Please see the attachment to this response.

(b) Please confirm the name of Centra's new Primary Gas supplier.

Centra's new supplier is ConocoPhillips Canada Marketing & Trading ULC.

(c) Please detail the non-price-related differences between the new gas supply contract and the recently expired contract.

Non-price-related features of the new contract that differ from the expired contract are as follows.

1. New contract: maximum baseload volume of 140,800 GJ/day in any month.
   Expired contract: maximum baseload volume of 127,000 GJ/day December-February and 110,000 GJ/day in the remaining months.
2. New contract: provision for supplier to reasonably accommodate annual adjustments to maximum baseload and swing volumes.

Expired contract: provision to negotiate such changes.

3. New contract: supply exclusivity is limited to Centra's requirements for its firm transportation from Empress (excluding WTS supply).

   Expired contract: supply exclusivity applies to all requirements at Empress (excluding WTS supply).

4. New contract: restriction on resale of supply (excluding situations in which Centra has excess supply at Empress) is limited to Empress.

   Expired contract: restriction applies to all delivery points.

5. New contract: in the event Centra is long gas at Empress, supplier has no right of first refusal on Centra's sale of excess supply.

   Expired contract: supplier has such right of first refusal.

(d) This evaluation matrix shows that the winning proponent obtained the maximum score for minimizing commodity costs. Please demonstrate that the gas costs for the new Gas Supply Contract are in fact less expensive by calculating the forecast Primary Gas costs at Empress for the 2009/10 Gas Year for each proponent and tabulating the results.

The following table provides the differentials between the successful proponent (Party A) and all other proponents which provided a complete proposal. All forecast costs assume provision of all of Centra's Primary Gas requirements for comparison purposes.

Forecast 2009/10 Gas Year Commodity Cost Differential of Proposals as of May 1, 2009	
Party A	-
Party B	$841,486
Party C	$1,540,901
Party E*	$1,397,415
Party F (1)	$1,686,146
Party F (2)	$1,637,316

- Party D's proposed pricing was incomplete and is therefore not included in the comparison.
- Party E indicated that its proposed pricing was only valid under certain assumptions that were not consistent with Centra's operating requirements.
- Party F provided two pricing proposals.

(e) 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).

Centra considered the following factors in performing the evaluation of the gas supply proposals:

1) The proponents were evaluated on factors such as their magnitude of operations in the Western Canadian Sedimentary Basin ("WCSB") including production volumes, their capability of moving large volumes of gas to Empress, and Centra's experience with the proponent. The successful proponent (Party A) is affiliated with one of largest natural gas producers in the WCSB; this affiliate's 2008 Canadian

gas production rate was greater than the combined production rates of the production affiliates of the other proponents.

2) 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. The proponents were then evaluated based on their credit ratings.

3) The proponents were evaluated based on the credit assurances that each expected to seek from Centra.

4) 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, and willingness to provide accommodating and flexible service.

5) The proponents were evaluated based on Centra's experience 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) The proponents were evaluated using publicly available information on corporate commitments to sustainability and the environment, such as inclusion on the Dow Jones Sustainability Index and corporate reports on sustainable practices.

Manitoba Hydro

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Telephone / N° de téléphone : (204) 360-3468 • Fax / N° de télécopieur : (204) 360-6147
mmurphy@hydro.mb.ca

October 16, 2009

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")
REQUEST FOR PROPOSALS WESTERN CANADIAN GAS SUPPLY - EVALUATION MATRIX**

Centra's gas commodity supply contract with Nexen Gas Marketing, Inc. is due to expire on October 31, 2009. As discussed below, Centra has undertaken a thorough process to solicit new natural gas commodity supply arrangements to take effect on November 1, 2009.

As noted in Centra's letter to the Public Utilities Board of Manitoba ("PUB") dated February 17, 2009 regarding the Request For Proposals ("RFP") for Western Canadian Gas Supply, Centra engaged the services of ICF International ("ICF") to assist in the assessment and evaluation of prospective gas commodity supply proposals. Centra issued a RFP to 50 interested counterparties on February 20, 2009. Six counterparties responded by submitting proposals by the deadline of March 17, 2009. During the review process, all proposals were assessed and evaluated with the assistance of ICF.

In order to evaluate the respective gas commodity supply proposals, a set of criteria were designed to produce the most cost effective combination of characteristics to serve the Manitoba market. An Evaluation Matrix was developed and utilized to assist in the evaluation and scoring of each respective commodity supply proposal. The following identifies the Evaluation Matrix criteria for which the proposals were rated:

- Provides Reliable Supply
- Minimizes Total Cost of Supply
- Credit/Financial Substantiation
- Counterparty Quality
- Consistent with other Corporate Goals
- Meets WTS Requirements
- Provides Operational Nomination Flexibility

The findings and scoring results of the various proposals were reviewed by Centra Management and the recommendations were presented to Centra's Board of Directors on June 24, 2009. Centra entered into a new three year gas commodity supply arrangement with the successful counterparty, with gas flows from this new arrangement to begin effective November 1, 2009.

Due to the sensitive commercial nature of the pricing formula contained in the terms of the new gas commodity supply contract, Centra has submitted this contract to the PUB as a separate confidential filing. Centra is respectfully submitting the results of the proposal evaluation scoring matrix as attached to this letter to the PUB and its advisors. Please note that the counterparty names have been redacted. Centra awaits further direction from the PUB as to the distribution of this letter to interested parties.

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.

RFP 029212 WESTERN CANADIAN GAS SUPPLY
CENTRA GAS MANITOBA INC. -- EVALUATION MATRIX

Description of Criteria:	Total Category Weight	Sub Category Weight	PARTY A	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**	9	10	7	7	7	5
2) Minimizes Total Cost of Supply	**0.30**							
2.1 Minimize commodity costs		**0.20**	10	7	7	7	5	6
2.2 Minimize fixed asset costs		**0.05**	10	10	10	10	10	10
2.3 Minimize internal Gas Supply mgmt costs		**0.05**	10	10	8	8	10	10
3) Credit □Financial Substantiation (must be investment grade)	**0.15**	**Yes □No**	Yes	Yes	Yes	Yes	Yes	Yes
3.1 Credit Rating / Worthiness		**0.10**	5	1	5	6.5	4	3.5
3.2 Credit requirements placed on Centra		**0.05**	8	10	6	2	2	2
4) Counterparty Quality	**0.10**							
4.1 Customer Service / Responsiveness		**0.05**	9	9	7	5	6	4
4.2 Proven performance / References and Existing Contracts		**0.05**	9	10	6	5	6	4
5) Consistent with other Corporate Goals	**0.05**							
5.1 Sustainable Development / Reduced Environmental Impacts		**0.05**	8.5	8.5	6.5	7.5	7	8
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	No	Yes	Yes
Total of All Categories			**8.83**	**8.38**	**6.88**	**6.73**	**6.25**	**5.45**
		RANK	**1**	**2**	**3**	**4**	**5**	**6**

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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) Termination process

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.

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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

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PUB/CENTRA II-178

Reference: PUB/Centra I-94 – NEB Decision

In the high level update of the NEB's Decision on TCPL's Business and Services Restructuring Application that is being prepared as stated in PUB/Centra I-94, please address the NEB's decision on each of the points Centra advocated in its closing submission, and how Centra anticipates these decisions will affect Centra and its ratepayers, both in the Test Year and beyond.

ANSWER:

The NEB issued its Reasons for Decision (the "decision") related to the RH-003-2011 hearing on TransCanada's Restructuring Proposal on March 27, 2013 to fix multi-year tolls on the Canadian Mainline (the "Mainline"). Highlights of the decision are as follow:

- The NEB approved multi-year fixed tolls which the NEB deemed to be competitive and provide TransCanada with a reasonable opportunity to recover its Mainline costs given the increase in Mainline throughput which is forecast. In its decision, the NEB established the Firm Transportation toll from Empress, Alberta to Dawn, Ontario at \$1.42/GJ compared to the current interim toll of \$1.89/GJ.
- The NEB expects this toll to remain in effect through 2017. Recognizing the increased business risk the Mainline is facing, the NEB approved the Mainline's return on equity at 11.5 per cent on a 40 per cent equity ratio. The NEB also approved an incentive mechanism which would further increase the Mainline's profits if annual net revenues are higher than forecast.

- The NEB developed a streamlined regulatory process for the Mainline to address new service and pricing proposals in a timelier manner.
- The NEB approved all of TransCanada's proposed changes to the Mainline's cost allocation and the elimination of both FT-RAM and toll zones on the Mainline. The NEB also gave greater discretion to TransCanada on how it prices IT and STFT services on the Mainline.
- The NEB did not approve other TransCanada proposals, including the Alberta System Extension (ASE). Among other things, the NEB viewed the ASE as inappropriate cost shifting among affiliated companies that is contrary to sound tolling principles. The NEB also denied the reallocation of accumulated depreciation and the new proposed treatment of costs related to TransCanada's agreement for transportation services on Trans Québec and Maritimes (TQM) Pipeline Inc.'s pipeline system.
- The NEB denied intervener proposals to disallow costs from the Mainline's rate base or revenue requirement.

The NEB observed in its decision that the Mainline is in an unprecedented position. No major NEB-regulated natural gas transmission pipeline has ever been affected by market forces to the extent that the Mainline is now affected. Throughput on the Mainline has decreased significantly, and as a result, Mainline tolls have increased substantially over a short period of time. The future of the Mainline depends on how TransCanada is able to respond to the changes to its business environment. The NEB also noted that it has provided TransCanada with the tools it requires to achieve positive outcomes for its investors and customers, and that TransCanada must now use those tools to construct a viable future.

Relative to the status quo the decision is directionally positive for Centra and its ratepayers although the net cost impact is uncertain at this point and the decision contains elements which are both favourable and unfavourable.

The NEB expects this toll to remain in effect through 2017 which has the potential to provide for toll certainty and stability and may facilitate contracting for Centra and the broader marketplace at least in the short-term; however there are off-ramps defined within the decision which could lead to the multi-year fixed tolls being in place for less time than expected.

The NEB gave greater discretion to TransCanada on how it prices Interruptible Transportation (IT) service and Short Term Firm Transportation (STFT) service on the Mainline. Centra has recently used STFT to shape its transportation contracts to better match its load curve. Centra anticipates that TransCanada will price STFT to Centra's delivery points (which TransCanada considers captive) at a price which will economically incent Centra back into holding more annual FT capacity. This will result in Centra having more Unutilized Demand Charges (UDC) to mitigate in the secondary market.

Centra's most effective UDC mitigation tool, the FT-Risk Alleviation Mechanism (FT-RAM), was eliminated by way of the decision. Centra will return to using FT-Diversions as a way of mitigating its UDC but, due to the nature of the market which it serves, FT-Diversions will be less effective than using FT-RAM. Centra was able to reduce its fixed costs on the Mainline by almost $5 million in the 2011/12 gas year through its use of the FT-RAM service attribute.

On May 1, 2013 TransCanada made a Compliance Filing which included an Application to Review and Vary portions of the NEB decision.

Centra along with other shippers awaits confirmation of tolls for all paths and services; and bid floors for IT and STFT services. Once this information becomes available, Centra will evaluate its options using this information to inform its transportation contracting and gas supply purchase decisions going forward.

Centra's three key expectations of TransCanada as one of its service providers and as outlined by Centra in its closing submission in the RH-003-2011 proceeding were as follow:

1) For stable and predictable tolls;
2) For TransCanada to be competitive; and
3) For TransCanada's interests and those of Mainline shippers to be more closely aligned such that the risk and costs of underutilization are shared.

Although there is some ambiguity in these objectives, in Centra's opinion the NEB's decision goes a long way to meeting all of these expectations.

Please find below a chart which presents the key components of TransCanada's proposal as compared with the position taken by Centra in its final argument and the NEB's decision.

TransCanada's Proposal	Centra	NEB Decision
Alberta System Extension	Against	Not Approved
Accumulated Depreciation Transfer	Against	Not Approved
Toll Design Changes		
• Elimination of toll zones	For	Approved
• Improvements to cost allocation	For	Approved
• Allocation of TBO costs on TQM system	No Position	Not Approved
Service & Pricing Changes		
• RAM Elimination	Against	Approved
• Multi-Year Fixed Price Service (MFP)	Against	Approved
• Pricing flexibility (IT/STFT)	*	Approved +
Return and other Cost of Service elements	No Position	Approved

*Centra's position on the appropriateness of granting TransCanada with pricing discretion was influenced by whether the discretion would be accompanied by regulatory oversight and TransCanada being accountable for the financial outcomes of the exercising of its discretion.

+ Approved with additional flexibility beyond what was requested by TCPL.

Attachment B4
Part B – Compliance Filing
2013 Toll Design Schedules

FT, STFT and IT Tolls
Mainline 2013 - 2017 Tolls effective July 1, 2013

Notes: (i) Any transportation with a Union Dawn receipt point is subject to a Union Dawn Receipt Point Surcharge. Transport under FT, FT-NR and FT-SN service is subject to the monthly surcharge toll, and other transportation services are subject to the daily equivalent toll. Refer to Toll Design Schedule 5.1 for the Union Dawn Receipt Point Surcharge tolls.
(ii) Transportation with receipt points from delivery areas or Spruce is for STFT and IT service only.
(iii) The following delivery points are subject to an additional charge for delivery pressure: Emerson 1 & 2, Union SWDA, Enbridge SWDA, Dawn Export, Niagara Falls, Iroquois, Chippawa, East Hereford. Refer to Toll Design Schedule 5.1 for the delivery pressure toll.
(iv) Bid floors for IT service may be set at any level and bid floors for STFT may be set at the daily equivalent FT toll or higher.

Line No.	Receipt Point	Delivery Point	FT Toll ($/GJ/MO)	Daily Equivalent FT for IT / STFT ($/GJ)
1	Empress	Empress	2.60027	0.0855
2	Empress	TransGas SSDA	9.34797	0.3073
3	Empress	Centram SSDA	12.11250	0.3982
4	Empress	Centram MDA	16.30938	0.5362
5	Empress	Centrat MDA	18.18844	0.5980
6	Empress	Union WDA	26.04170	0.8562
7	Empress	Nipigon WDA	28.35455	0.9322
8	Empress	Union NDA	40.05675	1.3169
9	Empress	Calstock NDA	33.49897	1.1013
10	Empress	Tunis NDA	37.54917	1.2345
11	Empress	GMIT NDA	40.88251	1.3441
12	Empress	Union SSMDA	36.33193	1.1945
13	Empress	Union NCDA	45.48285	1.4953
14	Empress	Union CDA	46.85749	1.5405
15	Empress	Enbridge CDA	47.62803	1.5659
16	Empress	Union EDA	50.20078	1.6504
17	Empress	Enbridge EDA	49.13597	1.6154
18	Empress	GMIT EDA	52.60135	1.7294
19	Empress	KPUC EDA	51.22500	1.6841
20	Empress	North Bay Junction	42.75425	1.4056
21	Empress	Kirkwall	46.18230	1.5183
22	Empress	Enbridge SWDA	43.24777	1.4218
23	Empress	Union SWDA	43.19178	1.4200
24	Empress	Spruce	18.18844	0.5980
25	Empress	Emerson 1	18.51678	0.6088
26	Empress	Emerson 2	18.51678	0.6088
27	Empress	St. Clair	42.87712	1.4097
28	Empress	Dawn Export	43.24777	1.4218
29	Empress	Niagara Falls	47.91468	1.5753
30	Empress	Chippawa	47.95186	1.5765
31	Empress	Iroquois	49.45575	1.6259
32	Empress	Cornwall	49.97276	1.6429
33	Empress	Napierville	52.36245	1.7215
34	Empress	Philipsburg	52.63402	1.7304
35	Empress	East Hereford	55.51318	1.8251
36	Empress	Welwyn	12.11250	0.3982
37	Bayhurst 1	Empress	3.07217	0.1010
38	Bayhurst 1	TransGas SSDA	8.87716	0.2919
39	Bayhurst 1	Centram SSDA	11.64060	0.3827
40	Bayhurst 1	Centram MDA	15.83764	0.5207
41	Bayhurst 1	Centrat MDA	17.71653	0.5825
42	Bayhurst 1	Union WDA	25.57011	0.8407
43	Bayhurst 1	Nipigon WDA	27.88265	0.9167
44	Bayhurst 1	Union NDA	39.58470	1.3014
45	Bayhurst 1	Calstock NDA	33.02706	1.0858
46	Bayhurst 1	Tunis NDA	37.07727	1.2190
47	Bayhurst 1	GMIT NDA	40.41060	1.3286
48	Bayhurst 1	Union SSMDA	35.86003	1.1790
49	Bayhurst 1	Union NCDA	45.01064	1.4798
50	Bayhurst 1	Union CDA	46.38575	1.5250
51	Bayhurst 1	Enbridge CDA	47.15597	1.5503
52	Bayhurst 1	Union EDA	49.72888	1.6349
53	Bayhurst 1	Enbridge EDA	48.66391	1.5999
54	Bayhurst 1	GMIT EDA	52.12930	1.7138
55	Bayhurst 1	KPUC EDA	50.75310	1.6686
56	Bayhurst 1	North Bay Junction	42.28235	1.3901
57	Bayhurst 1	Kirkwall	45.71040	1.5028
58	Bayhurst 1	Enbridge SWDA	42.77587	1.4063
59	Bayhurst 1	Union SWDA	42.71987	1.4045
60	Bayhurst 1	Spruce	17.71653	0.5825

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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.

Centra Gas Manitoba Inc.
2013/14 General Rate Application
Number of Customers by Customer Class

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%

Line	Volumes are stated in 10^3m^3	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
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

		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
3												
4	**System Supply**											
5	SGS Residential		1.7%	-18.6%	9.0%	6.5%	2.5%	-9.7%	6.2%	-10.4%	18.3%	0.3%
6	SGS Commercial		15.5%	-20.2%	6.9%	9.3%	5.7%	-12.1%	6.4%	-15.4%	21.3%	1.3%
7	Large General Service		1.5%	-14.0%	6.5%	3.5%	2.5%	-11.7%	2.6%	-14.9%	16.8%	-1.9%
8	High Volume Firm		-2.8%	-8.2%	9.3%	6.7%	-2.0%	-4.1%	-3.1%	-12.7%	10.1%	6.3%
9	Mainline Firm		-90.4%	-13.3%	-1.3%	2.4%	8.2%	12.6%	11.9%	16.8%	8.8%	0.0%
10	Interruptible Sales		-9.2%	-7.2%	3.1%	-0.6%	0.1%	-5.5%	-4.0%	-11.9%	8.7%	1.5%
11												
12	**Fixed Price Supply**											
13	SGS Residential								51.6%	26.2%	21.4%	13.2%
14	SGS Commercial								95.0%	-22.8%	65.8%	101.6%
15	Large General Service								99.3%	52.4%	24.2%	55.0%
16												
17	**Western Transportation Service**											
18	SGS Residential		19.3%	2.8%	-0.3%	-4.5%	-3.0%	-23.5%	-23.2%	-43.3%	-15.8%	-25.7%
19	SGS Commercial		80.8%	-2.7%	-4.9%	1.4%	-11.4%	-15.9%	0.7%	-14.0%	3.1%	-3.9%
20	Large General Service		42.7%	-4.0%	-1.5%	17.9%	12.4%	-8.4%	0.4%	5.6%	6.2%	-1.3%
21	High Volume Firm		12.7%	6.1%	20.5%	10.6%	-3.3%	-21.0%	21.4%	2.3%	4.0%	0.0%
22	Mainline Firm		-4.4%	-14.1%	-7.6%	12.2%	-24.2%	-50.6%	1.2%	-10.3%	9.2%	0.0%
23	Interruptible Sales		28.8%	-23.6%	-16.4%	1.9%	-1.2%	7.9%	-9.9%	-3.6%	-3.5%	1.7%
24												
25	**Transportation Service**											
26	Large General Service											
27	High Volume Firm		1.2%	4.0%	3.0%	0.8%	-4.3%	-14.8%	37.8%	16.9%	8.8%	0.0%
28	Mainline Firm		23.2%	-10.0%	-2.7%	8.3%	49.8%	10.0%	-7.6%	-4.2%	5.5%	0.8%
29	Interruptible Sales		17.4%	-1.9%	-4.2%	-0.7%	-7.8%	-14.6%	-21.9%	-6.3%	-1.7%	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	**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

Line		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
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												

16

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).

Change in Methodology to Calculate Normal Weather:

25 Year Rolling Average Instead of 10 Year Rolling Average

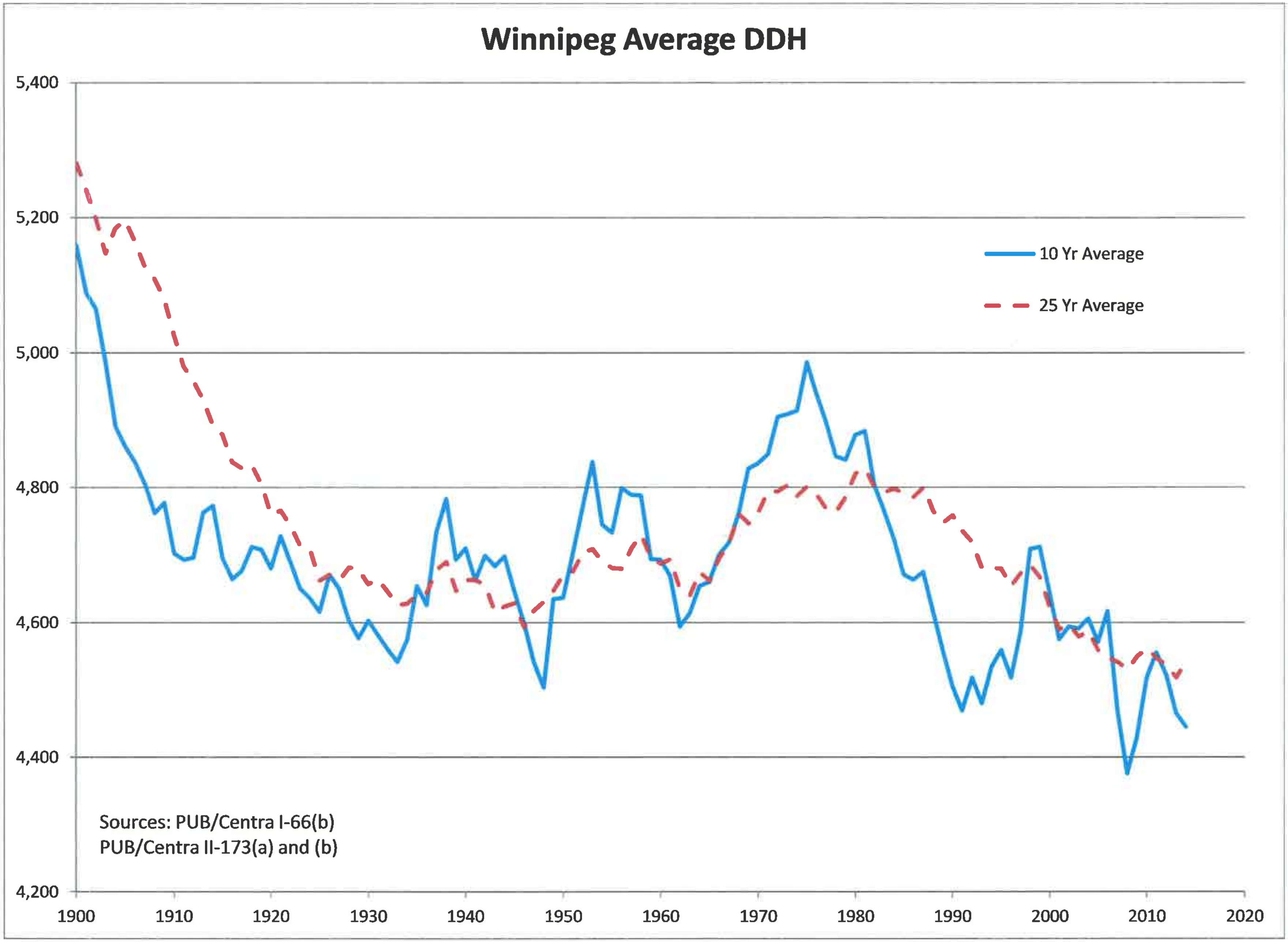
Year	Test Year(s) EDDH Forecast Used[1]	$EDDH_{10yr}$[2]	Change From Prior Year	$EDDH_{25yr}$[2]	Change From Prior Year	Impact on Net Income 10 Year Average[3]	Impact on Net Income 25 Year Average[3]
2006/07		4471	-	4541	-		
2007/08	GRA Test Years 2009/10, 2010/11	4376	(95)	4530	(11)	($1,425,000)	($165,000)
2008/09	COG Test Year 2010/11	4430	54	4550	20	$810,000	$300,000
2009/10	COG Test Year 2011/12	4518	88	4562	12	$1,320,000	$180,000
2010/11	-	4556	38	4547	(15)	($570,000)	$225,000
2011/12	GRA Test Year 2013/14	4523	(33)	4537[4]	(10)	($495,000)	($150,000)
2012/13		4466	(57)	4518	(19)	($855,000)	($285,000)

Note 1: For example, the EDDH average up to March 31, 2012 was used to prepare the 2012 Load Forecast which was used for the 2013/14 GRA Test Year

Note 2: PUB/Centra I-66(c) and PUB/Centra II-173(b)

Note 3: Net Income impact is change in EDDH multiplied by $15,000 per EDDH as stated in PUB/Centra I-66(e)

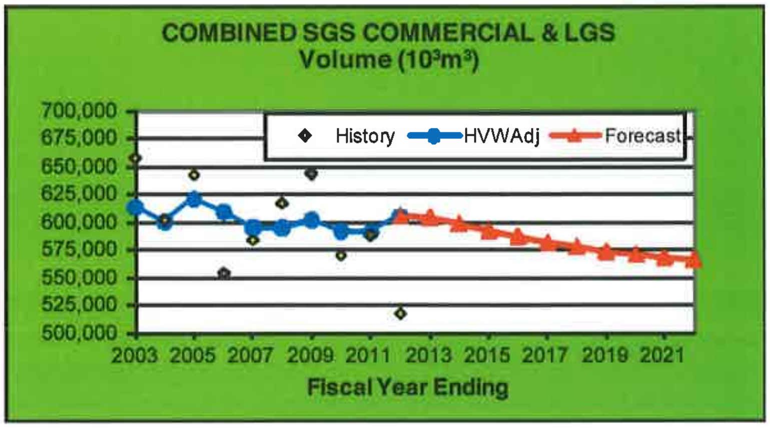
Note 4: Appendix 8.1 p.43


Winnipeg Average DDH
5,400
5,200
5,000
4,800
4,600
4,400
4,200
1900
1910
1920
1930
1940
1950
1960
1970
1980
1990
2000
2010
2020
10 Yr Average
25 Yr Average
Sources: PUB/Centra I-66(b)
PUB/Centra II-173(a) and (b)

SGS Commercial and LGS Volume

The combined total volume of SGS Commercial and LGS classes has decreased by 974 10^3m^3 or 0.2% per year over the last 9 years. It is expected to continue to decrease by 3,953 10^3m^3 or 0.7% per year for the next 10 years.

Figure 9 - SGS Commercial & LGS Volume



SGS Commercial volume has grown by 547 10^3m^3 or 0.6% over the last 9 years. The SGS Commercial class is forecast to increase by 933 10^3m^3 or 0.9% per year until 2021/22.

Figure 10 - SGS Commercial Volume

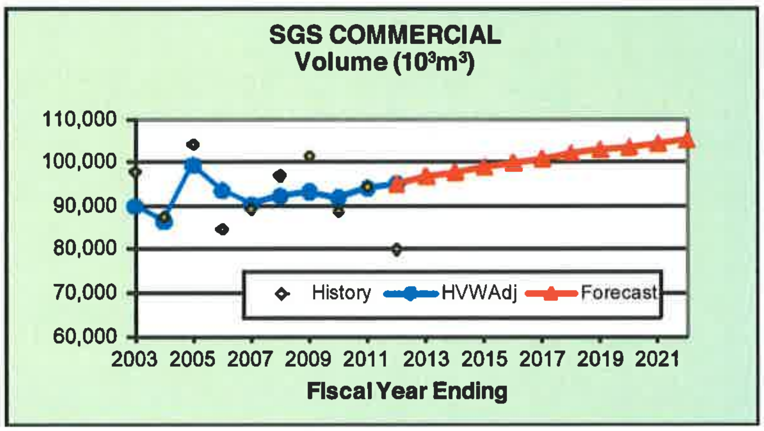
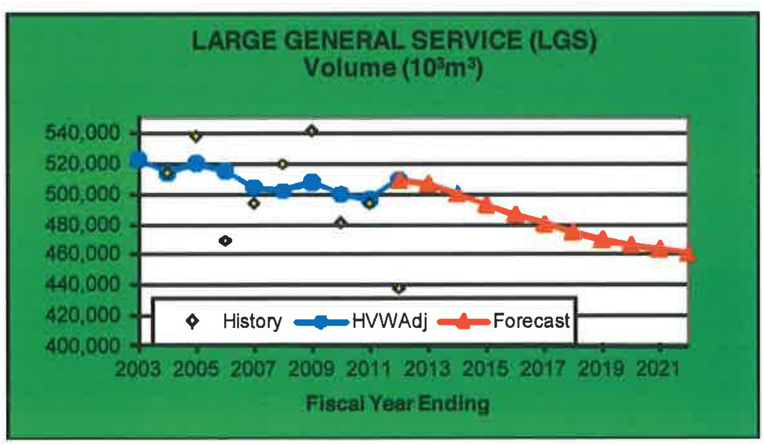
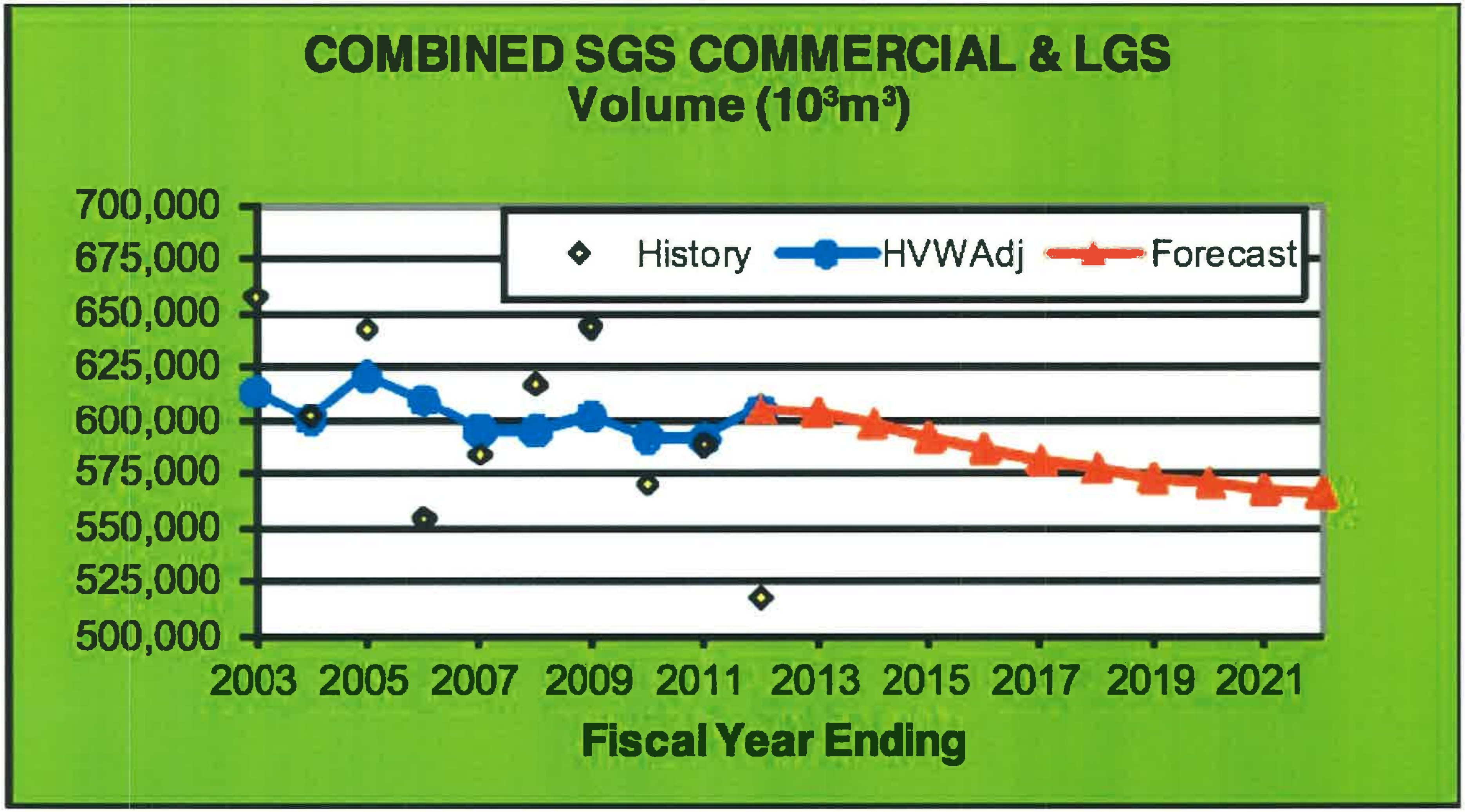
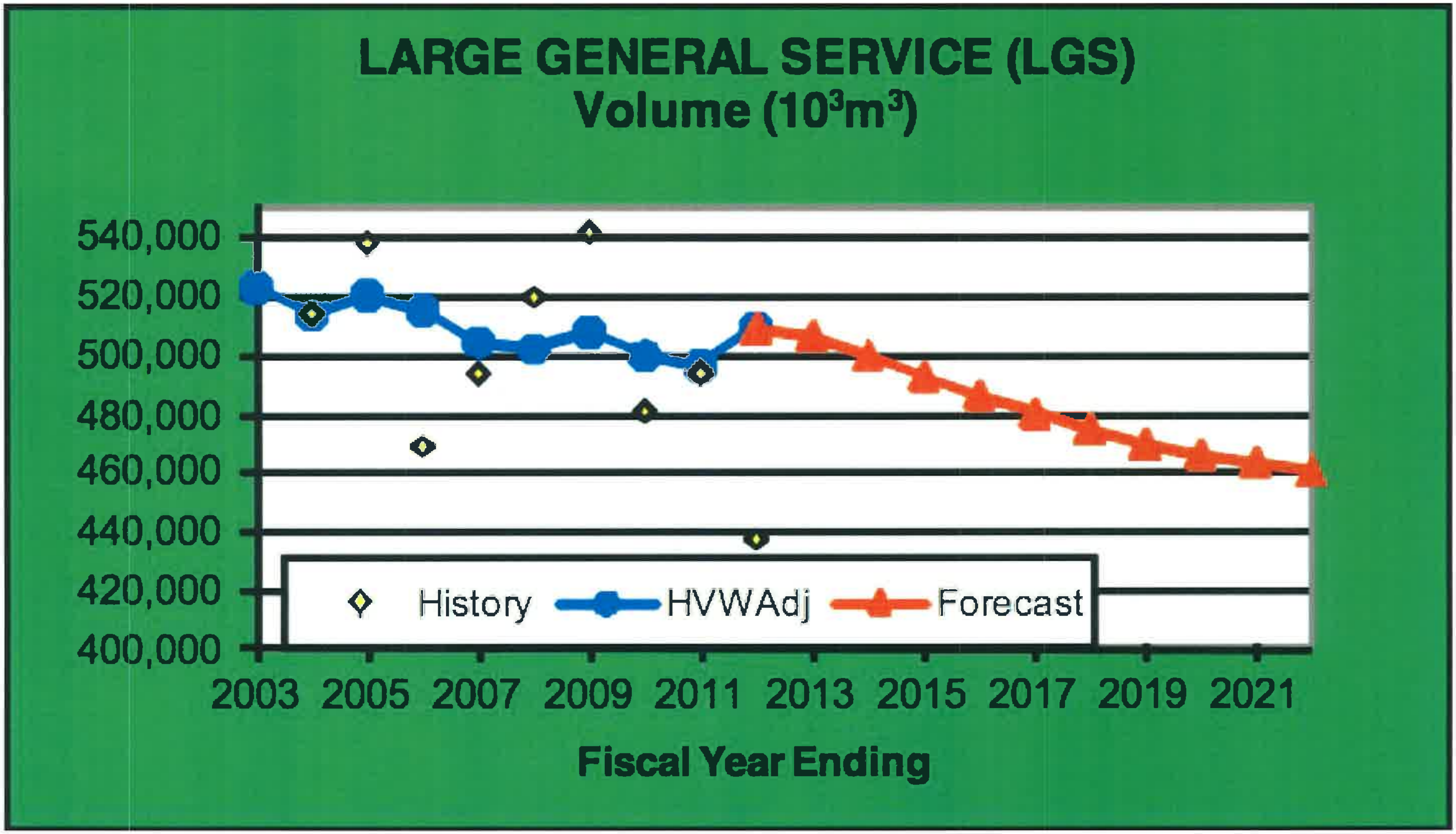


Figure 11 - LGS Volume

Large General Service volume has decreased by 1,521 10^3m^3 or 0.3% per year. It is forecast to continue to decrease by 4,886 10^3m^3 or 1.0% per year until 2021/22.




COMBINED SGS COMMERCIAL & LGS
Volume (10^3m^3)
History
HVWAdj
Forecast
700,000
675,000
650,000
625,000
600,000
575,000
550,000
525,000
500,000
2003 2005 2007 2009 2011 2013 2015 2017 2019 2021
Fiscal Year Ending


LARGE GENERAL SERVICE (LGS)
Volume (10^3m^3)
540,000
520,000
500,000
480,000
460,000
440,000
420,000
400,000
2003
2005
2007
2009
2011
2013
2015
2017
2019
2021
Fiscal Year Ending
History
HVWAdj
Forecast

18

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	

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PUB/CENTRA II-164

Reference: PUB/Centra I-53(a); 2013-2016 Power Smart Plan Page 2 - Utility Costs

Please extend the table in PUB/Centra I-53(a) comparing the DSM spending forecasts from the 2011 Power Smart Plan and the 2013-2016 Power Smart Plan to include the years 2014/15 and 2015/16.

ANSWER:

Please see the table below.

	(in $1000's)							
	2012/13		2013/14		2014/15		2015/16	
	2011 PS Plan (2011$)	Updated (2012$)	2011 PS Plan (2011$)	Updated (2012$)	2011 PS Plan (2011$)	Updated (2012$)	2011 PS Plan (2011$)	Updated (2012$)
RESIDENTIAL								
New Home Program	96	0	107	0	118	0	128	0
Lower Income:								
Power Smart	*692*	*760*	*686*	*744*	*532*	*730*	*447*	*647*
Furnace Replacement Program	*2,330*	*2,378*	*2,330*	*2,378*	*1,818*	*2,378*	*1,528*	*2,205*
Apportioned Affordable Energy Fund	*3,219*	*3,075*	*3,207*	*3,054*	*769*	*3,036*	*0*	*2,753*
Lower Income Total	6,242	6,213	6,223	6,177	3,120	6,144	1,974	5,606
Home Insulation Program	2,600	1,697	2,538	1,688	2,478	1,685	2,419	1,719
Water and Energy Saver Program	644	804	637	804	628	804	0	0
RESIDENTIAL TOTAL	9,582	8,714	9,504	8,669	6,343	8,632	4,522	7,324
COMMERCIAL								
Commercial Custom Measures Program	92	141	99	141	99	141	99	141
Commercial Windows Program	503	438	503	422	447	380	447	196
Commercial Insulation Program	3,373	1,613	3,373	1,435	2,777	1,291	2,778	951
Commercial New Construction Program	248	569	239	440	269	529	304	648
Commercial Building Optimization Program	314	255	335	193	335	214	335	214
Internal Retrofit Program	0	53	0	0	0	0	0	0
Commercial Kitchen Appliance Program	79	38	91	88	102	102	113	105
CO2 Sensors	64	58	66	56	68	58	70	59
Commercial Rinse & Save Program	2	0	0	0	0	0	0	0
Commercial Water Heater Program	91	0	97	0	106	0	120	0
Commercial Boiler Program	804	1,025	816	543	768	516	3	7
COMMERCIAL TOTAL	5,573	4,192	5,619	3,317	4,971	3,230	4,270	2,320
INDUSTRIAL								
Industrial Natural Gas Optimization Program	923	770	763	770	763	640	763	640
INDUSTRIAL TOTAL	923	770	763	770	763	640	763	640
EFFICIENCY PROGRAMS SUBTOTAL	16,077	13,676	15,885	12,756	12,077	12,503	9,555	10,285
CUSTOMER SELF-GENERATION								
BioEnergy Optimization Program	572	139	30	221	96	43	543	279
	572	139	30	221	96	43	543	279
PROGRAMS SUBTOTAL	16,649	13,815	15,915	12,977	12,173	12,546	10,097	10,564
CUSTOMER SERVICE INITIATIVES, SUPPORT AND CONTINGENCY	3,551	2,128	3,410	2,354	3,267	2,407	3,179	2,474
GRAND TOTAL	20,200	15,943	19,325	15,332	15,440	14,953	13,277	13,038

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PUB/CENTRA II-170

Reference: PUB/Centra I-56(a)

In a similar format as provided in PUB/Centra I-56(a), please provide the demographic data for gas customers only.

ANSWER:

	LICO Households in Manitoba					
	Natural Gas					
Dwelling Type	Own	% of Total LICO	Rent	% of Total LICO	Total By Dwelling Type	% of Total LICO
Single Detached	27,404	78%	2,068	6%	29,472	84%
Multi-Attached	3,065	9%	1,649	5%	4,714	14%
Apartment Suite	480	1%	212	1%	692	2%
Total by Ownership	30,949	88%	3,929	12%	34,878	100%

	LICO-125 Households in Manitoba					
	Natural Gas					
Dwelling Type	Own	% of Total LICO-125	Rent	% of Total LICO-125	Total By Dwelling Type	% of Total LICO-125
Single Detached	40,581	80%	2,464	5%	43,045	85%
Multi-Attached	4,944	9%	1,801	3%	6,745	12%
Apartment Suite	788	2%	307	1%	1,095	3%
Total by Ownership	46,313	91%	4,572	9%	50,885	100%

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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 II-172

Reference: PUB/Centra I-59

c) **Please update the response to PUB/Centra I-59(a) based on the 2013-2016 Power Smart Plan extending the schedule to include 2015/16.**

ANSWER:

Furnace Replacement Fund ending March 31 (000's)	2008/9 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Projected*	2013/14 Forecast**	2014/15 Forecast**	2015/16 Forecast**
Opening Balance	$ 2,327	$ 5,972	$ 9,050	$ 11,644	$ 14,145	$ 15,853	$ 17,644	$ 19,621
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)	$ (2,378)
Interest	$ 54	$ 93	$ 144	$ 290	$ 286	$ 369	$ 555	$ 746
Ending Balance	$ 5,972	$ 9,050	$ 11,644	$ 14,145	$ 15,853	$ 17,644	$ 19,621	$ 17,989
Number of Furnace Installations	280	508	445	662	660	900	937	1,018
Number of Boiler Installations	5	9	16	18	9	15	9	9
Cumulative Furnace Installations	280	788	1,233	1,895	2,555	3,455	4,393	5,410
Cumulative Boiler Installations	5	14	30	48	57	72	81	90

* 2012/13 values are a combination of actual values to the end of February, 2013 and forecasted values for March, 2013

** Disbursements indicated for the Forecast years do not include amounts in connection with the Neighbourhood Approach

PUB/CENTRA II-172

Reference: PUB/Centra I-59

d) Please estimate the number of furnaces and boilers (at the historical mix) that could be replaced under the FRP beginning in 2015/16 with the forecasted $19.6 million, and estimate how long until the FRP fund is depleted. Please also estimate the number of targeted furnaces that would remain after the FRP funds are depleted, factoring in furnaces that may be replaced independently of the FRP.

ANSWER:

Centra projects the Furnace and Boiler market would be depleted before all of the Furnace Replacement Funds are spent. The number of furnaces and boilers that could be replaced under the FRP beginning in 2015/16 are shown in the following table:

FRP Replacements	2015/16 Forecast	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
Number of Furnace Installations	1,018	1,183	1,183	312
Number of Boiler Installations	9	9	9	9
Cumulative Furnace Installations	5,410	6,593	7,776	8,088
Cumulative Boiler Installations	90	99	108	117

Furnace and boiler replacements could continue at the historical mix for the years 2015/16 through to 2017/18 but would drop off in year 2018/19 due to the reduced market size. The standard efficiency furnace market is projected to be depleted at the end of fiscal year

2018/19. The FRP Fund Balance is estimated to be $14,824,734 at the end of year 2018/19 based on the above activity.

The assumptions used in the Furnace Upgrade Market Table (see Appendix 7.3 p. 1) were also used to estimate the targeted standard furnaces remaining at the end of each year starting in 2015/16. Please see the chart below for the market estimations:

LIEEP Standard Efficiency Furnace Target Market			
Furnace Marketplace at Dec 1 2009	**LICO 125%**	**Non-LICO**	**All Dwellings**
Standard Furnace Market			
Owners	16,034	39,858	55,892
Rentals	2,285	2,152	4,437
Total Standard Furnaces (source: 2009 Survey)	18,319	42,010	60,329
Standard Furnaces Remaining at Fiscal Year End			
end of 2012/13	11,576	22,110	33,686
Furnace Marketplace Projections of Standard Furnaces Remaining			
end of 2015/16	5,307	8,194	13,500
end of 2016/17	3,223	4,521	7,744
end of 2017/18	1,223	1,191	2,413
end of 2018/19	0	0	0

PUB/CENTRA II-172

Reference: PUB/Centra I-59

e) Please confirm whether the Lower Income Energy Efficiency Program budget shown in PUB/Centra I-59(h) includes funding from the Furnace Replacement Program and the Affordable Energy Fund.

ANSWER:

Confirmed.

PUB/CENTRA II-172

Reference: PUB/Centra I-59

f) Please add a row to the table in PUB/Centra I-59(c) showing Centra's program administration and marketing unit cost per furnace and per boiler. Please confirm whether the program administration and marketing costs are included in the disbursements of the FRP.

ANSWER:

	Standard Furnace Replacement	**Standard Boiler Replacement**
	Average Cost	Average Cost
Customer contribution	$ 1,140	$ 6,445
Centra contribution	$ 2,387	$ 2,500
Total equipment cost	$ 3,527	$ 8,945
Marketing/Administration cost	$ 871	$ 871

Centra does not differentiate between furnace and boiler marketing and administration costs. Instead, the costs are incurred across all Furnace Replacement installations. The average marketing and administration cost per heating system replaced under the program is $871. The program administration and marketing costs under the Furnace Replacement Program are included in the disbursements of the FRP.

PUB/CENTRA II-172

Reference: PUB/Centra I-59(g)

g) Please provide a breakdown of FRP disbursements for each of years 2008/09 through 2014/15.

ANSWER:

FRP Disbursements Breakdown	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual
Internal - Labour			$358,204	$405,447
Internal - Other		$1,231	$1,993	$3,259
Marketing			$88,167	$113,821
Payments to Contractors	$264,258	$813,975	$863,256	$1,104,506
Total	**$264,258**	**$815,205**	**$1,311,620**	**$1,627,033**

FRP Disbursements Breakdown	2012/13 Projected	2013/14 Forecast	2014/15 Forecast	Total
Internal - Labour	$452,017	$452,017	$452,017	**$2,119,704**
Internal - Other	$3,837	$3,837	$3,837	**$17,993**
Marketing	$119,560	$119,560	$119,560	**$560,668**
Payments to Contractors	$1,802,973	$1,802,973	$1,802,973	**$8,454,913**
Total	**$2,378,387**	**$2,378,387**	**$2,378,387**	**$11,153,277**

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.

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.

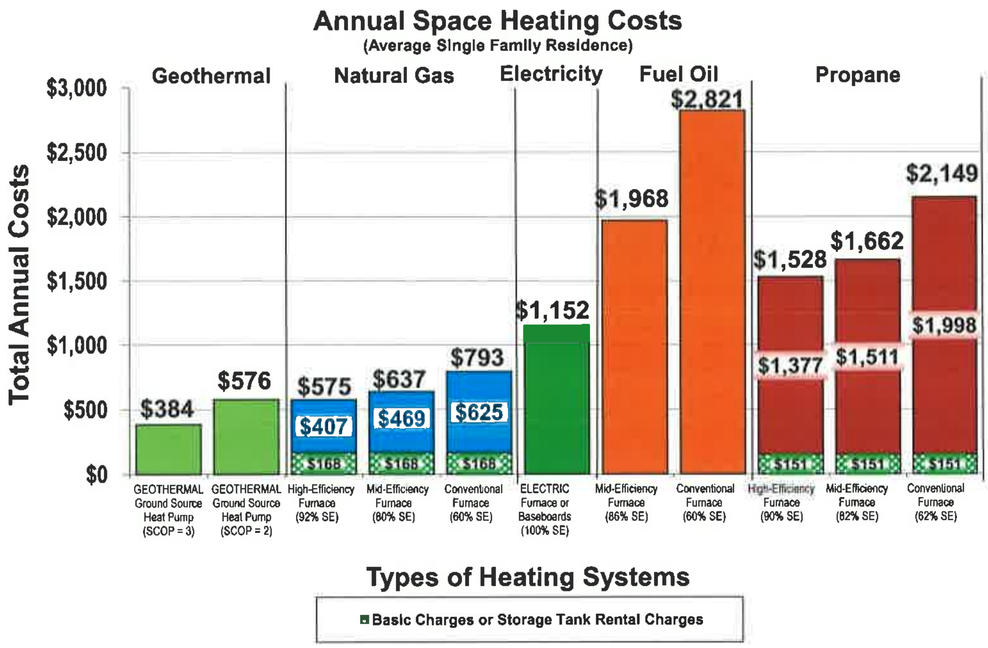
Typical space & water heating costs

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

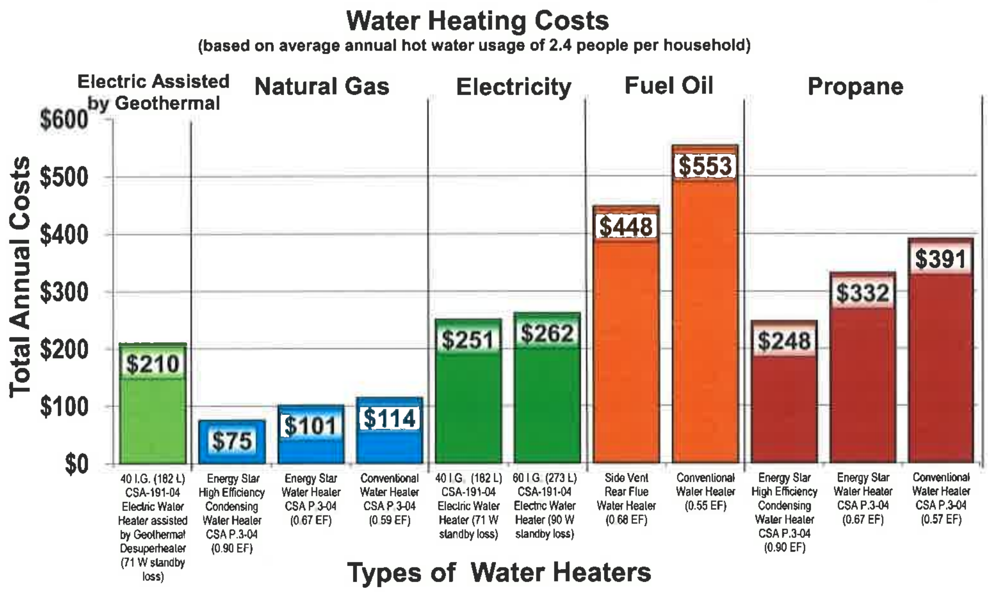
Electricity:
$0.0694/kilowatt-hour

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**



Manitoba Hydro
POWER SMART

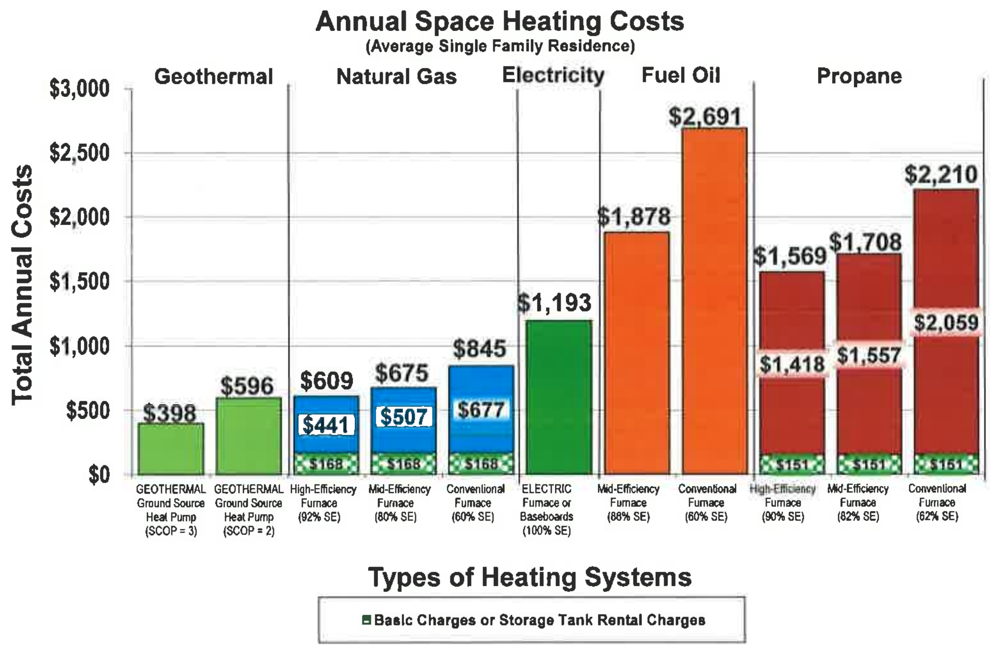
Typical space & water heating costs

Average single family residence at rates in effect May 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:
$0.2529/cubic metre

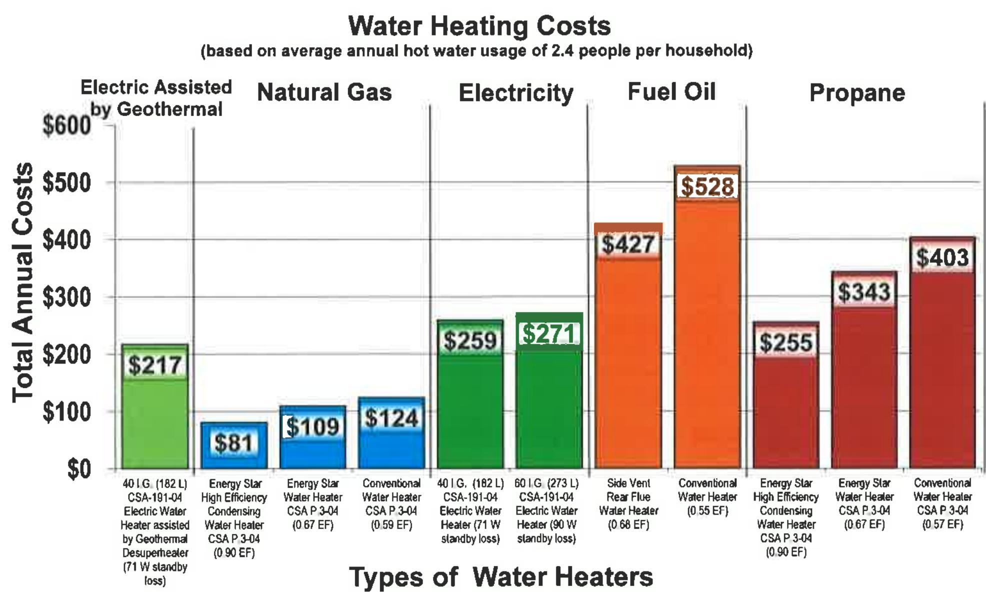
Electricity:
$0.07183/kilowatt-hour

Fuel oil:
$1.04/litre

Propane:
$0.545/litre

Basic monthly charge for natural gas is **$14** (**$168** per year)

Annual propane tank rental: **$151**



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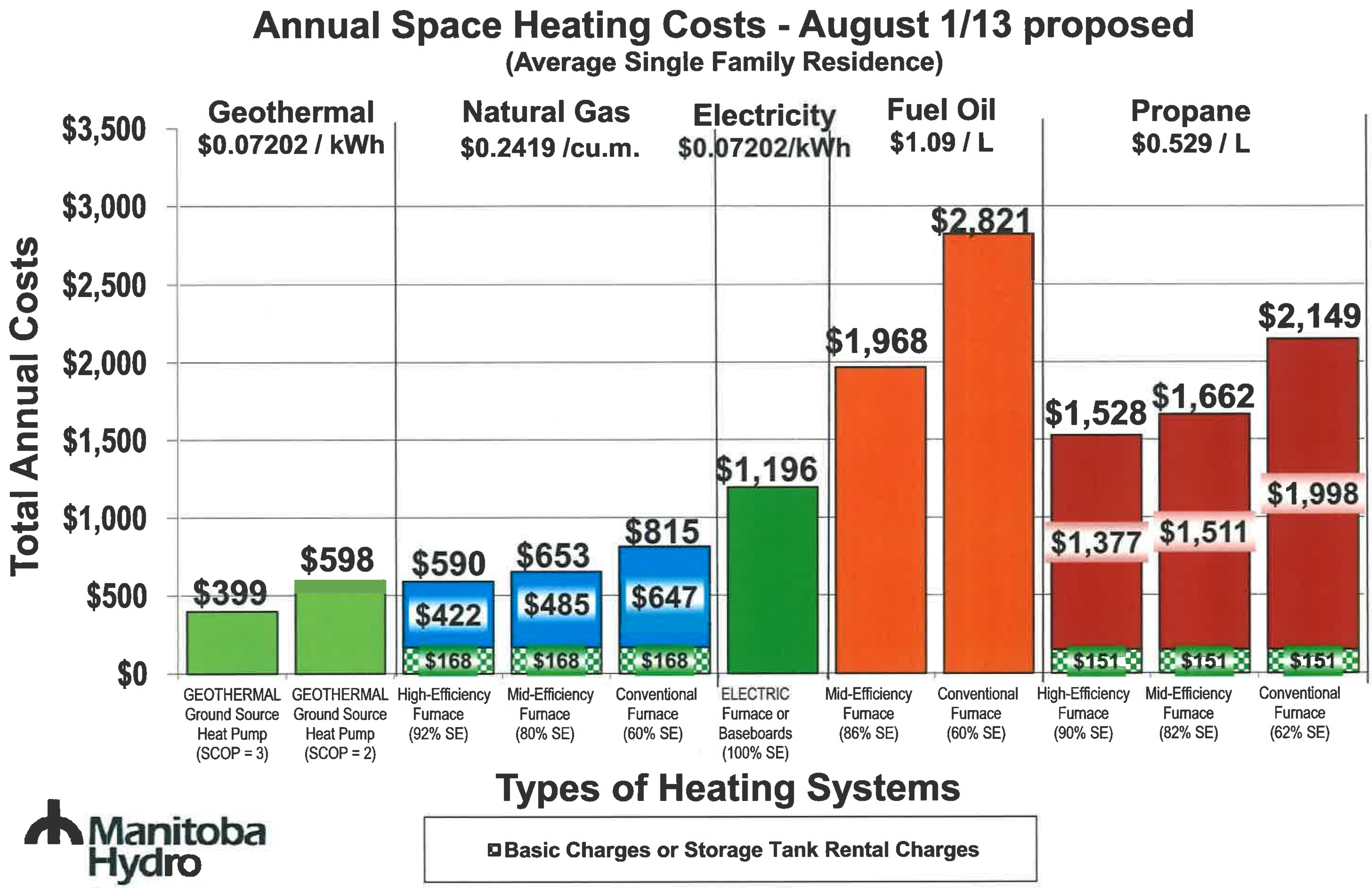
* Manitoba Hydro is a licensee of the Trademark and Official Mark.



Manitoba Hydro
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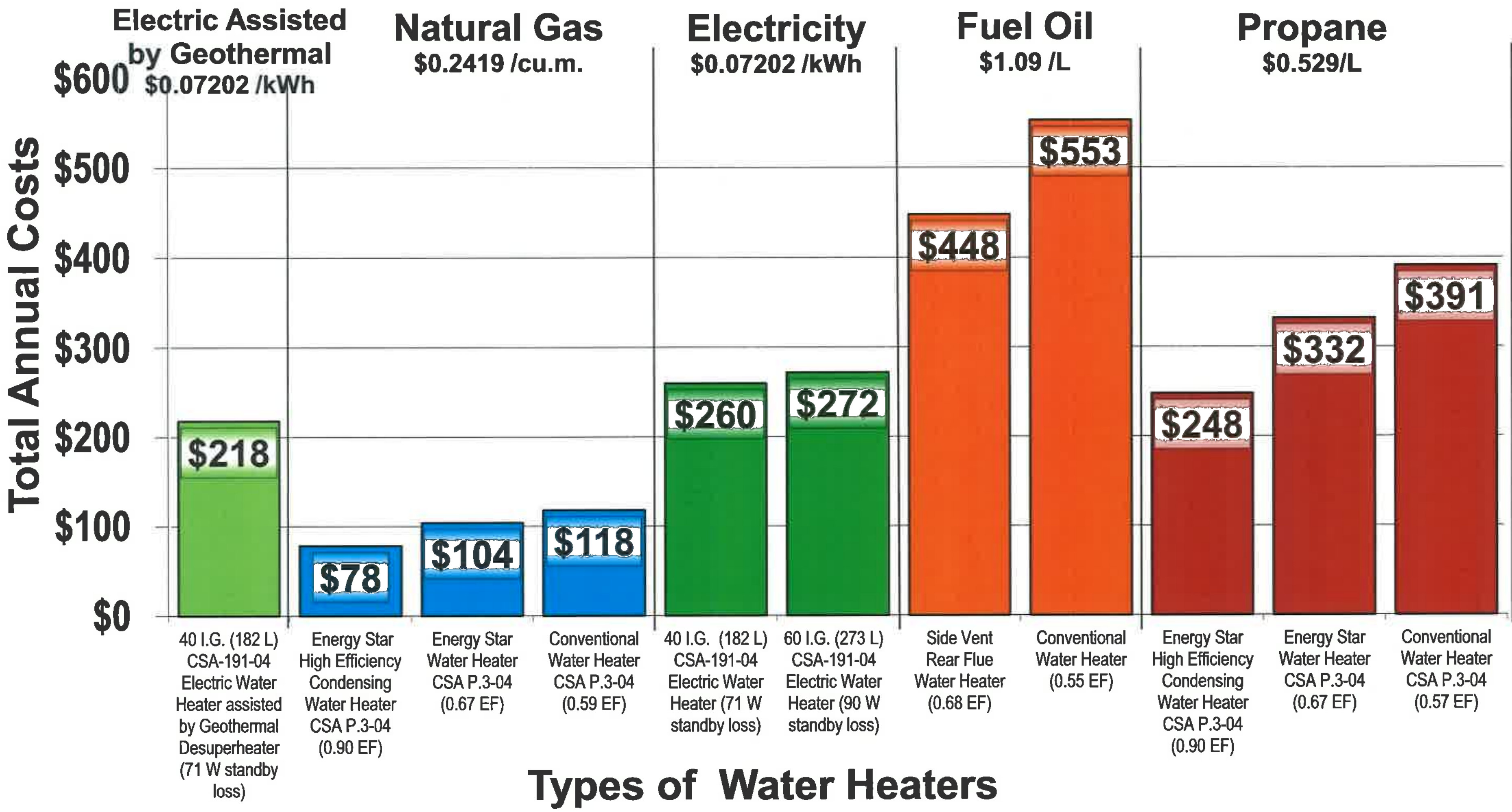
Water Heating Costs - August 1/13 proposed

(based on average annual hot water usage of 2.4 people per household)



Manitoba Hydro
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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.

26

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.

Centra Gas Manitoba Inc.
2013/14 General Rate Application
Power Stations Payments required to meet Minimum Gross Margin Amount - 9 years

PUB/Centra 119 c
Attachment
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 II-182

Reference: PUB/Centra I-119; Tab 11 Schedule 11.1.0

d) Please provide the forecasted Test Year revenue to cost ratio for this customer reflecting the anticipated revenue from the MAGMA.

ANSWER:

Please refer to the tables below.

i) Forecast RCC with all revenues included:

Cost Allocation	2013/14 GRA
Energy	125,157
Demand	67,332
Customer	196,785
Total Allocated costs	389,273
Revenue	
Energy	125,157
Minimum Annual Gross Margin	947,104
Total Revenue	1,072,261
Revenue To Cost Ratio	
Total Revenue	1,072,261
Total Allocated costs	389,273
Revenue To Cost Ratio:	2.8

ii) Forecast RCC excluding top-up payment to assure MAGMA:

Cost Allocation	2013/14 GRA
Energy	125,157
Demand	67,332
Customer	196,785
Total Allocated costs	389,273
Revenue	
Energy	125,157
Minimum Annual Gross Margin (MAGMA)	947,104
Total Revenue	1,072,261
Minimum Annual Gross Margin	947,104
Less: Demand	-67,332
Less: Customer	-196,785
Top-up payment to MAGMA	682,988
Revenue To Cost Ratio	
Total Revenue	1,072,261
Less: Top-up payment to MAGMA	-682,988
PS Revenue before Top-up payment	389,273
Total Allocated costs	389,273
Revenue To Cost Ratio:	1.0

Centra Gas Manitoba Inc.
2013/14 General Rates Application
Summary of Allocated Costs by Customer Class
2013/14 Test Year

Schedule 11.1.0
February 22, 2013

Cost of Service Elements

	SGS				LGS			
	Demand	Energy	Customer	Total	Demand	Energy	Customer	Total
Cost of Gas	22,676,289	2,990,131	0	25,666,420	16,277,741	2,156,876	0	18,434,617
Other Income	-54,334	-647	-1,665,022	-1,720,003	-39,019	-467	-57,259	-96,745
Operating & Maintenance Expenses	6,274,847	74,722	46,338,430	52,687,999	4,506,186	53,949	6,026,431	10,586,566
Depreciation & Amortization	3,580,785	4,179,804	17,228,810	24,989,399	2,243,547	2,450,889	2,307,445	7,001,881
Capital & Other Taxes	3,089,146	652,822	9,053,770	12,795,738	2,217,913	421,917	1,514,912	4,154,742
Finance Expense	2,249,196	1,669,042	7,746,978	11,665,216	1,613,739	1,078,528	1,338,702	4,030,968
Corporate Allocation	1,560,497	1,157,985	5,374,869	8,093,351	1,119,615	748,285	928,794	2,796,694
Net Income	729,272	541,165	2,511,856	3,782,293	523,234	349,698	434,056	1,306,988
Total Cost of Service	40,105,697	11,265,024	86,589,691	137,960,413	28,462,956	7,259,674	12,493,080	48,215,710

	HVF				Cooperative			
	Demand	Energy	Customer	Total	Demand	Energy	Customer	Total
Cost of Gas	3,606,148	542,200	0	4,148,348	9,090	600	0	9,690
Other Income	-11,371	-104	-9,411	-20,886	-16	0	-24	-40
Operating & Maintenance Expenses	1,313,241	12,013	1,021,725	2,346,980	1,884	20	2,569	4,473
Depreciation & Amortization	573,519	144,720	150,581	868,820	506	1	583	1,091
Capital & Other Taxes	623,806	61,526	73,700	759,032	577	105	298	979
Finance Expense	452,453	157,150	59,747	669,350	347	268	206	821
Corporate Allocation	313,913	109,031	41,453	464,397	241	186	143	569
Net Income	146,702	50,954	19,372	217,028	112	87	67	266
Total Cost of Service	7,018,409	1,077,491	1,357,168	9,453,068	12,740	1,266	3,842	17,848

	Main Line				Special Contract			
	Demand	Energy	Customer	Total	Demand	Energy	Customer	Total
Cost of Gas	366,040	201,115	0	567,154	30,722	63,441	0	94,163
Other Income	-5,525	-13	-806	-6,344	-5,103	-1	-112	-5,215
Operating & Maintenance Expenses	638,025	1,518	87,291	726,834	589,269	120	10,881	600,270
Depreciation & Amortization	181,973	287,971	14,376	484,320	11,777	-16	12,309	24,071
Capital & Other Taxes	192,315	32,055	7,427	231,797	362,664	29	7,656	370,349
Finance Expense	113,354	82,017	6,118	201,489	199,433	70	5,639	205,142
Corporate Allocation	78,645	56,904	4,245	139,794	138,367	49	3,912	142,328
Net Income	36,754	26,593	1,984	65,330	64,663	23	1,628	66,515
Total Cost of Service	1,601,581	688,159	120,635	2,410,375	1,391,792	63,716	42,114	1,497,622

	Power Station				Interruptible			
	Demand	Energy	Customer	Total	Demand	Energy	Customer	Total
Cost of Gas	2,977	124,617	0	127,594	1,139,858	470,877	0	1,610,735
Other Income	-743	-2	-270	-1,015	-3,744	-77	-4,098	-7,919
Operating & Maintenance Expenses	85,790	237	21,765	107,792	432,420	8,916	444,134	885,470
Depreciation & Amortization	-94,511	-31	67,503	-27,039	173,745	144,498	70,754	388,998
Capital & Other Taxes	35,374	57	43,175	78,607	194,803	49,355	36,008	280,166
Finance Expense	19,050	138	32,017	51,206	140,550	126,087	29,603	296,240
Corporate Allocation	13,217	96	22,213	35,527	97,514	87,479	20,539	205,532
Net Income	6,177	45	10,381	16,603	45,572	40,882	9,598	96,052
Total Cost of Service	67,332	125,157	196,785	389,273	2,220,719	928,017	606,538	3,755,274

	Primary Gas				Supplemental Gas - Firm			
	Demand	Energy	Customer	Total	Demand	Energy	Customer	Total
Cost of Gas	0	129,266,487	0	129,266,487	0	21,418,199	0	21,418,199
Other Income	0	-5,318	0	-5,318	0	-885	0	-885
Operating & Maintenance Expenses	0	614,606	0	614,606	0	101,834	0	101,834
Depreciation & Amortization	0	42,509	0	42,509	0	7,043	0	7,043
Capital & Other Taxes	0	64,614	0	64,614	0	10,706	0	10,706
Finance Expense	0	146,962	0	146,962	0	24,350	0	24,350
Corporate Allocation	0	101,962	0	101,962	0	16,894	0	16,894
Net Income	0	47,650	0	47,650	0	7,895	0	7,895
Total Cost of Service	0	130,279,472	0	130,279,472	0	21,586,037	0	21,586,037

	Supplemental Gas - Interruptible				Fixed Price Offering			
	Demand	Energy	Customer	Total	Demand	Energy	Customer	Total
Cost of Gas	0	1,887,503	0	1,887,503	0	955,827	0	955,827
Other Income	0	-78	0	-78	0	-40	-1,071	-1,110
Operating & Maintenance Expenses	0	8,974	0	8,974	0	4,545	123,657	128,201
Depreciation & Amortization	0	621	0	621	0	314	108,553	108,867
Capital & Other Taxes	0	943	0	943	0	478	1,850	2,328
Finance Expense	0	2,146	0	2,146	0	1,087	1,023	2,110
Corporate Allocation	0	1,489	0	1,489	0	754	710	1,464
Net Income	0	696	0	696	0	352	332	684
Total Cost of Service	0	1,902,294	0	1,902,294	0	963,317	235,054	1,198,371

	Unassigned				Total			
	Demand	Energy	Customer	Total	Demand	Energy	Customer	Total
Cost of Gas	0	0	0	0	44,108,865	160,077,872	0	204,186,737
Other Income	0	0	0	0	-119,856	-7,633	-1,738,072	-1,865,560
Operating & Maintenance Expenses	0	0	0	0	13,841,662	881,455	54,076,884	68,800,000
Depreciation & Amortization	0	0	0	0	6,671,341	7,258,324	19,960,914	33,890,579
Capital & Other Taxes	0	0	0	0	6,716,598	1,294,606	10,738,796	18,750,000
Finance Expense	0	0	0	0	4,788,122	3,287,845	9,220,033	17,296,000
Corporate Allocation	0	0	0	0	3,322,009	2,281,113	6,396,878	12,000,000
Net Income	0	0	0	0	1,552,485	1,066,040	2,989,474	5,608,000
Total Cost of Service	0	0	0	0	80,881,225	176,139,622	101,644,908	358,665,755

Centra Gas Manitoba Inc.
2013/14 General Rates Application
Unit Cost Component Summary
2013/14 Test Year

Schedule 11.1.1
February 22, 2013

		System Total	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	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Fixed Price Offering FRPGS
1	REVENUE REQUIREMENTS													
2	Upstream Demand ($)	45,478,615	23,405,764	16,801,319	3,718,618	9,383	368,254	0	0	1,175,277	0	0	0	0
3	Upstream Commodity ($)	162,544,655	3,825,955	2,785,297	650,852	1,266	69,266	0	0	480,898	130,279,472	21,586,037	1,902,294	963,317
4	Upstream Customer ($)	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Upstream Total ($)	208,023,270	27,231,719	19,586,616	4,369,470	10,648	437,520	0	0	1,656,176	130,279,472	21,586,037	1,902,294	963,317
6														
7	Downstream Demand ($)	35,402,610	16,699,933	11,661,637	3,299,791	3,358	1,233,327	1,391,792	67,332	1,045,441	0	0	0	0
8	Downstream Commodity ($)	13,594,968	7,439,069	4,474,377	426,638	0	618,893	63,716	125,157	447,119	0	0	0	0
9	Downstream Customer ($)	101,644,908	86,589,691	12,493,080	1,357,168	3,842	120,635	42,114	196,785	606,538	0	0	0	235,054
10	Downstream Total ($)	150,642,486	110,728,693	28,629,094	5,083,597	7,200	1,972,854	1,497,622	389,273	2,099,098	0	0	0	235,054
11														
12	Total (incl. gas costs)	358,665,755	137,960,413	48,215,710	9,453,068	17,848	2,410,375	1,497,622	389,273	3,755,274	130,279,472	21,586,037	1,902,294	1,198,371
13												92%	8%	0
14														
15	MONTHLY BILLING DETERMINANTS													
16	Upstream Demand (10^3m^3-day)	125,382	62,892	44,539	10,138	25	974	0	0	6,813	0	0	0	0
17	Upstream Commodity (10^3m^3)	1,409,778	680,452	499,617	123,628	270	13,496	0	0	92,315	1,102,093	131,746	11,078	7,720
18	Upstream Customer (customers)	3,282,042	3,188,090	92,428	1,044	12	24	0	0	444	0	0	0	7,391
19														
20	Downstream Demand (10^3m^3-day)	164,743	62,892	44,539	12,561	25	6,720	15,553	14,656	7,797	0	0	0	0
21	Downstream Commodity (10^3m^3)	2,027,285	680,452	499,617	163,446	270	134,963	421,289	15,196	112,051	0	0	0	0
22	Downstream Customer (customers)	3,289,635	3,194,330	93,577	1,104	12	96	12	24	480	0	0	0	0
23														
24	PERCENT IN DEMAND CHARGE		0.0%	0.0%	65.0%	100.0%	100.0%	100.0%	100.0%	65.0%	100.0%	100.0%	100.0%	100.0%
25														
26	RESULTING UNIT CHARGES													
27	Upstream Demand ($/$10^3m^3$-day)	362.720	0.000	0.000	238.413	369.950	377.915	0.000	0.000	112.120	0.000	0.000	0.000	0.000
28	Upstream Commodity ($/$10^3m^3$)	115.298	40.020	39.203	15.792	4.687	5.132	0.000	0.000	9.665	118.211	163.845	171.721	124.786
29	Upstream Customer ($/customer)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
30														
31	Downstream Demand ($/$10^3m^3$-day)	214.896	0.000	0.000	170.762	132.392	183.536	89.488	4.594	87.148	0.000	0.000	0.000	0.000
32	Downstream Commodity ($/$10^3m^3$)	6.706	35.475	32.297	9.676	0.000	4.586	0.151	8.236	7.256	0.000	0.000	0.000	0.000
33	Downstream Customer ($/customer)	30.899	27.107	133.506	1,229.319	320.192	1,256.611	3,509.512	8,199.358	1,263.621	0.000	0.000	0.000	0.000

Centra Gas Manitoba Inc.
2013/14 General Rates Application
Comparison of Gas Costs vs. Non-Gas Costs
2013/14 Test Year

Schedule 11.1.2
February 22, 2013

Line	Gas Costs vs. Non-Gas Costs	System Total	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	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Fixed Price Offering FRPGS
1	REVENUE REQUIREMENTS													
2	Upstream Demand ($)													
3	Gas Costs	43,910,421	22,598,686	16,221,976	3,590,393	9,059	355,556	0	0	1,134,752	0	0	0	0
4	Non-gas Costs	1,568,194	807,078	579,343	128,225	324	12,698	0	0	40,526	0	0	0	0
5	Total	45,478,615	23,405,764	16,801,319	3,718,618	9,383	368,254	0	0	1,175,277	0	0	0	0
6		0	0	0	0	0	0	0	0	0	0	0	0	0
7	Upstream Commodity ($)													
8	Gas Costs	157,812,116	2,120,081	1,533,793	342,813	600	35,714	0	0	251,099	129,266,487	21,418,199	1,887,503	955,827
9	Non-gas Costs	4,732,539	1,705,875	1,251,504	308,039	666	33,552	0	0	229,800	1,012,985	167,838	14,791	7,490
10	Total	162,544,655	3,825,955	2,785,297	650,852	1,266	69,266	0	0	480,898	130,279,472	21,586,037	1,902,294	963,317
11		0	0	0	0	0	0	0	0	0	0	0	0	0
12	Upstream Customer ($)													
13	Gas Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Non-gas Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Total	0	0	0	0	0	0	0	0	0	0	0	0	0
16														
17	Upstream Total ($)													
18	Total Gas Costs	201,722,537	24,718,767	17,755,769	3,933,206	9,659	391,270	0	0	1,385,850	129,266,487	21,418,199	1,887,503	955,827
19	Total Non-gas Costs	6,300,733	2,512,952	1,830,848	436,264	990	46,250	0	0	270,326	1,012,985	167,838	14,791	7,490
20	Total Upstream Costs	208,023,270	27,231,719	19,586,616	4,369,470	10,648	437,520	0	0	1,656,176	130,279,472	21,586,037	1,902,294	963,317
21		0	0	0	0	0	0	0	0	0	0	0	0	0
22	Downstream Demand ($)													
23	Gas Costs	198,444	77,603	55,765	15,755	31	10,484	30,722	2,977	5,107	0	0	0	0
24	Non-gas Costs	35,204,166	16,622,330	11,605,872	3,284,036	3,327	1,222,843	1,361,070	64,355	1,040,335	0	0	0	0
25	Total	35,402,610	16,699,933	11,661,637	3,299,791	3,358	1,233,327	1,391,792	67,332	1,045,441	0	0	0	0
26														
27	Downstream Commodity ($)													
28	Gas Costs	2,265,756	870,050	623,083	199,387	0	165,400	63,441	124,617	219,778	0	0	0	0
29	Non-gas Costs	11,329,212	6,569,019	3,851,294	227,252	0	453,492	275	540	227,340	0	0	0	0
30	Total	13,594,968	7,439,069	4,474,377	426,638	0	618,893	63,716	125,157	447,119	0	0	0	0
31														
32	Downstream Customer ($)													
33	Gas Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
34	Non-gas Costs	101,644,908	86,589,691	12,493,080	1,357,168	3,842	120,635	42,114	196,785	606,538	0	0	0	235,054
35	Total	101,644,908	86,589,691	12,493,080	1,357,168	3,842	120,635	42,114	196,785	606,538	0	0	0	235,054
36														
37	Downstream Total ($)													
38	Total Gas Costs	2,464,200	947,653	678,848	215,141	31	175,884	94,163	127,594	224,885	0	0	0	0
39	Total Non-gas Costs	148,178,286	109,781,040	27,950,246	4,868,456	7,169	1,796,970	1,403,459	261,679	1,874,213	0	0	0	235,054
40	Total Downstream Costs	150,642,486	110,728,693	28,629,094	5,083,597	7,200	1,972,854	1,497,622	389,273	2,099,098	0	0	0	235,054
41														
42	Grand Total Gas Costs	204,186,737	25,666,420	18,434,617	4,148,348	9,690	567,154	94,163	127,594	1,610,735	129,266,487	21,418,199	1,887,503	955,827
43	Grand Total Non-gas Costs	154,479,019	112,293,993	29,781,094	5,304,720	8,159	1,843,220	1,403,459	261,679	2,144,538	1,012,985	167,838	14,791	242,544
44	Grand Total	358,665,755	137,960,413	48,215,710	9,453,068	17,848	2,410,375	1,497,622	389,273	3,755,274	130,279,472	21,586,037	1,902,294	1,198,371
45														
46														

47 Calculation of the Primary Gas Overhead Rate: 1,012,985 (line 9, PG column)
48 1,102,093 (10^3m^3 (Schedule 11.1.1, line 17, PG column)
49 0.92 10^3m^3

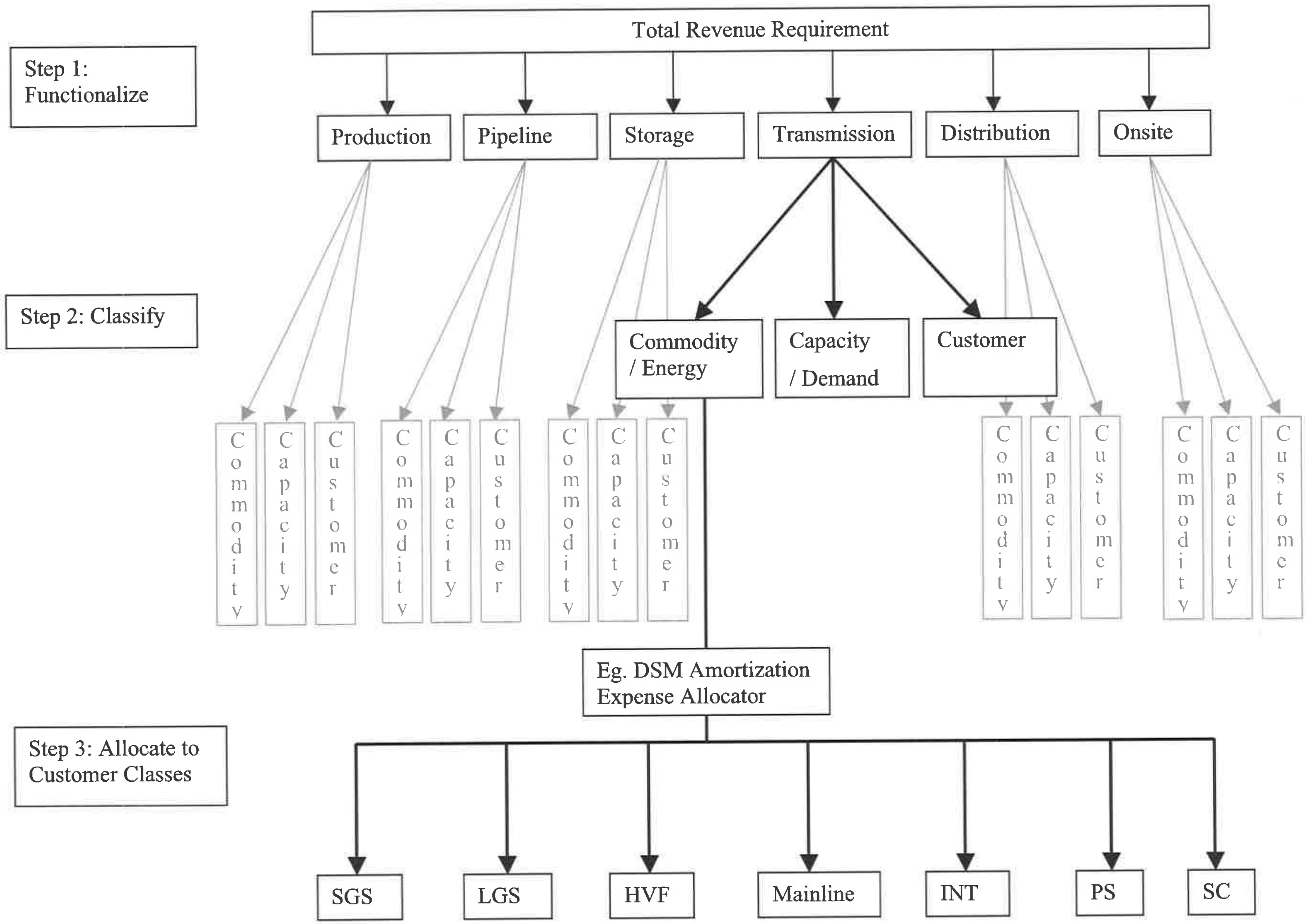
Calculation of the Fixed Rate Primary Gas PCR 242,544 (lines 9 & 34, FPO column)
7,720 (10^3m^3 (Schedule 11.1.1, line 17, FPO column)
31.42 per 10^3m^3

Schedule 11.1.3
February 22, 2013

Centra Gas Manitoba Inc.
2013/14 General Rate Application
Total Functionalization By Customer Class
2013/14 Test Year

		System Total	Residential SGS-R	Small Commercial SGS-C	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	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Fixed Price Offering FPO
1	PRODUCTION															
2	Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Energy	154,731,119	0	0	0	0	0	0	0	0	0	0	130,279,472	21,586,037	1,902,294	963,317
4	Customer	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Total	154,731,119	0	0	0	0	0	0	0	0	0	0	130,279,472	21,586,037	1,902,294	963,317
6																
7	PIPELINE															
8	Demand	31,492,725	13,885,480	2,322,386	16,207,866	11,634,464	2,575,044	6,497	255,006	0	0	813,848	0	0	0	0
9	Energy	1,626,230	672,099	112,827	784,926	576,326	142,609	311	15,568	0	0	106,489	0	0	0	0
10	Customer	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Total	33,118,955	14,557,579	2,435,213	16,992,792	12,210,790	2,717,653	6,809	270,574	0	0	920,337	0	0	0	0
12																
13	STORAGE															
14	Demand	13,985,890	6,166,529	1,031,369	7,197,898	5,166,855	1,143,574	2,885	113,248	0	0	361,429	0	0	0	0
15	Energy	6,187,306	2,595,067	445,962	3,041,029	2,208,971	508,243	954	53,698	0	0	374,410	0	0	0	0
16	Customer	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Total	20,173,196	8,761,596	1,477,331	10,238,927	7,375,826	1,651,818	3,840	166,946	0	0	735,839	0	0	0	0
18																
19	TRANSMISSION															
20	Demand	10,852,022	3,904,409	715,572	4,619,981	2,988,443	864,968	1,512	620,580	1,391,792	67,332	297,414	0	0	0	0
21	Energy	13,594,968	5,162,779	2,276,290	7,439,069	4,474,377	426,638	0	618,893	63,716	125,157	447,119	0	0	0	0
22	Customer	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23	Total	24,446,990	9,067,188	2,991,862	12,059,050	7,462,820	1,291,607	1,512	1,239,472	1,455,508	192,488	744,533	0	0	0	0
24																
25	DISTRIBUTION															
26	Demand	24,550,589	10,348,993	1,730,959	12,079,952	8,673,194	2,434,822	1,846	612,748	0	0	748,027	0	0	0	0
27	Energy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Customer	10,638,514	9,646,311	684,423	10,330,734	302,636	3,570	2	16	0	4	1,552	0	0	0	0
29	Total	35,189,103	19,995,304	2,415,381	22,410,686	8,975,830	2,438,393	1,848	612,763	0	4	749,580	0	0	0	0
30																
31	ONSITE															
32	Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
33	Energy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34	Customer	91,006,393	69,298,987	6,959,970	76,258,957	12,190,444	1,353,598	3,840	120,619	42,114	196,781	604,986	0	0	0	235,054
35	Total	91,006,393	69,298,987	6,959,970	76,258,957	12,190,444	1,353,598	3,840	120,619	42,114	196,781	604,986	0	0	0	235,054
36																
37	TOTAL SERVICE															
38	Demand	80,881,225	34,305,412	5,800,285	40,105,697	28,462,956	7,018,409	12,740	1,601,581	1,391,792	67,332	2,220,719	0	0	0	0
39	Energy	176,139,622	8,429,945	2,835,079	11,265,024	7,259,674	1,077,491	1,266	688,159	63,716	125,157	928,017	130,279,472	21,586,037	1,902,294	963,317
40	Customer	101,644,908	78,945,299	7,644,393	86,589,691	12,493,080	1,357,168	3,842	120,635	42,114	196,785	606,538	0	0	0	235,054
41	Total	358,665,755	121,680,655	16,279,757	137,960,413	48,215,710	9,453,068	17,848	2,410,375	1,497,622	389,273	3,755,274	130,279,472	21,586,037	1,902,294	1,198,371

Centra's Cost Allocation Methodology



From Tab 11 p.2-6

Centra Gas - Rate Changes Proposed for August 1, 2013

Base Rates

Basic Monthly Charge ($/month)	01-May	01-Aug	% Change
Small General Service	14	14	0.00%
Large General Service	77	77	0.00%
High Volume Firm	1118.31	1230.72	10.05%
Mainline	2353.33	1258.09	-46.54%
Interruptible	1042.72	1265.06	21.32%
Power Station	11565.6	8258.46	-28.59%
Special Contract	135424.7	120972.43	-10.67%

Demand ($/m3/month)	Transportation			Distribution		
	01-May	01-Aug	% Change	01-May	01-Aug	% Change
Small General Service	N/A	N/A	-	N/A	N/A	-
Large General Service	N/A	N/A	-	N/A	N/A	-
High Volume Firm	0.2408	0.2386	-0.91%	0.1504	0.1706	13.43%
Mainline	0.4209	0.3782	-10.14%	0.158	0.1847	16.90%
Interruptible	0.1127	0.1122	-0.44%	0.0772	0.0871	12.82%
Power Station	N/A	N/A	-	0.028	0.0047	-83.21%
Special Contract	N/A	N/A	-	N/A	N/A	-

Commodity ($/m3)	Transportation			Distribution		
	01-May	01-Aug	% Change	01-May	01-Aug	% Change
Small General Service	0.0462	0.04	-13.42%	0.0869	0.0971	11.74%
Large General Service	0.0451	0.0392	-13.08%	0.0362	0.0429	18.51%
High Volume Firm	0.0201	0.0158	-21.39%	0.0081	0.0096	18.52%
Mainline	0.0095	0.0051	-46.32%	0.0015	0.0046	206.67%
Interruptible	0.0139	0.0096	-30.94%	0.0051	0.0072	41.18%
Power Station	N/A	N/A	-	0.0165	0.008	-51.52%
Special Contract	N/A	N/A	-	0.0002	0.0001	-50.00%

Commodity ($/m3)	01-May	01-Aug	% Change
Supplemental Gas - Firm	0.1344	0.1605	19.42%
Supplemental Gas - Interruptible	0.1293	0.171	32.25%

Source: Schedule 12.2.0, 12.2.1 May 10, 2013

Centra Gas - Rate Changes Proposed for August 1, 2013

Billed Rates

Basic Monthly Charge ($/month)	01-May	01-Aug	% Change
Small General Service	14	14	0.00%
Large General Service	77	77	0.00%
High Volume Firm	1118.31	1230.72	10.05%
Mainline	2353.33	1258.09	-46.54%
Interruptible	1042.72	1265.06	21.32%
Power Station	11565.6	8258.46	-28.59%
Special Contract	135424.7	120972.43	-10.67%

Demand ($/m3/month)	Transportation			Distribution		
	01-May	01-Aug	% Change	01-May	01-Aug	% Change
Small General Service	N/A	N/A	-	N/A	N/A	-
Large General Service	N/A	N/A	-	N/A	N/A	-
High Volume Firm	0.2408	0.3619	50.29%	0.1504	0.1711	13.76%
Mainline	0.4209	0.2594	-38.37%	0.158	0.1844	16.71%
Interruptible	0.1127	0.1571	39.40%	0.0772	0.0875	13.34%
Power Station	N/A	N/A	-	0.028	0.0048	-82.86%
Special Contract	N/A	N/A	-	N/A	N/A	-

Commodity ($/m3)	Transportation			Distribution		
	01-May	01-Aug	% Change	01-May	01-Aug	% Change
Small General Service	0.0462	0.051	10.39%	0.0869	0.0876	0.81%
Large General Service	0.0451	0.0506	12.20%	0.0362	0.0333	-8.01%
High Volume Firm (Sales Service)	0.0201	0.0127	-36.82%	0.0081	0.0001	-98.77%
High Volume Firm (T-Service)	N/A	N/A	-	0.0081	0.0076	-6.17%
Mainline (Sales Service)	0.0095	0.0047	-50.53%	0.0015	-0.0045	-400.00%
Mainline (T-Service)	N/A	N/A	-	0.0015	0.003	100.00%
Interruptible (Sales Service)	0.0139	0.0139	0.00%	0.0051	-0.0056	-209.80%
Interruptible T-Service)	N/A	N/A	-	0.0051	0.0052	1.96%
Power Station	N/A	N/A	-	0.0165	0.008	-51.52%
Special Contract	N/A	N/A	-	0.0002	0.0001	-50.00%

Commodity ($/m3)	01-May	01-Aug	% Change
Supplemental Gas - Firm	0.1344	0.1605	19.42%
Supplemental Gas - Interruptible	0.1293	0.171	32.25%

Source: Schedule 12.2.0, 12.2.1 May 10, 2013

Manitoba Hydro

Customer name
Nom de l'abonné

Account number
N° de compte

Service location
Adresse de service

Date issued
Date d'émission
Apr 27 AVR 2012

Special messages / Messages particuliers

- **New Equal Payment Plan Instalment**
One or more of your EPP instalments has been revised to more accurately balance your Instalments billed and Use by the end of the EPP year. Your plan(s) will continue to be reviewed until August when your EPP instalment(s) will be recalculated for the beginning of the next EPP year.

Nouveau versement du Régime de paiements égaux(RPÉ)
Nous avons révisé le montant ou les montants de vos versements du RPÉ pour faire correspondre plus exactement les versements facturés et votre consommation jusqu'à la fin de l'année du RPÉ. Votre régime continuera d'être révisé jusqu'au mois d'août alors que votre versement sera recalculé pour le début de la prochaine année du RPÉ.

- The Public Utilities Board has approved new electricity rates. Please see the enclosed insert for details.

La Régie des services publics a approuvé de nouveaux tarifs d'électricité. Veuillez consulter l'encart ci-joint pour tous les détails.

Electricity - Residential / Électricité - Résidentiel

Meter number / ° de compteur	Service / Pour la période From / Du	To / Au	Days / Jours	Meter readings / Relevés du compteur Previous / Précédent	Present / Nouveau	Multiplier / Multiplicateur	kW.h / kWh	Reading type / Type de relevé
	Mar 23 MAR/12	Apr 25 AVR/12	33	1484	1588	10	1,040	Estimated Estimatif

Basic Charge / Redevance de base			$ 6.85	
Energy Charge / Frais d'énergie	252.121 kW.h	x $0.06620	16.69	
	787.879	x 0.06770	53.34	
Subtotal / Total partiel			76.88	
	2.50% City Tax / Taxe mun.		1.94	
	7.00% Prov Tax / Taxe prov.		5.38	
	5.00% GST / TPS		3.84	
Electricity charges / Frais d'électricité			**88.04**	
EPP instalment / Versement du R.P.É.				53.00

Natural gas - Residential / Gaz naturel - Résidentiel

Meter number / N° de compteur	Service / Pour la période From / Du	To / Au	Days / Jours	Meter readings / Relevés du compteur Previous / Précédent	Present / Nouveau	Usage / Consommation		Base pressure adj/Facteur de rajustement de la pression de base		Metric conversion factor/Facteur de conversion métrique		Cubic metres (m³) / Mètres cubes (m³)	Reading type / Type de relevé
	Mar 23 MAR/12	Apr 25 AVR/12	33	2683	2815	132	x	0.98780	x	2.832784	=	369.367	Estimated Estimatif

Basic Charge / Redevance de base					$ 14.00
Primary Gas (Centra) / Gaz d'inventaire (Centra)	99.0 % x	369.367 m³	x $0.11050		40.41
Supplemental Gas / Gaz de réserve	1.0 x	369.367	x 0.13440		0.50
Transportation to Centra / Transport jusqu'à Centra	100.0 x	369.367	x 0.05360		19.80
Distribution to Customer / Distribution aux abonnés	100.0 x	369.367	x 0.08490		31.36
Subtotal / Total partiel					106.07
	2.50% City Tax Based on Non Heating Load / Taxe mun. fondée sur la charge de non-chauffage				0.73
	1.40% Prov Tax / Taxe prov.				1.50
	5.00% GST / TPS				5.31
Natural gas charges / Frais de gaz naturel					**113.61**

Centra Gas Manitoba Inc.
2013/14 General Rates Application - Cost of Gas Update May 10, 2013
Bill Impact Comparison
2013/14 Test Year

BILLED VS. BILLED

	Load Factor	Annual Use 10^3m^3	Annual Use Mcf	May 1/13 APPROVED BILLED RATES Basic Chg	Demand	Commodity	Annual	AUG 1/13 PROPOSED BILLED RATES Basic Chg	Demand	Commodity	Annual	BILL IMPACTS $	%
Small General Service		1.00	35	$168	$0	$251	$419	$168	$0	$259	$427	$8	1.96%
		1.98	70	$168	$0	$497	$665	$168	$0	$513	$681	$16	2.45%
(Typical Residential Customer)		2.37	84	$168	$0	$595	$763	$168	$0	$615	$783	$19	2.55%
		2.80	99	$168	$0	$703	$871	$168	$0	$726	$894	$23	2.64%
		3.20	113	$168	$0	$803	$971	$168	$0	$829	$997	$26	2.71%
		3.68	130	$168	$0	$923	$1,091	$168	$0	$954	$1,122	$30	2.77%
		11.33	400	$168	$0	$2,841	$3,009	$168	$0	$2,934	$3,102	$93	3.09%
Large General Service		11.33	400	$924	$0	$2,254	$3,178	$924	$0	$2,314	$3,238	$60	1.88%
		59.49	2,100	$924	$0	$11,832	$12,756	$924	$0	$12,146	$13,070	$314	2.46%
		679.87	24,000	$924	$0	$135,221	$136,145	$924	$0	$138,811	$139,735	$3,590	2.64%
High Volume Firm	25%	850	30,000	$13,420	$43,720	$123,911	$181,051	$14,769	$59,565	$113,065	$187,398	$6,347	3.51%
	40%	850	30,000	$13,420	$27,325	$123,911	$164,656	$14,769	$37,228	$113,065	$165,062	$406	0.25%
	40%	1,416	50,000	$13,420	$45,542	$206,518	$265,480	$14,769	$62,046	$188,442	$265,257	($223)	-0.08%
	40%	2,833	100,000	$13,420	$91,084	$413,037	$517,540	$14,769	$124,093	$376,883	$515,745	($1,795)	-0.35%
	40%	6,200	218,866	$13,420	$199,351	$903,997	$1,116,768	$14,769	$271,597	$824,869	$1,111,235	($5,533)	-0.50%
	40%	12,600	444,792	$13,420	$405,133	$1,837,156	$2,255,708	$14,769	$551,956	$1,676,347	$2,243,072	($12,637)	-0.56%
	75%	685	24,181	$13,420	$11,747	$99,877	$125,044	$14,769	$16,004	$91,135	$121,907	($3,136)	-2.51%
	75%	850	30,000	$13,420	$14,573	$123,911	$151,904	$14,769	$19,855	$113,065	$147,689	($4,216)	-2.78%
	75%	1,416	50,000	$13,420	$24,289	$206,518	$244,227	$14,769	$33,091	$188,442	$236,302	($7,925)	-3.25%
	75%	2,833	100,000	$13,420	$48,578	$413,037	$475,035	$14,769	$66,183	$376,883	$457,835	($17,200)	-3.62%
	75%	6,200	218,866	$13,420	$106,321	$903,997	$1,023,738	$14,769	$144,852	$824,869	$984,490	($39,248)	-3.83%
	75%	12,600	444,792	$13,420	$216,071	$1,837,156	$2,066,646	$14,769	$294,376	$1,676,347	$1,985,492	($81,154)	-3.93%
Cooperative	35%	250	8,825	$3,289	$11,516	$31,702	$46,506	$3,854	$11,826	$31,275	$46,956	$449	0.97%
	35%	350	12,355	$3,289	$16,123	$44,382	$63,794	$3,854	$16,557	$43,785	$64,196	$403	0.63%
	35%	500	17,650	$3,289	$23,032	$63,403	$89,724	$3,854	$23,652	$62,550	$90,057	$333	0.37%
Mainline Firm	40%	2,833	100,000	$28,240	$134,786	$364,313	$527,339	$15,097	$103,344	$370,162	$488,603	($38,736)	-7.35%
	40%	14,164	500,000	$28,240	$673,931	$1,821,565	$2,523,736	$15,097	$516,719	$1,850,810	$2,382,625	($141,111)	-5.59%
	40%	28,328	1,000,000	$28,240	$1,347,862	$3,643,130	$5,019,232	$15,097	$1,033,437	$3,701,619	$4,750,153	($269,079)	-5.36%
	75%	2,833	100,000	$28,240	$71,886	$364,313	$464,439	$15,097	$55,117	$370,162	$440,376	($24,063)	-5.18%
	75%	14,164	500,000	$28,240	$359,430	$1,821,565	$2,209,235	$15,097	$275,583	$1,850,810	$2,141,490	($67,745)	-3.07%
	75%	28,328	1,000,000	$28,240	$718,860	$3,643,130	$4,390,230	$15,097	$551,166	$3,701,619	$4,267,883	($122,347)	-2.79%
	75%	41,000	1,447,339	$28,240	$1,040,434	$5,272,846	$6,341,520	$15,097	$797,725	$5,357,499	$6,170,321	($171,199)	-2.70%
Special Contract	89%	421,289	14,871,907	$1,625,097	$0	$84,258	$1,709,355	$1,451,669	$0	$42,129	$1,090,676	($618,679)	-36.19%
Power Stations	16%	15,196	536,433	$277,574	$87,429	$250,734	$615,737	$198,203	$14,978	$121,568	$23,735	($592,003)	-96.15%
Interruptible Sales	25%	850	30,000	$12,513	$21,223	$115,890	$149,625	$15,181	$27,339	$111,098	$153,619	$3,993	2.67%
	40%	2,833	100,000	$12,513	$44,215	$386,299	$443,026	$15,181	$56,957	$370,328	$442,466	($560)	-0.13%
	40%	14,164	500,000	$12,513	$221,074	$1,931,494	$2,165,080	$15,181	$284,786	$1,851,639	$2,151,606	($13,474)	-0.62%
	75%	850	30,000	$12,513	$7,074	$115,890	$135,477	$15,181	$9,113	$111,098	$135,392	($84)	-0.06%
	75%	2,833	100,000	$12,513	$23,581	$386,299	$422,393	$15,181	$30,377	$370,328	$415,886	($6,507)	-1.54%
	75%	14,164	500,000	$12,513	$117,906	$1,931,494	$2,061,913	$15,181	$151,886	$1,851,639	$2,018,706	($43,207)	-2.10%

Centra Gas Manitoba Inc.
2013/14 General Rates Application - Cost of Gas Update May 10, 2013
Bill Impact Comparison
2013/14 Test Year

BASE VS. BASE

	Load Factor	Annual Use 10³m³	Annual Use Mcf	MAY 1/13 APPROVED BASE RATES Basic Chg	Demand	Commodity	Annual	AUG 1/13 PROPOSED BASE RATES Basic Chg	Demand	Commodity	Annual	BASE IMPACTS $	%
Small General Service		1.00	35	$168	$0	$265	$433	$168	$0	$271	$439	$7	1.54%
		1.98	70	$168	$0	$524	$692	$168	$0	$537	$705	$13	1.91%
(Typical Residential Customer)		2.37	84	$168	$0	$628	$796	$168	$0	$644	$812	$16	1.99%
		2.80	99	$168	$0	$742	$910	$168	$0	$761	$929	$19	2.06%
		3.20	113	$168	$0	$847	$1,015	$168	$0	$868	$1,036	$21	2.11%
		3.68	130	$168	$0	$974	$1,142	$168	$0	$999	$1,167	$25	2.15%
		11.33	400	$168	$0	$2,997	$3,165	$168	$0	$3,073	$3,241	$76	2.39%
Large General Service		11.33	400	$924	$0	$2,410	$3,334	$924	$0	$2,450	$3,374	$40	1.19%
		59.49	2,100	$924	$0	$12,653	$13,577	$924	$0	$12,861	$13,785	$209	1.54%
		679.87	24,000	$924	$0	$144,603	$145,527	$924	$0	$146,987	$147,911	$2,385	1.64%
High Volume Firm	25%	850	30,000	$13,420	$43,720	$135,690	$192,830	$14,769	$45,732	$135,549	$196,049	$3,220	1.67%
	40%	850	30,001	$13,420	$27,326	$135,694	$176,440	$14,769	$28,583	$135,553	$178,905	$2,465	1.40%
	40%	1,416	50,000	$13,420	$45,542	$226,150	$285,111	$14,769	$47,637	$225,915	$288,321	$3,209	1.13%
	40%	2,833	100,000	$13,420	$91,084	$452,299	$556,803	$14,769	$95,275	$451,829	$561,872	$5,070	0.91%
	40%	6,200	218,866	$13,420	$199,351	$989,929	$1,202,700	$14,769	$208,524	$988,900	$1,212,192	$9,492	0.79%
	40%	12,600	444,792	$13,420	$405,133	$2,011,792	$2,430,344	$14,769	$423,774	$2,009,700	$2,448,243	$17,898	0.74%
	75%	685	24,181	$13,420	$11,747	$109,371	$134,538	$14,769	$12,287	$109,258	$136,313	$1,776	1.32%
	75%	850	30,000	$13,420	$14,573	$135,690	$163,683	$14,769	$15,244	$135,549	$165,561	$1,878	1.15%
	75%	1,416	50,000	$13,420	$24,289	$226,150	$263,858	$14,769	$25,407	$225,915	$266,090	$2,231	0.85%
	75%	2,833	100,000	$13,420	$48,578	$452,299	$514,297	$14,769	$50,813	$451,829	$517,411	$3,114	0.61%
	75%	6,200	218,866	$13,420	$106,321	$989,929	$1,109,670	$14,769	$111,213	$988,900	$1,114,881	$5,212	0.47%
	75%	12,600	444,792	$13,420	$216,071	$2,011,792	$2,241,282	$14,769	$226,013	$2,009,700	$2,250,482	$9,199	0.41%
Cooperative	35%	250	8,825	$3,289	$11,516	$35,167	$49,971	$3,854	$11,826	$34,725	$50,406	$434	0.87%
	35%	350	12,355	$3,289	$16,123	$49,233	$68,645	$3,854	$16,557	$48,615	$69,026	$382	0.56%
	35%	500	17,650	$3,289	$23,032	$70,333	$96,654	$3,854	$23,652	$69,450	$96,957	$303	0.31%
Mainline Firm	40%	2,833	100,000	$28,240	$134,786	$403,575	$566,602	$15,097	$131,061	$407,354	$553,512	($13,089)	-2.31%
	40%	14,164	500,000	$28,240	$673,931	$2,017,877	$2,720,048	$15,097	$655,304	$2,036,772	$2,707,173	($12,875)	-0.47%
	40%	28,328	1,000,000	$28,240	$1,347,862	$4,035,754	$5,411,856	$15,097	$1,310,609	$4,073,543	$5,399,249	($12,607)	-0.23%
	75%	2,833	100,000	$28,240	$71,886	$403,575	$503,701	$15,097	$69,899	$407,354	$492,351	($11,351)	-2.25%
	75%	14,164	500,000	$28,240	$359,430	$2,017,877	$2,405,547	$15,097	$349,496	$2,036,772	$2,401,364	($4,182)	-0.17%
	75%	28,328	1,000,000	$28,240	$718,860	$4,035,754	$4,782,854	$15,097	$698,991	$4,073,543	$4,787,632	$4,778	0.10%
	75%	41,000	1,447,339	$28,240	$1,040,434	$5,841,106	$6,909,780	$15,097	$1,011,678	$5,895,800	$6,922,575	$12,795	0.19%
Special Contract	89%	421,289	14,871,900	$1,625,097	$0	$84,258	$1,709,355	$1,451,669	$0	$42,129	$1,493,798	($215,557)	-12.61%
Power Stations	16%	15,196	536,442	$277,574	$87,431	$250,738	$615,743	$198,203	$14,676	$121,570	$334,449	($281,294)	-45.68%
Interruptible Sales	25%	850	30,000	$12,513	$21,223	$127,407	$161,142	$15,181	$22,274	$129,770	$167,224	$6,082	3.77%
	40%	2,833	100,000	$12,513	$44,215	$424,689	$481,416	$15,181	$46,403	$432,566	$494,150	$12,734	2.65%
	40%	14,164	500,000	$12,513	$221,074	$2,123,444	$2,357,030	$15,181	$232,017	$2,162,831	$2,410,028	$52,998	2.25%
	75%	850	30,000	$12,513	$7,074	$127,407	$146,994	$15,181	$7,425	$129,770	$152,375	$5,381	3.66%
	75%	2,833	100,000	$12,513	$23,581	$424,689	$460,783	$15,181	$24,748	$432,566	$472,495	$11,713	2.54%
	75%	14,164	500,000	$12,513	$117,906	$2,123,444	$2,253,862	$15,181	$123,742	$2,162,831	$2,301,754	$47,891	2.12%

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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%

- November 13 to December 14, 2012 (deliveries commencing February 1, 2013)
- February 8 to March 11, 2013 (deliveries commencing May 1, 2013)

The following table shows the rates associated with each FRPGS offering noted above and Centra's quarterly Primary Gas rate in effect during each enrolment period.

FRPGS Enrolment Period & Flow Date	Centra Fixed Rate ($/m^3)	Centra Quarterly Rate ($/m^3)
May 16 - June 9, 2011 *(August 1, 2011 flow)*	1-Year N/A 3-Year $0.1975 5-Year $0.2095	$0.1548 (May 1 - July 31)
Aug. 25 – Sept. 13, 2011 *(November 1, 2011 flow)*	1-Year N/A 3-Year $0.1960 5-Year $0.2067	$0.1468 (Aug. 1 – Oct. 31)
Feb. 8 – March 13, 2012 *(May 1, 2012 flow)*	1-Year $0.1500 3-Year $0.1661 5-Year N/A	$0.1105 (Feb. 1 – Apr. 30)
May 8 – June 12, 2012 *(August 1, 2012 flow)*	1-Year $0.1342 3-Year $0.1537 5-Year $0.1649	$0.0880 (May 1 – July 31)
Aug. 8 – Sept. 11, 2012 *(November 1, 2012 flow)*	1-Year $0.1523 3-Year $0.1694 5-Year $0.1807	$0.0967 (Aug. 1 – Nov 30)
Nov. 13 – Dec. 14, 2012 *(February 1, 2013 flow)*	1-Year $0.1706 3-Year $0.1815 5-Year $0.1912	$0.0967 (Nov. 1 – Jan. 31)
Feb. 8 – Mar. 11, 2012 *(May 1, 2013 flow)*	1-Year $0.1690 3-Year $0.1804 5-Year $0.1900	$0.0967 (Feb. 1 – Apr. 31)

13.1.1 Marketing

Centra currently provides FRPGS offerings once each quarter, with each marketing period to commence shortly after the implementation of the quarterly Primary Gas rate change. An offering was not available in November/December 2011 with a February 1,

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Subject: **Tab 13 FRPGS**

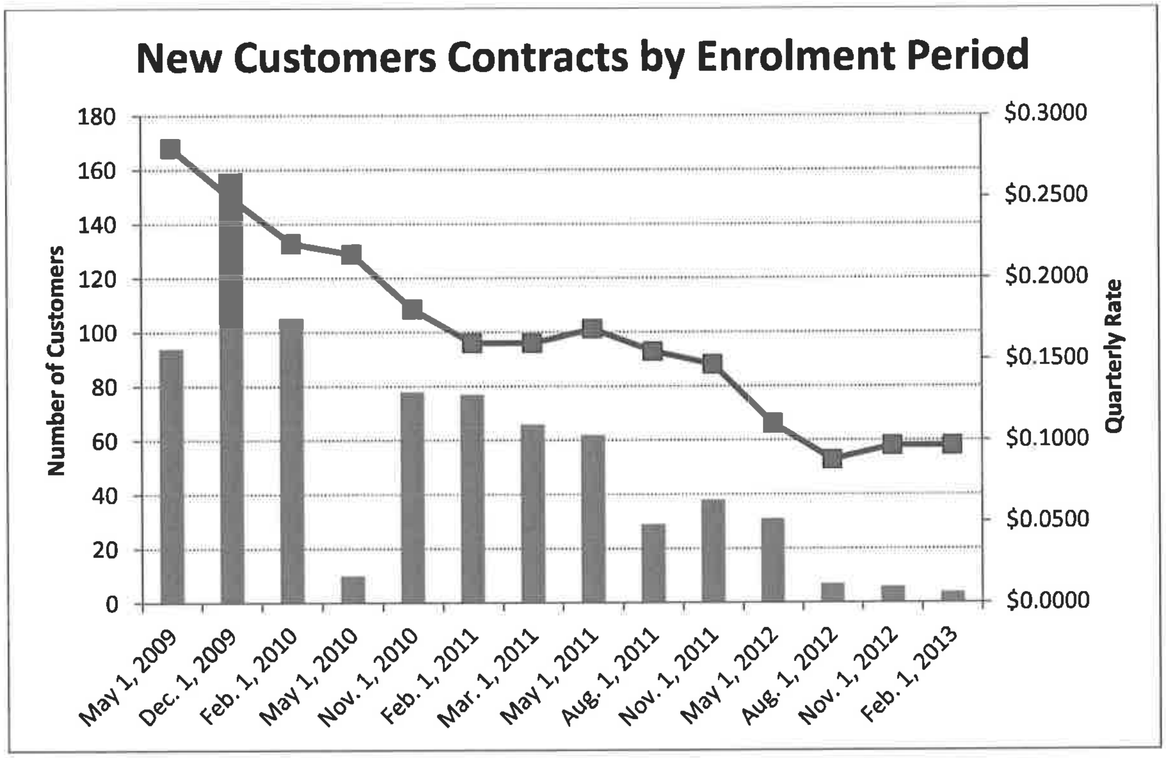
Reference: **Tab 13 Pages 8 to 11 of 11**

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

Centra Gas Manitoba Inc.
2013/14 General Rate Application
FRPGS Enrolment Results for Fiscal 2011 & 2012

Appendix 13.3
February 22, 2013

Enrolment Period - May 16 - June 9, 2011 (August 1, 2011 Flow)

Contracts PROJECTED					Contracts RECEIVED					Contracts for ACTIVATION					Subscription Analysis*	
Product	Res SGS	Com SGS	LGS	Total	Product	Res SGS	Com SGS	LGS	Total	Product	Res SGS	Com SGS	LGS	Total	Product	% Subscribed
1 year	0	0	0	0	1 year	n/a	n/a	n/a	n/a	1 year	n/a	n/a	n/a	n/a	1 year	n/a
3 year	25	0	3	28	3 year	13	0	0	13	3 year	12	0	0	12	3 year	14%
5 year	25	1	0	26	5 year	21	0	0	21	5 year	17	0	0	17	5 year	61%
Total	50	1	3	54	Total	34	0	0	34	Total	29	0	0	29	Total	27%

* Total volumes hedged were 33,090 GJs (24,400 GJs - 3 year, 8,690 GJs - 5 year offerings). Total volumes subscribed were 8,823 GJs (3,486 GJs - 3 year, 5,337 GJs - 5 year offerings)

Enrolment Period - August 25 - September 13, 2011 (November 1, 2011 Flow)

Contracts PROJECTED					Contracts RECEIVED					Contracts for ACTIVATION					Subscription Analysis	
Product	Res SGS	Com SGS	LGS	Total	Product	Res SGS	Com SGS	LGS	Total	Product	Res SGS	Com SGS	LGS	Total	Product	% Subscribed
1 year	n/a	n/a	n/a	n/a	1 year	n/a	n/a	n/a	n/a	1 year	n/a	n/a	n/a	n/a	1 year	n/a
3 year	n/a	n/a	n/a	n/a	3 year	24	0	1	25	3 year	19	0	1	20	3 year	n/a
5 year	n/a	n/a	n/a	n/a	5 year	16	2	2	20	5 year	14	2	2	18	5 year	n/a
Total	n/a	n/a	n/a	n/a	Total	40	2	3	45	Total	33	2	3	38	Total	n/a

* n/a - Since the November 1, 2011 flow offerings, Centra has been using the proxy methodology for calculating the FRPGS commodity gas prices; hence, no contracts projected or subscription analysis were prepared.

Enrolment Period - February 8 - March 13, 2012 (May 1, 2012 Flow)

Contracts PROJECTED					Contracts RECEIVED					Contracts for ACTIVATION					Subscription Analysis	
Product	Res SGS	Com SGS	LGS	Total	Product	Res SGS	Com SGS	LGS	Total	Product	Res SGS	Com SGS	LGS	Total	Product	% Subscribed
1 year	n/a	n/a	n/a	n/a	1 year	15	0	1	16	1 year	11	0	1	12	1 year	n/a
3 year	n/a	n/a	n/a	n/a	3 year	25	0	4	29	3 year	15	0	4	19	3 year	n/a
5 year	n/a	n/a	n/a	n/a	5 year	n/a	n/a	n/a	n/a	5 year	n/a	n/a	n/a	n/a	5 year	n/a
Total	n/a	n/a	n/a	n/a	Total	40	0	5	45	Total	26	0	5	31	Total	n/a

Enrolment Period - May 8 - June 12, 2012 (August 1, 2012 Flow)

Contracts PROJECTED					Contracts RECEIVED					Contracts for ACTIVATION					Subscription Analysis	
Product	Res SGS	Com SGS	LGS	Total	Product	Res SGS	Com SGS	LGS	Total	Product	Res SGS	Com SGS	LGS	Total	Product	% Subscribed
1 year	n/a	n/a	n/a	n/a	1 year	1	0	0	1	1 year	1	0	0	1	1 year	n/a
3 year	n/a	n/a	n/a	n/a	3 year	2	1	0	3	3 year	1	1	0	2	3 year	n/a
5 year	n/a	n/a	n/a	n/a	5 year	8	0	0	8	5 year	4	0	0	4	5 year	n/a
Total	n/a	n/a	n/a	n/a	Total	11	1	0	12	Total	6	1	0	7	Total	n/a

Enrolment Period - August 8 - September 11, 2012 (November 1, 2012 Flow)

Contracts PROJECTED					Contracts RECEIVED					Contracts for ACTIVATION					Subscription Analysis	
Product	Res SGS	Com SGS	LGS	Total	Product	Res SGS	Com SGS	LGS	Total	Product	Res SGS	Com SGS	LGS	Total	Product	% Subscribed
1 year	n/a	n/a	n/a	n/a	1 year	1	0	0	1	1 year	1	0	0	1	1 year	n/a
3 year	n/a	n/a	n/a	n/a	3 year	6	0	0	6	3 year	3	0	0	3	3 year	n/a
5 year	n/a	n/a	n/a	n/a	5 year	4	0	0	4	5 year	2	0	0	2	5 year	n/a
Total	n/a	n/a	n/a	n/a	Total	11	0	0	11	Total	6	0	0	6	Total	n/a

Enrolment Period - November 13 - December 14, 2012 (February 1, 2013 Flow)

Contracts PROJECTED					Contracts RECEIVED					Contracts for ACTIVATION					Subscription Analysis	
Product	Res SGS	Com SGS	LGS	Total	Product	Res SGS	Com SGS	LGS	Total	Product	Res SGS	Com SGS	LGS	Total	Product	% Subscribed
1 year	n/a	n/a	n/a	n/a	1 year	0	0	0	0	1 year	0	0	0	0	1 year	n/a
3 year	n/a	n/a	n/a	n/a	3 year	2	0	0	2	3 year	1	0	0	1	3 year	n/a
5 year	n/a	n/a	n/a	n/a	5 year	5	0	0	5	5 year	3	0	0	3	5 year	n/a
Total	n/a	n/a	n/a	n/a	Total	7	0	0	7	Total	4	0	0	4	Total	n/a

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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 ($/m^3)	Quarterly PG Effective Date	Quarterly PG Rates ($/m^3)	Typical Residential Quarterly/Monthly consumption (m^3)	Quarterly PG Total	FRPGS offerings Total	Difference
1-May-09	$0.2670	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 ($/m³)	Quarterly PG Effective Date	Quarterly PG Rates ($/m³)	Typical Residential Quarterly/Monthly consumption (m³)	Quarterly PG Total	FRPGS offerings Total	Difference
1-May-09	$0.3234	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			

Financial Results by Product Offering (FY 2012)

FISCAL MARCH 31, 2012 FINANCIAL RESULTS FOR FIXED RATE PRIMARY GAS PROGRAM OFFERINGS
Results reported in 000's

	1 Year	3 Year	5 Year	Fiscal Mar 31/2012	Fiscal Mar 31/2011
Primary Gas Revenue	$20	$552	$297	**$870**	**$617**
Less: Primary Cost of Gas Sold					
Cost of Gas [1]	($13)	($287)	($142)	**($442)**	**($353)**
Hedge Cost for Delivered Gas [2]	($3)	($179)	($106)	**($288)**	**($207)**
Total Cost of Gas Sold	($16)	($466)	($248)	**($730)**	**($560)**
Gross Margin	**$4**	**$86**	**$49**	**$140**	**$57**
Under/Over Subscribed Hedge Impacts [3]	($3)	($44)	($155)	**($202)**	**($238)**
Program Operating Expense				**($109)**	**($219)**
Net Program Income (loss)				**($171)**	**($400)**
Other Costs					
Amortization of Start Up Costs [4]				**($100)**	**($100)**
Mark to Market of Unsettled Hedges [5]				**($420)**	**$52**
Net Income Statement impact				**($691)**	**($448)**

Notes and explanations:

1. The actual cost of gas for the period is derived by applying the Fixed Rate Primary Gas Service contract volumes to the actual average unit cost of physical Primary Gas supplied to the load.

2. The hedge cost for delivered gas is the difference between the locked in cost of gas for each offering and the AECO monthly firm market index price for each period, multiplied by the contract volumes consumed by customers. It also includes hedge impacts on over/under consumed volumes.

3. Under/Over subscribed hedge impacts are the amounts either paid to or received from counterparties associated with excess hedge instruments due to under-subscription of offerings, as well as unhedged market price exposure impacts on over-subscribed primary gas volumes that have been subscribed but not hedged.

4. The amortization of start up costs represents 1 year of amortization of the deferred costs related to the introduction of the FRPGS program. These costs are amortized over a 5-year period with the annual amortization being recorded against the FRPGS offerings made in each year.

5. The mark to market cost of unsettled hedges for fiscal March 31, 2012 are the amounts expensed in fiscal 2012 relative to unrealized FRPGS hedges. During the future periods, these hedges will settle and net realized gains or losses will be recorded at that time.

Observations (FY 2012):

The Fixed Rate Primary Gas Service experienced a loss of $691,000 for FY 2012. It should be noted that:

1. Of the $691,000 loss, $202,000 relates to the mark-to-market position of over/under subscribed hedges and an additional $420,000 relates to the mark-to-market position of unsettled hedges as at March 31, 2012. These losses amount to 90% of the total program loss for FY 2012.
2. Program operating expenses were $57,000 lower than forecast ($109,000 actual versus $166,000 forecast).
3. Actual program operating expenses of $109,000 were significantly lower than the actual operating expenses incurred in previous fiscal years ($219,000 in FY 2011 and $354,000 in FY 2010).
4. The loss incurred in FY 2012 was primarily attributable to lower customer subscriptions than forecast, along with a continued reduction in the market price of natural gas.

Financial Results by Fiscal Year

FINANCIAL RESULTS FOR FIXED RATE PRIMARY GAS PROGRAM OFFERINGS FROM INCEPTION TO MARCH 31, 2012

Results reported in 000's

	Fiscal Mar 31/2009	Fiscal Mar 31/2010	Fiscal Mar 31/2011	Fiscal Mar 31/2012	Total Results
Primary Gas Revenue	$0	$388	$617	$870	$1,875
Less: Primary Cost of Gas Sold					
Cost of Gas [1]	$0	($263)	($353)	($442)	($1,058)
Hedge Cost for Delivered Gas [2]	$0	($65)	($207)	($288)	($560)
Total Cost of Gas Sold		($328)	($560)	($730)	($1,618)
Gross Margin		$60	$57	$140	$257
Unsubscribed Hedge Impacts [3]	$0	($76)	($238)	($202)	($516)
Program Operating Expense	($66)	($354)	($219)	($109)	($748)
Net Program Income (loss)	($66)	($370)	($400)	($171)	($1,007)
Other Costs					
Amortization of Start Up Costs [4]	$0	($100)	($100)	($100)	($300)
Mark to Market of Unsettled Hedges [5]	($77)	($451)	$52	($420)	($897)
Net Income Statement Impact	($143)	($921)	($448)	($691)	($2,204)

Notes and explanations:

1. The actual cost of gas for the period is derived by applying the Fixed Rate Primary Gas Service contract volumes to the actual average unit cost of physicaPrimary Gas supplied to the load.

2. The hedge cost for delivered gas is the difference between the locked in cost of gas for each offering and the AECO monthly firm market index price for eachperiod, multiplied by the contract volumes consumed by customers. It also includes hedge impacts on over/under consumed volumes.

3. Under/Over subscribed hedge impacts are the amounts either paid to or received from counterparties associated with excess hedge instruments due to under-subscription of offerings, as well as unhedged market price exposure impacts on over-subscribed primary gas volumes that have been subscribed but not hedged.

4. The amortization of start up costs represents 1 year of amortization of the deferred costs related to the introduction of the FRPGS program. These costs areamortized over a 5-year period with the annual amortization being recorded against the FRPGS offerings made in each year.

5. The mark to market cost of unsettled hedges for fiscal March 31, 2012 are the amounts expensed in fiscal 2012 relative to FRPGS hedges. During the futureperiods, these hedges will settle and the mark to market cost will be reversed.

Centra Gas Manitoba Inc.
2013/14 Cost of Gas Application
FRPGS Settled and Mark-to-Market Projections (Hedging Instruments Only)

PUB/Centra I-127
April 1, 2013

		Total
SETTLED RESULTS to March 31, 2013		
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-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

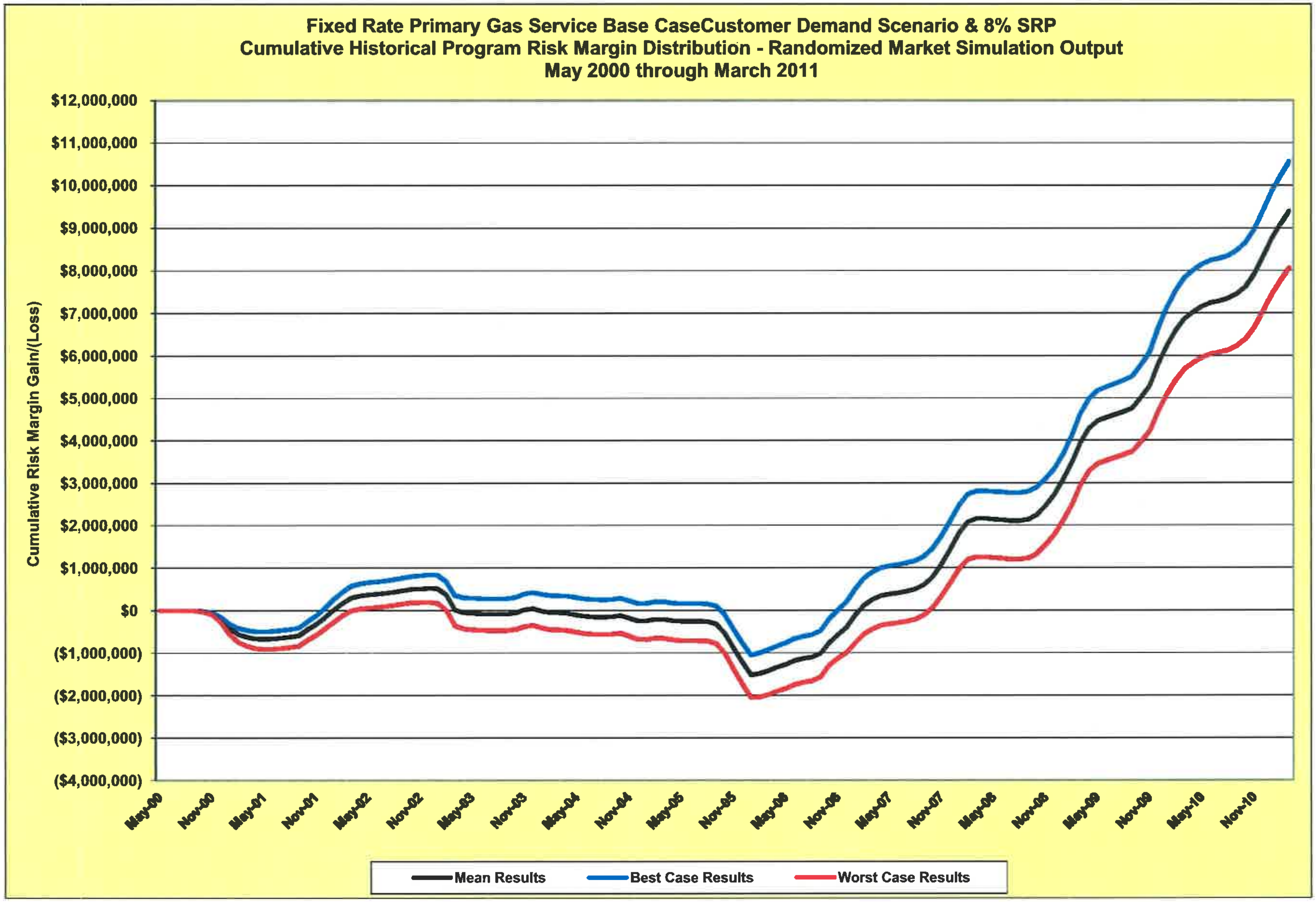
Subject: **Tab 13 FRPGS**

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).


Fixed Rate Primary Gas Service Base CaseCustomer Demand Scenario & 8% SRP
Cumulative Historical Program Risk Margin Distribution - Randomized Market Simulation Output
May 2000 through March 2011
Cumulative Risk Margin Gain/(Loss)
$12,000,000
$11,000,000
$10,000,000
$9,000,000
$8,000,000
$7,000,000
$6,000,000
$5,000,000
$4,000,000
$3,000,000
$2,000,000
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($1,000,000)
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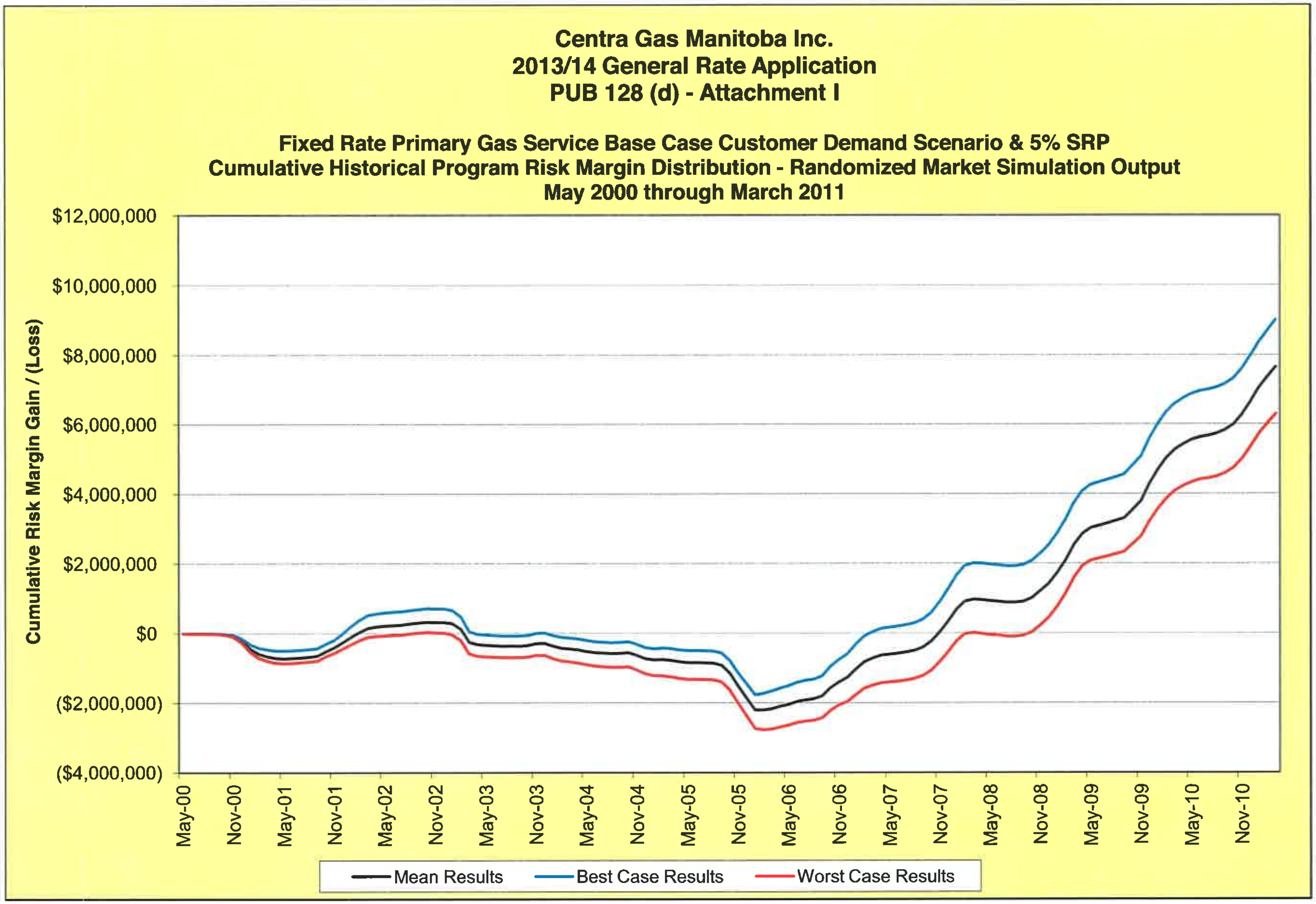
Mean Results
Best Case Results
Worst Case Results


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)
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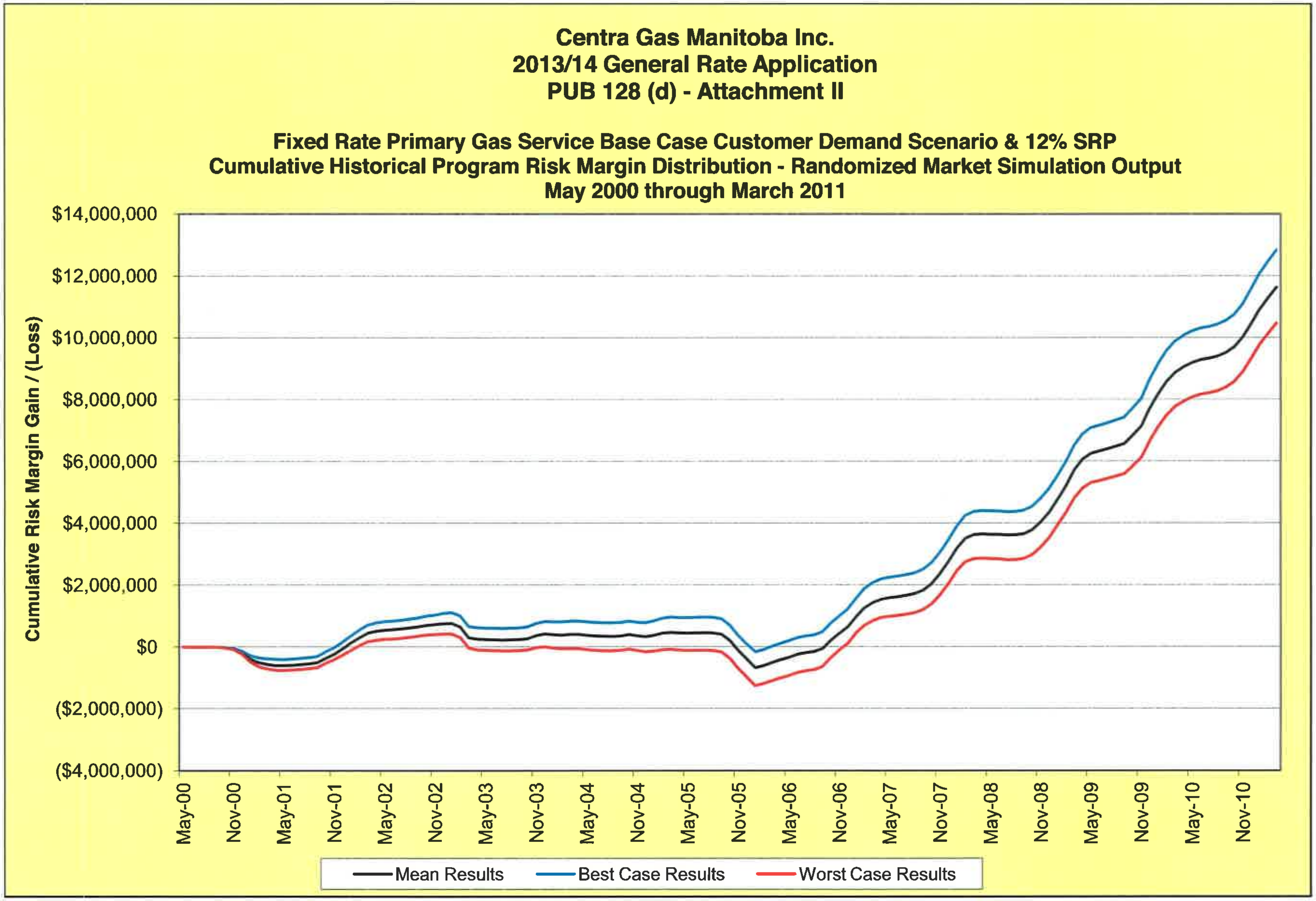
Nov-10
Mean Results
Best Case Results
Worst Case Results


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)
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May-09
Nov-09
May-10
Nov-10
Mean Results
Best Case Results
Worst Case Results

PUB/CENTRA II-184

Reference: PUB/Centra I-127 – FRPGS Mark to Market

In light of the reported updated settled and unsettled results, please indicate to what level the balances have to reach to trigger the proposed review of the program based on the million-dollar threshold established

ANSWER:

Please see the table below. The proposed $1 million threshold includes results of the FRPGS offerings that did not use hedging instruments (i.e. commencing with the November 1, 2011 flow offering). Please note that the information contained in the referenced response to PUB/Centra I-127 reflects FRPGS hedging impacts only. As the $1 million settled and unsettled thresholds are with respect to risk margin results (i.e. Total FRPGS program revenues less program cost rate revenues, minus FRPGS WACOG, plus or minus hedging impacts if applicable), additional information has been included in the table in order to illustrate risk margin results as at March 31, 2013.

FRPGS Risk Margin as March 31, 2013
Relative to $1 Million Risk Margin Thresholds Calculated From the Inception of Self-Insurance

	Settled	Unsettled Mark-to-Market
FRPGS Revenue (Not Incl. Program Cost Rate Revenue)	$2,470,355	$1,382,521
Less FRPGS WACOG	$1,500,592	$1,045,607
FRPGS Gross Margin (Not Incl. Program Cost Rate Revenue & Hedge Impacts)	$969,763	$336,914
Hedging Impact	($1,512,945)	($336,089)
Risk Margin as @ March 31, 2013	**($543,182)**	**$825**
Risk Margin on Unhedged Offerings From November 2011 through February 2013 (Included Above)	$50,146	$29,282
Further Deterioration in Risk Margin Required to Reach $1 Million Threshold	($1,050,146)	($1,029,282)
Net Risk Margin Balance @ $1 Million Threshold Calculated From the Inception of Self-Insurance	**($1,593,328)**	**($1,028,457)**

allocation model would result in a much larger PCR in the initial years with a decreasing rate in subsequent years. Because of the averaging that Centra has proposed, at any point in time the PCR may not exactly reflect the cost to provide the service. The Board agrees with CAC/MSOS that Centra's suggested approach of using the five-year average cost and the five year average volume is appropriate and will not penalize customers in the initial years that would otherwise bear a disproportionate amount of the program costs.

Over time and on average, the PCR will reflect the cost to provide the fixed price offering service. The Board hereby approves Centra's modification of its cost allocation model and the resulting allocation of costs to the fixed price offering program.

6.6.2. Regulatory Costs

On page 94 of Order 160/07, the Board commented:

> "Not needing to include a profit margin in the price of its offerings is a major advantage that Centra has over retailer offerings. The Board notes that this is partially offset by regulatory costs that would be priced into their offerings."

Centra, in response to PUB/Centra 21(a), states that regulatory costs are not included in the program costs because regulatory activities are undertaken for the benefit of all customers and are thus recovered from all customers in the distribution rate.

Centra has incurred regulatory costs in the preparation of this Application, responses to information requests, and Centra's final submission. These costs are, for the most part, labour costs and Centra states that they are non-incremental. As well, Centra will incur regulatory costs in the future when it undertakes its reporting activities.

The Board draws a distinction between regulatory costs incurred in offering fixed price offerings and the additional costs for facilitation of the WTS. In the 2007 Competitive Landscape proceeding, the Board reviewed the allocation of these additional costs for facilitation of the WTS, which included a premium for the additional flexibility in the Nexen gas supply contract, the additional bad debt expense related to the agency, billing, and collection (ABC) service, and costs to administer and process Direct Purchase enrolments.

Centra had argued that these costs were incurred for the benefit of the marketers, and thus they should be borne by the marketers. In Order 160/07 (p 66-67), the Board disagreed with Centra and ordered they continue cross-subsidization of these costs by all ratepayers, as the benefits of increased choice flow to all consumers.

Notwithstanding Centra's assertion that its regulatory costs are incurred for the benefit of all consumers, the regulatory activities of Centra for the provision of fixed price offerings provide a benefit to Centra's fixed price offering customers.

The marketers also incur regulatory costs which could be argued are for the benefit of giving all customers more choice, but the marketers have historically paid their own regulatory costs. Centra must compete with the marketers, and this means that each participant must bear their own regulatory costs.

Therefore, the Board requires Centra to include its regulatory costs – both the costs incurred to date and anticipated future regulatory costs – in its cost allocation model. This will yield a new PCR, which Centra must submit to the Board for approval.

6.6.3. Double Allocation of Costs

An issue arose during the current proceeding concerning Centra allocating staff and their associated costs to the fixed price offering program that had already been allocated to the distribution rates for all customers. Centra states that this "double counting" is not material, and it will be addressed in the next General Rate Application (GRA), that to occur in 2009.