Board Counsel's Book of Documents **Exhibit# PUB-11**
Centra 2015/16 Cost of Gas Application

Tab #	Description	Reference
Depreciation & Amortization		
1	Application Overview	Letter of Application Bill Impact Schedule
2	Financial Position	PUB/Centra I-28 Attachment 3 PUB/Centra I-28a-e Attachment 3 Pub/Centra I-29d-f p. 5 PUB/Centra I-29f IFF14-1 Excerpts Quarterly Report – June 30, 2015
3	Impact of Weather	PUB/Centra I-28a-e Attachment 1 PUB/Centra I-29d PUB/Centra I-29e PUB/Centra I-29f
4	Capital Structure	PUB/Centra I-26b,c,d 2015 Authorized Return on Equity Newsletter Order 99/07 Excerpt
5	Bill Impacts/Disallowance	PUB/Centra I-29a-c PUB/Centra I-69
6	Disallowances in Other Jurisdictions	PUB/Centra I-26a-f PUB/Centra I-27a-c
7	Rate Stabilization	MPIC 2016 Annual Report Excerpt Board Order 99/07 Excerpt
8	Prior Orders	PUB Order 128/09 Excerpt PUB Order 112/12 Excerpt NEB Order 3-2011 (March 2013) PUB Order 85/13 Excerpt NEB Order 1-2013 (October 2013) NEB Order 1-2013 (November 2013)
9	Manitoba Hydro Org Chart	Manitoba Hydro Org Chart
10	Fixed-Rate Primary Gas Service	PUB/Centra I-61a-b PUB/Centra I-70b
11	Compliance with Board Directives	Tab 7 Appendix 7.2 Excerpt
12	Timeline & History	Figure 2.2 Figure 2.7 Figure 3.3 PUB/Centra I-30 Figure 3.4 Appendix 3.1
13	Gas Supply Arrangements	Appendix 3.1 Appendix 3.4

Board Counsel's Book of Documents **Exhibit# PUB-11**
Centra 2015/16 Cost of Gas Application

Tab #	Description	Reference
14	Gas Costs	Schedule 3.0.0 Schedule 3.1.2a-b Schedule 3.10.0 Schedule 3.11.0 Schedule 3.12.4
15	Cost Allocation and Rate Design	PUB/Centra I-80a-d PUB/Centra I-65

Tab 1

CENTRA GAS MANITOBA INC.
2015/16 COST OF GAS APPLICATION

LETTER OF APPLICATION

IN THE MATTER OF: *The Public Utilities Board Act* (Manitoba); and

IN THE MATTER OF: An Application by Centra Gas Manitoba Inc. for an Order of the Public Utilities Board Approving Rates for the Sale, Transportation and Distribution of Gas.

TO: The Executive Director of the
Public Utilities Board of Manitoba
Winnipeg, Manitoba

APPLICATION

1. Centra Gas Manitoba Inc. ("Centra") hereby applies to the Public Utilities Board of Manitoba ("PUB" or "Board") for an Order pursuant to *The Public Utilities Board Act*, for the following:

   a) Approval of Supplemental Gas, Transportation (to Centra), and Distribution (to Customers) Sales and Transportation rates, effective November 1, 2015;

   b) Approval of the recovery through rate riders effective November 1, 2015 of a net outlook balance in the prior period non-Primary Gas deferral accounts of $35.4 million, which includes the recovery of the remaining 50% balance in the Supplemental Gas deferral account as at October 31, 2014 (with current rate rider amortizations and carrying costs to October 31, 2015), $0.4 million owing to customers in the other prior period deferral accounts, as well as a net outlook balance of $13.5 million in the various non-Primary Gas deferral accounts for the 2014/15 Gas Year;

c) Approval of the continuation of the current temporary rate rider treatment for Interruptible customers that migrate to Firm Service and customers that migrate to or from Transportation Service ("T-Service") on or after May 1, 2014;

d) Final approval of Primary Gas, Supplemental Gas, Transportation (to Centra) and Distribution (to Customers) sales rates effective August 1, 2013, which were approved on an interim basis in Order 89/13;

e) Final approval of Transportation (to Centra) and Distribution (to Customers) sales rates effective August 1, 2014, reflecting the removal of non-Primary Gas rate riders expiring on July 31, 2014, which were approved on an interim basis in Order 85/14;

f) Final approval of the Transportation (to Centra), and Distribution (to Customers) Sales and Transportation rates, reflecting the implementation of new non-Primary Gas Rate Riders on November 1, 2014, which were approved on an interim basis in Order 123/14;

g) Final approval of Distribution (to Customers) Sales rates, reflecting the implementation of new non-Primary Gas Rate Riders on February 1, 2015, which were approved on an interim basis in Order 12/15;

h) Final approval of actual gas costs from November 1, 2012 to October 31, 2013 of $205.6 million;

i) Final approval of actual gas costs from November 1, 2013 to October 31, 2014 of $343.5 million;

j) Final approval of Primary Gas Sales Rates and Franchise Application interim ex-parte orders as found in Appendix 7.1 of Tab 7; and,

k) Final approval of any other interim Orders issued by the PUB prior to the conclusion of the public review process for this Application.

2. Centra's Application is organized as follows:

a) Tab 2 discusses the use of gas cost pass-through mechanisms in the gas distribution industry and how Centra meets the needs of the Manitoba natural gas market with extraordinary reliability. This Tab also provides the chronology of the events leading to this Application. Appendix 2.2 provides expert testimony of Mr. Mark Drazen of Drazen Consulting Group, Inc. with respect to the appropriateness of using gas cost pass-through mechanisms in the natural gas distribution industry.

b) Tab 3 discusses the gas supply, storage and transportation arrangements that Centra contracts for and manages on a day-to-day basis in order to provide safe, cost effective, reliable and environmentally sensitive natural gas service to its customers. Tab 3 also provides the details of the gas costs incurred and the resulting deferral account balances for the period November 1, 2012 to October 31, 2015, and provides details of the forecast gas costs for the period November 1, 2015 to October 31, 2016.

c) Tab 4 provides a discussion and forecast of the number of customers and gas sales volumes for the 2015/16 forecast year.

d) Tab 5 provides an explanation of the purpose of a Cost Allocation Study, the process used to allocate costs to customers, the results of the Cost Allocation Study and addresses rate design matters.

e) Tab 6 discusses the proposed rates to be effective November 1, 2015 and the related customer bill impacts.

f) Tab 7 provides responses to Interrogatories from the Interim Application for Non-Primary Gas Rate Riders, includes Centra's request to confirm as final various Interim Orders, and provides a status update on the responses to past PUB directives issued.

Communication related to this Application should be addressed to Centra in the following fashion:

Centra Gas Manitoba Inc.
c/o: 22nd Floor, 360 Portage Avenue
Winnipeg, Manitoba R3C 0G8
Attention: Mr. Brent Czarnecki
Telephone No. 204-360-3257
Fax No. 204-360-6147
E-Mail: baczarnecki@hydro.mb.ca

DATED at Winnipeg, Manitoba this 12th day of June 2015.

CENTRA GAS MANITOBA INC.
A subsidiary of Manitoba Hydro

Per: ______________________

Brent A. Czarnecki

Centra Gas Manitoba Inc.
2015/16 Cost of Gas Application
Annual Bill Impacts

1 **May 1, 2015 Billed Rates vs. November 1, 2015 Billed Rates**

2													
3				**MAY 1, 2015 BILLED RATES**				**NOVEMBER 1, 2015 BILLED RATES**				**BILL IMPACTS**	
4													
5		Load	Annual Use	Basic Chg	Demand	Commodity	Annual	Basic Chg	Demand	Commodity	Annual	$	%
6		Factor	m³										
7													
8	Small General Service		1,000	$168	$0	$281	$449	$168	$0	$292	$460	$12	2.6%
9			1,980	$168	$0	$556	$724	$168	$0	$578	$746	$23	3.2%
10	*(Typical Residential Customer)*		2,243	$168	$0	$630	$798	$168	$0	$655	$823	$26	3.2%
11			2,800	$168	$0	$786	$954	$168	$0	$818	$986	$32	3.4%
12			3,200	$168	$0	$898	$1,066	$168	$0	$935	$1,103	$37	3.5%
13			3,680	$168	$0	$1,033	$1,201	$168	$0	$1,075	$1,243	$42	3.5%
14			11,330	$168	$0	$3,180	$3,348	$168	$0	$3,310	$3,478	$130	3.9%
15													
16	Large General Service		11,331	$924	$0	$2,570	$3,494	$924	$0	$2,690	$3,614	$119	3.4%
17			59,488	$924	$0	$13,495	$14,419	$924	$0	$14,120	$15,044	$626	4.3%
18			679,868	$924	$0	$154,223	$155,147	$924	$0	$161,377	$162,301	$7,154	4.6%
19													
20	High Volume Firm	25%	850,000	$14,657	$65,425	$137,112	$217,194	$14,657	$63,927	$135,715	$214,300	($2,895)	-1.3%
21		40%	850,000	$14,657	$40,891	$137,112	$192,660	$14,657	$39,955	$135,715	$190,327	($2,333)	-1.2%
22		40%	1,416,392	$14,657	$68,138	$228,476	$311,271	$14,657	$66,578	$226,148	$307,384	($3,887)	-1.2%
23		40%	2,832,784	$14,657	$136,277	$456,951	$607,885	$14,657	$133,156	$452,297	$600,110	($7,775)	-1.3%
24		40%	6,200,000	$14,657	$298,263	$1,000,111	$1,313,031	$14,657	$291,434	$989,924	$1,296,015	($17,016)	-1.3%
25		40%	12,600,000	$14,657	$606,148	$2,032,483	$2,653,288	$14,657	$592,269	$2,011,780	$2,618,706	($34,582)	-1.3%
26		75%	685,000	$14,657	$17,575	$110,496	$142,728	$14,657	$17,173	$109,371	$141,200	($1,528)	-1.1%
27		75%	849,835	$14,657	$21,804	$137,085	$173,547	$14,657	$21,305	$135,689	$171,651	($1,896)	-1.1%
28		75%	1,416,392	$14,657	$36,340	$228,476	$279,473	$14,657	$35,508	$226,148	$276,314	($3,159)	-1.1%
29		75%	2,832,784	$14,657	$72,681	$456,951	$544,289	$14,657	$71,017	$452,297	$537,970	($6,319)	-1.2%
30		75%	6,200,000	$14,657	$159,074	$1,000,111	$1,173,842	$14,657	$155,431	$989,924	$1,160,012	($13,829)	-1.2%
31		75%	12,600,000	$14,657	$323,279	$2,032,483	$2,370,419	$14,657	$315,877	$2,011,780	$2,342,314	($28,105)	-1.2%
32													
33	Co-op	35%	250,000	$3,819	$11,770	$31,825	$47,413	$3,819	$13,768	$31,500	$49,087	$1,673	3.5%
34		35%	350,000	$3,819	$16,478	$44,555	$64,851	$3,819	$19,276	$44,100	$67,194	$2,343	3.6%
35		35%	500,000	$3,819	$23,540	$63,650	$91,008	$3,819	$27,537	$63,000	$94,355	$3,347	3.7%
36													
37	MLC (Sales Service)	40%	2,500,000	$14,966	$124,362	$396,680	$536,008	$14,966	$164,527	$368,913	$548,406	$12,398	2.3%
38		40%	11,000,000	$14,966	$547,194	$1,745,393	$2,307,552	$14,966	$723,921	$1,623,216	$2,362,102	$54,550	2.4%
39		75%	2,500,000	$14,966	$66,327	$396,680	$477,972	$14,966	$87,748	$368,913	$471,626	($6,346)	-1.3%
40		75%	11,000,000	$14,966	$291,837	$1,745,393	$2,052,195	$14,966	$386,091	$1,623,216	$2,024,273	($27,923)	-1.4%
41													
42	MLC (T-Service)	40%	14,000,000	$14,966	$208,964	$63,000	$286,930	$14,966	$208,964	$72,800	$296,730	$9,800	3.4%
43		40%	18,000,000	$14,966	$268,668	$81,000	$364,634	$14,966	$268,668	$93,600	$377,234	$12,600	3.5%
44		40%	44,000,000	$14,966	$656,745	$198,000	$869,711	$14,966	$656,745	$228,800	$900,511	$30,800	3.5%
42		75%	14,000,000	$14,966	$111,448	$63,000	$189,413	$14,966	$111,448	$72,800	$199,213	$9,800	5.2%
43		75%	18,000,000	$14,966	$143,290	$81,000	$239,255	$14,966	$143,290	$93,600	$251,855	$12,600	5.3%
44		75%	44,000,000	$14,966	$350,264	$198,000	$563,230	$14,966	$350,264	$228,800	$594,030	$30,800	5.5%
45													
44	Special Contract	81%	400,000,000	$1,415,641	$0	$40,000	$1,382,292	$1,414,970	$0	$40,000	$1,731,686	$349,393	25.3%
45													
46	Power Stations	5%	14,000,000	$192,626	$38,184	$112,000	$279,787	$192,626	$40,730	$117,600	$423,388	$143,601	51.3%
45		6%	15,000,000	$192,626	$38,184	$120,000	$287,787	$192,626	$40,730	$126,000	$431,788	$144,001	50.0%
46													
47	Interruptible Sales	25%	849,835	$15,053	$23,325	$125,481	$163,860	$15,053	$32,533	$128,180	$175,766	$11,907	7.3%
46		40%	2,832,784	$15,053	$48,594	$418,270	$481,918	$15,053	$67,777	$427,266	$510,097	$28,179	5.8%
47		40%	14,163,920	$15,053	$242,970	$2,091,350	$2,349,374	$15,053	$338,886	$2,136,331	$2,490,270	$140,896	6.0%
48		75%	849,835	$15,053	$7,775	$125,481	$148,309	$15,053	$10,844	$128,180	$154,078	$5,768	3.9%
47		75%	2,832,784	$15,053	$25,917	$418,270	$459,240	$15,053	$36,148	$427,266	$478,467	$19,227	4.2%
48		75%	14,163,920	$15,053	$129,584	$2,091,350	$2,235,988	$15,053	$180,739	$2,136,331	$2,332,123	$96,136	4.3%

49 Firm Billing percentages: 90% Primary Gas, 10% Supplemental Gas
48 Interruptible Billing percentages: 79% Primary Gas, 21% Supplemental Gas

Tab 2

Financial Statements

Centra Gas Manitoba Inc.

March 31, 2015

EY
Building a better working world

INDEPENDENT AUDITORS' REPORT

To the Shareholder of
Centra Gas Manitoba Inc.

We have audited the accompanying financial statements of **Centra Gas Manitoba Inc.**, which comprise the balance sheet as at March 31, 2015, and the statements of income (loss), retained earnings and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the financial statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of **Centra Gas Manitoba Inc.** as at March 31, 2015, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Winnipeg, Canada
June 24, 2015

Chartered Accountants

CENTRA GAS MANITOBA INC.

STATEMENT OF INCOME

For the year ended March 31

	Notes	**2015**	2014
		millions of dollars	
Revenues			
Commodity		**274**	252
Distribution		**152**	161
		426	413
Cost of gas sold		**274**	252
		152	161
Other income		**2**	2
		154	163
Expenses			
Operating and administrative	4	**67**	67
Finance expense	4 & 5	**16**	16
Depreciation and amortization	6	**29**	28
Capital and other taxes	7	**20**	20
Corporate allocation	8	**12**	12
		144	143
Net Income		**10**	20

The accompanying notes are an integral part of the financial statements.

STATEMENT OF RETAINED EARNINGS

For the year ended March 31

	2015	2014
	millions of dollars	
Retained earnings, beginning of year	**62**	42
Net income	**10**	20
Retained earnings, end of year	**72**	62

The accompanying notes are an integral part of the financial statements.

CENTRA GAS MANITOBA INC.
BALANCE SHEET
As at March 31

	Notes	2015	2014
		millions of dollars	
Assets			
Property, Plant and Equipment	9	**466**	448
Current Assets			
Accounts receivable and accrued revenue		**83**	109
Gas in storage		**17**	-
		100	109
Other Assets			
Regulated assets	10	**116**	124
Intangible assets	11	**7**	8
		123	132
		689	689
Liabilities and Shareholder's Equity			
Long-Term Debt	12	**305**	270
Current Liabilities			
Due to parent	13	**79**	34
Accounts payable and accrued liabilities		**50**	107
Current portion of long-term debt	12	**-**	35
		129	176
Other Liabilities			
Regulated liabilities	10	**6**	6
Refundable advances from customers		**14**	12
		20	18
Contributions in Aid of Construction		**42**	42
Shareholder's Equity			
Share capital	16	**121**	121
Retained earnings		**72**	62
		193	183
		689	689

The accompanying notes are an integral part of the financial statements.

Approved on behalf of the Board:

William Fraser, FCA
Chair of the Board and
Acting Chair of the Audit Committee

CENTRA GAS MANITOBA INC.
STATEMENT OF CASH FLOWS
For the year ended March 31

	2015	2014
	millions of dollars	
Operating Activities		
Cash receipts from customers	**462**	318
Cash paid to suppliers	**(442)**	(271)
Interest paid	**(18)**	(18)
Cash provided by operating activities	**2**	29
Financing Activities		
Long-term advances from parent	**-**	10
Short-term advances from parent	**45**	8
Cash provided by financing activities	**45**	18
Investing Activities		
Property, plant and equipment, net of contributions	**(36)**	(35)
Other	**(11)**	(12)
Cash used for investing activities	**(47)**	(47)
Net change in cash and cash equivalents	**-**	-
Cash and cash equivalents, beginning of year	**-**	-
Cash and cash equivalents, end of year	**-**	-

The accompanying notes are an integral part of the financial statements.

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2015

NOTE 1 NATURE OF THE ORGANIZATION

Centra Gas Manitoba Inc. (Centra) distributes natural gas to more than 274 000 residential, commercial and industrial customers throughout Manitoba. Centra delivers natural gas to its customers through a network of transmission pipelines and distribution mains totaling approximately 9 900 kilometres in length. Centra is a wholly owned subsidiary of the Manitoba Hydro-Electric Board (Manitoba Hydro) and is regulated by the Public Utilities Board of Manitoba (PUB).

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation - The financial statements were prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP) as set forth in Part V of the Chartered Professional Accountants (CPA) of Canada Handbook - Accounting - Pre-Changeover Accounting Standards and include the significant accounting policies described hereafter.

Rate-Regulated Accounting - The prices charged for the sale of natural gas within Manitoba are subject to review and approval by the PUB. The rate-setting process is designed such that rates charged to natural gas customers recover all costs incurred in providing gas service to customers. As permitted under Canadian GAAP, Centra applies standards issued by the Financial Accounting Standards Board (FASB) in the United States as another source of Canadian GAAP. FASB Accounting Standards Codification Section 980 - Regulated Operations, represents the standard Centra applies for rate-regulated accounting. These accounting policies differ from enterprises that do not operate in a rate-regulated environment. Such accounting policies allow for the deferral of certain costs or credits which will be recovered or refunded in future rates. These costs or credits would otherwise have been included in the determination of net income in the year that the cost or credit is incurred. Centra refers to such deferred costs or credits as regulated assets or regulated liabilities (Note 10) which are generally comprised of the following:

- Power Smart programs - The costs of Centra's energy conservation programs, referred to as Power Smart, are deferred and amortized on a straight-line basis over a period of 10 years.
- Deferred taxes - As a result of its acquisition by Manitoba Hydro in 1999, Centra became non-taxable and, in so doing, incurred a non-recurring tax expense. This non-recurring tax expense has been deferred and is being amortized over a period of 30 years.
- Site restoration costs - Site restoration costs incurred are deferred and amortized on a straight-line basis over a period of 15 years.
- Regulatory costs - Costs associated with regulatory hearings are deferred and amortized on a straight-line basis over periods up to 5 years.
- Purchased gas variance accounts - Accounts are maintained to recover/refund differences between the actual cost of gas and the cost of gas incorporated into rates charged to customers as approved by the PUB. The difference between the recorded

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2015

cost of natural gas and the actual cost of natural gas is recovered or refunded in future rates.

- Demand side management (DSM) deferral - In Board Order 85/13, the PUB directed that the differences between actual and planned spending on gas DSM for the 2013-14 fiscal year be recorded in a regulatory deferral account. The cumulative difference for 2013-14 has been recorded as a regulated liability with an offsetting balance recorded as a regulated asset. The disposition of this regulatory deferral will be determined at a future PUB proceeding.

Centra's other significant accounting policies are as follows:

a) **Property, Plant and Equipment**
Property, plant and equipment is stated at cost which includes direct labour, materials, contracted services, a proportionate share of overhead costs and interest applied at the average cost of debt. Interest is allocated to construction until a capital project becomes operational or a decision is made to abandon, cancel or indefinitely defer construction. Once the transfer to in-service property, plant and equipment is made, interest allocated to construction ceases and depreciation and interest charged to operations commences.

b) **Depreciation**
Depreciation is provided on a straight-line remaining-life basis. The range of estimated service lives of each major asset category is as follows:

Distribution	5 - 68 years
General plant	10 - 45 years

Provision for removal costs of major property, plant and equipment is charged to depreciation expense on a straight-line basis over the remaining service lives of the related assets. Retirements of these assets, including costs of removal, are charged to accumulated depreciation with no gains or losses reflected in operations. The estimated service lives and removal costs of the assets are based upon depreciation studies conducted periodically by Centra. A depreciation study was completed during 2014-15 which resulted in changes to the estimated service lives.

c) **Intangible Assets**
Intangible assets include computer application development costs and land easements. Intangible assets are recorded at cost. The cost of computer application development includes direct labour, materials, contracted services, a proportionate share of overhead costs and interest applied at the average cost of debt. Intangible assets with finite useful lives are amortized over their useful lives on a straight-line basis. The expected useful lives are as follows:

Computer application development	7 - 10 years
Land easements	75 years

The estimated service lives of intangible assets are based upon depreciation studies conducted periodically by Centra. A depreciation study was completed during 2014-15 which resulted in changes to the estimated service lives.

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2015

d) **Contributions in Aid of Construction**
Contributions are required from customers whenever the costs of extending service exceed specified construction allowances. Contributions are amortized on a straight-line basis over the estimated service lives of the related assets.

e) **Gas in Storage**
Gas in storage is valued at average cost.

f) **Revenues**
Gas sales are recognized upon delivery to the customer and include an estimate of gas deliveries not yet billed at period-end.

g) **Cost of Gas Sold**
Cost of natural gas sold is recorded at the same rates charged to customers.

h) **Financial Instruments**
All financial instruments are measured at fair value on initial recognition as of the trade date. Measurement in subsequent periods depends on the classification of the instrument. Financial instruments are classified into one of the following five categories: held-to-maturity investments, loans and receivables, held-for-trading, available-for-sale, or other financial liabilities. Financial instruments classified as loans and receivables and other financial liabilities are measured at amortized cost using the effective interest method of amortization. Held-for-trading financial instruments are measured at fair value and all gains and losses are included in income in the period in which they arise.

i) **Comprehensive Income**
Comprehensive income consists of net income and other comprehensive income (OCI). As Centra has no items related to OCI, comprehensive income for the year is equivalent to net income.

j) **Foreign Currency Translation**
Current monetary assets and liabilities denominated in foreign currencies are translated into Canadian currency at the exchange rate prevailing as at the balance sheet date. Gains or losses related to natural gas storage purchases which arise from the date of receipt to date of payment are included as inventoried cost. All other exchange gains and losses on the translation of current monetary assets and liabilities are credited or charged to finance expense in the current period.

k) **Derivatives**
Centra does not engage in derivative trading or speculative activities. Centra mitigates natural gas price volatility to customers through the use of natural gas price swaps. Fixed price swaps are carried at fair value on the balance sheet with gains and losses recorded in income.

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2015

l) **Debt Discounts and Premiums**
Debt discounts and premiums are amortized to finance expense using the effective interest method.

m) **Use of Estimates**
The preparation of financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements. Actual amounts could differ from those estimates, but differences are not expected to be material.

NOTE 3 ACCOUNTING CHANGES

Depreciation Rate Estimates
Depreciation is recognized on a straight-line remaining-life basis with estimated service lives of assets being based upon depreciation studies conducted periodically by Centra. In accordance with a depreciation study completed in 2014-15, the estimated useful lives of a number of asset components were adjusted. This change in estimate was applied prospectively effective April 1, 2014 and resulted in a $1 million decrease in depreciation and amortization expense in 2014-15.

Future Accounting Changes

International Financial Reporting Standards (IFRS)
The Canadian Accounting Standards Board (AcSB) and the Public Sector Accounting Board confirmed that government business enterprises such as Centra would be required to follow IFRS for fiscal years beginning on or after January 1, 2011. However, the AcSB has announced a number of optional deferrals on the adoption of IFRS for qualifying entities with rate-regulated activities. As Centra is a qualifying entity with rate-regulated activities, the Company was permitted to defer the adoption of IFRS until years beginning on or after January 1, 2015.

Although IFRS and Canadian GAAP are premised on a similar conceptual framework, there are a number of differences with respect to recognition, measurement and disclosure. Centra is in the process of finalizing the transition from Canadian GAAP to IFRS and intends to adopt IFRS for its 2015-16 fiscal year with comparative information presented for the 2014-15 fiscal year.

On January 30, 2014, the International Accounting Standards Board (IASB) issued the interim standard IFRS 14 *Regulatory Deferral Accounts* for rate regulated activities effective January 1, 2016 with earlier adoption permitted. Centra will adopt the interim standard upon transition to IFRS effective April 1, 2015 and will continue to recognize regulatory deferral accounts for its financial reporting. The new interim standard is only intended to provide temporary guidance until the IASB completes its comprehensive project on Rate-regulated activities.

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2015

NOTE 4 RELATED PARTY TRANSACTIONS

Centra has related party transactions with its parent which are recorded at the exchange amount. The following transactions are in addition to those disclosed elsewhere in the financial statements:

	2015	2014
	millions of dollars	
Expense		
Net operating and administrative costs	**67**	67
Interest on advances from parent	**16**	16

NOTE 5 FINANCE EXPENSE

	2015	2014
	millions of dollars	
Interest on debt	**18**	19
Interest capitalized	**(2)**	(3)
	16	16

Included in interest on debt is $3 million (2014 - $3 million) in respect of the Provincial Debt Guarantee Fee. The fee during the year was 1.0% of the total outstanding debt guaranteed by the Province of Manitoba (2014 - 1.0%).

NOTE 6 DEPRECIATION AND AMORTIZATION

	2015	2014
	millions of dollars	
Depreciation of property, plant and equipment	**17**	17
Amortization of regulated assets	**9**	8
Amortization of intangible assets	**3**	3
	29	28

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2015

NOTE 7 CAPITAL AND OTHER TAXES

	2015	2014
	millions of dollars	
Property taxes	**12**	11
Captial taxes	**3**	3
Payroll taxes	**1**	1
Other	**4**	5
	20	20

NOTE 8 CORPORATE ALLOCATION

Financing costs related to the acquisition of Centra are allocated between gas and electricity operations in accordance with the synergies and benefits derived by each segment of the business at the time of acquisition.

NOTE 9 PROPERTY, PLANT AND EQUIPMENT

	2015			
	In service	Accumulated depreciation	Construction in progress	Total
	millions of dollars			
Distribution	**698**	**242**	**6**	**462**
General plant	**11**	**7**	**-**	**4**
	709	**249**	**6**	**466**

	2014			
	In service	Accumulated depreciation	Construction in progress	Total
	millions of dollars			
Distribution	672	232	4	444
General plant	12	8	-	4
	684	240	4	448

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2015

NOTE 10 REGULATED ASSETS AND REGULATED LIABILITIES

	2015	2014
	millions of dollars	
Regulated assets		
Power Smart programs	**55**	54
Purchased gas variance accounts	**32**	39
Deferred taxes	**25**	27
Site restoration costs	**3**	3
Regulatory costs	**1**	1
	116	124
Regulated liabilities		
DSM deferral	**6**	6
	6	6

If Centra was not subject to rate regulation, the costs associated with the regulated assets would be charged to operations in the period that they were incurred and the net income for 2015 would have increased by $1 million (2014 - net income decreased by $1 million).

In total, regulated assets of $13 million (2014 - $12 million) were amortized to operations during the period.

Centra passes costs related to the purchase and transportation of natural gas onto its customers without markup. If Centra was not subject to rate regulation, the purchased gas variance accounts would not be maintained and the actual cost of gas would be expensed in the period incurred. For fiscal year 2015, if actual gas costs were expensed and sales rates were not adjusted accordingly, net income would have increased by $7 million (2014 - decreased by $63 million).

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2015

NOTE 11 INTANGIBLE ASSETS

		2015	
	Cost	Accumulated amortization	Net book value
		millions of dollars	
Computer application development	**8**	**6**	**2**
Land easements	**6**	**1**	**5**
	14	**7**	**7**

		2014	
	Cost	Accumulated amortization	Net book value
		millions of dollars	
Computer application development	8	4	4
Land easements	5	1	4
	13	5	8

The additions to intangible assets for the year were $1 million (2014 - $1 million). In total, intangible assets of $1 million (2014 - $1 million) were amortized to operations during the period.

NOTE 12 LONG-TERM DEBT

	2015	2014
	millions of dollars	
Long-term advances from parent	**305**	305
Less: Current portion of long-term debt	**-**	35
	305	270

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2015

Debt principal amounts and related yields are summarized by fiscal years in which advances are required to be repaid in the following table:

	2015		2014
	Total principal amount of repayment	Weighted average yield rate	Total principal amount of repayment
	millions of dollars		*millions of dollars*
2020-2024	**30**	**3.26%**	30
2025-2029	**-**	**-**	-
2030-2034	**80**	**4.95%**	80
2035-2039	**110**	**4.57%**	110
2040-2044	**50**	**4.43%**	50
2045-2049	**35**	**2.90%**	-
	305	**4.29%**	270

NOTE 13 DUE TO PARENT

Centra's short-term funding is provided by Manitoba Hydro with interest calculated at the three-month T-Bill rate plus 1% Provincial Guarantee Fee on the outstanding balance. The effective rate for fiscal year 2015 was 0.84% (2014 - 0.95%). There are no fixed repayment terms.

NOTE 14 FINANCIAL INSTRUMENTS

The carrying amounts and fair values of Centra's financial instruments at March 31 were as follows:

	2015		2014	
Financial instruments	Carrying value	Fair value	Carrying value	Fair value
		millions of dollars		
Loans and Receivables				
Accounts receivable and accrued revenue	**83**	**83**	109	109
Other Financial Liabilities				
Long-term debt	**305**	**378**	305	334
Accounts payable and accrued liabilities	**50**	**50**	107	107
Due to parent	**79**	**79**	34	34

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2015

The fair value measurement of financial instruments is classified in accordance with a hierarchy of three levels, based on the type of inputs used in making these measurements:

Level 1 - Quoted prices in active markets for identical assets and liabilities;
Level 2 - Inputs other than quoted prices that are observable in active markets for the asset or liability; and
Level 3 - Inputs for the asset or liability that are not based on observable market data.

Financial instrument measurements are Level 1 measurements with the exception of long-term debt which is a Level 2 measurement. Fair value measurement of Centra's long-term debt is based on market yields at close of business on the balance sheet date for similar instruments available in capital markets. The carrying values of all other financial assets and liabilities approximate fair values.

Financial Risks
During the normal course of business, Centra is exposed to a number of financial risks including credit and liquidity risks, and market risk resulting from fluctuations in interest rates and commodity prices. Risk management policies, processes and systems have been established to identify and analyze financial risks faced by Centra, to set risk tolerance limits, establish controls and to monitor risk and adherence to policies. An integrated risk management plan has been developed, and reviewed by the Audit Committee of the Centra Gas Board, to ensure the adequacy of the risk management framework in relation to the risks faced by Centra. The nature of the financial risks and Centra's strategy for managing these risks has not changed significantly from the prior year.

a) Credit Risk
Credit risk is the risk that one party to a financial instrument will cause a financial loss to the other party by failing to discharge an obligation. Exposure to credit risk related to accounts receivable arising from natural gas sales is minimized due to a large and diversified customer base.

The values of Centra's aged accounts receivable for customers and related bad debt provisions are presented in the following table:

	2015	2014
	millions of dollars	
Under 30 days	**77**	103
31 to 60 days	**4**	4
Over 60 days	**4**	4
	85	111
Provision at end of year	**(2)**	(2)
Total accounts receivable	**83**	109

The provision for bad and doubtful accounts is reviewed annually, based on an estimate of aged receivables that are considered uncollectible. There was no significant change to the allowance for doubtful accounts from last year.

To mitigate credit risk related to the use of derivative instruments, Centra adheres to well established credit exposure limits with institutions that possess a minimum credit rating

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2015

of 'A' from recognized bond rating agencies or provide a parental guarantee from an 'A' rated parent company. The maximum exposure to credit risk related to Centra's derivative counterparties is equal to the positive fair value of its financial derivatives.

b) Liquidity Risk
Liquidity risk refers to the risk that Centra will not be able to meet its financial obligations as they come due. To meet forecasted cash requirements, Centra uses cash generated from operations, as well as short-term funding and long-term advances from Manitoba Hydro.

The following is an analysis of the contractual undiscounted cash flows payable under financial liabilities and derivative liabilities as at the balance sheet date:

	Carrying Value	2016	2017	2018	2019	2020	2021 and thereafter
				millions of dollars			
Non-derivative financial liabilities							
Accounts payable and accrued liabilities	50	50	-	-	-	-	-
Due to parent	79	79	-	-	-	-	-
Long-term debt*	305	12	13	13	13	13	507
Derivative financial liabilities							
Fixed price swap contracts	-	-	-	-	-	-	-
		141	13	13	13	13	507

*including current portion and interest payments

c) Market Risk
Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. Centra is exposed to interest rate risk and commodity price risk associated with the price of natural gas.

i. Interest Rate Risk
Interest rate risk is the risk that the future cash flows of a financial instrument will fluctuate due to changes in market interest rates. Centra is exposed to interest rate risk associated with amounts due to the parent company, floating rate long-term debt, fixed rate long-term debt maturing within 12 months, and the purchased gas variance accounts, offset by the change in interest capitalization. At March 31, 2015, an increase or decrease of 1% in the interest rate would reduce or increase net income, respectively, by $0.4 million (2014 - $0.2 million).

ii. Commodity Price Risk
Centra is exposed to natural gas price risk through its purchase of gas for delivery to customers throughout Manitoba. Centra mitigates commodity price risk for its fixed rate service with the use of natural gas price swaps. Centra does not use derivative contracts for trading or speculative purposes.

Centra has entered into natural gas price swaps until July 2016 to purchase 27 400 gigajoules (GJ) of natural gas at a weighted average fixed price of $4.82/GJ. The weighted average forward price of the swaps per AECO at March

CENTRA GAS MANITOBA INC.
NOTES TO THE FINANCIAL STATEMENTS
For the year ended March 31, 2015

31, 2015 was $2.81/GJ. These contracts are reported as derivatives and carried at fair value on the balance sheet. The unrealized fair value losses of these natural gas derivative contracts at March 31 are nil (2014 - nil).

NOTE 15 COMMITMENTS AND CONTINGENCIES

Centra has energy purchase commitments of $199 million (2014 – $182 million) that relate to future purchases of natural gas (including transportation and storage contracts), which expire in 2020.

Centra has various legal and operational matters pending. It is not possible at this time to predict with any certainty the outcome of these matters. Management believes that any settlements related to these matters will not have a material effect on Centra's financial position or results of operations.

NOTE 16 SHARE CAPITAL

	2015	2014
	millions of dollars	
Share capital		
Authorized		
Unlimited number of common shares		
Issued		
1 505 common shares	**121**	121
	121	121

NOTE 17 CAPITAL MANAGEMENT

Centra manages its capital structure to ensure sufficient retained earnings to enable it to absorb the financial effects of adverse circumstances. Centra's capital requirements are met through cash generated from operations as well as short-term funding and long-term advances from its parent company, Manitoba Hydro.

Centra Gas Manitoba Inc.
Actual Net Income and Retained Earnings

Attachment 3
February 12, 2015
($000's)

	2012/13 Actual	2012/13 Weather Normalized	2013/14 Actual	2013/14 Weather Normalized
Revenue	$ 327,724	$ 327,724	$ 412,674	$ 412,674
Weather Impact on Net Income	$ -	$ (4,064)	$ -	$ (14,456)
	$ 327,724	$ 323,660	$ 412,674	$ 398,218
Cost of Sales	$ 181,636	$ 181,636	$ 251,733	$ 251,733
Gross Margin	$ 146,088	$ 142,024	$ 160,941	$ 146,485
Other Income	$ 1,296	$ 1,296	$ 1,598	$ 1,598
	$ 147,384	$ 143,320	$ 162,539	$ 148,083
Expenses	$ 139,573	$ 139,573	$ 142,746	$ 142,746
Net Income (Loss)	$ 7,811	$ 3,747	$ 19,793	$ 5,337
Retained Earnings	$ 42,111		$ 61,904	

Centra Gas Manitoba Inc.

Attachment 4
February 12, 2015

GAS OPERATIONS (CGM14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	419	423	393	394	398	399	401	402	402	402
additional revenue requirement*	0	0	0	7	8	8	8	8	8	14
	419	423	393	401	405	407	409	410	410	416
Cost of Gas Sold	270	277	247	247	246	247	247	248	247	247
Gross Margin	149	147	146	154	159	160	161	162	162	169
Other	1	2	2	2	2	2	2	2	2	2
	151	148	148	156	161	162	163	164	164	171
EXPENSES										
Operating and Administrative	68	67	68	69	69	70	71	71	73	74
Finance Expense	16	17	19	21	21	22	22	23	24	25
Depreciation and Amortization	29	29	29	31	31	32	32	33	33	34
Capital and Other Taxes	19	19	20	20	20	20	21	21	21	21
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
	144	144	148	152	154	157	157	160	162	167
Net Income	7	4	0	3	7	5	6	4	2	4
* Additional Revenue Requirement										
Percent Increase	0.00%	0.00%	0.00%	2.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.75%
Cumulative Percent Increase	0.00%	0.00%	0.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	3.79%
Financial Ratios										
Equity Ratio (PUB Methodology)	35%	34%	34%	34%	34%	35%	35%	35%	34%	34%
Interest Coverage	1.41	1.22	1.01	1.16	1.33	1.24	1.25	1.18	1.07	1.15
Capital Coverage	0.52	0.94	0.74	0.96	0.98	0.87	0.82	0.76	0.66	0.76

GAS OPERATIONS (CGM14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	716	765	800	823	846	872	899	929	960	990
Accumulated Depreciation	(248)	(256)	(267)	(279)	(292)	(306)	(320)	(335)	(351)	(368)
Net Plant in Service	468	509	533	544	554	566	579	594	609	623
Construction in Progress	4	4	4	4	4	4	4	4	4	4
Current and Other Assets	120	121	121	121	121	121	121	121	121	121
Goodwill and Intangible Assets	7	6	6	5	5	4	4	4	4	4
Regulated Assets	85	84	85	82	78	75	72	70	68	66
	684	723	748	756	762	770	780	792	806	817
LIABILITIES AND EQUITY										
Long-Term Debt	300	310	320	320	330	330	340	320	350	370
Current and Other Liabilities	130	137	137	126	97	84	64	76	43	15
Contributions in Aid of Construction	64	83	98	114	131	148	163	178	193	208
Share Capital	121	121	121	121	121	121	121	121	121	121
Retained Earnings	69	72	72	75	82	87	93	97	99	102
	684	723	748	756	762	770	780	792	806	817

Centra Gas Manitoba Inc.

Attachment 4
February 12, 2015

GAS OPERATIONS (CGM14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	457	461	430	438	439	441	443	445	444	451
Cash Paid to Suppliers and Employees	(413)	(380)	(373)	(382)	(384)	(386)	(388)	(390)	(391)	(393)
Interest Paid	(19)	(19)	(20)	(21)	(22)	(22)	(23)	(23)	(24)	(25)
	25	61	37	35	34	33	33	32	29	33
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	30	10	10	-	10	-	10	-	40	20
Retirement of Long-Term Debt	(35)	-	-	-	-	-	-	-	(20)	(10)
Other	-	-	-	-	-	-	-	-	-	-
	(5)	10	10	-	10	-	10	-	20	10
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(50)	(66)	(52)	(37)	(35)	(39)	(40)	(42)	(45)	(44)
Other	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	(50)	(66)	(52)	(37)	(36)	(39)	(41)	(43)	(46)	(44)
Net Increase (Decrease) in Cash	(30)	6	(4)	(2)	8	(6)	2	(11)	4	(1)
Cash at Beginning of Year	(34)	(64)	(59)	(63)	(65)	(57)	(63)	(61)	(72)	(68)
Cash at End of Year	(64)	(59)	(63)	(65)	(57)	(63)	(61)	(72)	(68)	(69)

Centra Gas Manitoba Inc.

Attachment 4
February 12, 2015

GAS OPERATIONS (CGM14)
PUB METHODOLOGY DEBT TO EQUITY RATIO

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Average Gas Long-Term Debt	303	305	315	320	325	330	335	340	350	365
Average Gas Due to Parent	49	62	61	64	61	60	62	67	70	69
	352	367	376	384	386	390	397	407	420	434
Average CG Capital Stock	121	121	121	121	121	121	121	121	121	121
Average Retained Earnings	65	70	72	73	79	85	90	95	98	101
	186	191	193	195	200	206	211	216	219	222
Total Debt and Equity (PUB Methodology)	538	558	569	579	586	596	608	623	639	655
Equity Ratio	**35%**	**34%**	**34%**	**34%**	**34%**	**35%**	**35%**	**35%**	**34%**	**34%**

GAS OPERATIONS (CG14)
PROJECTED FINANCIAL RATIOS

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
INTEREST COVERAGE										
Net Income	7	4	0	3	7	5	6	4	2	4
Finance Expense	16	17	19	21	21	22	22	23	24	25
Capitalized Interest	0	0	0	(0)	(0)	0	0	0	0	0
	23	21	19	24	28	27	28	27	26	29
Finance Expense	16	17	19	21	21	22	22	23	24	25
Capitalized Interest	0	0	0	(0)	(0)	0	0	0	0	0
	16	17	19	21	21	22	22	23	24	25
Interest Coverage	**1.41**	**1.22**	**1.01**	**1.16**	**1.33**	**1.24**	**1.25**	**1.18**	**1.07**	**1.15**
CAPITAL COVERAGE										
Internally Generated Funds	25	61	37	35	34	33	33	32	29	33
Net Capital Construction Expenditures	48	65	51	36	35	38	40	42	45	43
Capital Coverage	**0.52**	**0.94**	**0.74**	**0.96**	**0.98**	**0.87**	**0.82**	**0.76**	**0.66**	**0.76**

Comparison of Forecast (CGM14) Total Cost of Service with Actual Results **($000's)**

	CGM14 2014/15 Forecast	2014/15 Actual	Variance	Explanation
	[1]	[2]	[3] = [2] - [1]	[4]
Cost of Gas	269 683	273 905	4 222	Increased usage partially offset by decreased natural gas prices.
Other Income	(1 482)	(1 543)	(61)	
Operating & Administrative	67 829	67 458	(371)	
Depreciation & Amortization	29 174	29 027	(147)	
Capital & Other Taxes	19 122	19 461	339	
Finance Expense	16 218	16 188	(30)	
Furnace Replacement Program	3 800	-	(3 800)	FRP funding is treated as a revenue reduction item in actuals.
Corporate Allocation	12 000	12 000	-	
Net Income (Loss)	6 636	10 206	3 570	Increased natural gas sales due to higher customer usage partially offset by warmer weather.
Total Cost of Service	422 980	426 702	3 722	

f)

Total Cost of Service Basis

($000's)

	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Actual	2014/15 Actual	2015/16 Forecast
Cost of Gas	386 490	430 759	315 840	260 835	197 099	181 636	251 733	273 905	276 845
Other Income	(1 967)	(1 901)	(1 924)	(1 394)	(991)	(1 296)	(1 598)	(1 543)	(1 554)
Operating & Administrative	56 270	59 803	60 951	60 644	62 117	63 735	66 810	67 458	66 691
Depreciation & Amortization	23 293	24 901	23 697	25 591	25 501	27 624	28 060	29 027	29 373
Capital & Other Taxes	23 021	23 412	23 351	20 490	19 274	18 263	19 755	19 461	19 383
Finance Expense	21 711	20 158	18 921	17 888	18 464	17 952	16 120	16 188	16 887
Corporate Allocation	12 000	12 000	12 000	12 000	12 000	12 000	12 000	12 000	12 000
Net Income (Loss)	5 899	8 596	(950)	6 609	(5 751)	7 810	19 793	10 206	3 813
Total Cost of Service	526 717	577 728	451 885	402 663	327 713	327 724	412 673	426 702	423 438
Less: Cost of Gas	386 490	430 759	315 840	260 835	197 099	181 636	251 733	273 905	276 845
Non-Gas Cost of Service	140 227	146 969	136 045	141 828	130 615	146 088	160 940	152 797	146 593

December 2014

Integrated Financial Forecast (IFF14)

2014/15 - 2033/34

Financial Planning
Finance & Regulatory

Manitoba Hydro

19.0 ELECTRIC OPERATIONS FINANCIAL FORECAST (MH14)

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	1,437	1,454	1,460	1,483	1,490	1,501	1,506	1,513	1,525	1,538
additional*	0	57	118	183	250	321	394	471	554	641
BPIII Reserve Account	(30)	(32)	(34)	(36)	(11)	0	0	0	0	0
Extraprovincial	409	434	450	457	479	514	817	943	959	987
Other	15	14	14	14	15	15	15	15	16	16
	1,831	1,928	2,008	2,101	2,222	2,352	2,732	2,944	3,054	3,182
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	601	607	619	631
Finance Expense	495	510	548	581	752	887	1,194	1,326	1,334	1,349
Depreciation and Amortization	405	401	422	445	521	524	613	667	736	752
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	191	202	207	205	234	263	257	267
Capital and Other Taxes	99	107	121	134	143	144	145	151	150	161
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1,754	1,824	1,956	2,044	2,317	2,471	2,920	3,150	3,239	3,304
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	115	59	64	(90)	(116)	(178)	(206)	(187)	(124)
* Additional General Consumers Revenue										
Percent Increase	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	0.00%	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
REVENUES										
General Consumers										
at approved rates	1,551	1,565	1,580	1,593	1,607	1,624	1,641	1,659	1,677	1,696
additional*	734	832	935	1,043	1,157	1,280	1,409	1,486	1,566	1,649
BPIII Reserve Account	0	0	0	0	0	0	0	0	0	0
Extraprovincial	996	928	944	921	920	927	911	901	883	884
Other	16	17	17	18	18	18	19	19	19	20
	3,298	3,342	3,475	3,575	3,702	3,849	3,980	4,065	4,145	4,248
EXPENSES										
Operating and Administrative	644	657	669	683	697	706	719	733	748	763
Finance Expense	1,351	1,348	1,338	1,337	1,321	1,301	1,263	1,197	1,161	1,116
Depreciation and Amortization	767	780	791	804	811	820	831	842	857	873
Water Rentals and Assessments	133	132	133	133	134	134	135	135	136	137
Fuel and Power Purchased	278	275	283	283	291	302	307	317	320	333
Capital and Other Taxes	162	163	164	165	166	167	168	170	173	174
Corporate Allocation	8	8	8	8	8	6	5	6	5	5
Other Expenses	3	2	2	2	2	2	3	3	3	3
	3,346	3,365	3,388	3,415	3,430	3,439	3,432	3,403	3,403	3,404
Non-controlling Interest	(5)	(2)	(3)	(5)	(6)	(10)	(12)	(15)	(17)	(19)
Net Income	(53)	(24)	84	155	266	400	536	647	725	826
* Additional General Consumers Revenue										
Percent Increase	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	2.00%	2.00%	2.00%
Cumulative Percent Increase	47.31%	53.13%	59.18%	65.47%	72.01%	78.80%	85.86%	89.58%	93.37%	97.24%

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17,163	17,912	19,127	19,988	24,957	28,333	33,202	33,846	34,478	35,142
Accumulated Depreciation	(5,676)	(6,012)	(6,392)	(6,795)	(7,270)	(7,798)	(8,403)	(9,055)	(9,721)	(10,401)
Net Plant in Service	11,487	11,900	12,735	13,193	17,687	20,535	24,800	24,791	24,757	24,741
Construction in Progress	3,257	4,932	6,755	8,982	6,040	3,939	169	185	241	263
Current and Other Assets	1,798	1,570	1,822	2,268	2,295	2,598	2,727	2,167	2,238	2,442
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16,993	18,866	21,801	24,961	26,585	27,668	28,299	27,727	27,788	27,965
LIABILITIES AND EQUITY										
Long-Term Debt	11,705	13,808	16,681	18,689	21,177	21,906	22,792	22,955	23,250	23,441
Current and Other Liabilities	2,016	2,151	2,097	3,069	2,214	2,654	2,604	2,104	2,028	2,101
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	81	115	151	162	108	54	-	-	-
Retained Earnings	2,717	2,778	2,837	2,902	2,812	2,696	2,518	2,312	2,126	2,001
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16,993	18,866	21,801	24,961	26,585	27,668	28,299	27,727	27,788	27,965

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ASSETS										
Plant in Service	35,822	36,544	37,410	38,124	38,859	39,555	40,294	41,050	41,823	42,952
Accumulated Depreciation	(11,096)	(11,807)	(12,532)	(13,274)	(14,030)	(14,800)	(15,585)	(16,384)	(17,200)	(18,031)
Net Plant in Service	24,725	24,737	24,878	24,849	24,828	24,754	24,710	24,666	24,623	24,921
Construction in Progress	322	344	225	254	277	323	365	402	465	255
Current and Other Assets	2,387	2,536	2,801	3,049	3,421	3,773	3,629	4,288	4,963	5,703
Goodwill and Intangible Assets	107	93	80	68	57	45	34	23	11	(0)
Regulated Assets	374	353	333	313	300	295	293	296	304	311
	27,914	28,063	28,316	28,533	28,884	29,191	29,030	29,675	30,366	31,189
LIABILITIES AND EQUITY										
Long-Term Debt	23,395	24,198	24,401	24,343	24,476	23,749	23,739	23,743	23,737	23,381
Current and Other Liabilities	2,112	1,443	1,373	1,456	1,372	1,968	1,243	1,199	1,132	1,446
Contributions in Aid of Construction	764	802	839	876	914	952	990	1,029	1,069	1,109
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	1,948	1,924	2,007	2,161	2,427	2,826	3,361	4,008	4,732	5,557
Accumulated Other Comprehensive Income	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)
	27,914	28,063	28,316	28,533	28,884	29,191	29,030	29,675	30,366	31,189

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	1,859	1,958	2,039	2,134	2,231	2,349	2,729	2,941	3,051	3,180
Cash Paid to Suppliers and Employees	(803)	(871)	(942)	(973)	(1,000)	(1,015)	(1,069)	(1,099)	(1,124)	(1,155)
Interest Paid	(511)	(514)	(547)	(593)	(784)	(928)	(1,222)	(1,349)	(1,329)	(1,341)
Interest Received	13	15	21	30	35	34	31	28	15	16
	558	587	571	598	482	441	469	522	613	699
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1,953	2,390	3,190	3,200	2,790	1,600	1,590	600	560	580
Sinking Fund Withdrawals	110	21	-	7	448	204	294	716	165	27
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1,195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1,218	2,077	2,836	2,857	2,013	1,470	933	573	243	285
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1,900)	(2,518)	(3,134)	(3,244)	(2,253)	(1,550)	(1,010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(241)	(245)	(262)	(358)	(252)	(258)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2,046)	(2,742)	(3,323)	(3,508)	(2,516)	(1,830)	(1,302)	(1,144)	(980)	(986)
Net Increase (Decrease) in Cash	(270)	(78)	84	(53)	(21)	80	100	(50)	(124)	(2)
Cash at Beginning of Year	133	(137)	(214)	(130)	(183)	(204)	(124)	(24)	(73)	(198)
Cash at End of Year	(137)	(214)	(130)	(183)	(204)	(124)	(24)	(73)	(198)	(200)

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
OPERATING ACTIVITIES										
Cash Receipts from Customers	3,295	3,340	3,472	3,572	3,699	3,846	3,977	4,062	4,142	4,245
Cash Paid to Suppliers and Employees	(1,179)	(1,189)	(1,211)	(1,225)	(1,247)	(1,269)	(1,288)	(1,314)	(1,334)	(1,363)
Interest Paid	(1,348)	(1,353)	(1,354)	(1,371)	(1,368)	(1,360)	(1,341)	(1,250)	(1,230)	(1,200)
Interest Received	19	21	35	49	62	71	84	63	78	92
	787	818	943	1,024	1,146	1,288	1,432	1,561	1,655	1,775
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	390	780	190	(10)	180	(30)	(20)	(20)	(40)	(30)
Sinking Fund Withdrawals	297	103	-	-	60	100	700	13	30	-
Retirement of Long-Term Debt	(402)	(450)	-	-	(60)	(70)	(700)	(13)	-	20
Other	(31)	(30)	(29)	(27)	(25)	(22)	(21)	(38)	(37)	(36)
	254	403	161	(37)	155	(22)	(41)	(58)	(47)	(46)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(744)	(751)	(752)	(745)	(762)	(748)	(787)	(800)	(846)	(928)
Sinking Fund Payment	(271)	(270)	(278)	(291)	(303)	(313)	(320)	(298)	(309)	(320)
Other	(30)	(31)	(25)	(26)	(26)	(26)	(26)	(26)	(27)	(27)
	(1,045)	(1,051)	(1,056)	(1,062)	(1,091)	(1,087)	(1,134)	(1,125)	(1,182)	(1,275)
Net Increase (Decrease) in Cash	(4)	170	48	(75)	210	179	257	378	427	454
Cash at Beginning of Year	(200)	(204)	(34)	14	(61)	149	328	585	963	1,390
Cash at End of Year	(204)	(34)	14	(61)	149	328	585	963	1,390	1,844

20.0 GAS OPERATIONS FINANCIAL FORECAST (CGM14)

GAS OPERATIONS (CGM14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	419	423	393	394	398	399	401	402	402	402
additional revenue requirement*	0	0	0	7	8	8	8	8	8	14
	419	423	393	401	405	407	409	410	410	416
Cost of Gas Sold	270	277	247	247	246	247	247	248	247	247
Gross Margin	149	147	146	154	159	160	161	162	162	169
Other	1	2	2	2	2	2	2	2	2	2
	151	148	148	156	161	162	163	164	164	171
EXPENSES										
Operating and Administrative	68	67	68	69	69	70	71	71	73	74
Finance Expense	16	17	19	21	21	22	22	23	24	25
Depreciation and Amortization	29	29	29	31	31	32	32	33	33	34
Capital and Other Taxes	19	19	20	20	20	20	21	21	21	21
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
	144	144	148	152	154	157	157	160	162	167
Net Income	7	4	0	3	7	5	6	4	2	4
* Additional Revenue Requirement										
Percent Increase	0.00%	0.00%	0.00%	2.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.75%
Cumulative Percent Increase	0.00%	0.00%	0.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	3.79%

GAS OPERATIONS (CGM14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	716	765	800	823	846	872	899	929	960	990
Accumulated Depreciation	(248)	(256)	(267)	(279)	(292)	(306)	(320)	(335)	(351)	(368)
Net Plant in Service	468	509	533	544	554	566	579	594	609	623
Construction in Progress	4	4	4	4	4	4	4	4	4	4
Current and Other Assets	120	121	121	121	121	121	121	121	121	121
Goodwill and Intangible Assets	7	6	6	5	5	4	4	4	4	4
Regulated Assets	85	84	85	82	78	75	72	70	68	66
	684	723	748	756	762	770	780	792	806	817
LIABILITIES AND EQUITY										
Long-Term Debt	300	310	320	320	330	330	340	320	350	370
Current and Other Liabilities	130	137	137	126	97	84	64	76	43	15
Contributions in Aid of Construction	64	83	98	114	131	148	163	178	193	208
Share Capital	121	121	121	121	121	121	121	121	121	121
Retained Earnings	69	72	72	75	82	87	93	97	99	102
	684	723	748	756	762	770	780	792	806	817

GAS OPERATIONS (CGM14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	457	461	430	438	439	441	443	445	444	451
Cash Paid to Suppliers and Employees	(413)	(380)	(373)	(382)	(384)	(386)	(388)	(390)	(391)	(393)
Interest Paid	(19)	(19)	(20)	(21)	(22)	(22)	(23)	(23)	(24)	(25)
	25	61	37	35	34	33	33	32	29	33
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	30	10	10	-	10	-	10	-	40	20
Retirement of Long-Term Debt	(35)	-	-	-	-	-	-	-	(20)	(10)
Other	-	-	-	-	-	-	-	-	-	-
	(5)	10	10	-	10	-	10	-	20	10
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(50)	(66)	(52)	(37)	(35)	(39)	(40)	(42)	(45)	(44)
Other	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	(50)	(66)	(52)	(37)	(36)	(39)	(41)	(43)	(46)	(44)
Net Increase (Decrease) in Cash	(30)	6	(4)	(2)	8	(6)	2	(11)	4	(1)
Cash at Beginning of Year	(34)	(64)	(59)	(63)	(65)	(57)	(63)	(61)	(72)	(68)
Cash at End of Year	(64)	(59)	(63)	(65)	(57)	(63)	(61)	(72)	(68)	(69)

The Manitoba Hydro-Electric Board

QUARTERLY REPORT

for the three months ended June 30, 2015

Financial Overview

Manitoba Hydro's consolidated net loss from electricity and natural gas operations was $29 million for the first three months of the 2015-16 fiscal year compared to net income of $10 million for the same period last year. The decrease in net income of $39 million was largely attributable to higher expenses and decreased revenues from gas sales partially offset by higher extraprovincial sales.

The consolidated net loss was comprised of a $21 million loss in the electricity sector and an $8 million loss in the natural gas sector. The loss in the natural gas sector is the result of seasonal variations in the demand for natural gas and is expected to be recouped over the winter heating season.

Based on the continuation of current water flow and export market conditions, Manitoba Hydro is forecasting that financial results will improve over the balance of the fiscal year and net income should exceed $80 million by March 31, 2016.

Transition to International Financial Reporting Standards

Effective April 1, 2015 Manitoba Hydro adopted International Financial Reporting Standards (IFRS) including IFRS 1 *First Time Adoption of IFRS*. This is the first quarterly report prepared under IFRS.

The Consolidated Statement of Income was prepared using the new interim standard IFRS 14 *Regulatory Deferral Accounts* which allows Manitoba Hydro to continue to recognize regulated balances for financial reporting purposes. This results in the deferral of costs and recoveries that under IFRS would otherwise be recorded as expenses or income in the current accounting period. The net movement in regulatory deferral account balances on the Consolidated Statement of Income captures the timing differences between IFRS and those amounts approved by the Public Utilities Board (PUB) for rate-setting purposes. The deferred amounts are either recovered or refunded through future rate adjustments. The new interim standard is only intended to provide temporary guidance until the International Accounting Standards Board completes its comprehensive project on rate regulated activities.

In addition, retrospective adjustments have been made to equity upon adoption of IFRS as a result of changes in accounting policies for employee benefits between IFRS and Canadian Generally Accepted Accounting Principles (GAAP). The most notable change is that the cumulative actuarial gains and losses related to pensions are recognized in the opening balance of other comprehensive income.

Manitoba Hydro will make significant accounting policy changes under IFRS. Manitoba Hydro has adopted the Equal Life Group method for calculating depreciation expense and asset retirement costs will no longer be included in depreciation rates. IFRS specifically excludes administrative and general overhead costs from capitalization and as a result these costs will now be expensed as incurred. IFRS requires immediate recognition of actuarial gains and losses associated with pension plans in Other Comprehensive Income in the period in which they occur. In addition, past service costs associated with plan improvements or amendments are expensed as incurred and actuarial obligations are recognized for all accumulating benefit plans.

Electricity Operations

Revenues from electricity sales within Manitoba totaled $310 million for the three-month period, which was $4 million or 1% lower than same period last year. The decrease in domestic revenue was primarily attributable to warmer weather as compared to the prior year resulting in lower heating loads. Extraprovincial revenues of $111 million were $9 million or 9% higher than the same period last year reflecting higher contract prices on dependable sales and increased opportunity sales volumes, partially offset by lower dependable sales volumes and lower opportunity rates. Energy sold in the export market was 3.0 billion kilowatt-hours compared to 2.9 billion kilowatt-hours sold in the same period last year.

Expenses attributable to electricity operations, including the net movement in regulatory deferral balances, totaled $466 million for the three-month period, an increase of $43 million or 10% higher than the same period last year. The increase was primarily the result of a $19 million increase in finance expense, a $12 million increase in operating and administrative costs, an $8 million increase in other expenses and an $8 million increase in depreciation and amortization partially offset by a $6 million net movement in regulatory deferral account balances. The increase in finance expense was primarily due to higher volumes of long-term debt to finance capital expenditures and the impact of the weakening Canadian dollar partially offset by lower interest rates. The increase in operating and administrative costs is mainly due to higher benefit costs as a result of a lower market driven discount rate and higher costs of system maintenance. The increase in other expenses, which is mainly offset by the change in the net movement in regulatory deferral accounts is primarily the result of higher spending on demand-side management programs (DSM). The increase in depreciation and amortization is mainly attributable to new additions to plant and equipment coming into service including the Riel Station and the Pointe du Bois spillway replacement.

The net loss before net movement in regulatory deferral balances is $25 million. After considering the net movement of $1 million in the regulatory deferral account balances, there is a net loss of $24 million of which $21 million is attributable to the Manitoba Hydro and $3 million is attributable to non-controlling interest. The non-controlling interest represents Taskinigahp Power Corporation's 33% share of the Wuskwatim Power Limited Partnership's operating results, for the first three months of the 2015-16 fiscal year.

Capital expenditures for the three-month period amounted to $496 million compared to $373 million for the same period last year. Expenditures during the current period included $185 million for Bipole III project, $163 million related to future Keeyask generation, and $17 million for the Pointe du Bois project. The remaining capital expenditures were incurred for ongoing system additions and modifications necessary to meet the electrical service requirements of customers throughout the province. The Corporation also incurred $10 million for electric DSM programs.

Natural Gas Operations

In the natural gas sector, a net loss of $8 million was incurred for the three-month period compared to a $6 million net loss for the same period last year. Revenue, net of cost of gas sold, was $27 million which was $10 million higher than the same period last year. The increase in net revenue was largely the result of lower gas costs compared to the prior year partially offset by warmer weather than the previous period. Delivered gas volumes were 347 million cubic metres compared to 379 million cubic metres in the same period last year.

Expenses attributable to natural gas operations excluding cost of gas sold amounted to $34 million compared to $35 million for the same period last year.

The net loss before net movement in regulatory deferral balances is $7 million. The $13 million change in the regulatory deferral account balance over the prior year is primarily attributable to the actual cost of gas being higher than PUB approved rates in the previous year. After considering the net movement of $1 million in the regulatory deferral account balances, there is a net loss of $8 million.

Capital expenditures in the natural gas sector were $7 million for the current three-month period compared to $6 million for the same period last year. Capital expenditures are related to system improvements and other expenditures necessary to meet the natural gas service requirements of customers throughout the province. The Corporation also incurred $2 million for gas DSM programs.

Natural Gas Rate Decrease

In accordance with Manitoba Hydro's methodology to change natural gas rates every quarter depending on the price of gas purchased from Alberta, rates for residential customers decreased on May 1, 2015 by 1.7% or approximately $14 per year. Rate decreases for larger volume customers ranged from 1.9% to 3.2% depending on the customer class and consumption levels.

William Fraser, FCA
Chair of the Board

Scott Thomson, CA
President and
Chief Executive Officer
August 14, 2015

Consolidated Statement of Income

In Millions of Dollars (Unaudited)

	Three Months Ended June 30 2015	Three Months Ended June 30 2014
Revenues		
Domestic – Electric	310	314
– Gas	60	69
Extraprovincial	111	102
Other	21	17
	502	502
Expenses		
Cost of gas sold	33	52
Operating and administrative	150	139
Finance expense	143	124
Depreciation and amortization	98	90
Water rentals and assessments	31	29
Fuel and power purchased	26	27
Capital and other taxes	30	29
Other expenses	23	15
	534	505
Net loss before net movement in regulatory deferral account balances	(32)	(3)
Net movement in regulatory deferral account balances	-	7
Net Income (Loss)	(32)	4
Net income (Loss) attributable to:		
Manitoba Hydro	(29)	10
Non-controlling interest	(3)	(6)
	(32)	4

Consolidated Statement of Financial Position

In Millions of Dollars (Unaudited)

	As at June 30 2015	As at June 30 2014
Assets		
Current assets	1 106	782
Capital assets	15 650	13 924
Non-current assets	823	695
Regulatory deferral account debit balances	350	378
	17 929	15 779
Liabilities and Equity		
Current liabilities	1 145	896
Long-term debt (net)	12 607	10 800
Other long-term liabilities	1 590	1 242
Deferred Revenue	451	391
Non-controlling interest	127	67
Retained earnings	2 697	2 653
Accumulated other comprehensive income	(688)	(270)
	17 929	15 779

Consolidated Cash Flow Statement

In Millions of Dollars (Unaudited)

	Three Months Ended June 30	
	2015	**2014**
Operating Activities		
Cash receipts from customers	599	616
Cash paid to suppliers and employees	(282)	(483)
Net interest	(159)	(146)
	158	(13)
Financing Activities	392	372
Investing Activities	(504)	(353)
Net increase in cash	46	6
Cash at beginning of period	494	142
Cash at end of period	540	148

Consolidated Statement of Comprehensive Income

In Millions of Dollars (Unaudited)

	Three Months Ended June 30	
	2015	**2014**
Net Income (Loss) attributable to Manitoba Hydro	(29)	10
Other Comprehensive Income (Loss)		
Unrealized foreign exchange gains (loss) on debt in cash flow hedges	31	62
Realized foreign exchange (gains) losses on debt in cash flow hedges	(4)	-
	27	62
Comprehensive Income (Loss)	(2)	72

Segmented Information

In Millions of Dollars (Unaudited)

Three Months Ended June 30	Electricity 2015	Electricity 2014	Gas 2015	Gas 2014	Total 2015	Total 2014
Revenue	442	433	60	69	502	502
Expenses	467	418	67	87	534	505
Net income (Loss) before net movement in regulatory deferral account balances	(25)	15	(7)	(18)	(32)	(3)
Net movement in regulatory deferral account balances	1	(5)	(1)	12	-	7
Net Income (Loss)	(24)	10	(8)	(6)	(32)	4
Net income (Loss) attributable to:						
Manitoba Hydro	(21)	16	(8)	(6)	(29)	10
Non-controlling interest	(3)	(6)	-	-	(3)	(6)
	(24)	10	(8)	(6)	(32)	4
Total Assets	17 263	15 099	666	680	17 929	15 779

Generation and Delivery Statistics

	Three Months Ended June 30 2015	2014
Electricity in gigawatt-hours		
Hydraulic generation	8 548	8 437
Thermal generation	-	5
Scheduled energy imports	9	30
Wind purchase (MB)	212	233
Total system supply	8 769	8 705
Gas in millions of cubic metres		
Gas sales	169	196
Gas transportation	178	183
	347	379

For further information contact:

Public Affairs
Manitoba Hydro
PO Box 815 STN Main
Winnipeg, Manitoba, Canada
R3C 2P4
Telephone: 1-204-360-3233

Cover: Cofferdam construction in the spring of 2015 at the site of the Keeyask Generating Station on the Nelson River in northern Manitoba. Keeyask is being developed by the Keeyask Hydropower Limited Partnership, a venture between four partner First Nations (Tataskweyak Cree Nation, War Lake First Nation, Fox Lake Cree Nation, and York Factory First Nation) and Manitoba Hydro.

Tab 3

Centra Gas Manitoba Inc.
2015/16 Cost of Gas Application
Impact of Weather on Retained Earnings

PUB/Centra 28a-e
Attachment 1

($000's)

	2003/04 Actual	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Actual	2014/15 Actual
Opening Retained Earnings	34,966	27,054	25,428	20,053	21,127	27,382	34,393	33,443	40,052	34,301	42,111	61,904
Net Income (Loss)	(7,912)	(1,626)	(5,375)	1,074	5,899	8,596	(950)	6,609	(5,751)	7,810	19,793	10,207
Ending Retained Earnings	27,054	25,428	20,053	21,127	27,026	35,978	33,443	40,052	34,301	42,111	61,904	72,111
Retained Earnings Adjustments (1) (2)					356	(1,585)						
Adjusted Ending Retained Earnings	27,054	25,428	20,053	21,127	27,382	34,393	33,443	40,052	34,301	42,111	61,904	72,111
Actual Net Income	(7,912)	(1,626)	(5,375)	1,074	5,899	8,596	(950)	6,609	(5,751)	7,810	19,793	10,207
Weather Normalized Net Income	(6,828)	(4,214)	2,189	2,157	957	1,386	1,901	6,552	7,166	3,738	5,314	9,379
Difference	(1,084)	2,588	(7,564)	(1,083)	4,942	7,210	(2,851)	57	(12,917)	4,072	14,479	828
Actual EHDD	4,401	4,656	3,975	4,382	4,741	4,944	4,330	4,536	3,714	4,773	[redacted]	[redacted]
Normal EHDD (forecasted)	4,487	4,443	4,548	4,458	4,406	4,455	4,497	4,536	4,537	4,518	[redacted]	[redacted]
Difference	(86)	213	(573)	(76)	335	489	(167)	0	(823)	254	[redacted]	[redacted]

(1) Adjustment of $356 for the implementation of the financial instrument standards.
(2) Adjustment of $1,585 for the implementation of the goodwill and intangible standard.
Represents cumulative reduction earnings related to the write-off of general advertising and promotion costs related to Centra's Power Smart programs.

d)

Actual and Forecast Net Income and Retained Earnings

($000's)

	Actual	Weather Normalized	Actual	Weather Normalized	Actual	Weather Normalized	Actual	Weather Normalized	Actual	Weather Normalized	Actual	Weather Normalized	Actual	Weather Normalized	Actual	Weather Normalized	Forecast
	2007/08		2008/09		2009/10		2010/11		2011/12		2012/13		2013/14		2014/15		2015/16
Revenue	526 717	526 717	577 728	577 728	451 885	451 885	402 663	402 663	327 713	327 713	327 724	327 724	412 674	412 674	426 702	426 702	423 438
Weather Impact on Net Income	-	(4 942)	-	(7 210)	-	2 851	-	(57)	-	12 917	-	(4 072)	-	(14 479)	-	(828)	
Additional Annualized Revenue Requirement	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	526 717	521 775	577 728	570 518	451 885	454 736	402 663	402 606	327 713	340 630	327 724	323 652	412 674	398 195	426 702	425 874	423 438
Cost of Sales	386 490	386 490	430 759	430 759	315 840	315 840	260 835	260 835	197 099	197 099	181 636	181 636	251 733	251 733	273 905	273 905	276 845
Gross Margin	140 227	135 285	146 969	139 759	136 045	138 896	141 828	141 771	130 614	143 531	146 088	142 016	160 941	146 462	152 797	151 969	146 593
Other Income	1 967	1 967	1 901	1 901	1 924	1 924	1 394	1 394	991	991	1 296	1 296	1 598	1 598	1 543	1 543	1 554
	142 194	137 252	148 870	141 660	137 969	140 820	143 222	143 165	131 605	144 522	147 384	143 312	162 539	148 060	154 340	153 512	148 146
Expenses	136 295	136 295	140 274	140 274	138 919	138 919	136 613	136 613	137 356	137 356	139 574	139 574	142 746	142 746	144 133	144 133	144 333
Net Income (Loss)	5 899	957	8 596	1 386	(950)	1 901	6 609	6 552	(5 751)	7 166	7 810	3 738	19 793	5 314	10 207	9 379	3 813
Retained Earnings	27 382		34 393		33 443		40 052		34 301		42 111		61 904		72 111		71 550

e)

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

	2013/14 Approved [1]	2013/14 Actual [2]	Variance [3] = [2] - [1]	Explanation [4]
Cost of Gas	183 202	251 733	68 531	Colder weather resulting in higherconsumption as well as increased natural gas prices.
Other Income	(1 866)	(1 598)	268	
Operating & Administrative	68 800	66 810	(1 990)	Reduction of costs in most programs primarily as a result of cost saving measures partially offset by increased benefit costs due to changes in the discount rate and unexpected activities resulting from the Otterburne explosion.
Depreciation & Amortization	30 091	28 060	(2 031)	Primarily due to assets becoming fully depreciated, lower allocation of depreciation on common assets due to costing changes and timing of amortization of cost of gas hearing.
Capital & Other Taxes	18 750	19 755	1 005	Primarily due to increased corporate capital taxes.
Finance Expense	16 945	16 120	(825)	Interest on assets decreased due to lower interest rates and the impact of cost allocation changes.
Furnace Replacement Program	3 800	-	(3 800)	FRP funding was treated as a revenue reduction item in 2013/14 actuals.
Corporate Allocation	12 000	12 000	-	
Net Income (Loss)	2 506	19 793	17 287	Increased natural gas sales due to colder weather resulting in higher consumption as well as lower operating costs.
Total Cost of Service	334 227	412 673	78 445	

Comparison of Forecast (CGM14) Total Cost of Service with Actual Results **($000's)**

	CGM14 2014/15 Forecast	2014/15 Actual	Variance	Explanation
	[1]	[2]	[3] = [2] - [1]	[4]
Cost of Gas	269 683	273 905	4 222	Increased usage partially offset by decreased natural gas prices.
Other Income	(1 482)	(1 543)	(61)	
Operating & Administrative	67 829	67 458	(371)	
Depreciation & Amortization	29 174	29 027	(147)	
Capital & Other Taxes	19 122	19 461	339	
Finance Expense	16 218	16 188	(30)	
Furnace Replacement Program	3 800	-	(3 800)	FRP funding is treated as a revenue reduction item in actuals.
Corporate Allocation	12 000	12 000	-	
Net Income (Loss)	6 636	10 206	3 570	Increased natural gas sales due to higher customer usage partially offset by warmer weather.
Total Cost of Service	422 980	426 702	3 722	

Comparison of Forecast (CGM12) Total Cost of Service with Updated Forecast (CGM14) Results **($000's)**

	CGM12 2014/15 Forecast [1]	CGM14 2014/15 Forecast [2]	Variance [3] = [2] - [1]	Explanation [4]
Cost of Gas	212 056	269 683	57 627	Higher due to increased natural gas prices.
Other Income	(1 863)	(1 482)	381	
Operating & Administrative	76 885	67 829	(9 056)	CGM12 assumes regulated assets were expensed through OM&A, however CGM14 assumes Centra Gas continues to recognize rate-regulated accounts upon its transition to IFRS as a result of the issuance by IASB of an interim standard for rate-regulated activities. In addition, the average annual increase was limited to 1% in CGM14 compared to 2% in CGM12.
Depreciation & Amortization	19 696	29 174	9 478	CGM12 assumes the write-off of regulated assets in 2015, however CGM14 assumes Centra Gas continues to recognize rate-regulated accounts upon its transition to IFRS.
Capital & Other Taxes	14 699	19 122	4 423	CGM12 assumes the write-off of the deferred tax balance in 2015, however CGM14 assumes Centra Gas continues to recognize rate-regulated accounts upon its transition to IFRS and therefore includes the amortization of deferred taxes.
Finance Expense	20 677	16 218	(4 459)	CGM12 assumes the write-off of the deferred tax balance in 2015, however CGM14 assumes Centra Gas continues to recognize rate-regulated accounts upon its transition to IFRS and therefore includes the carrying costs on deferred taxes. In addition, CGM14 reflects a reduction in interest on assets due to lower interest rates and higher PGVA receivable balances.
Furnace Replacement Program	3 800	3 800	-	
Corporate Allocation	12 000	12 000	-	
Net Income (Loss)	8 899	6 636	(2 263)	Primarily due to lower gross margin.
Total Cost of Service	366 849	422 980	56 131	

Comparison of Forecast (CGM12) Total Cost of Service with Updated Forecast (CGM14) Results **($000's)**

	CGM12 2015/16 Forecast	CGM14 2015/16 Forecast	Variance	Explanation
	[1]	[2]	[3] = [2] - [1]	[4]
Cost of Gas	203 006	276 845	73 839	Higher due to increased gas prices. In addition, CGM14 forecasted prior period gas deferrals which is included in the cost of gas. In CGM12 prior period gas deferrals were not forecasted.
Other Income	(1 855)	(1 554)	301	
Operating & Administrative	77 268	66 691	(10 577)	CGM12 assumes regulated assets were expensed through OM&A, however CGM14 assumes Centra Gas continues to recognize rate-regulated accounts upon its transition to IFRS as a result of the issuance by IASB of an interim standard for rate-regulated activities. In addition, the average annual increase was limited to 1% in CGM14 compared to 2% in CGM12.
Depreciation & Amortization	20 669	29 373	8 704	CGM12 assumes the write-off of regulated assets in 2015, however CGM14 assumes Centra Gas continues to recognize rate-regulated accounts upon its transition to IFRS.
Capital & Other Taxes	15 182	19 383	4 201	CGM12 assumes the write-off of the deferred tax balance in 2015, however CGM14 assumes Centra Gas continues to recognize rate-regulated accounts upon its transition to IFRS and therefore includes the amortization of deferred taxes.
Finance Expense	22 019	16 887	(5 132)	CGM12 assumes the write-off of the deferred tax balance in 2015, however CGM14 assumes Centra Gas continues to recognize rate-regulated accounts upon its transition to IFRS and therefore includes the carrying costs on deferred taxes. In addition, CGM14 reflects a reduction in interest on assets due to lower interest rates and higher PGVA receivable balances.
Furnace Replacement Program	3 800	3 800	-	
Corporate Allocation	12 000	12 000	-	
Net Income (Loss)	9 243	3 813	(5 430)	Primarily due to lower gross margin partially offset by lower operating expenses.
Total Cost of Service	361 332	427 238	65 906	

f)

Total Cost of Service Basis

($000's)

	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Actual	2014/15 Actual	2015/16 Forecast
Cost of Gas	386 490	430 759	315 840	260 835	197 099	181 636	251 733	273 905	276 845
Other Income	(1 967)	(1 901)	(1 924)	(1 394)	(991)	(1 296)	(1 598)	(1 543)	(1 554)
Operating & Administrative	56 270	59 803	60 951	60 644	62 117	63 735	66 810	67 458	66 691
Depreciation & Amortization	23 293	24 901	23 697	25 591	25 501	27 624	28 060	29 027	29 373
Capital & Other Taxes	23 021	23 412	23 351	20 490	19 274	18 263	19 755	19 461	19 383
Finance Expense	21 711	20 158	18 921	17 888	18 464	17 952	16 120	16 188	16 887
Corporate Allocation	12 000	12 000	12 000	12 000	12 000	12 000	12 000	12 000	12 000
Net Income (Loss)	5 899	8 596	(950)	6 609	(5 751)	7 810	19 793	10 206	3 813
Total Cost of Service	526 717	577 728	451 885	402 663	327 713	327 724	412 673	426 702	423 438
Less: Cost of Gas	386 490	430 759	315 840	260 835	197 099	181 636	251 733	273 905	276 845
Non-Gas Cost of Service	140 227	146 969	136 045	141 828	130 615	146 088	160 940	152 797	146 593

Tab 4

Section:	Appendix 2.2	**Page No.:**	2-4
Topic:	Evidence of Drazen Consulting Group		
Subtopic:	Use of PGVAs		
Issue:	Whether retained earnings should be used to reduce bill impacts		

PREAMBLE TO IR (IF ANY):

Drazen states: "Centra's PGVA was proposed and approved by the Board on the basis that it would recover exactly the cost incurred;"

QUESTION:

a) Please confirm whether the PGVA approved in Order 10/93 was proposed by Centra or by the Board

b) Please provide Mr. Drazen's view whether the use of PGVAs shifts the risk of over- or under-collection of gas costs to ratepayers from the utility.

c) Please quantify the cost to ratepayers if the utility was to assume the risk of over- or under-collection of gas costs. That is, what level of net income would Centra reasonably be expected to require if it was at risk of over- or under-collection of gas costs?

d) Please indicate which gas utilities take on the commodity cost risk and what level of compensation do these utilities earn for taking on this risk.

e) Please summarize how the Ontario Energy Board treated the increase in gas costs experienced by its two major utilities Union and Enbridge following the 2013/14 winter.

f) Please provide links to the Ontario Energy Board decisions EB-2014-0039 and EB-2014-0050, as well as links to the applications and evidence filed in these proceedings.

RATIONALE FOR QUESTION:

To clarify the origin of the PGVA, to understand the risk-shifting nature of the PGVA, and to understand how other jurisdictions treated similar cost consequences of the 2013/14 winter.

RESPONSE:

a) The PGVA approved by the PUB in Order 10/93 was proposed by Centra.

b) The following response was provided by Mr. Drazen:

Whether use of PGVAs shifts risk to ratepayers depends on the underlying assumption regarding who should properly pay the cost of supply. The near-universal approach is that the cost of gas to the utility (excepting costs determined to be imprudent) should be paid by those who consume the gas. This happens directly with customers who buy gas in the market (that is, not from the utility). The same is true for customers of utilities that flow through the current cost of gas on a monthly basis (for example, those in Alberta).

Overcollection or undercollection with a PGVA is the result of the decision to fix the price of supply to customers for an extended period. That fixed price will almost inevitably differ from the actual market prices at which the gas is acquired over that period. The longer the period, the greater the potential variance. This changes the timing of gas cost recovery from customers, but not, in principle, the amount.

Thus, a PGVA is a method of modulating the variations in gas cost. It changes the *timing* of cost recovery, but is not normally intended to change the *amount* of recovery. As such, the PGVA should produce an overall financial result similar to that of a market price flow through regime and does not, in and of itself, shift any additional risk to ratepayers.

c) The following response was provided by Mr. Drazen:

Were Centra required to absorb the variances, it would be necessary to identify: (1) the target (or baseline) cost of gas from which variances would be measured; and (2) the portions of variances that are to be absorbed.

The costs to ratepayers of this type of regime include direct costs to the utility and potential external costs to gas users. The direct costs include additional return on equity to cover the higher income risk and possible additional regulatory costs in determining the baseline gas cost and risk compensation. Note that the higher return on equity would rightly apply only to those customers buying the gas covered by the PGVA; the rates to customers purchasing gas from marketers should not be affected by the higher required return related to the utility's risk related to gas cost variances.

Potential external costs include any distortions in the marketplace that result from the differences between pricing of gas from Centra and from marketers.

Given the assumptions and variables involved (e.g., weather fluctuations and unpredictability of TransCanada Pipeline non-firm tolls), quantifying the cost is not possible.

d) The following response was provided by Mr. Drazen:

We have not made an exhaustive search. To our knowledge, there is no utility in Canada or the U.S. that absorbs the full amount of variances. Utilities in the state of Oregon (Avista Utilities, Cascade Natural Gas and Northwest Natural Gas) do absorb a limited portion of purchased gas cost variances, subject to an annual earnings review. A utility can elect to absorb either 10% or 20% of variances. If 10%, the utility's earnings cap is raised by 100 basis points. If 20%, by 150 basis points. The Oregon utilities have equity ratios around 50% and allowed returns on equity around 9.5%.

The Oregon utilities have decoupling and weather normalization mechanisms, which ensure the companies' recovery of fixed costs regardless of variations in weather and changes in per-customer usage, thereby reducing risk.

e) The following response was provided by Mr. Drazen:

The Ontario Energy Board (OEB) allowed the utilities to recover the full cost, but modified the recovery period for Enbridge Gas. Ontario utilities use a Quarterly Rate Adjustment Mechanism (QRAM). The primary QRAM factors include: (1) the previous

CONCENTRIC ENERGY ADVISORS

Authorized Return on Equity
for Canadian and U.S. Gas and Electric Utilities
Volume III, May 1, 2015

INTRODUCTION

Concentric Energy Advisors, Inc. (Concentric) is pleased to publish the third edition of this newsletter summarizing authorized returns on common equity (ROEs) and common equity ratios for Canadian gas and electric distributors, Canadian electric transmission companies, U.S. gas and electric distributors, and select bond yields. Many regulators, stakeholders and analysts in Canada consider allowed returns in other Canadian jurisdictions and U.S. utilities when assessing the cost of capital. This newsletter seeks to assist with these inter-jurisdictional comparisons.

This newsletter and supporting database contain the authorized ROEs and common equity ratios for over 40 Canadian electric and gas utilities. For comparison purposes, the newsletter also presents the average and median authorized ROEs and common equity ratios for U.S. gas and electric distributors, as reported by SNL Financial's Regulatory Research Associates.

ROE

Concentric observes that the differential between the median authorized ROEs for Canadian and U.S. gas distributors continues to narrow, from 100 basis points in 2000 to 53 basis points in 2014 and to only 18 basis points through the first three months of 2015. There is a larger gap between Canadian and U.S. electric distributors, at 125 basis points in 2014 and 122 basis points in 2015. Concentric notes that gas ROEs are higher than their electric counterparts in Canada, while the opposite is generally true in the U.S. Median ROEs for Canadian electric transmission companies are 20 basis points lower than those awarded to Canadian electric distributors, but 142–145 basis points below U.S. electric distributors over the 2014–2015 period.

Concentric attributes the closure of the gap between Canadian and U.S. authorized ROEs over the past decade to the resetting and replacement of automatic formulas widely used in Canada, which has generally increased allowed ROEs from previous formula levels. Simultaneously, U.S. ROEs have followed the decline in interest rates and earnings growth projections that drive ROE estimates.

EQUITY RATIOS

While authorized ROEs have converged between the two countries, the authorized common equity ratios have not. In 2014, the median common equity ratio for Canadian gas distributors was 39.3% while the U.S. median was 51.9%, comparable to the difference for electric distributors which was 40.0% and 50.1%, respectively. Allowed equity ratios for Canadian electric transmission companies are 4.0% lower than their electric distribution counterparts, and 14.0% below U.S. electric distributors.

RECENT DECISIONS

Canadian utility regulators have issued several important cost of capital decisions since the second edition of this newsletter was published in May 2014. Notably, in Alberta, the Alberta Utilities Commission recently issued its decision in the 2013 Generic Cost of Capital proceeding for all gas and electric utilities in the Province. The allowed ROE for Alberta's gas and electric utilities was set at 8.3% for 2015. In addition, the AUC determined that the allowed ROE for 2013 and 2014 would be modified from the previous interim rate of 8.75% to 8.3%. The AUC also reduced the deemed common equity ratio by one percentage point for most Alberta regulated utilities and decided to forego returning to an automatic formula at this time. The Alberta utilities have filed applications to appeal this decision.

In Ontario, the Ontario Energy Board's revised ROE formula established in December 1999 remains in effect but is scheduled to be reviewed in 2015. In Québec, the Régie again decided to allow Gaz Métro to maintain its allowed ROE of 8.9% without a formal proceeding, and similarly for Hydro-Québec Distribution and TransÉnergie, maintaining 8.2% for both divisions.

BOND YIELDS

Government and corporate bond yields are often considered when setting authorized ROEs for utilities. As shown in the chart on page 3, after declining for many years, the long-term government bond yields (considered the risk-free rate of return) in both Canada and the U.S. increased from mid-2012 through mid-2013, but have since resumed their prolonged decline. While government bond yields play an important role in determining the authorized ROE for regulated utilities, changes in government bond yields do not imply a one-for-one change in the cost of equity for utilities. The relationship between government bond yields and the equity risk premium (the spread between government bond yields and the cost of equity) has historically exhibited an inverse relationship.

Going forward, Concentric anticipates that improving economic conditions and the withdrawal of accommodative monetary policy in both Canada and the U.S. will begin to exert upward pressure on the cost of capital for utilities over the next several years.

CONCENTRIC ENERGY ADVISORS

Authorized Return on Equity for Canadian and U.S. Gas and Electric Utilities [1]

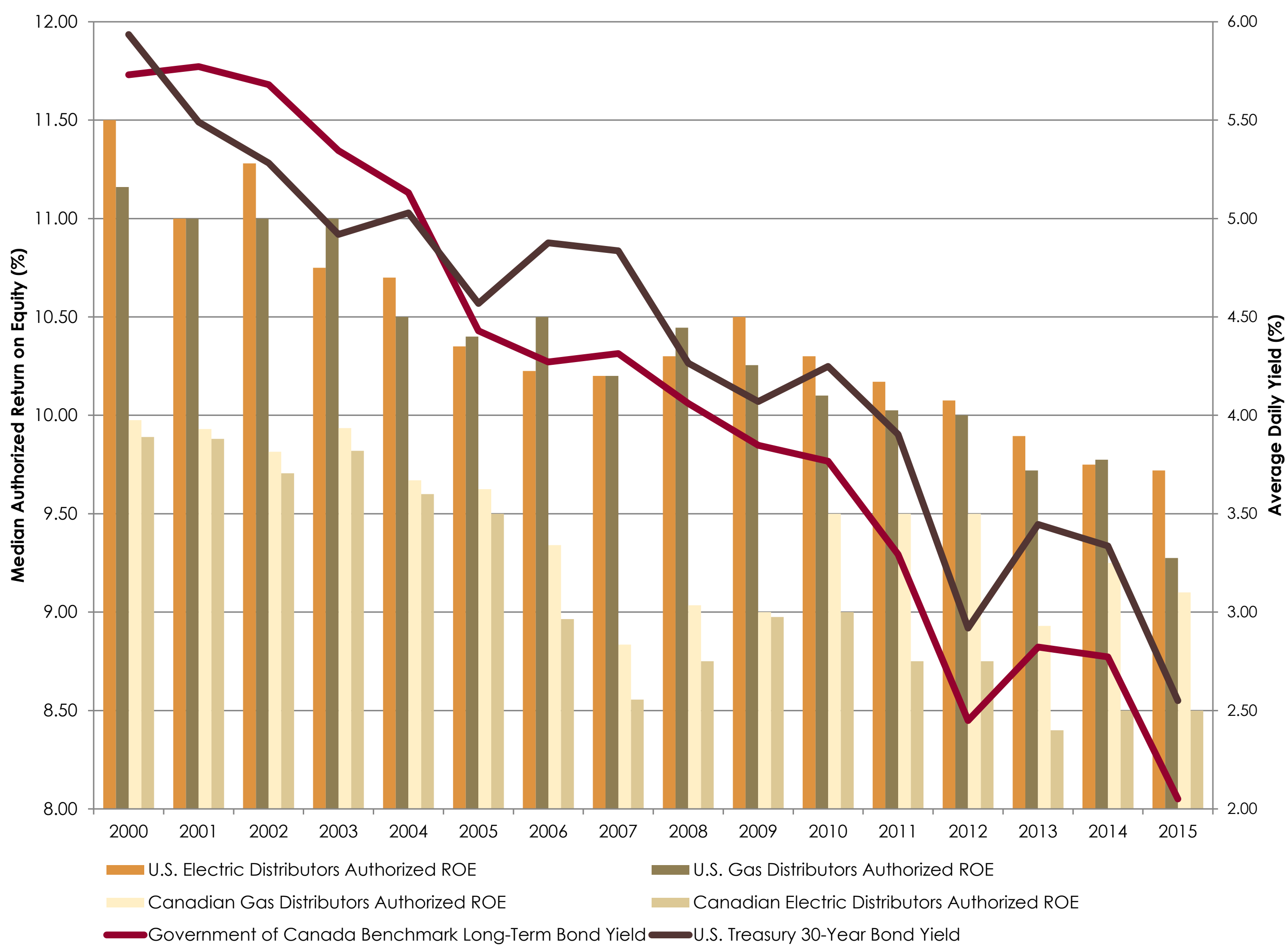
	Return on Common Equity (%)			Common Equity Ratio (%)		
	2013	2014	2015	2013	2014	2015
Canadian Gas Distributors [2]						
AltaGas Utilities Inc. [3]	8.30	8.30	8.30	42.00	42.00	42.00
ATCO Gas [3]	8.30	8.30	8.30	38.00	38.00	38.00
Centra Gas Manitoba Inc.	N/A	N/A	N/A	30.00	30.00	30.00
Enbridge Gas Distribution Inc. [4]	8.93	9.36	9.30	36.00	36.00	36.00
Enbridge Gas New Brunswick	10.90	10.90	10.90	45.00	45.00	45.00
FortisBC Energy Inc.	8.75	8.75	8.75	38.50	38.50	38.50
FortisBC Energy (Vancouver Island) Inc. [5]	9.25	9.25	—	41.50	41.50	—
FortisBC Energy (Whistler) Inc. [5]	9.50	9.50	—	41.50	41.50	—
Gaz Métro Limited Partnership	8.90	8.90	8.90	38.50	38.50	38.50
Gazifère Inc.	7.82	9.10	9.10	40.00	40.00	40.00
Heritage Gas Limited	11.00	11.00	11.00	45.00	45.00	45.00
Pacific Northern Gas Ltd.	9.50	9.50	9.50	46.50	46.50	46.50
Pacific Northern Gas (N.E.) Ltd. (Fort St. John/Dawson Creek)	9.25	9.25	9.25	41.00	41.00	41.00
Pacific Northern Gas (N.E.) Ltd. (Tumbler Ridge)	9.50	9.50	9.50	46.50	46.50	46.50
SaskEnergy Inc.	8.75	8.75	7.74	37.00	37.00	37.00
Union Gas Limited [6]	8.93	8.93	8.93	36.00	36.00	36.00
Average	9.17	9.29	9.19	40.19	40.19	40.00
Median	8.93	9.25	9.10	40.50	40.50	39.25
U.S. Gas Distributors [7]						
Average of all Rate Cases Decided in the Year	9.68	9.78	9.48	50.60	51.25	50.60
Median of all Rate Cases Decided in the Year	9.72	9.78	9.28	50.38	51.90	50.48
Canadian Electric Distributors [2]						
ATCO Electric Ltd. [3]	8.30	8.30	8.30	38.00	38.00	38.00
ENMAX Power Corporation [3]	8.30	8.30	8.30	40.00	40.00	40.00
EPCOR Distribution Inc. [3]	8.30	8.30	8.30	40.00	40.00	40.00
FortisAlberta Inc. [3]	8.30	8.30	8.30	40.00	40.00	40.00
FortisBC Inc.	9.15	9.15	9.15	40.00	40.00	40.00
Hydro-Québec Distribution	6.19	8.20	8.20	35.00	35.00	35.00
Manitoba Hydro	* N/A	N/A	N/A	25.00	25.00	25.00
Maritime Electric Company Limited	9.75	9.75	9.75	43.50	43.10	41.90
Newfoundland and Labrador Hydro [8]	4.47	Pending	Pending	20.00	Pending	Pending
Newfoundland Power Inc.	8.80	8.80	8.80	45.00	45.00	45.00
Nova Scotia Power Inc.	9.00	9.00	9.00	37.50	37.50	37.50
Ontario's Electric Distributors [4]	8.98	9.36	9.30	40.00	40.00	40.00
Saskatchewan Power Corporation	8.50	8.50	8.50	40.00	40.00	40.00
Average	8.17	8.72	8.72	37.23	38.63	38.53
Median	8.40	8.50	8.50	40.00	40.00	40.00
U.S. Electric Distributors [7]						
Average of all Rate Cases Decided in the Year	10.02	9.75	9.66	49.25	50.57	51.81
Median of all Rate Cases Decided in the Year	9.90	9.75	9.72	50.84	50.14	51.43

CONCENTRIC ENERGY ADVISORS

Authorized Return on Equity for Canadian and U.S. Gas and Electric Utilities

	Return on Common Equity (%)			Common Equity Ratio (%)		
	2013	2014	2015	2013	2014	2015
Canadian Electric Transmission Companies [2]						
AltaLink Management Ltd. [3]	8.30	8.30	8.30	36.00	36.00	36.00
ATCO Electric Ltd. [3]	8.30	8.30	8.30	36.00	36.00	36.00
ENMAX Power Corporation [3]	8.30	8.30	8.30	36.00	36.00	36.00
EPCOR Transmission Inc. [3]	8.30	8.30	8.30	36.00	36.00	36.00
Hydro One Networks Inc.	8.93	9.36	9.30	40.00	40.00	40.00
Hydro-Québec TransÉnergie	6.41	8.20	8.20	30.00	30.00	30.00
Average	8.09	8.46	8.45	35.67	35.67	35.67
Median	8.30	8.30	8.30	36.00	36.00	36.00

Economic Indicators (% Yields) [9]	2013	2014	2015
Government of Canada Benchmark Long-Term Bond Yield	2.82	2.77	2.05
U.S. Treasury 30-Year Bond Yield	3.45	3.34	2.55
Bloomberg Fair Value Canada A-rated Utility Bond Yield	4.24	4.14	3.50
Moody's A-rated Utility Bond Index (U.S.)	4.48	4.27	3.67



NOTES

1. Data for an expanded group of Canadian gas transmission companies is contained in the Concentric Energy Advisors Return on Equity Database.
2. Allowed in rates for the corresponding year; where the year overlaps, the rate/ratio shown prevails for the majority of the year. Sources: Regulatory decisions and documents; annual information forms; annual reports.
3. The Alberta Utilities Commission's 2015 decision in the Generic Cost of Capital proceeding was retroactive. Returns on common equity and common equity ratios were adjusted for 2013–2015. This also affects the category averages for 2013–2015 as compared to those reported in previous years.
4. Beginning in 2014, the Ontario Energy Board updates cost of capital parameters for setting rates in cost of service applications only once per year.
5. FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc. were amalgamated with FortisBC Energy Inc. and are no longer separate entities in 2015.
6. Union's ROE per settlement agreement in its five-year incentive regulation plan for 2014–2018.
7. Source: SNL Financial LC's Regulatory Research Associates Division. Data for 2015 includes decisions through March 31, 2015.
8. Newfoundland and Labrador Hydro (NLH) filed a General Rate Application (GRA) on July 30, 2013. A decision has not yet been issued on that GRA. The Company subsequently filed a request for interim rates that was denied by the Board in Order No. P.U. 39 (2014), issued September 17, 2014. On November 10, 2014, NLH filed an amended 2013 GRA based on changes to the previous 2014 test year and a new forecasted 2015 test year. That amended GRA remains pending before the Board.
9. Average daily yield. Source: Bloomberg Finance L.P. Data for 2015 through March 31, 2015.

* N/A indicates the data are not available.

CONCENTRIC ENERGY ADVISORS, INC.

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Tab 5

Section:	Appendix 2.2	**Page No.:**	11
Topic:	Evidence of Drazen Consulting Group		
Subtopic:	Centra's Financial Results		
Issue:	Whether retained earnings should be used to reduce bill impacts		

PREAMBLE TO IR (IF ANY):

Mr. Drazen highlights Centra's historical net incomes.

QUESTION:

a) Please file the most current IFF CGMI14 for Centra operations including financial targets based on Board approved methodology for Debt to Equity.

b) Please provide detailed supporting calculations (CGM14) for the debt to equity ratio based on the Board's approved methodology.

c) Please file an IFF CGMI14 including Board-approved methodology for debt to equity for each of the following two scenario(s) reflecting:

   i. 50% of the remaining 2013/14 Prior Period Supplementary Gas PGVA balance (i.e. approximately 25% of the original $46 million balance) being recovered in rates.

   ii. No further recovery of the 2013/14 Prior Period Supplementary Gas PGVA balance.

RATIONALE FOR QUESTION:

To understand Centra's current and forecasted financial position after the record level of net income earned in 2013/14.

RESPONSE:

The CGM14 projected financial statements and supporting calculations, including the projected financial ratios with the PUB approved methodology for Debt to Equity, in response to parts a and b are attached.

The scenario projected financial statements, including the projected financial ratios with the PUB approved methodology for Debt to Equity, in response to part c(i) and c(ii) are also attached. However, Centra submits that disallowing the recovery of any portion of the remaining $23 million Prior Period Supplemental Gas PGVA balance, is detrimental to Centra's financial position and ultimately increases the risk of significant customer rate impacts in the future.

In scenario PUB/Centra I-29c(i), where 50% of the remaining Prior Period Supplemental Gas PGVA balance ($12 million) is written-off, 2015/16 CGM14 net income of $4 million becomes a net loss of $8 million. By 2023/24, projected retained earnings are $17 million lower compared to CGM14 due to the incremental borrowing and associated financing costs that must be borne by customers in the future. The debt/equity ratio (as calculated under the PUB methodology) weakens from about 35% in CGM14, which is already well below the approximate 40% industry average[1] for Canadian gas distributors, to about 31% under 29c(i).

In scenario PUB/Centra I-29c(ii), where all of the remaining Prior Period Supplemental Gas PGVA balance ($23 million) is written-off, 2015/16 CGM14 net income of $4 million becomes a net loss of $20 million. By 2023/24, projected retained earnings are $35 million lower compared to CGM14 due to the incremental borrowing and associated financing costs that must be borne by customers in the future. The debt/equity ratio (as calculated under the PUB methodology) weakens from about 35% in CGM14 to about 29% under 29c(ii).

Mr. Drazen's evidence (Appendix 2.2, p.5) outlines that all Canadian gas distributors, and virtually all U.S. distributors, have exact cost recovery mechanisms. If the risk of variation in gas supply costs now shifts to Centra, Centra would have to manage that risk is through higher financial reserves in the form of retained earnings. Based on the current level of retained earnings and the historical variability of gas prices, it is easy to see that Centra's

[1] Concentric Energy Advisors Inc., Authorized Return on Equity for Canadian and U.S. Gas and Electric Utilities, Volume III, May 1, 2015, downloaded July 30, 2015 from the Canadian Gas Association website (http://www.cga.ca/wp-content/uploads/2015/07/2015-Authorized-Return-on-Equity-Newsletter.pdf).

retained earnings could be quickly wiped out and there would be sudden and significant impacts to customers' non-commodity general rates. In order to insulate customers from such potential variability, annual net income and retained earnings would have to be increased dramatically from the current approximate $3 to $5 million level of annual earnings as a Crown Corporation to something much in excess of the 9.2% industry average[2] allowed return on equity for Canadian gas distributors, which factors in utilities' exact cost recovery mechanisms.

Further, as Mr. Drazen's evidence states (Appendix 2.2, p.11), Centra's 2013-14 results should not be looked at in isolation. The actual financial results in Table 1 show that Centra can just as easily experience a net loss due mainly to warmer than normal weather. If Centra's retained earnings deteriorate further due to a write-off of the remaining Prior Period Supplemental Gas PGVA balance (or portion thereof), customers are further exposed to this weather-related risk. The remaining Prior Period Supplemental Gas PGVA balance represents a cash outlay that Centra has already made and has financed. If there is no expectation of recovery of this balance from customers, the result is an overall increase in borrowing requirements that Centra would have otherwise offset with the collection of the PGVA balance from customers. Customer non-commodity revenue requirements will be $1 to $2 million higher annually due to the incremental financing costs alone. When combined with the weather-related volatility, the incremental finance expense further increases pressure on customers' non-commodity general rate increases.

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[2] Concentric Energy Advisors Inc., Authorized Return on Equity for Canadian and U.S. Gas and Electric Utilities, Volume III, May 1, 2015, downloaded July 30, 2015 from the Canadian Gas Association website (http://www.cga.ca/wp-content/uploads/2015/07/2015-Authorized-Return-on-Equity-Newsletter.pdf).

GAS OPERATIONS (CGM14 Restated for PUB/Centra-I-29a)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	419	423	393	394	398	399	401	402	402	402
additional revenue requirement*	0	0	0	7	8	8	8	8	8	14
	419	423	393	401	405	407	409	410	410	416
Cost of Gas Sold	270	277	247	247	246	247	247	248	247	247
Gross Margin	149	147	146	154	159	160	161	162	162	169
Other	1	2	2	2	2	2	2	2	2	2
	151	148	148	156	161	162	163	164	164	171
EXPENSES										
Operating and Administrative	68	67	68	69	69	70	71	71	73	74
Finance Expense	16	17	19	21	21	22	22	23	24	25
Depreciation and Amortization	29	29	29	31	31	32	32	33	33	34
Capital and Other Taxes	19	19	20	20	20	20	21	21	21	21
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
	144	144	148	152	154	157	157	160	162	167
Net Income	7	4	0	3	7	5	6	4	2	4
* Additional Revenue Requirement										
Percent Increase	0.00%	0.00%	0.00%	2.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.75%
Cumulative Percent Increase	0.00%	0.00%	0.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	3.79%
Financial Ratios										
Equity (PUB Methodology)	35%	34%	34%	34%	34%	35%	35%	35%	34%	34%
Interest Coverage	1.41	1.22	1.01	1.16	1.33	1.24	1.25	1.18	1.07	1.15
Capital Coverage	0.52	0.94	0.74	0.96	0.98	0.87	0.82	0.76	0.66	0.76

Manitoba Hydro

Centra Gas Manitoba Inc. 2015/16 Cost of Gas Application
PUB/Centra-I-29a-c

GAS OPERATIONS (CGM14 Restated for PUB/Centra-I-29a)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	716	765	800	823	846	872	899	929	960	990
Accumulated Depreciation	(248)	(256)	(267)	(279)	(292)	(306)	(320)	(335)	(351)	(368)
Net Plant in Service	468	509	533	544	554	566	579	594	609	623
Construction in Progress	4	4	4	4	4	4	4	4	4	4
Current and Other Assets	120	121	121	121	121	121	121	121	121	121
Goodwill and Intangible Assets	7	6	6	5	5	4	4	4	4	4
Regulated Assets	85	84	85	82	78	75	72	70	68	66
	684	723	748	756	762	770	780	792	806	817
LIABILITIES AND EQUITY										
Long-Term Debt	300	310	320	320	330	330	340	320	350	370
Current and Other Liabilities	130	137	137	126	97	84	64	76	43	15
Contributions in Aid of Construction	64	83	98	114	131	148	163	178	193	208
Share Capital	121	121	121	121	121	121	121	121	121	121
Retained Earnings	69	72	72	75	82	87	93	97	99	102
	684	723	748	756	762	770	780	792	806	817

GAS OPERATIONS (CGM14 Restated for PUB/Centra-I-29a)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	457	461	430	438	439	441	443	445	444	451
Cash Paid to Suppliers and Employees	(413)	(380)	(373)	(382)	(384)	(386)	(388)	(390)	(391)	(393)
Interest Paid	(19)	(19)	(20)	(21)	(22)	(22)	(23)	(23)	(24)	(25)
	25	61	37	35	34	33	33	32	29	33
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	30	10	10	-	10	-	10	-	40	20
Retirement of Long-Term Debt	(35)	-	-	-	-	-	-	-	(20)	(10)
Other	-	-	-	-	-	-	-	-	-	-
	(5)	10	10	-	10	-	10	-	20	10
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(50)	(66)	(52)	(37)	(35)	(39)	(40)	(42)	(45)	(44)
Other	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	(50)	(66)	(52)	(37)	(36)	(39)	(41)	(43)	(46)	(44)
Net Increase (Decrease) in Cash	(30)	6	(4)	(2)	8	(6)	2	(11)	4	(1)
Cash at Beginning of Year	(34)	(64)	(59)	(63)	(65)	(57)	(63)	(61)	(72)	(68)
Cash at End of Year	(64)	(59)	(63)	(65)	(57)	(63)	(61)	(72)	(68)	(69)

b) Capital Structure Calculation
($000's)

	2014 Actual	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast
Advances from Parent	34 092	64 304	58 754	63 245	65 312	57 059	63 108	61 245	71 861	67 913	69 200
Long-Term Debt	305 000	300 000	310 000	320 000	320 000	330 000	330 000	340 000	340 000	360 000	370 000
Total Debt	339 092	364 304	368 754	383 245	385 312	387 059	393 108	401 245	411 861	427 913	439 200
Share Capital	121 250	121 250	121 250	121 250	121 250	121 250	121 250	121 250	121 250	121 250	121 250
Retained Earnings	61 904	68 540	71 550	71 717	75 114	82 052	87 250	92 825	96 933	98 661	102 385
Total Equity	183 154	189 790	192 800	192 967	196 364	203 302	208 500	214 075	218 183	219 911	223 635
Average Total Debt		351 698	366 529	376 000	384 279	386 186	390 084	397 177	406 553	419 887	433 557
Average Total Equity		186 472	191 295	192 884	194 666	199 833	205 901	211 288	216 129	219 047	221 773
Total Capitalization		538 170	557 824	568 883	578 944	586 019	595 985	608 464	622 682	638 934	655 330
Debt Ratio		65.4%	65.7%	66.1%	66.4%	65.9%	65.5%	65.3%	65.3%	65.7%	66.2%
Equity Ratio		34.6%	34.3%	33.9%	33.6%	34.1%	34.5%	34.7%	34.7%	34.3%	33.8%

Manitoba Hydro

GAS OPERATIONS (CGM14 Restated for PUB/Centra-I-29c-i)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	419	415	390	394	398	399	401	402	402	402
additional revenue requirement*	0	0	0	7	8	8	8	8	8	14
	419	415	390	401	405	407	409	410	410	416
Cost of Gas Sold	270	280	244	247	246	247	247	248	247	247
Gross Margin	149	135	146	154	159	160	161	162	162	169
Other	1	2	2	2	2	2	2	2	2	2
	151	136	148	156	161	162	163	164	164	171
EXPENSES										
Operating and Administrative	68	67	68	69	69	70	71	71	73	74
Finance Expense	16	17	19	21	22	23	23	24	25	26
Depreciation and Amortization	29	29	29	31	31	32	32	33	33	34
Capital and Other Taxes	19	19	20	20	20	20	21	21	21	21
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
	144	144	148	153	155	157	158	160	163	168
Net Income	7	(8)	(0)	3	6	5	5	4	1	3
* Additional Revenue Requirement										
Percent Increase	0.00%	0.00%	0.00%	2.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.75%
Cumulative Percent Increase	0.00%	0.00%	0.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	3.79%
Financial Ratios										
Equity (PUB Methodology)	35%	33%	32%	31%	32%	32%	32%	32%	32%	31%
Interest Coverage	1.41	0.54	0.98	1.13	1.28	1.20	1.21	1.15	1.03	1.11
Capital Coverage	0.52	0.81	0.67	0.95	0.95	0.85	0.80	0.75	0.64	0.74

Manitoba Hydro

GAS OPERATIONS (CGM14 Restated for PUB/Centra-I-29c-i)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	716	765	800	823	846	872	899	929	960	990
Accumulated Depreciation	(248)	(256)	(267)	(279)	(292)	(306)	(320)	(335)	(351)	(368)
Net Plant in Service	468	509	533	544	554	566	579	594	609	623
Construction in Progress	4	4	4	4	4	4	4	4	4	4
Current and Other Assets	120	121	121	121	121	121	121	121	121	121
Goodwill and Intangible Assets	7	6	6	5	5	4	4	4	4	4
Regulated Assets	85	84	85	82	78	75	72	70	68	66
	684	723	748	756	762	770	780	792	806	817
LIABILITIES AND EQUITY										
Long-Term Debt	300	320	330	340	340	340	340	340	360	390
Current and Other Liabilities	130	139	140	119	101	88	79	72	50	13
Contributions in Aid of Construction	64	83	98	114	131	148	163	178	193	208
Share Capital	121	121	121	121	121	121	121	121	121	121
Retained Earnings	69	60	59	62	68	73	78	81	82	85
	684	723	748	756	762	770	780	792	806	817

Manitoba Hydro

GAS OPERATIONS (CGM14 Restated for PUB/Centra-I-29c-i)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	457	452	427	438	439	441	443	445	444	451
Cash Paid to Suppliers and Employees	(413)	(380)	(373)	(382)	(384)	(386)	(388)	(390)	(391)	(393)
Interest Paid	(19)	(19)	(21)	(22)	(23)	(23)	(23)	(24)	(25)	(26)
	25	53	34	34	33	32	32	31	29	32
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	30	20	10	10	-	-	-	20	30	30
Retirement of Long-Term Debt	(35)	-	-	-	-	-	-	-	(20)	(10)
Other	-	-	-	-	-	-	-	-	-	-
	(5)	20	10	10	-	-	-	20	10	20
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(50)	(66)	(52)	(37)	(35)	(39)	(40)	(42)	(45)	(44)
Other	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	(50)	(66)	(52)	(37)	(36)	(39)	(41)	(43)	(46)	(44)
Net Increase (Decrease) in Cash	(30)	7	(8)	7	(3)	(7)	(9)	9	(7)	8
Cash at Beginning of Year	(34)	(64)	(57)	(66)	(58)	(61)	(68)	(76)	(68)	(75)
Cash at End of Year	(64)	(57)	(66)	(58)	(61)	(68)	(76)	(68)	(75)	(67)

GAS OPERATIONS (CGM14 Restated for PUB/Centra-I-29c-ii)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	419	406	387	394	398	399	401	402	402	402
additional revenue requirement*	0	0	0	7	8	8	8	8	8	14
	419	406	387	401	405	407	409	410	410	416
Cost of Gas Sold	270	283	241	247	246	247	247	248	247	247
Gross Margin	149	123	146	154	159	160	161	162	162	169
Other	1	2	2	2	2	2	2	2	2	2
	151	125	148	156	161	162	163	164	164	171
EXPENSES										
Operating and Administrative	68	67	68	69	69	70	71	71	73	74
Finance Expense	16	17	20	22	23	23	24	25	26	27
Depreciation and Amortization	29	29	29	31	31	32	32	33	33	34
Capital and Other Taxes	19	19	20	20	20	20	21	21	21	21
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
	144	145	149	154	155	158	159	161	164	169
Net Income	7	(20)	(1)	2	6	4	4	3	(0)	2
* Additional Revenue Requirement										
Percent Increase	0.00%	0.00%	0.00%	2.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.75%
Cumulative Percent Increase	0.00%	0.00%	0.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	3.79%
Financial Ratios										
Equity (PUB Methodology)	35%	32%	30%	29%	30%	30%	30%	30%	29%	29%
Interest Coverage	1.41	(0.14)	0.96	1.10	1.25	1.17	1.17	1.10	1.00	1.07
Capital Coverage	0.52	0.68	0.60	0.93	0.94	0.84	0.78	0.72	0.62	0.72

Manitoba Hydro

GAS OPERATIONS (CGM14 Restated for PUB/Centra-I-29c-ii)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	716	765	800	823	846	872	899	929	960	990
Accumulated Depreciation	(248)	(256)	(267)	(279)	(292)	(306)	(320)	(335)	(351)	(368)
Net Plant in Service	468	509	533	544	554	566	579	594	609	623
Construction in Progress	4	4	4	4	4	4	4	4	4	4
Current and Other Assets	120	121	121	121	121	121	121	121	121	121
Goodwill and Intangible Assets	7	6	6	5	5	4	4	4	4	4
Regulated Assets	85	84	85	82	78	75	72	70	68	66
	684	723	748	756	762	770	780	792	806	817
LIABILITIES AND EQUITY										
Long-Term Debt	300	320	340	340	340	350	360	350	370	390
Current and Other Liabilities	130	151	142	131	114	92	73	77	56	30
Contributions in Aid of Construction	64	83	98	114	131	148	163	178	193	208
Share Capital	121	121	121	121	121	121	121	121	121	121
Retained Earnings	69	48	47	49	55	59	63	66	65	67
	684	723	748	756	762	770	780	792	806	817

GAS OPERATIONS (CGM14 Restated for PUB/Centra-I-29c-ii)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	457	443	424	438	439	441	443	445	444	451
Cash Paid to Suppliers and Employees	(413)	(380)	(373)	(382)	(384)	(386)	(388)	(390)	(391)	(393)
Interest Paid	(19)	(19)	(21)	(23)	(23)	(24)	(24)	(25)	(26)	(27)
	25	44	30	34	33	32	31	30	28	31
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	30	20	20	-	-	10	10	10	30	20
Retirement of Long-Term Debt	(35)	-	-	-	-	-	-	-	(20)	(10)
Other	-	-	-	-	-	-	-	-	-	-
	(5)	20	20	-	-	10	10	10	10	10
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(50)	(66)	(52)	(37)	(35)	(39)	(40)	(42)	(45)	(44)
Other	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	(50)	(66)	(52)	(37)	(36)	(39)	(41)	(43)	(46)	(44)
Net Increase (Decrease) in Cash	(30)	(2)	(2)	(3)	(3)	3	0	(2)	(8)	(3)
Cash at Beginning of Year	(34)	(64)	(66)	(68)	(71)	(74)	(71)	(71)	(73)	(81)
Cash at End of Year	(64)	(66)	(68)	(71)	(74)	(71)	(71)	(73)	(81)	(84)

Section:	Tab 5, Tab 6	**Page No.:**	Schedules 5.5.0, 5.5.1, 6.2.0
Topic:	Cost Allocation and Rate Design, Proposed Rates & Customer Impacts		
Subtopic:	Bill Impacts		
Issue:	Supplemental Gas PGVA Recovery Scenarios		

PREAMBLE TO IR (IF ANY):

Centra proposes rate riders and corresponding bill impacts to recover the remaining $22 million of the Prior Period Supplemental Gas deferral account balance after October 31, 2015.

QUESTION:

Please re-file schedules 5.5.0, 5.5.1, and 6.2.0 for the following two scenarios:

iii. recovery of 50% of the remaining Supplemental PGVA balance (i.e. approximately 25% of the original $46 million balance), and

iv. no further recovery of the remaining

RATIONALE FOR QUESTION:

To understand the impacts of a recovery of less than the amount requested by Centra.

RESPONSE:

The attached schedules provide the cost and bill impacts only related to the short term treatment of gas cost recoveries. These schedules do not reflect any impacts to customers of future general rate increases that may be required as a result of any associated reduction in Centra's financial reserves.

Schedule 5.5.0 is not impacted by the requested scenarios as the remaining 2013/14 Supplemental PGVA balance, given Centra's proposed rate treatment and its materiality, has not been included as a prior period deferral.

Centra Gas Manitoba Inc.
2015/16 Cost of Gas Application
2015/16 Proposed Rate Riders (Unit Cost) - 2014/15 Gas Year
12-month Rate Riders
Reflecting recovery of 50% of the remaining Supplemental PGVA balance

	SGS		**LGS**		**HVF**				**Co-op**				**MAINLINE**			
	Transportation Commodity	Distribution Commodity	Transportation Commodity	Distribution Commodity	Transportation Commodity	Transportation Demand	Distribution Commodity	Distribution Demand	Transportation Commodity	Transportation Demand	Distribution Commodity	Distribution Demand	Transportation Commodity	Transportation Demand	Distribution Commodity	Distribution Demand
$ (Lines 14 & 34 of Schedule 6.0.0)	5,534,119	434,283	4,348,452	331,701	-1,150,899	1,419,574	79,697	961					-5,914	22,788	96,718	-262
Billing Determinant	659,089	659,089	511,014	511,014	166,698	13,391	211,955	15,963					4,081	254	129,063	6,427
$/10³m³	8.397	0.659	8.509	0.649	(6.904)	106.007	0.376	0.060					(1.449)	89.709	0.749	(0.041)
Rate Rider ($/m3)	0.0084	0.0007	0.0085	0.0006	(0.0069)	0.1060	0.0004	0.0001					(0.0014)	0.0897	0.0007	(0.0000)

	INTERRUPTIBLE				**SPECIAL**				**POWER STATIONS**				**SUPPLEMENTAL (INCL. IN DIST COMM)**			**TOTAL**
	Transportation Commodity	Transportation Demand	Distribution Commodity	Distribution Demand	Transportation Commodity	Transportation Demand	Distribution Commodity	Distribution Demand	Transportation Commodity	Transportation Demand	Distribution Commodity	Distribution Demand	Firm	Interruptible		
$ (Lines 14 & 34 of Schedule 6.0.0)	-133,045	209,420	159,403	2,634	0	0	277,670	-954	0	0	67,850	4,582	1,428,161	28,099		13,155,037
Billing Determinant	44,669	3,163	55,728	3,628			438,209				14,211	13,135	1,340,882	44,669		
$/10³m³	(2.978)	66.207	2.860	0.726			0.634				4.774	0.349	1.065	0.629		
Rate Rider ($/m3)	(0.0030)	0.0662	0.0029	0.0007			0.0006				0.0048	0.0003	0.0011	0.0006		
Lump Sum Payment							**276,716**				**72,432**					

	2013/14 SUPPLEMENTAL (INCL. IN DIST COMM)			
	Firm	Interruptible		
$ (table on page 2 Tab 6 - line 8)	10,863,749	236,271	11,100,020	24,255,056
Billing Determinant	1,318,705	78,467		
$/10³m³	8.238	3.011		
Rate Rider ($/m3)	0.0082	0.0030		

Centra Gas Manitoba Inc.
2015/16 Cost of Gas Application
Annual Bill Impacts reflecting recovery of 50% of the remaining Supplemental PGVA balance

PUB/Centra 69 (iii)
Attachment
August 21, 2015

1													
2	**May 1, 2015 Billed Rates vs. November 1, 2015 Billed Rates**												
3				**MAY 1, 2015 BILLED RATES**				**NOVEMBER 1, 2015 BILLED RATES**				**BILL IMPACTS**	
4													
5		Load	Annual Use	Basic Chg	Demand	Commodity	Annual	Basic Chg	Demand	Commodity	Annual	$	%
6		Factor	m³										
7													
8	Small General Service		1,000	$168	$0	$281	$449	$168	$0	$284	$452	$3	0.7%
9			1,980	$168	$0	$556	$724	$168	$0	$562	$730	$6	0.9%
10	*(Typical Residential Customer)*		2,243	$168	$0	$630	$798	$168	$0	$637	$805	$7	0.9%
11			2,800	$168	$0	$786	$954	$168	$0	$795	$963	$9	0.9%
12			3,200	$168	$0	$898	$1,066	$168	$0	$908	$1,076	$10	1.0%
13			3,680	$168	$0	$1,033	$1,201	$168	$0	$1,045	$1,213	$12	1.0%
14			11,330	$168	$0	$3,180	$3,348	$168	$0	$3,216	$3,384	$36	1.1%
15													
16	Large General Service		11,331	$924	$0	$2,570	$3,494	$924	$0	$2,596	$3,520	$25	0.7%
17			59,488	$924	$0	$13,495	$14,419	$924	$0	$13,627	$14,551	$132	0.9%
18			679,868	$924	$0	$154,223	$155,147	$924	$0	$155,734	$156,658	$1,511	1.0%
19													
20	High Volume Firm	25%	850,000	$14,657	$65,425	$137,112	$217,194	$14,657	$63,927	$128,660	$207,245	($9,950)	-4.6%
21		40%	850,000	$14,657	$40,891	$137,112	$192,660	$14,657	$39,955	$128,660	$183,272	($9,388)	-4.9%
22		40%	1,416,392	$14,657	$68,138	$228,476	$311,271	$14,657	$66,578	$214,392	$295,628	($15,643)	-5.0%
23		40%	2,832,784	$14,657	$136,277	$456,951	$607,885	$14,657	$133,156	$428,785	$576,598	($31,287)	-5.1%
24		40%	6,200,000	$14,657	$298,263	$1,000,111	$1,313,031	$14,657	$291,434	$938,464	$1,244,555	($68,476)	-5.2%
25		40%	12,600,000	$14,657	$606,148	$2,032,483	$2,653,288	$14,657	$592,269	$1,907,200	$2,514,126	($139,162)	-5.2%
26		75%	685,000	$14,657	$17,575	$110,496	$142,728	$14,657	$17,173	$103,685	$135,515	($7,213)	-5.1%
27		75%	849,835	$14,657	$21,804	$137,085	$173,547	$14,657	$21,305	$128,635	$164,597	($8,949)	-5.2%
28		75%	1,416,392	$14,657	$36,340	$228,476	$279,473	$14,657	$35,508	$214,392	$264,558	($14,915)	-5.3%
29		75%	2,832,784	$14,657	$72,681	$456,951	$544,289	$14,657	$71,017	$428,785	$514,458	($29,831)	-5.5%
30		75%	6,200,000	$14,657	$159,074	$1,000,111	$1,173,842	$14,657	$155,431	$938,464	$1,108,552	($65,289)	-5.6%
31		75%	12,600,000	$14,657	$323,279	$2,032,483	$2,370,419	$14,657	$315,877	$1,907,200	$2,237,734	($132,685)	-5.6%
32													
33	Co-op	35%	250,000	$3,819	$11,770	$31,825	$47,413	$3,819	$13,768	$31,500	$49,087	$1,673	3.5%
34		35%	350,000	$3,819	$16,478	$44,555	$64,851	$3,819	$19,276	$44,100	$67,194	$2,343	3.6%
35		35%	500,000	$3,819	$23,540	$63,650	$91,008	$3,819	$27,537	$63,000	$94,355	$3,347	3.7%
36													
37	MLC (Sales Service)	40%	2,500,000	$14,966	$124,362	$396,680	$536,008	$14,966	$164,527	$348,163	$527,656	($8,352)	-1.6%
38		40%	11,000,000	$14,966	$547,194	$1,745,393	$2,307,552	$14,966	$723,921	$1,531,916	$2,270,802	($36,750)	-1.6%
39		75%	2,500,000	$14,966	$66,327	$396,680	$477,972	$14,966	$87,748	$348,163	$450,876	($27,096)	-5.7%
40		75%	11,000,000	$14,966	$291,837	$1,745,393	$2,052,195	$14,966	$386,091	$1,531,916	$1,932,973	($119,223)	-5.8%
44													
45	MLC (T-Service)	40%	14,000,000	$14,966	$208,964	$63,000	$286,930	$14,966	$208,964	$72,800	$296,730	$9,800	3.4%
46		40%	18,000,000	$14,966	$268,668	$81,000	$364,634	$14,966	$268,668	$93,600	$377,234	$12,600	3.5%
47		40%	44,000,000	$14,966	$656,745	$198,000	$869,711	$14,966	$656,745	$228,800	$900,511	$30,800	3.5%
48		75%	14,000,000	$14,966	$111,448	$63,000	$189,413	$14,966	$111,448	$72,800	$199,213	$9,800	5.2%
49		75%	18,000,000	$14,966	$143,290	$81,000	$239,255	$14,966	$143,290	$93,600	$251,855	$12,600	5.3%
50		75%	44,000,000	$14,966	$350,264	$198,000	$563,230	$14,966	$350,264	$228,800	$594,030	$30,800	5.5%
51													
52	Special Contract	81%	400,000,000	$1,415,641	$0	$40,000	$1,382,292	$1,414,970	$0	$40,000	$1,731,686	$349,393	25.3%
53													
54	Power Stations	5%	14,000,000	$192,626	$38,184	$112,000	$279,787	$192,626	$40,730	$117,600	$423,388	$143,601	51.3%
55		6%	15,000,000	$192,626	$38,184	$120,000	$287,787	$192,626	$40,730	$126,000	$431,788	$144,001	50.0%
56													
57	Interruptible Sales	25%	849,835	$15,053	$23,325	$125,481	$163,860	$15,053	$32,533	$125,630	$173,217	$9,357	5.7%
58		40%	2,832,784	$15,053	$48,594	$418,270	$481,918	$15,053	$67,777	$418,768	$501,598	$19,681	4.1%
59		40%	14,163,920	$15,053	$242,970	$2,091,350	$2,349,374	$15,053	$338,886	$2,093,839	$2,447,779	$98,405	4.2%
60		75%	849,835	$15,053	$7,775	$125,481	$148,309	$15,053	$10,844	$125,630	$151,528	$3,219	2.2%
61		75%	2,832,784	$15,053	$25,917	$418,270	$459,240	$15,053	$36,148	$418,768	$469,969	$10,729	2.3%
62		75%	14,163,920	$15,053	$129,584	$2,091,350	$2,235,988	$15,053	$180,739	$2,093,839	$2,289,632	$53,644	2.4%
63	Firm Billing percentages: 90% Primary Gas, 10% Supplemental Gas												
64	Interruptible Billing percentages: 79% Primary Gas, 21% Supplemental Gas												

Centra Gas Manitoba Inc.
2015/16 Cost of Gas Application
2015/16 Proposed Rate Riders (Unit Cost) - 2014/15 Gas Year
12-month Rate Riders
Reflecting no recovery of the remaining Supplemental PGVA balance

PUB/Centra 69 (iv)
Attachment
August 21, 2015

	SGS		**LGS**		**HVF**				**Co-op**				**MAINLINE**			
	Transportation Commodity	Distribution Commodity	Transportation Commodity	Distribution Commodity	Transportation Commodity	Transportation Demand	Distribution Commodity	Distribution Demand	Transportation Commodity	Transportation Demand	Distribution Commodity	Distribution Demand	Transportation Commodity	Transportation Demand	Distribution Commodity	Distribution Demand
$ (Lines 14 & 34 of Schedule 6.0.0)	5,534,119	434,283	4,348,452	331,701	-1,150,899	1,419,574	79,697	961					-5,914	22,788	96,718	-262
Billing Determinant	659,089	659,089	511,014	511,014	166,698	13,391	211,955	15,963					4,081	254	129,063	6,427
$/10³m³	8.397	0.659	8.509	0.649	(6.904)	106.007	0.376	0.060					(1.449)	89.709	0.749	(0.041)
Rate Rider ($/m3)	0.0084	0.0007	0.0085	0.0006	(0.0069)	0.1060	0.0004	0.0001					(0.0014)	0.0897	0.0007	(0.0000)

	INTERRUPTIBLE				**SPECIAL**				**POWER STATIONS**				**SUPPLEMENTAL (INCL. IN DIST COMM)**		**TOTAL**
	Transportation Commodity	Transportation Demand	Distribution Commodity	Distribution Demand	Transportation Commodity	Transportation Demand	Distribution Commodity	Distribution Demand	Transportation Commodity	Transportation Demand	Distribution Commodity	Distribution Demand	Firm	Interruptible	
$ (Lines 14 & 34 of Schedule 6.0.0)	-133,045	209,420	159,403	2,634	0	0	277,670	-954	0	0	67,850	4,582	1,428,161	28,099	13,155,037
Billing Determinant	44,669	3,163	55,728	3,628			438,209				14,211	13,135	1,340,882	44,669	
$/10³m³	(2.978)	66.207	2.860	0.726			0.634				4.774	0.349	1.065	0.629	
Rate Rider ($/m3)	(0.0030)	0.0662	0.0029	0.0007			0.0006				0.0048	0.0003	0.0011	0.0006	
Lump Sum Payment							**276,716**				**72,432**				

Centra Gas Manitoba Inc.
2015/16 Cost of Gas Application
Annual Bill Impacts reflecting no recovery of the remaining Supplemental PGVA balance

Line		Load Factor	Annual Use m³	MAY 1, 2015 BILLED RATES Basic Chg	Demand	Commodity	Annual	NOVEMBER 1, 2015 BILLED RATES Basic Chg	Demand	Commodity	Annual	BILL IMPACTS $	%
1													
2	**May 1, 2015 Billed Rates vs. November 1, 2015 Billed Rates**												
7													
8	Small General Service		1,000	$168	$0	$281	$449	$168	$0	$276	$444	($5)	-1.1%
9			1,980	$168	$0	$556	$724	$168	$0	$546	$714	($10)	-1.4%
10	*(Typical Residential Customer)*		2,243	$168	$0	$630	$798	$168	$0	$618	$786	($11)	-1.4%
11			2,800	$168	$0	$786	$954	$168	$0	$772	$940	($14)	-1.5%
12			3,200	$168	$0	$898	$1,066	$168	$0	$882	$1,050	($16)	-1.5%
13			3,680	$168	$0	$1,033	$1,201	$168	$0	$1,014	$1,182	($18)	-1.5%
14			11,330	$168	$0	$3,180	$3,348	$168	$0	$3,123	$3,291	($56)	-1.7%
15													
16	Large General Service		11,331	$924	$0	$2,570	$3,494	$924	$0	$2,503	$3,427	($68)	-1.9%
17			59,488	$924	$0	$13,495	$14,419	$924	$0	$13,139	$14,063	($356)	-2.5%
18			679,868	$924	$0	$154,223	$155,147	$924	$0	$150,159	$151,083	($4,064)	-2.6%
19													
20	High Volume Firm	25%	850,000	$14,657	$65,425	$137,112	$217,194	$14,657	$63,927	$121,690	$200,275	($16,920)	-7.8%
21		40%	850,000	$14,657	$40,891	$137,112	$192,660	$14,657	$39,955	$121,690	$176,302	($16,358)	-8.5%
22		40%	1,416,392	$14,657	$68,138	$228,476	$311,271	$14,657	$66,578	$202,778	$284,013	($27,258)	-8.8%
23		40%	2,832,784	$14,657	$136,277	$456,951	$607,885	$14,657	$133,156	$405,556	$553,369	($54,516)	-9.0%
24		40%	6,200,000	$14,657	$298,263	$1,000,111	$1,313,031	$14,657	$291,434	$887,624	$1,193,715	($119,316)	-9.1%
25		40%	12,600,000	$14,657	$606,148	$2,032,483	$2,653,288	$14,657	$592,269	$1,803,880	$2,410,806	($242,482)	-9.1%
26		75%	685,000	$14,657	$17,575	$110,496	$142,728	$14,657	$17,173	$98,068	$129,898	($12,830)	-9.0%
27		75%	849,835	$14,657	$21,804	$137,085	$173,547	$14,657	$21,305	$121,667	$157,629	($15,918)	-9.2%
28		75%	1,416,392	$14,657	$36,340	$228,476	$279,473	$14,657	$35,508	$202,778	$252,943	($26,530)	-9.5%
29		75%	2,832,784	$14,657	$72,681	$456,951	$544,289	$14,657	$71,017	$405,556	$491,230	($53,060)	-9.7%
30		75%	6,200,000	$14,657	$159,074	$1,000,111	$1,173,842	$14,657	$155,431	$887,624	$1,057,712	($116,129)	-9.9%
31		75%	12,600,000	$14,657	$323,279	$2,032,483	$2,370,419	$14,657	$315,877	$1,803,880	$2,134,414	($236,005)	-10.0%
32													
33	Co-op	35%	250,000	$3,819	$11,770	$31,825	$47,413	$3,819	$13,768	$31,500	$49,087	$1,673	3.5%
34		35%	350,000	$3,819	$16,478	$44,555	$64,851	$3,819	$19,276	$44,100	$67,194	$2,343	3.6%
35		35%	500,000	$3,819	$23,540	$63,650	$91,008	$3,819	$27,537	$63,000	$94,355	$3,347	3.7%
36													
37	MLC (Sales Service)	40%	2,500,000	$14,966	$124,362	$396,680	$536,008	$14,966	$164,527	$327,663	$507,156	($28,852)	-5.4%
38		40%	11,000,000	$14,966	$547,194	$1,745,393	$2,307,552	$14,966	$723,921	$1,441,716	$2,180,602	($126,950)	-5.5%
39		75%	2,500,000	$14,966	$66,327	$396,680	$477,972	$14,966	$87,748	$327,663	$430,376	($47,596)	-10.0%
40		75%	11,000,000	$14,966	$291,837	$1,745,393	$2,052,195	$14,966	$386,091	$1,441,716	$1,842,773	($209,423)	-10.2%
44													
45	MLC (T-Service)	40%	14,000,000	$14,966	$208,964	$63,000	$286,930	$14,966	$208,964	$72,800	$296,730	$9,800	3.4%
46		40%	18,000,000	$14,966	$268,668	$81,000	$364,634	$14,966	$268,668	$93,600	$377,234	$12,600	3.5%
47		40%	44,000,000	$14,966	$656,745	$198,000	$869,711	$14,966	$656,745	$228,800	$900,511	$30,800	3.5%
48		75%	14,000,000	$14,966	$111,448	$63,000	$189,413	$14,966	$111,448	$72,800	$199,213	$9,800	5.2%
49		75%	18,000,000	$14,966	$143,290	$81,000	$239,255	$14,966	$143,290	$93,600	$251,855	$12,600	5.3%
50		75%	44,000,000	$14,966	$350,264	$198,000	$563,230	$14,966	$350,264	$228,800	$594,030	$30,800	5.5%
51													
52	Special Contract	81%	400,000,000	$1,415,641	$0	$40,000	$1,382,292	$1,414,970	$0	$40,000	$1,731,686	$349,393	25.3%
53													
54	Power Stations	5%	14,000,000	$192,626	$38,184	$112,000	$279,787	$192,626	$40,730	$117,600	$423,388	$143,601	51.3%
55		6%	15,000,000	$192,626	$38,184	$120,000	$287,787	$192,626	$40,730	$126,000	$431,788	$144,001	50.0%
56													
57	Interruptible Sales	25%	849,835	$15,053	$23,325	$125,481	$163,860	$15,053	$32,533	$123,081	$170,667	$6,808	4.2%
58		40%	2,832,784	$15,053	$48,594	$418,270	$481,918	$15,053	$67,777	$410,269	$493,100	$11,183	2.3%
59		40%	14,163,920	$15,053	$242,970	$2,091,350	$2,349,374	$15,053	$338,886	$2,051,347	$2,405,287	$55,913	2.4%
60		75%	849,835	$15,053	$7,775	$125,481	$148,309	$15,053	$10,844	$123,081	$148,979	$669	0.5%
61		75%	2,832,784	$15,053	$25,917	$418,270	$459,240	$15,053	$36,148	$410,269	$461,471	$2,230	0.5%
62		75%	14,163,920	$15,053	$129,584	$2,091,350	$2,235,988	$15,053	$180,739	$2,051,347	$2,247,140	$11,152	0.5%
63	Firm Billing percentages: 90% Primary Gas, 10% Supplemental Gas												
64	Interruptible Billing percentages: 79% Primary Gas, 21% Supplemental Gas												

MANITOBA	**Order No. 99/07**
THE PUBLIC UTILITIES BOARD ACT	**July 27, 2007**

Before: Graham Lane, CA, Chairman
Len Evans, LL.D., Member
Eric Jorgensen, Member

CENTRA GAS MANITOBA INC. 2007/08 AND 2008/09 GENERAL RATE APPLICATION AND OTHER MATTERS

Debt: Equity Ratio

Centra indicated that with respect to net income and the development of sufficient retained earnings from natural gas distribution operations to provide for a prudent foundation, MH sought only to gradually bring Centra's debt: equity ratio, now calculated in accordance with MH's perspective at 86:14, to 75:25.

Firstly, the Board again rejects the premise that Centra's debt: equity ratio for regulatory purposes be calculated ignoring its share capital. The Board continues to agree with CAC/MSOS that Centra's debt: equity ratio is to be considered on a standalone basis.

The Board agrees with Centra that there are alternate and perhaps acceptable ways of calculating debt: equity ratios, however the Board continues to find that calculating Centra's debt: equity ratio on a standalone basis is the most appropriate approach for rate setting. In short, the Board does not accept that a different target other than one based on a standalone view of Centra's balance sheet should be utilized.

As to the debt:equity ratio to be selected as the target on the standalone basis, the Board accepts Mr. Matwichuk's advice and finds that given Centra's borrowings are guaranteed by the Province, with the fee for the guarantee allowed in costs for rate setting, a 70:30 ratio is adequate, rather than the 60:40 model that would be acceptable if there were no provincial guarantee.

The Board notes that Centra's debt: equity ratio already exceeds the 70:30 standalone test, and that this reinforces the Board's determination to hold Centra's allowable annual Net Income to $3 million, given the Corporate Allocation remains at $12 million. The Board also notes that contributions from customers, unlike the case with MH, is not included as equity in Centra's calculation of the standalone debt:equity ratio. If it were, Centra would be well in excess of the target.

Tab 6

Section:	Appendix 2.2	**Page No.:**	2-4
Topic:	Evidence of Drazen Consulting Group		
Subtopic:	Use of PGVAs		
Issue:	Whether retained earnings should be used to reduce bill impacts		

PREAMBLE TO IR (IF ANY):

Drazen states: "Centra's PGVA was proposed and approved by the Board on the basis that it would recover exactly the cost incurred;"

QUESTION:

a) Please confirm whether the PGVA approved in Order 10/93 was proposed by Centra or by the Board

b) Please provide Mr. Drazen's view whether the use of PGVAs shifts the risk of over- or under-collection of gas costs to ratepayers from the utility.

c) Please quantify the cost to ratepayers if the utility was to assume the risk of over- or under-collection of gas costs. That is, what level of net income would Centra reasonably be expected to require if it was at risk of over- or under-collection of gas costs?

d) Please indicate which gas utilities take on the commodity cost risk and what level of compensation do these utilities earn for taking on this risk.

e) Please summarize how the Ontario Energy Board treated the increase in gas costs experienced by its two major utilities Union and Enbridge following the 2013/14 winter.

f) Please provide links to the Ontario Energy Board decisions EB-2014-0039 and EB-2014-0050, as well as links to the applications and evidence filed in these proceedings.

RATIONALE FOR QUESTION:

To clarify the origin of the PGVA, to understand the risk-shifting nature of the PGVA, and to understand how other jurisdictions treated similar cost consequences of the 2013/14 winter.

RESPONSE:

a) The PGVA approved by the PUB in Order 10/93 was proposed by Centra.

b) The following response was provided by Mr. Drazen:

Whether use of PGVAs shifts risk to ratepayers depends on the underlying assumption regarding who should properly pay the cost of supply. The near-universal approach is that the cost of gas to the utility (excepting costs determined to be imprudent) should be paid by those who consume the gas. This happens directly with customers who buy gas in the market (that is, not from the utility). The same is true for customers of utilities that flow through the current cost of gas on a monthly basis (for example, those in Alberta).

Overcollection or undercollection with a PGVA is the result of the decision to fix the price of supply to customers for an extended period. That fixed price will almost inevitably differ from the actual market prices at which the gas is acquired over that period. The longer the period, the greater the potential variance. This changes the timing of gas cost recovery from customers, but not, in principle, the amount.

Thus, a PGVA is a method of modulating the variations in gas cost. It changes the *timing* of cost recovery, but is not normally intended to change the *amount* of recovery. As such, the PGVA should produce an overall financial result similar to that of a market price flow through regime and does not, in and of itself, shift any additional risk to ratepayers.

c) The following response was provided by Mr. Drazen:

Were Centra required to absorb the variances, it would be necessary to identify: (1) the target (or baseline) cost of gas from which variances would be measured; and (2) the portions of variances that are to be absorbed.

The costs to ratepayers of this type of regime include direct costs to the utility and potential external costs to gas users. The direct costs include additional return on equity to cover the higher income risk and possible additional regulatory costs in determining the baseline gas cost and risk compensation. Note that the higher return on equity would rightly apply only to those customers buying the gas covered by the PGVA; the rates to customers purchasing gas from marketers should not be affected by the higher required return related to the utility's risk related to gas cost variances.

Potential external costs include any distortions in the marketplace that result from the differences between pricing of gas from Centra and from marketers.

Given the assumptions and variables involved (e.g., weather fluctuations and unpredictability of TransCanada Pipeline non-firm tolls), quantifying the cost is not possible.

d) The following response was provided by Mr. Drazen:

We have not made an exhaustive search. To our knowledge, there is no utility in Canada or the U.S. that absorbs the full amount of variances. Utilities in the state of Oregon (Avista Utilities, Cascade Natural Gas and Northwest Natural Gas) do absorb a limited portion of purchased gas cost variances, subject to an annual earnings review. A utility can elect to absorb either 10% or 20% of variances. If 10%, the utility's earnings cap is raised by 100 basis points. If 20%, by 150 basis points. The Oregon utilities have equity ratios around 50% and allowed returns on equity around 9.5%.

The Oregon utilities have decoupling and weather normalization mechanisms, which ensure the companies' recovery of fixed costs regardless of variations in weather and changes in per-customer usage, thereby reducing risk.

e) The following response was provided by Mr. Drazen:

The Ontario Energy Board (OEB) allowed the utilities to recover the full cost, but modified the recovery period for Enbridge Gas. Ontario utilities use a Quarterly Rate Adjustment Mechanism (QRAM). The primary QRAM factors include: (1) the previous quarter's variance spread over a 12-month period, and (2) a forecast of the anticipated commodity cost based on NYMEX future prices.

The OEB dealt with the increased 2013/14 gas costs in Proceedings EB-2014-0039 (Enbridge Gas Distribution) and EB-2014-0050 (Union Gas). Both utilities experienced much higher costs in the 2013/14 winter, similar to Centra's experience.

It is noteworthy that in its EB-2014-0039 QRAM Application, Enbridge's commodity related variance account balance associated with the 2013/14 winter period was $453.6 million. The annual bill impact for the average residential customer associated with this variance account balance was approximately $250 per year, based on the traditional 12-month disposition period. Combined with the bill impact from the change in the projected cost of gas going forward, the total bill impact for the average residential customer sought by Enbridge was approximately $400 per year.

The OEB issued its Decision and Order (D&O) regarding Union Gas on March 21, 2014. A Decision and Interim Order for Enbridge was issued on March 27, 2014, with a final D&O on May 22, 2014.

For Union, the OEB applied the normal QRAM approach. For Enbridge, which had a higher unrecovered variance, the OEB decided to use a 27-month smoothing period. Although the longer period reduced the price signal effect, the OEB considered that it was necessary to avoid rate shock.

The Decisions for both utilities contained identical language:

> *The Board's objectives with regards to the natural gas sector include the following:*
>
> - *To facilitate competition in the sale of gas to users;*
> - *To protect the interests of consumers with respect to prices and the reliability and quality of gas service.*
>
> *The QRAM is designed to adjust the price for regulated gas supply every quarter to reflect natural gas market prices. Under the QRAM framework, Union makes no profit on the gas commodity.* ***The actual cost of the gas purchased by Union for its customers is passed onto Union's customers without any mark-up or added costs.*** (Union Gas Decision and Order, page 3, emphasis added)

Identical language (other than the utility's name) is in the Enbridge decision at pages 4-5.

Regarding Union Gas, the OEB noted:

> *First, higher than forecast gas supply costs were incurred by Union over the past quarter. The higher costs were as a result of the impact that much colder than normal weather had on customer demand and on natural gas prices.* ***As a result of the weather, Union paid higher prices for its planned purchases of natural gas. In addition, due to high customer demand, Union was required to buy more gas than would normally be required.*** *The incremental natural gas purchased by Union was at prices that reflected the high market demand.* (Decision and Order, pages 3-4, emphasis added)

For Union, the OEB applied its normal QRAM approach. The retrospective cost increase was spread over a period of 12 months. In response to suggestions that the retrospective cost increase be spread over a longer period, the OEB commented:

> *. . . The Board is satisfied that the standard 12 month disposition period effectively balances the Board's objective of protecting the interests of consumers with respect to price and the intent of the QRAM to have natural gas price signals which reflect the actual market price.* (Decision and Order, pages 4-5)

Regarding Enbridge, the OEB stated:

> *. . . As a natural gas distributor, Enbridge purchases gas on behalf of customers in its service area that do not have their gas supplied by a natural gas marketer. This gas is generally known as the regulated gas supply or system gas or the default supply . . ..*
>
> * * *
>
> *Enbridge purchases this default supply through a combination of fixed contracts and spot market purchases in accordance with an approved gas supply plan. The plan is based on the amount of gas that would be expected to be needed to address the normal range of demand.* ***The extremely cold temperatures experienced this past winter had a dramatic impact on the North American demand for natural gas and the market price for gas rose accordingly. Enbridge purchased more of its gas at spot market prices than would be expected in more typical winter periods.*** (Decision and Order, page 6, emphasis added)

The OEB noted the unexpected extreme severity of the weather conditions:

> *The planning criteria for the 2013-2014 winter assumed that the winter could be as severe as any winter in five years, while **the winter actually proved to have a severity of one in twenty-five years**.* (Decision and Interim Order, page 8, emphasis added)

In its final D&O, the OEB allowed full recovery of the extra costs but decided that the magnitude of the extra costs justified a change in the smoothing period:

> *The QRAM process is designed to strike an appropriate balance between providing consumers with market pricing signals and protecting those same consumers from rate volatility by smoothing rate impacts over time. The standard 12-month smoothing period used in the QRAM already has the effect of dampening market price signals. **The QRAM inherently has an effect on competition and reduces the accuracy of pricing information by spreading the impacts of price changes over a 12-month period.** These are considered to be acceptable negative consequences in light of the equally important desire to provide a level of protection to system supply consumers by smoothing rate change impacts over time.*
>
> *The balancing of these two competing QRAM features in this case requires a consideration of the effectiveness of the standard 12-month smoothing period. Given the magnitude of the current increase, the Board considers the standard 12-month smoothing period inadequate to provide the appropriate balance between the competing objectives that the QRAM is designed to achieve.*
>
> ***The Board will provide the appropriate level of consumer protection from the impacts of the sharp increase in price by lengthening the normal 12-month smoothing period by an additional 15 months.** The Board is of the view that the magnitude of the increase that will be incurred by customers over a 27-month smoothing period strikes the appropriate balance between transparency of market prices and the consumer protection from rate shock.* (page 7, emphasis added)

f) The Decision and Order EB-2014-0039 dated May 22, 2014 can be found at the link below:
http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/438602/view/dec_order_Enbridge_QRAM_20140522.PDF

The Decision and Interim Order EB-2014-0039 dated March 27, 2014 can be found

at the below:
http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/431263/view/Dec_InterimOrder_Enbridge_%20April%202014%20QRAM_20140327.PDF

The Application filed by Enbridge Gas Distribution Inc. in the EB-2014-0039 proceeding can be found at the link below:
http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/430970/view/EGDI_APPL_QRAM_correction_20140312.PDF

All other evidence filed with respect to the OEB EB-2014-0039 proceeding can be found at the link below:
http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/search/rec&sm_udf10=eb-2014-0039&sortd1=rs_dateregistered&rows=200

The link to Decision and Order EB-2014-0050 dated March 21, 2014 is found below:
http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/430661/view/dec_order_Union%20QRAM_20140321.PDF

The Application filed by Union Gas Limited in the EB-2014-0050 proceeding can be found at the link below:
http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/428228/view/UNION_APPL_QRAM_%20corrected_v2_20140306.PDF

All other evidence filed with respect to the OEB EB-2014-0050 proceeding can be found at the link below:
http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/search/rec&sm_udf10=eb-2014-0050&sortd1=rs_dateregistered&rows=200

Section:	Appendix 2.2	**Page No.:**	7
Topic:	Evidence of Drazen Consulting Group		
Subtopic:	Recovery of Gas Costs		
Issue:	Disallowances of gas costs not prudently acquired		

PREAMBLE TO IR (IF ANY):

Mr. Drazen notes an example where the Board disallowed a portion of Centra's gas costs as the Board found that Centra's hedging strategy had not been prudently managed.

QUESTION:

a) Please summarize the reasons for disallowance by the Ontario Energy Board of some of Union's 1995 gas costs as ordered in EBRO-486-04 dated April 12, 1996.

b) Please provide a copy or link to the OEB Order EBRO-486-04 dated April 12, 1996.

c) Please provide any examples from other Canadian or U.S. jurisdictions where the regulator disallowed gas costs because they were not prudently required.

RATIONALE FOR QUESTION:

To explore reasons for prudence disallowance by other Canadian regulators.

RESPONSE:

The following responses were provided by Mr. Drazen:

a) The OEB considered that Union did not follow its own supply planning procedure; specifically, that it was tardy in responding to changed circumstances. The Decision With Reasons (April 12, 1996) stated first:

> *3.1.18. Based on Union's evidence, the Board has some reservations about the effectiveness of Union's gas supply planning process. The Board has difficulty in understanding why it was only in late November that Union recognized its need to*

> *enter the market to purchase spot gas supplies to meet the demands of its firm service customers. The Board appreciates that management must make its decisions based on the best information available at the time decisions are made; equally it is important that in making decisions, provision be made for contingencies that may arise if the assumptions underlying those decisions are wrong.* ***While the Board considers that Union's gas supply planning process was adequate, the Board believes that Union was slow in reacting to early signals that demand was higher than forecast*** *and in making appropriate contingency arrangements*. (page 15, emphasis added)

Further:

> *3.2.14. The Board has previously found that Union's gas supply planning process was adequate. However, the Board considers that Union's implementation of the gas supply plan was deficient.* (page 18)

Regarding curtailments, the Board said:

> *3.4.11. The Board understands Union's need to balance its use of curtailments with its need to retain some interruptible capability as a contingency for late winter season supply difficulties and considers it would not have been reasonable for Union to have utilized all its curtailment capability early on in the winter season. However, the Board believes that if Union had initiated curtailment earlier it might have reduced its need to purchase as much gas as it did in January when the premium on spot gas purchases appears to have been highest.* ***The Board is of the view that Union's delay in applying curtailment to interruptible customers is another instance of the Company's slow response in implementing its gas supply plans*** *following the identification of the 12 Bcf shortfall. The Board has considered this slow response in its findings on the PGVA debit reduction above.* (page 23, emphasis added)

b) The Order EBRO-486-04 dated April 12, 1996 can be found at the link below:
http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/478761/view/EBRO%20486.PDF

c) Here are several cases. We have not made an exhaustive search.

ATCO Gas South

Alberta Energy and Utilities Board (now Alberta Utilities Commission) Decision 2001-110 (2001)

The AEUB determined that ATCO Gas South (AGS) had operated its Carbon storage facility in a rigid manner that differed from the flexible way utilized in previous years and in a fashion that was not in the best interest of its customers:

> *AGS operated Carbon in a significantly different manner during the 2000/2001 winter period than in previous periods. Exhibit 54 shows that in all previous winters since 1995/1996, there was considerable variation in the quantity of gas being withdrawn on a daily basis. In contrast, the exhibit also shows the basically flat pattern of withdrawal used by AGS during the 2000/2001 winter period.* (page 27)
>
> ***The Board finds AGS's actions to be inconsistent with respect to the utilization of the deliverability under its control.*** *The Board questions the prudence of designing and rigidly sticking to a withdrawal strategy with a maximum deliverability of 140 TJs per day, when AGS had the ability to use up to 300 TJs per day. The Board finds that AGS could have, and ought to have, maximized the value of the 'excess' deliverability by using it on days when prices were spiking or by selling the deliverability it did not intend to use (the difference between 300 TJs per day and the amount it planned to use each day).* ***The Board finds that the utility was not acting in the best interests of customers by having AGS retain deliverability that it did not use for even a single day during the entire winter period.*** (page 28, emphasis added)

And:

> *In the circumstances described above, the Board considers that* ***it would have been prudent for AGS to do one or more of the following****:*
>
> - *employ a decision making tool similar to that described by Mr. VanderSchee,*
> - ***continue to use its considerable experience to withdraw varying amounts of gas depending on market conditions, as it had done in the past, or***
> - *sell in advance the firm deliverability that it had determined not to use.*

Alternatively, AGS could have developed other strategies on its own to deal with the forecast high gas prices. ***The Board finds that by not using any of these options, AGS failed to exercise good judgement and discretion.*** *Based on forecast information available to AGS at the time it made its decisions regarding the use of storage for the 2000/2001 winter period,* ***it was not reasonable for AGS to rigidly adhere to a strategy based on flat daily withdrawals. The Board finds that AGS acted imprudently by not responding to the obvious fact that gas prices were increasing dramatically by utilizing its knowledge and experience to mitigate the higher cost of purchased gas by using storage.*** (page 29, emphasis added)

http://www.auc.ab.ca/applications/decisions/Decisions/2001/2001-110.pdf

Fitchburg Gas and Electric (d/b/a Unitil)

Massachusetts Department of Public Utilities 09-09 (2009)

The DPU disallowed portions of three gas purchases on the grounds that: (1) the utility had not sought pre-approval of its gas purchasing plans; and (2) that the spacing of each series of purchases was too close to mitigate price volatility and was, therefore, imprudent. On appeal, the Massachusetts Supreme Judicial Court reversed the DPU decision in part, but upheld one of the findings of imprudence.

Regarding the surviving part, the DPU's reasoning was:

For purchases made for the 2007/2008 peak period, the Company did not have any predetermined purchasing plan or written guidelines *and, instead, relied on the judgment of four energy traders in the Company's energy contracts department to determine the timing of the purchases as well as the amount of gas to be purchased every month [references omitted]. The Company secured 69.3 percent of its 2007/2008 peak period supply requirements, including price locks and storage, over only nine weeks in 2007 [references omitted] A nine-week purchasing period could not allow for a sufficient number of pricing points to smooth prices and, thus, mitigate price volatility [references omitted]. For the 2007/2008 peak period,* ***the Department finds that Unitil's decisions to make price-lock purchases (1) without a predetermined purchasing plan to be followed regardless of changes in market conditions, and (2) over a time period that was too short to effectively mitigate price volatility, were unreasonable and imprudent based on all the Company knew or***

> ***should have known at the time in light of the then-existing circumstances***. (page 42, emphasis added)

http://www.mass.gov/eea/docs/11209gasdpuord.pdf

http://www.ma-appellatecourts.org/display_docket.php?src=party&dno=SJ-2009-0606

Indiana Gas Inc.

Indiana Utility Regulatory Commission, Cause No. 37394-GCA68 (2000)

The IURC disallowed recovery of part of the gas purchase costs of Indiana Gas on the basis that the utility had not instituted proper methods of supply planning:

> *The record in this Cause shows that* ***IGC's gas commodity planning and procurement process is deficient in several areas****. First, the quartile system is really a single tool keyed to historic prices.* ***IGC recognized that strict adherence to the quartile system provides no meaningful price volatility protection*** *to customers during periods of sustained rising gas prices outside of the usual seasonal historical fluctuations. Thus, the tool upon which IGC predominately relied to mitigate exposure to gas price volatility is unable to adjust to the extreme volatility and price increases present in today's gas markets. The static, backward nature of the quartile tool requires that it be used in a broader planning and procurement process that better accounts for the dynamic nature of the natural gas market.* ***Evidence in the record fails to show that an adequate planning and procurement process was in place.*** (page 7, emphasis added)

The Order goes on to describe the actions that the utility took and found them inadequate:

> *The Commission does not believe that merely monitoring basic industry trade literature, discussing gas supply and prices with peers, and following the weather amounts to an additional method of gas planning and procurement. Hence,* ***while IGC recognized that its quartile system was inadequate and that another method was needed, it failed to devise an appropriate method****.* (page 8, emphasis added)

Further:

> *We are disturbed that IGC was not more concerned about the price risk mitigation for its customers, and that a more sophisticated process was not in place to ensure a thorough consideration and analysis of possible volatility mitigation measures.* ***We therefore find that Indiana Gas has failed to demonstrate that it was prudent to deviate from past diversification practices that incorporate a level of fixed priced contracts or other hedged gas purchases previously found by this Commission to be reasonable and therefore recoverable.*** *With regard to the quantity of gas IGC reasonably should have purchased on a fixed price or other hedged basis in accordance with the previously Commission-approved levels of diversification for the prior two heating seasons, we find that Indiana Gas has failed to sustain its burden of proof in demonstrating that it has made every reasonable effort to acquire long term gas supplies so as to provide gas to its retail customers at the lowest cost reasonably possible. For the remainder of gas, primarily swing supply, purchased by IGC we find that IGC has met its statutory obligation.* (page 10, emphasis added)

https://myweb.in.gov/IURC/eds/Modules/Ecms/Cases/Docketed_Cases/ViewDocument.aspx?DocID=0900b631800ed616

Michigan Consolidated Gas Company

Michigan Public Service Commission, Case No. U-14401-R (2007)

The Commission disallowed $7.6 million of purchased gas cost based on evidence that Michigan Consolidated improperly delayed the beginning of its dollar cost averaging (DCA) purchases. It stated:

> *The Commission is persuaded that* ***Mich Con's DCA purchase pattern in the spring of 2005 was unreasonable and imprudent****, and adopts the adjustment proposed by the Staff.*
>
> * * *
>
> *. . . As the Staff points out,* ***Mich Con should not have attempted a beat-the-market approach in its timing of DCA purchases, since this defeats the point of the DCA purchasing strategy.*** *The intent of the DCA purchasing strategy was known to Mich Con throughout the 90-day period in question. Under these circumstances, the Commission finds that Mich Con's market-driven decision to wait until the 90th day*

to make the first purchase was not reasonable and prudent. (Pages 9-10, emphasis added)

http://www.dleg.state.mi.us/mpsc/orders/gas/2007/u-14401-r_12-18-2007.pdf

Tab 7

2014

ANNUAL REPORT

Manitoba Public Insurance

RATE STABILIZATION RESERVE

The Corporation establishes and maintains a Rate Stabilization Reserve (RSR) to protect motorists from rate increases made necessary by unexpected losses arising from non-recurring events or factors.

The Corporation's Board of Directors current target for total equity (which includes Basic retained earnings and the Basic portion of Accumulated Other Comprehensive Income (AOCI)) is $213.0 million (2014 - $172.0 million for the retained earnings only target) based on the 2014 Basic Insurance Dynamic Capital Adequacy Test (DCAT) report. In his report, the Corporation's Chief Actuary concluded that a minimum total equity level of $213.0 million would be required for Basic to achieve a satisfactory future financial condition. A total equity level lower than $213.0 million would result in a "not satisfactory" opinion because there were plausible adverse scenarios identified where liabilities could exceed assets.

In 2010, the Corporation began using the maximum of the Public Utilities Board RSR target in its Public Utilities Board rate application for ratemaking purposes. The Public Utilities Board has established the Basic RSR target for rate-setting purposes based on 10.0 per cent to 20.0 per cent of written premiums. Twenty per cent of 2014 written premiums is $165.0 million.

INVESTMENTS

In accordance with Section 12(1) of *The Manitoba Public Insurance Corporation Act*, the Minister of Finance is responsible for the investments of the Corporation. The Minister has charged the Department of Finance with the operational management of the fund. The Corporation, through the Investment Committee of the Board, works collaboratively with the Department of Finance and makes recommendations to the Minister regarding appropriate policies and strategies to maximize return, minimize volatility and mitigate risk. For example, because the unpaid claims liabilities of the Corporation are inflation sensitive, investments that are inflation sensitive, such as real estate and infrastructure, are included in the portfolio. The Investment Committee has completed asset liability management studies to ensure that the asset mix chosen is compatible with the Corporation's liability profile. A complete description of these risks and risk mitigation strategies is outlined in Note 28 of the 2014/15 audited financial statements located on the Corporation's website mpi.mb.ca.

CLAIMS CONTROL STRATEGIES

Our cost-control measures with respect to claims management include:

» Management of an accreditation program for the collision repair industry to ensure high-quality, safe repairs at a reasonable cost. This requires shops and the technicians within shops to meet standards for facilities, equipment and annual training of technicians.

» Delivery of high-quality training programs to the collision repair industry to ensure repairs are performed by highly trained technicians to high standards using current technologies.

» Use of estimating compliance software to ensure all repair estimates are prepared accurately and consistently, ensuring that only required repairs are performed.

» Use of industry-recognized valuation tools to determine actual cash value of vehicles when settling total loss claims.

» Use of aftermarket and recycled parts in vehicle repairs.

» Discounted pricing on glass parts used in vehicle repairs.

» Ensuring collection of claims costs from other insurers and at-fault parties (subrogation).

» Sale of autos through salvage and tenders.

» A team-based approach to managing bodily injury claims intended to assist individuals in achieving as full a recovery as possible.

Each year, these initiatives create significant savings that are directly passed on to customers in the form of lower insurance premiums. For example, salvage auto sales and tenders resulted in savings of almost $33.7 million.

INFORMATION TECHNOLOGY PROCESSES

Information Technology Optimization

The Corporation depends on highly integrated, quality systems to serve customers and fulfill its legislated mandate. It is imperative that we continue to ensure that the Corporation's systems infrastructure is operating in the most effective and efficient manner. Applications and supporting infrastructure must be current and well-supported.

With respect to protecting our ongoing ability to serve customers, we are adopting processes and protocols to ensure "business continuity" in place of the previous approach of "disaster recovery" and continue working to improve our capacity in this area. Through Data Centre Optimization, we are creating an environment of "high availability" where backup systems continue to operate using current information from a second site in the event of a disaster or other business interruption, thus providing better customer service from more highly reliable and available systems.

Business Continuity

The objective of our Business Continuity Management Program (BCMP) is to create corporate plans and responses that ensure continued customer service in the event of a business disruption. BCMP includes emergency response, crisis management, business recovery, IT service continuity, catastrophe, contingency and pandemic responses, and the processes used to ensure ongoing readiness. The program is focused on creating and implementing a Corporate Business Continuity Plan through a strong understanding of our products and services, people, delivery processes and technology.

Business continuity includes planning, prevention, preparedness and a proactive program approach to crisis responses and business delivery. The practice of business continuity recognizes the need for continuity in contrast to recovery. This approach leverages the prevention and proactive aspects of business continuity that provide continuous service during business disruptions as opposed to suspension and recovery.

MANITOBA	Order No. 99/07
THE PUBLIC UTILITIES BOARD ACT	July 27, 2007

Before: Graham Lane, CA, Chairman
Len Evans, LL.D., Member
Eric Jorgensen, Member

CENTRA GAS MANITOBA INC. 2007/08 AND 2008/09 GENERAL RATE APPLICATION AND OTHER MATTERS

particularly customers that carefully scrutinize their bills. Such customers may wonder why they are being rewarded for increasing their gas usage;

e. the argument that based on purely economic principles, an inverted rate schedule is not justified if marginal costs are not decidedly different than average embedded cost of gas -- the evidence adduced from this hearing indicates that such a difference does not exist; and

f. as RCM/TREE's witness noted, a natural gas inverted rate would risk fuel-switching to electric heating and appliances.

In short, the Board is not prepared to direct inverted rates be established ahead of broader public recognition and understanding of environmental issues and the implementation of a coherent overall approach to reduce environmental damage and enhance conservation.

In the interim, the Board anticipates that aggressive low-income DSM has the prospect of developing large overall reductions in GHG emissions while conserving natural gas and bringing down the bills of low-income households – a potential win/win/win result.

Decoupling

The Board considered two options given the disparate opinions of Centra and RCM/TREE with respect to potentially amending rate setting to include weather decoupling:

i) Direct Centra to create a decoupling mechanism to adjust distribution rates to result in more stable, weather-independent revenue from customers; or

ii) Accept the status quo, no weather decoupling mechanism

The Board finds merit in the decoupling principle proposed by RCM/TREE's witness Mr. Weiss, in that it reduces the risk that Centra would over or under collect its revenue requirement over a period of time. A non-gas deferral account could be established to function in a similar fashion to the gas cost deferral accounts currently in use. The magnitude of over- or under collections due to weather fluctuation was indicated to range from an under collection of $7.5 million to an over collection of $12 million in any one year.

Centra's position was that its Cost of Service methodology for determining revenue requirement adequately addresses over- and under collections, in that "weather-induced fluctuations in revenue will be recovered over time" and short-term reductions in retained earnings due to weather are not a sufficient cause to bring a rate application.

Yet, the recent experience of 2005/06 when Centra experienced an operating loss of $5 million when it had forecast a weather-normalized Net Income of $2.5 million, a negative swing of $7.5 million equivalent to 2 and ½ years of allowable Net Income could easily be repeated. The risk of experiencing such scenarios in back-to-back years, which is a distinct possibility, is of some concern to the Board.

However, the Board is wary of adding additional regulatory burden, and the monthly rate amendments required for decoupling would be onerous and possibly confusing to customers. With over 50% of Centra's customers enrolled in the equal monthly payment plan, the benefits for the consumer appear less than stellar for the extra costs and confusion that would result.

By the testimony of its witnesses, Centra indicated that there are several methods for employing a decoupling mechanism, all of which it viewed as being onerous. Accordingly, the Board will not direct the implementation of a rate decoupling mechanism. Centra is to maintain the status quo and continue with the prescribed methodology for setting its revenue requirement, and, ultimately, rates.

Tab 8

M A N I T O B A	Order No. 128/09
THE PUBLIC UTILITIES BOARD ACT	September 16, 2009

BEFORE: Graham Lane, CA, Chairman
Len Evans, LL.D., Member
Monica Girouard, Member

CENTRA GAS MANITOBA INC. 2009/10 AND 2010/11 GENERAL RATE APPLICATION AND OTHER MATTERS

At that time, PUB will expect Centra to provide an opinion on the sufficiency of its then-level of retained earnings, presumably a time in which the implications of IFRS will be known.

Corporate Allocation & Net Income

MH acquired Centra in 1999 for $253.8 million, funding the acquisition by debt, purchasing Centra's business and assets, assuming its liabilities, and recognizing goodwill, asset write-ups, and acquisition and integration costs. In Order 118/03, the Board discussed the source of funds available to MH from Centra to fund the acquisition, and stated:

> *The Board believes the no-harm principle is paramount, and that both Centra and MH ratepayers should, to the extent possible, be held harmless as a result of the decision by MH to acquire Centra. The Board also recognizes that since MH initiated the transaction, it should bear some risk relative to the transaction, particularly since MH's size relative to Centra makes it better able to manage any negative cost implications resulting from the acquisition.*

As articulated in that Order, prior to MH's acquisition, and during the period under the former private ownership, Centra produced average annual after tax profits of between $14 and $16 million. At that time, it was expected, and expectation supported by subsequent PUB Orders, that after taking into account the same level of return allowed to the former private owner and the expected savings to arise out of operational synergies, MH would acquire Centra without any negative rate implications for either the customers of Centra or MH.

At the 2005 GRA, Centra confirmed that approximately $19 million was required annually to amortize MH's 'costs' arising out of the acquisition, and that Centra's share of those costs was to be $12 million, with the other $7 million to be borne by MH.

Also at the 2005 GRA, a detailed assessment of whether Centra's customers had been harmed by MH's acquisition of ownership was undertaken. In part, this included an assessment of the savings reported to have accrued to Centra as a result of operating synergies with MH. The analysis and discussion also involved considering current O&A expenses and other revenue requirement items and the comparing of these results and forecasts with the levels prior to the date of acquisition.

Estimates of avoided costs and synergy savings were extensively examined and tested. Centra provided specific examples of savings arising out of the acquisition and later integration of Centra operating functions and staff into MH, citing in particular reductions in executive costs, steps to make construction initiatives more productive, and income tax savings as Centra is now income tax exempt.

By Order 103/05, the Board agreed with the contention that synergies had been realized, and approved both an annual Corporate Allocation of $12 million, to be paid by Centra annually to MH, and allowed annual Net Income of $3 million to be also reflected in rates. Considering the allowable annual Net Income of $3 million, though not to be actually paid out as a dividend to MH, and the approved Corporate Allocation of $12 million, to be paid to MH, the Board concluded that MH's ownership would be allowed to realize $15 million each year from Centra's operations, although only $12 million would be paid to MH.

This $15 million of overall return to MH is consistent with the annual net income range allowed to Centra's former private owner, just as contemplated by Board Order 118/03.

At the past GRA the Board reaffirmed that position in Order 99/07 stating:

> *The Board had also stated in Order 103/05 the return to MH as determined under Rate Base Rate of Return is to be the absolute limit for shareholder returns. That return may take the form of an annual Corporate Allocation by MH against Centra and/or Centra's annual net income result. The Board further clarifies its position relative to testing the reasonableness of the net income limit. In assessing the reasonableness the Board also considers the no harm principle to be paramount and*

> *that a total return of $14-16 million contemplated at the time of MH's acquisition of Centra currently remains appropriate to ensure neither Centra nor MH customers are negatively impacted from the transaction.*
>
> *The Board continues to accept the annual Corporate Allocation of $12 million, the premise that synergies have been sufficient to uphold the "no harm" principle and that, as now to be reviewed, an annual Net Income of $3 million does not represent an unwarranted return on investment for MH.*

Centra sought a Corporate Allocation of $12 million and a net income of $3 million for each test year (fiscal years 2007/08 and 2008/09). In the recent proceeding, Centra sought the allowance in rates of the continuing annual Corporate Allowance of $12 million, but revised its allowable Net Income to $2.9 million for 2009/10 and $2.8 million in 2010/11 (both weather normalized, and slightly below what PUB has allowed to be reflected in rates).

Board Findings - Corporate Allocation & Net Income

CAC/MSOS proposes that the allowed return to MH be limited by the employment of the Rate Base Rate of Return model, holding that under that model the calculated allowable return on equity would be between $10.5 million and $13.5 million (for the period 2003/04 to 2008/09), rather than the overall $15 million, weather normalized, allowed to be reflected in prospective rates by PUB.

CAC/MSOS' calculation of the allowable annual maximum return to MH has been significantly affected by the much lower interest rates that have prevailed since the 1999 acquisition by MH. The Board also notes that the formula for establishing the rate of return ignores the much larger spreads between Government of Canada bonds and privately issued bonds that have also developed over the period, and observes that a major national debate is now underway as to the appropriateness of the extant NEB formula.

23. Changes to the Terms and Conditions of Service and final approval of interim order 102/08 relating to Service Disconnection and Reconnection Policies and Procedures BE AND IS HEREBY APPROVED;

24. Centra file revised calculations and schedules for Rate Base, Revenue Requirement, rates, and customer class bill impacts that reflect all of the Directives of this Order;

25. Centra provide all customers with bill inserts explaining the effects of this Order, the bill inserts to be pre-approved by the Public Utilities Board prior to being distributed, and Centra reference the Board's Order and website in Centra's press release and web postings related to this Order; and

26. If and when Centra becomes aware of any material change in its financial circumstances, including but not limited to significant changes to accounting, gas supply, or operations, Centra must inform the Board of the change and the resulting impact or anticipated impact on Centra's financial position.

THE PUBLIC UTILITIES BOARD

"GRAHAM LANE, CA"
Chairman

"GERRY GAUDREAU, CMA"
Secretary

Certified a true copy of Order No. 128/09 issued by the Public Utilities Board

Secretary

M A N I T O B A | **Order No. 112/12**

THE PUBLIC UTILITIES BOARD ACT

August 23, 2012

BEFORE: Régis Gosselin, CGA, MBA, Chair
Raymond Lafond, B.A., C.M.A., F.C.A.

A FINAL ORDER WITH RESPECT TO
CENTRA GAS MANITOBA INC.'S
TRANSPORTATION & STORAGE PORTFOLIO APPLICATION
TO THE PUBLIC UTILITIES BOARD

rights as primarily ensuring capacity at the expiry of its contractual relationship rather than securing favourable pricing.

3.5.0 Impact of TCPL Tolls

TCPL tolls have increased significantly in recent years, as TCPL has faced fixed costs that must be recovered from decreasing throughput volumes. Centra advised the PUB that, from 2007 to 2011, the TCPL toll from Empress to the Eastern Zone rose from $1.03/GJ to $2.24/GJ; the toll to the Manitoba Delivery Area is approximately one third of the Eastern Zone Toll. These tolls were based on a settlement agreement reached between TCPL and the shippers on the Mainline that was in effect for 2007 through 2011. The settlement agreement originally contemplated Eastern Zone Tolls in the range of $1.03/GJ to $1.06/GJ by 2011, based on throughput forecasts made at the time the settlement agreement was approved by the NEB, and considerably less than the toll eventually approved for 2011. The interim approved Eastern Zone Toll for 2012 is also $2.24/GJ.

The reasons for the reduced throughput on the TCPL Mainline are related to the development of previously uneconomic gas resources closer to the eastern load centres which therefore do not require long haul transportation on the Mainline, as well as new competing pipelines, such as the Rockies Express in the United States, that bring alternative (to WCSB) supplies of gas to Eastern markets. These alternatives to WCSB gas transported on the Mainline have resulted in reduced long haul contracting on the Mainline. As the long haul contracts have decreased, the tolls needed by TCPL to recover its fixed costs have increased. This has created an iterative dilemma, whereby increasing tolls reduces the long haul contracted volumes, which in turn increases tolls further to recover the same fixed costs.

TCPL is currently proposing a restructuring to the NEB, part of which includes a reduction to the tolls from current levels. Centra is intervening in that proceeding and advised that it is likely that tolls based on the restructuring will be at least 30% higher

National Energy Board
Office national de l'énergie

Reasons for Decision

TransCanada PipeLines Limited, NOVA Gas Transmission Ltd., and Foothills Pipe Lines Ltd.

RH-003-2011

March 2013

Tolls and Tariff

Canada

agreement for transportation services on Trans Québec and Maritimes Pipeline Inc.'s (TQM) pipeline system. We view the ASE as inappropriate cost shifting among affiliate companies that is contrary to sound tolling principles, such as the principle of "no acquired rights or obligations," which we believe must be upheld. In our opinion, shippers' costs and benefits do not extend beyond a contract under which service was requested and made available. The ASE violates this principle and, accordingly, cannot produce tolls that are just and reasonable.

Multi-Year Fixed Tolls

We believe that multi-year fixed tolls will better enable the Mainline to address the current challenges imposed on it by the business environment in which it operates. Given the increase in throughput that is forecast, averaging the FT toll over a multi-year period lowers the FT toll immediately and better allows the Mainline to compete.

Multi-year fixed tolls provide toll certainty and stability for shippers. Shippers noted it was difficult to make contracting and investment decisions without knowing how much it would cost to transport on the Mainline. Multi-year fixed tolls provide a competitive advantage over the Status Quo and over the elements of the Restructuring Proposal that we have approved.

Greater Pricing Discretion

The current pricing methodology for IT and STFT is not appropriate. Shippers using IT or STFT to meet a firm operating requirement do not contribute sufficiently to the Mainline's fixed costs. For example, shippers are increasingly able to meet their peak requirements for gas by contracting for STFT for a short term (for as little as one week), often paying only 110 per cent of the corresponding FT toll for that term. This provides shippers the assurance that they will receive service when they need it, but pay only a fraction of the full year's cost of having the Mainline's capacity available to them.

The pricing discretion proposed by TransCanada under the Restructuring Proposal did not go far enough. In our view, conferring greater discretion on TransCanada to set bid floors for IT and STFT service will provide TransCanada the opportunity to recover the costs of its capacity, during the period of time in which its capacity is used, from those who use it.

TransCanada will have to assess how to price IT and STFT. Optimizing billing determinants and maximizing net revenues on the Mainline, while mitigating the threat of bypass, requires TransCanada to exercise judgment about how much it charges. TransCanada is accountable for how it exercises its discretion and is encouraged by the new incentive mechanism to make decisions that result in the greatest Mainline net revenue, which in the long-run will benefit shippers who require Mainline service.

A Streamlined Regulatory Process

The North American natural gas market has changed and is continuing to change. We understand that the Mainline may need to develop new products and services to respond to market changes. In our view, the current process for approving changes to Mainline products and services can be

Chapter 8

Mainline Services and Pricing Proposals

8.1 Flexible Pricing of IT and STFT

TransCanada has traditionally constructed Mainline facilities only when those facilities are supported by long-term contracts for firm service. When those facilities are used at a high load factor, any remaining available capacity – caused by ambient-related conditions or contracted but unused firm capacity – is marginal. TransCanada offers two short-term services that take advantage of its available capacity: IT and STFT. When Mainline facilities are used at low load factors, there is abundant capacity and IT and STFT service may offer greater value to shippers compared to FT service because of the lower level of commitment required.

STFT service does not require the minimum one-year commitment from shippers that is required for FT service. STFT service is available for a term between seven days and one year less a day. It is not subject to curtailment or interruption, except in exceptional circumstances. In return, shippers must pay TransCanada for the transportation service purchased during the term of the contract irrespective of whether they use the Mainline to transport gas.

IT service does not require shippers to commit to transport a volume of gas, or to pay TransCanada if that volume is not transported, as is the case for FT service. IT service is subject to curtailment or interruption if higher priority service, such as FT service or STFT service, requires Mainline capacity. In essence, a shipper using IT service is not reserving any capacity on the Mainline to transport its gas.

A detailed history of the attributes and pricing of IT service and STFT service can be found in the Board's RH-1-99 Decision.[53] The pricing regime for IT service, or its predecessor services, has changed as the load factor on the Mainline has changed. For example, pricing for IT service (including its predecessors) has varied from the incremental cost of providing that service[54] to a (theoretically) unlimited amount.[55] STFT service was approved by the Board in its RH-4-93 Decision.[56] Pricing for that service has varied from being the same as the FT rate to a (theoretically) unlimited amount.

Currently, IT service and STFT service are offered through an auction process, with set minimum floor prices and a bidding mechanism that allocates the capacity to the highest bidder. Under the Mainline's current tariff, the IT bid floor is currently fixed at 110 per cent of the applicable FT toll for all paths and all periods, and the STFT bid floor is currently fixed at 100 per cent of the corresponding FT toll. There is no cap on the amount that may be bid for IT and STFT.

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53 National Energy Board, RH-1-99, Reasons for Decision, TransCanada PipeLines Limited, Tariff, April 2000.

54 National Energy Board, RH-1-78, Reasons for Decision, TransCanada PipeLines Limited, Rates, July 1978; National Energy Board, RH-2-83, TransCanada PipeLines Limited, Tolls, July 1982.

55 National Energy Board, RH-4-91, Reasons for Decision, TransCanada PipeLines Limited, Tolls, March 1992; RH-1-2002.

56 National Energy Board, RH-4-93, Reasons for Decision, TransCanada PipeLines Limited, Tolls, June 1994.

Views of TransCanada

TransCanada sought approval to have flexibility, on any path at any time of year, to:

- increase the bid floor for IT as high as 160 per cent of the corresponding FT toll;
- increase the bid floor as high as 140 per cent of the corresponding FT toll for Seasonal STFT, 150 per cent for Monthly STFT, and 160 per cent for Weekly STFT; and
- set the IT and STFT bid floors to as low as 100 per cent of the FT toll.

TransCanada submitted that different paths are valued differently in the market and the value of any path may change over time. The current system-wide fixed bid floor approach neither recognizes this diversity nor provides any ability for TransCanada to respond to these changes in value. TransCanada sought the flexibility to better optimize throughput and revenues on the system which would benefit shippers through lower FT tolls overall.

TransCanada submitted that, given the current level of system utilization, the current tolls for discretionary services provide little incentive to use FT service. TransCanada is not able to capture increased discretionary revenue to lower tolls for the benefit of FT shippers, and there is greater toll instability due to difficulty in projecting short-term contracting and throughput. According to TransCanada, it has a duty to innovate and pursue initiatives in order to remain economically viable. Enhanced pricing flexibility would help TransCanada achieve this objective.

TransCanada sought to preserve the value of FT service relative to discretionary services, reduce or reverse the migration from FT service to discretionary services, and increase discretionary revenue on a per-unit basis. Higher IT and STFT tolls during certain periods would reduce FT tolls from what they would be otherwise, and thus make the Mainline more competitive and less susceptible to bypass risk.

TransCanada submitted evidence that the market value for long-haul capacity on the Mainline between NIT and Dawn has exceeded 160 per cent of the underlying FT toll on numerous occasions since 2004. In addition, the market value for short-haul paths has also exceeded this level. However, as a result of uncontracted capacity on the system, shippers rarely bid above the current bid floors for STFT and IT services, even when the value of transportation exceeds the total transportation cost. TransCanada submitted the ability to establish the minimum bid floors at up to 160 per cent of the applicable FT toll for the shortest-term contracts would allow the Mainline to capture some of that benefit for firm shippers, while reasonably reflecting the value of the short-term services relative to FT service. TransCanada estimated this would result in increased annual revenue of $20 million to $80 million.

TransCanada stated its proposal was consistent with prior Board decisions regarding the need for flexibility in the pricing of short-term services to preserve the value of FT. According to TransCanada, the Board has approved tolls for IT and STFT that were between market value and incremental cost, and has recognized that, at times, the prices would be above the applicable FT toll.

TransCanada calculated that on a fully allocated cost basis, the proposed bid floors for IT and STFT service could be considered cost-based. The annual average load factor[57] for the twelve months ended October 2011 was 64 per cent for western Mainline short-haul IT flow and 63 per cent for eastern Mainline short-haul IT flow. Therefore, TransCanada's proposed IT bid floor of up to 160 per cent would recover no more than the equivalent fully allocated cost of these short-haul IT flows.[58] Long-haul IT flow for this same period had a much lower load factor, and thus the equivalent fully allocated cost for this service would be well above TransCanada's proposed IT bid floor of up to 160 per cent. TransCanada indicated that similar results on a fully allocated cost basis would occur for STFT service as well for this period.

Accordingly, TransCanada concluded that the proposed bid floors are consistent with, or lower than, the tolls that could be derived based on the fully allocated costs for these services. However, such tolls would not account for the inherent value in contracting flexibility of these short-term services. Therefore, TransCanada submitted that minimum bid floors above those proposed by TransCanada would also be reasonable.

TransCanada submitted that a higher bid floor range could provide additional flexibility and opportunity to optimize revenues; however, selling capacity at a market-clearing price below the FT toll, would be inconsistent with the objective of preserving the value and promoting contracting of long-term firm services. TransCanada insisted that it would not be in the Mainline's competitive interest to maintain prices for short-term services at unsustainable levels throughout the year, as this would exacerbate the existing tolling situation.

TransCanada indicated that in the U.S., the FERC has permitted very broad flexibility in pipelines offering negotiated rate alternatives to the cost-based service as long as there is a cost-based recourse rate. Negotiated rates may be higher than the recourse cost-based FT rates because there is another feature that the shipper finds attractive. However, the presence of the recourse rates constrains the pipeline's potential market power. TransCanada submitted that its discretionary pricing proposal is still cost-based, since the increase in bid floors is tied to the cost-based FT rate.

TransCanada submitted that it would have a powerful and over-riding incentive to optimize revenues by actively adjusting the bid floors for discretionary services. Doing so would help to keep FT tolls as low as possible and thus improve the long-term viability of TransCanada, and the probability that TransCanada would recover its investment in the Mainline.

TransCanada submitted that no party can guarantee the outcome of a proposed change, but that does not mean TransCanada should not take steps to improve the Mainline's competitiveness. Even if TransCanada's proposed pricing flexibility were not to increase FT contracting, it would provide the opportunity to generate additional discretionary revenue that would lower FT tolls and make the Mainline more competitive. According to TransCanada, this would result in the

[57] The average annual load factor is the ratio of the average load throughout the year compared to the maximum load on the system during the year. For example, an annual load factor of 60 per cent means that if 100 units of capacity were used during the peak day, an average of 60 units were used to provide that service over the course of the year. Conversely, the capacity would not have been used 40 per cent of the time, on average.

[58] Paying $1.60/GJ for 63 per cent of the year equates to approximately the same amount as paying $1.00/GJ for 100 per cent of the year, because $1.60/GJ multiplied by 0.63 equals $1.008/GJ and $1.00/GJ multiplied by 1.0 equals $1.000.

Mainline retaining its existing FT contracting by minimizing the threats of de-contracting and bypass.

TransCanada asserted that posting the applicable bid floors for each path, as detailed in the Application, would ensure that all shippers have transparent access to IT and STFT services. TransCanada also proposed to continue posting information related to successful IT and STFT bids, as is currently done. TransCanada submitted that its current posting requirements were the result of customer consultation that attempted to balance transparency of bidding results with the requirement for customer confidentiality of commercially sensitive information. TransCanada indicated that it would be prepared to consider the posting of additional information to the extent that such disclosure reflects a stakeholder consensus and addresses concerns of confidentiality, relevance and reasonableness, and does not negatively impact the Mainline's ability to optimize discretionary revenue.

Views of Intervenors

Several parties were opposed to TransCanada's discretionary pricing proposal.

MAS submitted that TransCanada failed to provide sufficient evidence to demonstrate that the proposed changes would improve the long-term sustainability of the Mainline.

Centra submitted that the lack of information and protocol around the proposed flexibility introduced uncertainty and left Centra with the inability to properly plan its operations with regard to the use of these services. Centra argued the proposed flexibility violates section 62 of the NEB Act whereby the resulting tolls would not be just and reasonable. In Centra's opinion, TransCanada's ability to charge higher rates based on delivery points where customers are considered captive could violate section 67 of the NEB Act, which prohibits a company from making any "unjust discrimination in tolls, service or facilities against any person or locality". Centra further argued the manner in which TransCanada will assess the maximum price for the discretionary services is contrary to section 60 of the NEB Act, since the toll will not be "specified in a tariff that has been filed with the Board and is in effect, or approved by an order of the Board". In Centra's view, setting the rate in this fashion is not transparent, encourages TransCanada to be arbitrary and leaves room for error that will be difficult to review, even on a retrospective basis. Centra submitted if the Board were to approve the proposed flexibility, it will have refrained from regulating an important component of TransCanada's service.

Tenaska submitted that TransCanada's preoccupation with forcing shippers to contract for one-year firm service is misconceived and very likely counterproductive in the current competitive environment. In doing so, Tenaska concluded that TransCanada is effectively refusing to compete in the market for short term transportation services and has put the Mainline at a competitive disadvantage.

Tenaska indicated a proper cost-based toll for short-term services would be the 100 per cent load factor FT toll. Tenaska submitted that, in principle, the tolls charged for all pipeline services should be cost-based, and therefore, the Mainline's short-term services should be priced at the FT level. Tenaska suggested that if the criterion for setting pipeline tolls at a just and reasonable level were that tolls reflect the value of pipeline services, there would be no point in regulating pipeline tolls. Customers would never pay more for a service than its value to them, so any toll a customer could be persuaded to pay would be just and reasonable on that analysis.

Tenaska submitted that higher tolls for discretionary services could lead to lower demand for Mainline service, higher demand for alternative pipelines, increased costs for captive customers, lower NIT prices, increased Mainline diversions, and eventually bypass of the Mainline. Tenaska indicated the flexibility to discount the IT and STFT floor prices would be entirely at TransCanada's discretion and it would generally have no financial incentive to reduce IT and STFT tolls. TransCanada would usually benefit from those tolls being as high as possible. According to Tenaska, there would be no reason to expect TransCanada to use the proposed pricing flexibility in most situations.

Other intervenors supported increased flexibility in the pricing of discretionary services, but had some concerns with TransCanada's proposal.

CAPP submitted that discretion would not be acceptable as proposed because of the lack of accountability. However, CAPP asserted its multi-year fixed Mainline tolls proposal would discipline the exercise of this discretion by TransCanada. Thus, with the incentives under CAPP's proposal, TransCanada would have a strong motivation to manage this discretion prudently and in a manner that is customer responsive. CAPP also suggested TransCanada should be able to price below the full FT toll level to attract volumes to the Mainline.

CAPP was also concerned with transparency and proposed that, if given pricing flexibility, TransCanada should make timely information available to all potential users of the discretionary services. CAPP stated such information would include the paths available for bidding, the minimum floor price by path, the individual bid prices by path without identifying the bidder, the winning bids by path without identifying the bidder, and the capacity awarded by path. This would, in CAPP's opinion, provide consistent information to all market participants, and further enhance accountability.

APPrO submitted that allowing market based tolls for STFT and IT would allow the Mainline to better maximize future system utilization.

IGUA submitted the magnitude of the under-utilized capacity is so significant that it allows discretionary shippers to contract for discretionary services knowing that they will rarely, if ever, be curtailed. This results in long-term firm and IT shippers receiving essentially identical transportation services but paying very different costs, since firm shippers pay demand charges 365 days of the year and IT shippers do not. This sends incorrect price signals to those discretionary shippers who are receiving a virtual firm service without fear of interruption.

ANE observed that TransCanada is transforming into a peaking pipeline and submitted this reflects a decline in the reliability benefits of FT service relative to IT service. In ANE's view without substantial pricing adjustments, IT service would further erode TransCanada's ability to optimize revenues. ANE submitted that broad pricing flexibility is needed to address the substantial concerns associated with excess capacity. ANE recommended the maximum bid floor for IT service be set at 300 per cent of the corresponding FT toll to bring FT tolls closer to the levels representative of a fully contracted system. The extra discretion would, according to ANE, allow TransCanada to capture the extra revenue that may be available in peak periods, when it may be able to price the service at levels that would exceed 160 per cent of the FT toll.

ANE submitted that FT shippers should commit to paying a full proportionate share of TransCanada's annual revenue requirement based on the contract quantity and associated distance of haul and any future toll adjustments attributable to variances in TransCanada's throughput or costs. STFT shippers should commit to paying fixed charges for 7 to 364 days of the year, on average, committing to less than 10 per cent of the commitments of FT shippers. ANE observed that IT shippers make the shortest and least commitment for the transportation service received as there is no commitment to pay any fixed charge for service or to make any future contribution to the costs of facilities relied upon to provide IT service.

According to ANE, the revenue consequences of failing to provide TransCanada with adequate pricing discretion for IT and STFT service would be significant. The consequences would not harm IT shippers that may pay more for service that entails no commitment, but would harm FT shippers that must pay all of the unrecovered costs of excess TransCanada capacity. ANE noted that IT shippers have the option of purchasing STFT service or FT service if either of these services better meet the shippers' needs for daily toll certainty.

ANE agreed that TransCanada had identified the proper factors to consider in applying the pricing discretion. However, ANE indicated it would be essential to provide a means of ensuring that shippers are protected against TransCanada setting a bid floor below 110 per cent in situations when it is not absolutely necessary. ANE stated that its proposed revenue incentive mechanism would provide such a safeguard.

ANE submitted that in the absence of an incentive mechanism, the Board could require TransCanada to report more regarding its performance in setting bid floors. In that case, ANE suggested TransCanada should retain information that it uses to set bid floors. For example, flow data on popular IT and STFT paths such as Empress to Emerson, and basis differentials, should be included in reports to the Board.

Views of the Board

Natural gas pipeline projects require significant upfront investment, which is usually underpinned by long-term contracts. It is generally expected that these costs will be recovered continually over the life of the pipeline. Accordingly, shippers who enter into firm contacts with a pipeline company are essentially agreeing to pay a share of the costs for the pipeline facilities over the term of the firm contract. Although firm shippers must pay for the transportation service regardless of whether they use the Mainline to transport gas, they have the benefit of requesting TransCanada build additional facilities or provide additional transportation services if increased capacity is needed.

In circumstances where a pipeline is well utilized with much of its capacity contracted for firm service, the annual costs of the pipeline are distributed among firm shippers. When spare capacity is available on the pipeline, over and above the capacity needed to meet firm shipping requirements, the pipeline can earn additional revenue by offering discretionary services such as IT or STFT and credit this revenue to the gross revenue requirement. The Board applied this rationale in deciding to approve the STFT service in its RH-4-93 decision. In this decision, the Board noted that TransCanada applied to implement STFT service "because it had small increments of excess capacity available for short periods of time."[59] In approving STFT service, the Board reasoned that STFT service would enable TransCanada to "increase revenues for the benefit of all firm shippers."[60]

Since firm contracts have priority in accessing pipeline capacity, in a high load factor environment, discretionary services may be prone to interruption making them unreliable and unattractive to shippers. In a low load factor environment, there is little incentive for shippers to contract for firm service if the FT toll is similar to the toll for discretionary services because shippers can obtain flexibility of using the pipeline without committing for an entire year.

In the current circumstances of underutilization, users of discretionary services receive virtually guaranteed service whenever they need it, but pay for only a portion of the annual costs of the capacity, making it difficult for TransCanada to recover the costs of that capacity. In our view, allowing TransCanada to charge higher rates for discretionary services will provide it with a better opportunity to recover the costs of that capacity from those who use it, during the period of time in which it is used.

IT and STFT Pricing and FT Recourse Rates

In this Decision, we have decided to go further than what TransCanada applied for in respect of pricing for IT and STFT service. TransCanada proposed that it be allowed to set bid floors for IT services as high as 160 per cent of the FT toll and bid floors for STFT services as high as 140 to 160 per cent of the FT toll, depending on the length of the term. We see fit to give TransCanada full discretion to determine the bid floors for IT and STFT services at any level with one exception. TransCanada will have the discretion to set bid floors for STFT only at 100 per cent of the corresponding FT rate or higher. It is up to TransCanada to determine bid floors that better maximize system revenues. This goes into effect on 1 July 2013.

We recognize that giving TransCanada the flexibility to increase and decrease bid floors may give it the opportunity to charge very high tolls in certain markets and at certain times, for example, during significant weather events. We are of the view, however, that it is important to provide TransCanada with the necessary tools to capture market opportunities, if and when they arise, and to recover costs associated with its system from those who use it. The vast majority of the revenue earned through discretionary services will be credited to reducing TSA balances.

[59] National Energy Board Reasons for Decision RH-4-93, TransCanada PipeLines Limited, Tolls (June 1994) at p. 57

[60] *Ibid*.

We are of the view that it is just and reasonable for shippers who need guaranteed access to the Mainline throughout the year to pay for the full annual costs related to the capacity they need. Shippers that truly require Mainline service can cap their exposure to discretionary tolls by opting to contract for FT service. In this way, FT tolls act as a recourse rate to protect shippers from high tolls for discretionary services.

In our view, the existence of a cost-based recourse rate, the FT toll, provides an implicit cap for discretionary shippers that need guaranteed access to the Mainline to meet their requirements. These shippers may elect to contract for FT service and pay the annual costs related to the capacity they need. Alternatively, they may find features of the IT and STFT services more attractive and accept the risk that at certain times of the year they may have to choose between paying high discretionary tolls or not using the Mainline.

Moreover, we are of the view that the ability of TransCanada to charge for discretionary services at whatever level will be constrained. All shippers purchasing FT service at recourse rates may resell capacity in the secondary market to mitigate demand charges. And, as indicated by ANE, it is unlikely there will be many days when TransCanada will be able to achieve pricing for IT and STFT service over a pricing level of 300 per cent for the FT toll.

For these reasons, and given the reporting requirements discussed below, we find that the tolls for IT and STFT service set pursuant to this Decision will be just and reasonable.

Pricing of IT and STFT is not Unjustly Discriminatory and Does Not Violate section 67 of the NEB Act

Centra contended that any move by TransCanada to charge higher rates based on delivery points where customers are considered captive could be a violation of section 67 of the NEB Act.

We find that it would not be unjustly discriminatory for TransCanada to raise the bid floor and charge higher rates for some delivery points, but not others. As we stated above, eliminating the cap on the minimum bid floor for IT and STFT service, subject to the floor for STFT not being lower than the FT toll, enables the Mainline to recover the cost of its capacity from shippers that use the Mainline to meet their requirements. In our view, it is not unjust that these shippers pay for that capacity.

Shippers can choose to purchase FT service at the cost-based recourse rates set by the Board. Alternately, there may be an advantage in using flexible discretionary services, such as an annual discount relative to the 365-day FT rate. TransCanada will set bid floors on each path based on numerous factors such as the availability of competitive alternatives in each locality. The Board expects that prices will be set differently in different localities because of different circumstances in each locality. Ultimately, the magnitude of tolls that can be charged is capped by the cost-based FT recourse rate. In our view, neither the ground for treating shippers of different localities differently, nor the potential magnitude of the differential treatment, constitutes unjust discrimination within the meaning of section 67 of the NEB Act.[61]

TransCanada's Discretion in Setting Bid Floors

As TransCanada exercises its discretion in setting bid floors, pipeline throughput may increase or decrease. There is no guarantee that the overall revenue will be higher, but having the flexibility to charge higher tolls for discretionary services provides the Mainline with the opportunity to generate greater revenue and recover the costs of its capacity from those who use it. Similarly, the flexibility to discount tolls gives the Mainline the opportunity to retain volume and attract incremental revenue. TransCanada must compete and it is TransCanada's responsibility to manage the pipeline. It will be imperative for TransCanada to carefully and effectively use its discretion in promoting the use of the pipeline.

Centra contended that if discretion was conferred upon TransCanada to set the minimum bid floor then it would not promote transparency, accountability in toll making and it also would allow for misjudgments. It is our opinion that the multi-year fixed tolls and net revenue incentive mechanism implemented in this Decision provide TransCanada with strong incentives to make appropriate decisions in how it prices IT and STFT. If TransCanada makes material misjudgments about how IT and STFT services are priced – for example, by pricing those services too high and encouraging bypass of the Mainline, or by pricing those services too low and missing out on revenue – then it will have larger deferrals of revenue than it otherwise would. Moreover, as we noted in Chapter 4 of this Decision, the Mainline faces fundamental risk. Material misjudgment in the pricing of IT and STFT services may result in that risk materializing and cost disallowances occurring, making TransCanada accountable for the effects of its business decisions.

As for transparency, we agree with Centra and others that transparency is important. Accordingly, to ensure transparency we direct TransCanada to post sufficient information including that outlined in its Application. This includes applicable bid floors for each path and information related to successful STFT and IT bids. During the hearing, TransCanada indicated it is prepared to consider the posting of additional information to the extent that such disclosure reflects a stakeholder consensus and addresses concerns of confidentiality, relevance and reasonableness, and does not negatively impact the Mainline's ability to optimize discretionary revenue. As suggested by CAPP, this could include the individual bid prices by path without identifying the bidder, the winning bids by path without identifying the bidder, and the capacity awarded by path.

We direct TransCanada to consult with stakeholders and file with the Board as part of the Compliance Filing for this Decision:

[61] In its argument, Centra also alleged that TransCanada's proposal for STFT and IT service pricing violated section 60 and 62 of the NEB Act. We did not address these arguments in this Decision because Centra did not explain how TransCanada's pricing proposal would contravene those sections.

- the information to be posted for shippers to ensure transparency in the way TransCanada sets bid floors; and
- the information to be contained in quarterly reports to the Board regarding TransCanada's management of bid floors.

Tolls for IT and STFT will be regulated on a complaint basis. Should any interested person be denied access to the recourse rates, the interested person may file a complaint with the Board.

Decision

The Board grants TransCanada full discretion to set bid floors for IT service and discretion to set bid floors for STFT service at 100 per cent of the FT toll or higher.

8.2 Minimum Term for STFT

Views of Intervenors

ANE proposed that the minimum term for STFT service be increased to five months to reflect the current and expected market circumstances on TransCanada. ANE contented that, in order to maintain its competitiveness, TransCanada must realize appropriate revenue levels from shippers requesting firm service. In ANE's view, a five-month commitment is reasonable in view of the substantial facility investments made by TransCanada to provide firm service.

ANE submitted that STFT offers shippers the ability to lock up firm capacity rights on TransCanada for a short period at a steep discount relative to the year-round costs of the service. Even though TransCanada has proposed to increase the maximum bid floor for STFT service, in ANE's view, the short commitment would still undercut TransCanada's firm revenue opportunities.

ANE suggested that allowing shippers to secure firm rights on TransCanada's system to meet peak needs without committing to paying for the costs of the associated facilities results in a revenue requirement shortfall. According to ANE, the existing regulatory framework has allowed TransCanada to pass on the unrecovered costs of its system to remaining firm customers and a substantial portion of the toll increases over recent years could be attributed to the revenue shortfalls caused by selling STFT service.

ANE indicated that even if TransCanada were able to increase the bid floor to 160 per cent of the corresponding FT toll for all STFT service with terms of less than one month, shippers would still be able to acquire service for seven days during the peak period at a 97 per cent discount compared to the annual costs of providing service. Reducing the discount from 98 per cent, as it is with current bid floors, to 97 per cent would have virtually no impact on curtailing the future migration of FT to STFT service.

M A N I T O B A	**Order No. 85/13**
THE PUBLIC UTILITIES BOARD ACT	**July 26, 2013**

Before: Régis Gosselin, C.G.A.., M.B.A., Chair
Marilyn Kapitany, B.Sc. Hon., M.Sc., Member,
Larry Soldier, Member

CENTRA GAS MANITOBA INC.
2013/14 GENERAL RATE APPLICATION
AND OTHER MATTERS

2.0.0 IT IS ORDERED:

1. That Centra's Application for an increase in general revenues effective August 1, 2013 **BE AND IS HEREBY APPROVED as varied by the following Directives:**

    (a) Centra shall include in its revenue requirement a net income of $3 million on an annualized basis as opposed to the $5.6 million applied for.

    (b) Centra shall adjust its 2013 interest rate forecast by removing the highest forecast interest rate in each quarter used in the determination of the interest rates for 2013/14 and incorporate this change in the revenue requirement.

    (c) Centra shall adjust its Finance Expense forecast for 2013/14 to reflect downward adjustments to interest rates applied to CG-10, of 20 basis points and downward adjustments to interest rates applied to CG-15 of 38 basis points.

    (d) Centra's revenue requirement is determined based on the level of Demand-Side Management spending as set out in Manitoba Hydro's 2011 Power Smart Plan of $19.3 million for 2013/14. To the extent Centra's spending on Demand-Side Management in the Test Year, including the Affordable Energy Fund and the Lower Income Energy Efficiency Program, falls below $19.3 million, Centra shall establish a deferral account for the discrepancy, the disposition of which the Board will consider at the next General Rate Application.

2. Centra to reduce the co-payment required of lower income customers for the Furnace Replacement Program to $9.50 for five years, and increase the grant provided to lower income customers for replacement of standard efficiency boilers to $3000.

3. That Centra file with the Board an International Financial Reporting Standards status update report prior to the next General Rate Application that will provide the Board with options available for rate-setting purposes.

4. That Centra file an update to its interest rate forecast for the Board's consideration when Centra files its rebuttal evidence during any future General Rate Application.

CAC supported Centra's selection of ConocoPhillips as the Primary Gas supplier. CAC was satisfied that Centra's purchase price at Empress under the new ConocoPhillips contract more accurately reflects the market price at Empress than Centra's previous contract, as the current one recognizes the value of natural gas liquid by-products included in the transported gas.

8.1.2 National Energy Board's TransCanada Pipelines Tolls Decision

Centra's single largest pipeline capacity expense is for Centra's firm capacity on the TransCanada Pipelines Mainline, which brings gas from Empress on the Alberta – Saskatchewan border to Manitoba. Since 2006, the tolls charged by TransCanada Pipelines have been escalating as TransCanada sought to recover its fixed costs to operate the pipeline from decreasing volumes of gas shipped through the Mainline. The decreasing volumes caused the unit tolls to increase. As the unit tolls increased, shippers on the Mainline further reduced their firm contracted capacity, further decreasing the volumes transported and increasing the unit tolls even more. The result was a 140% increase in the firm capacity toll between 2006 and 2012.

TransCanada Pipelines applied to the National Energy Board in 2011 to restructure its Mainline business and services and amend its Mainline tolls. The National Energy Board issued its Reasons For Decision on this matter on March 27, 2013. The principal decisions that impact Centra are:

- the reduction in the representative firm toll from $1.89/GJ to $1.42/GJ for a period of five years;
- the elimination of the Firm Transportation – Risk Alleviation Mechanism; and
- TransCanada Pipelines' ability to set the bid floors for Interruptible Transportation and Short Term Firm Transportation, where previously the bid floors were established at fixed premiums to the Firm Transportation toll;

The reduction in the Firm Transportation toll will lower Centra's fixed transportation costs effective July 1, 2013. Centra quantified the reduction in tolls paid to TransCanada Pipelines at $1.5 million for the remaining four months of the 2012/13 gas year (to October 31, 2013), and the full year toll reduction at $3 million.

The Firm Transportation – Risk Alleviation Mechanism was an attribute of the Firm Transportation contracts held by Centra. The elimination of the Risk Alleviation

Mechanism is expected to reduce the potential for earning Capacity Management revenues that offset Centra's gas costs.

Centra's other option to mitigate unutilized demand charges related to its TransCanada Pipelines firm capacity is through the Diversions mechanism. TransCanada Pipelines has proposed amendments to its tariffs that will restrict the utility of Diversions in reducing Centra's unutilized demand charges. The National Energy Board will hold a hearing into the tariff amendments in September 2013.

Centra was not able to estimate the magnitude of any expected additional costs resulting from the ability of TransCanada Pipelines to set the minimum bid floor for Interruptible Transportation or Short Term Firm Transportation. Centra expects that TransCanada will set the Short Term Firm Transportation bid floors at a level high enough to instead force Centra to use annual Firm Transportation resulting in higher gas costs.

Even though Centra is expecting a reduction in its Firm Transportation tolls, there is still uncertainty related to the Short Term Firm Transportation tolls starting in October of this gas year, the elimination of the Risk Alleviation Mechanism, and the potential restriction of diversions which could negatively impact the capacity management revenues earned by Centra to offset its total gas costs. Accordingly, Centra does not propose to update its gas cost forecast for the 2012/13 gas year. CAC supported Centra's decision, stating that it did not make sense to reduce the forecast and corresponding rates this year only to raise them next year. CAC recommended that the differences between the forecasted costs and actual costs be tracked in a Purchased Gas Variance Account which will be refunded to or collected from customers in a future period.

8.2.0 Board Findings

The Board has reviewed Centra's gas costs for the 2010/11 and 2011/12 gas years and finds them reasonable. The Board approves the 2010/11 gas costs of $251.3 million and the 2011/12 gas costs of $160.1 million.

The Board has provided the opportunity for the public and interveners to review the previous *ex parte* Primary Gas rate orders that were approved on an interim basis. No issues, concerns, or objections were raised by the public or any interveners, so the Board approves the following Orders on a final basis: 106/10, 20/11, 96/11, 150/11, 7/12, 89/12, 137/12, and 10/13. Order 40/13 related to the May 1, 2013 Primary Gas rate was released subsequent to the discovery phase of this proceeding and thus the public and interveners have not been afforded an opportunity to test the application and supporting data. Consequently, the Board will not provide final approval for this interim Order at this time.

The Board is satisfied with the Request For Proposal process undertaken by Centra to replace its Primary Gas supply contract last year. The Board finds that Centra selected the best proposal from those submitted, based on the scoring of the proposals according to criteria such as reliability, cost, creditworthiness, consistency with Centra's sustainable development goals, and meeting Centra's operational requirements. The scoring criteria were the same criteria used to select Centra's previous Primary Gas supply contract in 2009. The Board approves the gas cost consequences of the new Primary Gas supply contract with ConocoPhillips for the period November 1, 2012 to October 31, 2014.

On the surface, the National Energy Board's decision to fix and reduce the Firm Transportation tolls on the TransCanada Pipeline is positive for Centra and its Manitoba consumers. Centra's estimate of a $1.5 million net reduction in firm tolls in the remaining four months of the 2012/13 gas year, along with a $3 million reduction in annual firm tolls, is good news.

The Board is concerned however with the other aspects of the National Energy Board's decision that directly impact Centra. Elimination of the Risk Alleviation Mechanism and the proposed amendments to the Diversions mechanism will have a direct, negative financial impact on Centra and its ratepayers, as Centra's ability to mitigate its unutilized demand charges will be detrimentally affected.

The Board wishes to be apprised of the results and expected cost consequences of the National Energy Board's September hearing into TransCanada Pipelines' tariff matters and specifically any impacts on Capacity Management revenues. The Board requests that Centra provide an update to the Board once Centra has had time to assess the National Energy Board's order and estimate its impact on Centra's ratepayers. In order to reflect the impact in Centra's rates, the Board requires Centra to file an application to amend its Cost of Gas no later than January 31, 2014. Because of the uncertainty related to the Short Term Firm Transportation tolls in October of this gas year, the elimination of the Risk Alleviation Mechanism, and the potential restriction of Diversions, the Board will not require Centra to amend its forecast cost of gas for 2012/13. Any variances between Centra's current forecast and the actual costs will accrue and be tracked by Purchased Gas Variance Accounts. The variances will be refunded to or collected from customers following a subsequent Cost of Gas proceeding which the Board anticipates will occur next year.

In its upcoming deliberations of TransCanada's proposed tariff amendments, this Board asks the National Energy Board to consider the impacts on Manitoba consumers of potentially forcing Centra to contract for excess Firm Transportation capacity while eliminating the tools used by Centra to mitigate its unutilized demand charges associated with this excess capacity. The Board encourages Centra to intervene in these proceedings to represent the interests of Manitoba ratepayers.

8.3.0 Primary Gas Rate Application For August 1, 2013

Primary Gas rates are set on a quarterly basis in accordance with the Board-established Rate Setting Methodology. Quarterly approvals are provided on an interim basis and are finalized through either a General Rate Application or Cost of Gas Application proceeding.

Subsequent to the completion of the General Rate Application hearing, Centra filed an application for a revised Primary Gas rate to be effective August 1, 2013. The Board-approved Rate Setting Methodology determines a Primary Gas rate based on the forecast of natural gas prices and includes several factors that reflect the costs Centra incurs in providing Primary Gas to its customers.

Centra's Primary Gas rates are based on futures prices at the Alberta Energy Company ("AECO") trading hub in Alberta. Table 1 reflects the 12 month futures price strip for natural gas on July 2, 2013 and used in the calculation of the August 1, 2013 Primary Gas rate. The futures strip prices from January 2013 and April 2013 from previous quarterly rate applications are shown in Table 2. As can be seen when comparing the Tables, the August 2013 futures prices have decreased compared to the futures prices as of April 2013.

Table 1 - Alberta Energy Company (AECO) Futures Price (Cdn$/GJ)

	Aug/13	Sep/13	Oct/13	Nov/13	Dec/13	Jan/14	Feb/14	Mar/14	Apr/14	May/14	Jun/14	Jul/14
Jan Strip	3.1275	3.2950	3.3600	3.1275	3.2950	3.3600	-	-	-	-	-	-
Apr Strip	3.4075	3.415	3.4725	3.610	3.725	3.745	3.7425	3.720	3.460	-	-	-
Jul Strip	2.906	2.958	3.038	3.283	3.393	3.378	3.383	3.365	3.278	3.283	3.293	3.313

National Energy Board
Office national de l'énergie

LETTER DECISION

File OF-Tolls-Group1-T211-2011-04 03
10 October 2013

To: Parties to the RH-001-2013 Proceeding

TransCanada PipeLines Limited (TransCanada)
Application for Approval of Tariff Amendments (Tariff Amendment Application)
RH-001-2013 Decision with Reasons to Follow

On 17 June 2013, TransCanada filed the Tariff Amendment Application under Part I and Part IV of the *National Energy Board Act*[1] (NEB Act). In the Tariff Amendment Application, TransCanada sought National Energy Board (Board) approval to amend its Canadian Mainline Gas Transportation Tariff (Tariff) as follows:

- to modify provisions applicable to Diversions and Alternate Receipt Points (ARPs);
- to eliminate the overrun feature of Storage Transportation Service (STS);
- to eliminate provisions that establish requirements for the timing and duration of open seasons for Short-Term Firm Transportation (STFT) service and Short-Term Short Notice (ST-SN) service; and
- to modify renewal provisions for Firm Mainline Services.[2]

The Board set the Tariff Amendment Application down for an oral public hearing. A number of parties participated in the hearing and opposed the Tariff Amendment Application in whole or in part. The oral portion of the hearing, consisting of cross-examination and reply argument, took place in Calgary, Alberta in September 2013 over nine days.

The Board has decided to release its decision on the Tariff Amendment Application with reasons to follow. It is the Board's view that there is market uncertainty surrounding the terms and conditions of access to transportation services on the Mainline. Releasing the decision, in advance of the reasons, provides shippers with information that may affect their contracting decisions for the upcoming Gas Year.[3]

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[1] *National Energy Board Act*, R.S.C. 1985, c. N-7.
[2] In this letter and Appendix A, "Firm Mainline Service" or "Firm Mainline Services" refers to any one or more of the following services: Firm Transportation; Storage Transportation Service; Storage Transportation Service Linked, Firm Transportation - Short Notice; and Short Notice Balancing.
[3] In this letter, "Gas Year" refers to the annual period between 1 November of a year and 31 October of the following year.

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Filing Deadline

The Board directs TransCanada to file, pursuant to paragraph 60(1)(a) of the NEB Act, amendments to the Tariff to reflect this decision (the Filing).The Board directs TransCanada to make the Filing by **15 November 2013**.

Diversions and ARPs

The Board has decided to deny the proposed amendments to the Tariff in respect of alternate receipt points and diversions.

STS Overrun

The Board has decided to deny the proposed amendments to eliminate the overrun feature of STS service.

STFT and ST-SN Open Season Requirements

The Board has decided to maintain the current timing of the open seasons for STFT and ST-SN. However, the Board has decided to amend the Tariff provisions so that the minimum duration TransCanada is required to hold these open seasons is reduced to 48 hours.

Renewal Provisions

The Board has decided to amend renewal provisions for Firm Mainline Services to require contract holders to provide TransCanada with two years' notice of their intention to renew (instead of the six month renewal notice provision in existence prior to this decision), and to require a renewal term to be one or more full years (the Amended Renewal Provisions).

The Board directs TransCanada, as part of the Filing, to amend the Tariff to reflect the Amended Renewal Provisions. TransCanada may, as part of the Filing, amend the Tariff to give contract holders for Firm Mainline Services the choice to align their renewal terms with the Gas Year, provided that the renewal term exceeds one year.

Other aspects of the renewal provisions for Firm Mainline Services, for example, provisions prescribing the form and content of a renewal notice, and how that notice is to be provided to TransCanada, are unchanged by this decision. The Board rescinds the suspension of the renewal provisions set out in its 22 May 2013 letter.

Renewal Notice Transition Mechanism

The Amended Renewal Provisions are in effect immediately with one exception. The Board recognizes that many Existing Contracts[4] have terms of less than two years. It is impossible for these contract holders to provide TransCanada two years notice of their intention to renew the contracts. Applying the Amended Renewal Provisions immediately to these contracts would effectively make them non-renewable. Therefore, the Board has decided to establish the transition mechanism set out in Appendix A to this letter and apply that mechanism to the Existing Contracts as indicated in that Appendix.

[4] In this letter and Appendix A, "Existing Contracts" refers to contracts for Firm Mainline Services that are made on or before the date of this letter decision.

The transition mechanism is in effect immediately until 31 January 2014. The transition mechanism provides Firm Mainline Service contract holders with at least 90 days' notice to decide whether to renew their Existing Contracts and maintain the option of retaining their renewal rights. The Amended Renewal Provisions will come into effect on 1 February 2014 for the Existing Contracts set out in Appendix A.

Under the transition mechanism, a contract that is renewed for a total of two or more years will maintain renewal rights in accordance with the Amended Renewal Provisions. A contract holder may renew a contract for only one year, but the contract holder would not maintain renewal rights in accordance with the Amended Renewal Provisions. For greater clarity, as of 31 January 2014, contracts must have a termination date in 2016 or later to retain renewal rights.

Decision on Union Renewals

The Board's decision on Union's "expiring shipper evidence" was pronounced on the bench. It can be found at Transcript Volume 9, paragraphs 10128 to 10131.

Disposition

The foregoing constitutes our Decision in respect of TransCanada's Application for Approval of Tariff Amendments heard by the Board in the RH-001-2013 proceeding.

L. Mercier
Presiding Member

R.R. George
Member

J. Gauthier
Member

Calgary, Alberta
October 2013

Appendix A

Transition Mechanism

This Appendix applies to contracts for Firm Mainline Services that expire between 11 April 2014 and 31 December 2015 and sets notice and term requirements for renewing these contracts. Other aspects of the renewal provisions for Mainline Firm Services, for example, provisions prescribing the form and content of a renewal notice, and how that notice is to be provided to TransCanada, are unchanged by the transition mechanism.

STEP 1: Applicable to Existing Contracts that expire between 11 April 2014 and 30 July 2014, inclusive

A contract holder has the option of extending the term of its contract for a period of one or more full years, provided that the contract holder provides TransCanada six months' notice of its intention to renew the contract before the contract termination date. If the new termination date of the contract falls between the dates set out in Step 2, then the contact holder has an additional opportunity to extend the term of its contract in accordance with Step 2.

STEP 2: Applicable to Existing Contracts that expire between 31 July 2014 and 31 December 2015, inclusive

A contract holder has the option of extending the term of its contract for a period of one or more full years, provided that the contract holder provides TransCanada notice of its intention to extend the term of the contract by 31 January 2014.

National Energy Board

Office national de l'énergie

File OF-Tolls-Group1-T211-2011-04-03
25 November 2013

To: Parties to Hearing Order RH-001-2013

Hearing Order RH-001-2013
TransCanada PipeLines Limited (TransCanada)
Application for Approval of Tariff Amendments

This letter provides the reasons for our decision in respect of TransCanada's 17 June 2013 Application for Approval of Tariff Amendments (Tariff Amendment Application). We released our decision on 10 October 2013 and indicated that our reasons for decision would follow.

1. Background

TransCanada filed the Tariff Amendment Application following the release of the National Energy Board's (Board) RH-003-2011 Decision. Most of the proposals made in the Tariff Amendment Application were first made in TransCanada's 1 May 2013 application to review and vary the RH-003-2011 Decision (Review Application).[1] The Board dismissed the Review Application, but in doing so deemed part of the Review Application requesting variances to the Canadian Mainline Gas Transportation Tariff (Tariff) as a separate application made under Part IV of the Act and directed TransCanada to re-file that part of the Review Application and to make any amendments to it as TransCanada saw fit.

In the Tariff Amendment Application, TransCanada requested Board approval to amend the Tariff:

- to modify provisions applicable to diversions and Alternate Receipt Points (ARPs);
- to eliminate the overrun feature of Storage Transportation Service (STS);
- to eliminate provisions that establish requirements for the timing and duration of open seasons for Short-Term Firm Transportation (STFT) service and Short-Term Short Notice (ST-SN) service; and
- to modify renewal provisions for Firm Transportation Service (FT), STS, Storage Transportation Service Linked, Firm Transportation Short-Notice service (FT-SN) and Short-Notice Balancing.[2]

[1] TransCanada did not propose Tariff amendments that would give it discretion to decline contract renewals in the Review Application.
[2] In this letter, "Firm Mainline Services" refers to any one or more of the following services: FT, STS, Storage Transportation Service Linked, FT-SN and Short-Notice Balancing.

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We heard the Tariff Amendment Application pursuant to the streamlined procedure set out in the RH-003-2011 Decision, and modified the streamlined procedure to allow for cross-examination. A number of parties participated in the hearing and opposed the Tariff Amendment Application in whole or in part. The oral portion of the hearing, consisting of cross-examination and reply argument, took place in Calgary, Alberta over nine days in September 2013.

2. Issues

2.1 Diversions and ARPs

Diversions and ARPs are features of FT, Non-Renewable Firm Transportation (FT-NR), Multi-Year Fixed Price (MFP) and FT-SN contracts. Diversions currently can be nominated to delivery points that are either upstream or downstream of the contracted delivery point, but not upstream of the contracted receipt point. ARPs currently can be nominated from receipt points that are downstream of the contracted receipt point, but not downstream of the contracted delivery point.

A shipper who has a contract for FT, FT-NR, MFP and FT-SN can use diversions and ARPs as part of its nominations for transportation on the same day. Diversions and ARPs have a service priority above Interruptible Transportation (IT) service and, in certain circumstances, are available at the same firm priority level as STFT service. Generally, only diversions and ARPs that result in a greater distance of haul are subject to a toll, which is based on the difference between the FT toll of the longer nominated path and toll of the contracted path.

Views of TransCanada

In the Tariff Amendment Application, TransCanada requested that the Board approve modifications to the Tariff that changes the methodology used to determine eligible diversions and ARPs (the Diversion Proposal). Under the Diversion Proposal, ARPs and diversions would be permitted within a shippers' primary contracted path. The primary contracted path would be the same path determined by the methodology used to determine tolls.[3] As a result of the Diversion Proposal, a shipper could access alternative points through diversions and ARPs only on the primary path that reflects the paid toll. The list of eligible ARP and diversion points for applicable contract paths will be posted on TransCanada's website, and updated infrequently, such as to reflect new receipt or delivery points or changes in system configuration.

TransCanada's made clear that its proposed Tariff amendments, including the Diversion Proposal, were required to enable it to effectively utilize the tools provided by the Board's RH-003-2011 Decision, and to meet the objectives of the RH-003-2011 Decision to maximize net revenues over the multi-year fixed toll period. TransCanada submitted that it remains short or in the hole with respect to the balance in the Long-Term Adjustment Account (LTAA) and that denial of approval of its proposed Tariff amendments, including the Diversion Proposal, will seriously undermine its ability to meet the objectives of the RH-003-2011 Decision.

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[3] The current methodology used to determine all FT tolls is the shortest distance path from the applicable receipt point to the delivery point or load centre of the Distributor Delivery Area (DDA) using both the Mainline system as well as the Mainline's Transportation By Others arrangements on other pipelines.

TransCanada explained that the Diversion Proposal enhances the ability of the Mainline to generate revenues in two ways. First, it enhances TransCanada's ability to generate discretionary revenues because shippers wanting to access paths outside their contract path may purchase discretionary service from TransCanada. Second, FT revenues may increase because shippers will be encouraged to contract for the path over which they require firm service and, assuming the out-of-path diversion or ARP is longer than the contracted path, the corresponding FT toll will be higher. Using historical data,[4] TransCanada estimated that its revenue would increase $30 million to $40 million annually if the Diversion Proposal were adopted.

TransCanada contended that if the Diversion Proposal is not approved, shippers would have a significant incentive to contract for FT on short paths and change their receipt and/or delivery points outside of the contracted path (the short-path strategy). TransCanada stated that this short-path strategy allows shippers to circumvent the applicable IT and STFT pricing regime on the longer path and noted that, by accessing out-of-path diversions and ARPs, shippers receive a higher priority and possibly a lower toll than the toll they would be required to pay for IT service on that path. TransCanada contended that, in essence, these shippers have a valuable option for free, that is, the option for high priority, out-of-path service.

All else equal, TransCanada anticipated the Diversion Proposal would enhance the functioning of the secondary market[5] by aligning contracting incentives, and removing shippers' ability to implement the short-path strategy to the detriment of other shippers and TransCanada. TransCanada indicated that it seeks to maximize revenues from short-term services to provide a larger credit to the revenue requirement, reduce the Toll Stabilization Adjustment account (TSA) balance, and keep its future tolls as competitive as possible. In TransCanada's view, the Diversion Proposal enhances its ability to sell STFT and IT services in the secondary market by removing shippers' ability to circumvent the implementation of pricing flexibility for discretionary services.

TransCanada observed that the Diversion Proposal may or may not affect the liquidity in the secondary market. It submitted that the impact on liquidity will depend on a number of factors, including: (i) the paths for which shippers subscribe relative to the paths that are desired by others for STFT and/or IT, (ii) the periods for which those paths are desired and (iii) the amount of that contracted capacity to be sold by shippers in the secondary market. TransCanada suggested that the Diversion Proposal may increase liquidity if shippers lengthen their contract path and if shippers increase the use of within-path diversions and ARPs.

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[4] TransCanada emphasized that historical information may not necessarily be representative of how shippers may use out-of-path diversions and ARPs in the future. TransCanada explained that the expected increase in use of downstream diversions in future periods under the RH-003-2011 Decision, the revenue benefits of eliminating out-of-path diversions and ARPs could well exceed the $30 million to $40 million range.

[5] TransCanada defined the primary market as the market for the sale of non-discretionary services such as FT by TransCanada or other pipelines, and the secondary market as including TransCanada's and other pipelines' sale of discretionary services and shippers' sales of their unutilized capacity.

TransCanada stated that it does not believe that the Diversion Proposal would reduce the market constraints on its pricing of discretionary services. TransCanada stated the constraint on its pricing of discretionary services would continue because shippers would still have the ability to resell their capacity in the secondary market and to use in-path diversions and ARPs.

TransCanada suggested that if the Board were of the view that increased transparency in the secondary market would benefit customers, then all parties, not just TransCanada, should be subject to the same conditions and reporting requirements, such as posting prices for secondary market transactions.

TransCanada evaluated various alternatives to the Diversion Proposal canvassed by Board counsel and was of the view that some of the alternatives could be workable. TransCanada specifically suggested that the alternative scenario allowing shippers access to one liquid out-of-path point could be workable and feasible if it was modified to allow Ontario and Quebec shippers with out-of-path access to the Dawn hub, while shippers in Saskatchewan and Manitoba would have out-of-path access to the Emerson export point. Compared to the Diversion Proposal, this alternative scenario expands shippers' rights to use out-of-path diversions, and addresses shippers' concerns about having access to liquid pricing points and out-of-path storage, which helps mitigate Unutilized Demand Charges (UDCs).

Views of Intervenors

Association of Power Producers of Ontario (APPrO)

APPrO explained that Ontario's gas fired power generators would be very much, and materially detrimentally, affected by the Diversion Proposal. APPrO described how some of Ontario's gas fired power generators that are captive to TransCanada's Mainline are "peaking" facilities with a relatively low load profile, and that this profile increases their reliance on diversions to manage UDCs. APPrO stated that the "in path" diversion locations in the Diversion Proposal provide far less liquidity and value than the status quo.

APPrO argued that the Diversion Proposal is out of proportion with TransCanada's stated concerns, and inflicts significant collateral damage to shippers at large who contract for firm transportation for the path upon which they intend to ship. APPrO suggested that that because the Mainline operates as an "integrated system," it is contradictory and unjustifiable to preclude all shippers from accessing diversions to all Mainline facilities. APPrO illustrated how the Diversion Proposal results in shipper constraints that seem illogical in light of the integrated nature of the Mainline system and the significant contribution to TransCanada's facilities costs that most firm shippers are making. APPrO also explained that the Diversion Proposal's attempt to eliminate the short-path strategy, while perhaps eliminating some isolated occurrences, is overbroad, inequitable, unsupported by TransCanada's tolling rationale and discriminatory against some shippers.

Canadian Association of Petroleum Producers (CAPP)

CAPP supported maintaining the status quo on diversions and ARPs. CAPP referred to evidence showing that, since the issuance of the RH-003-2011 Decision, shippers are signing up for more firm service, including shippers with low load factors, which results in a need for shippers to have a reasonable means to mitigate UDCs. Without the ability to reasonably mitigate UDCs, CAPP suggested that this would increase the economic hurdle for all shippers in signing up for firm service.

CAPP explained that diversions and ARPs contribute to a robust secondary market. CAPP contended that evidence on TransCanada's current use of its pricing discretion has resulted in TransCanada effectively not offering short-term services on occasion. CAPP expressed concern that the Diversion Proposal would further reduce competition for short-term services, which is not aligned with the intention of the pricing discretion conferred on TransCanada in the RH-003-2011 Decision. CAPP further emphasized that maintaining the current policy on diversions and ARPs is necessary to support the new business model articulated in the RH-003-2011 Decision.

CAPP also argued that TransCanada has not shown that any increase in Mainline revenues as a result of the Diversion Proposal will be of greater benefit than the financial loss due to increased UDCs of some shippers. Rather, the opposite would occur, such that that the Diversion Proposal will harm shippers through unmitigated UDCs well in excess of the claimed gains of TransCanada.

Alberta Northeast Gas, Limited (ANE)

ANE expressed concern that the Diversion Proposal was inconsistent with the RH-003-2011 record because in that proceeding TransCanada had implied that out-of-path diversions and ARPs would remain in effect upon the elimination of the Risk Alleviation Mechanism (RAM). In ANE's view, nothing has changed since the Board's review in that proceeding and no experience is available to evaluate this issue now that RAM has been eliminated. Furthermore, ANE indicated that the Diversion Proposal could devalue FT service, making it less attractive to the market and thus reducing the likelihood of increasing FT contract levels.

ANE suggested that the determination of the appropriate level of FT flexibility is a matter of what is fair and reasonable between shippers and the Mainline. While RAM offered shippers far too much flexibility, the Diversion Proposal offers too little. ANE suggested that at least a few years of experience may be required to gain a reasonable understanding of the implications of the new RH-003-2011 framework.

BP Canada Energy Group ULC (BP)

BP submitted that the Diversion Proposal is inconsistent with the findings of the Board in the RH-003-2011 Decision and should be denied. BP submitted that the Diversion Proposal introduces an artificial determination of what is "in-path." As a result, BP argued that diversions would be severely proscribed and effectively half of the Mainline's delivery points would be unavailable for diversions, depending on the artificial path designated by TransCanada.

BP submitted that TransCanada put forward no evidence that the short-path strategy was actually taking place in material amounts since the RH-003-2011 Decision was implemented on 1 July 2013. BP contended that if the Diversion Proposal were implemented the harm that would occur to the secondary market would outweigh any benefit that may accrue to TransCanada in terms of incremental additional revenue. BP pointed out that TransCanada may not receive higher revenues if the Diversion Proposal were implemented. It pointed out that the market may not respond to the premiums TransCanada charges for discretionary services and therefore transactions may not happen.

BP evaluated various alternatives to the Diversion Proposal suggested by Board counsel and noted that there is no evidence to support the need to alter the existing Tariff provisions. It submitted that the best approach is to retain the RH-003-2011 structure. BP pointed out that neither the Board nor TransCanada should dictate market outcomes, such as setting out a liquid point where out-of-path diversions would be permitted, but should instead facilitate informed choice by buyers and sellers.

Overall, BP argued that the Diversion Proposal impairs shippers' ability to mitigate UDCs, unduly hinders competition on the system and erodes the value of the FT service. The end result would shift risk from TransCanada to its shippers, which BP submitted is contrary to the RH-003-2011 Decision. BP concluded that there is a lack of evidence on the current record that would justify the drastic action of altering fundamental terms of FT service, interfering in the secondary market, and limiting shippers' ability to mitigate UDCs. BP argued it would be more appropriate to deny the applied-for changes to diversions and to observe what happens in the market, and allow parties to have the certainty they need in order to meet their business needs while parties gets used to the new regime created by RH-003-2011.

Centra Gas Manitoba, Inc. (Centra)

Centra stated that out-of-path diversions are a basic reasonable means to mitigate UDCs. Centra explained that out-of-path diversions do not provide guaranteed access to a path. Centra further indicated that it experiences challenges executing diversions because, due to the nature of its load profile, it is unable to commit to a diversion transaction day-ahead at the timely nomination cycle or even same-day at the intra-day 1 nomination cycle. Instead, it often needs to wait until the intra-day 2 nomination cycle when Centra indicated the market for diversions can be very limited. With respect to the Diversion Proposal, Centra stated that there are limited or no opportunities to mitigate UDCs within-path on either its Empress to Manitoba Delivery Area or Empress to South Saskatchewan Delivery Area transportation paths.

Centra was of the view that the RH-003-2011 Decision did not suggest that FT shippers should no longer have access to basic UDC mitigation tools. Centra stated it values a robust and competitive secondary market, with numerous participants even though it is a long-term and captive shipper on the Mainline and therefore has a strong interest in minimizing its exposure to future cost deferrals. Overall, Centra's position is that the RH-003-2011 Decision appears to be working as envisioned and that it should be given time to continue to work. Centra did not support the alternate scenarios canvassed by Board counsel during the hearing.

Market Areas Shippers (MAS)[6]

MAS opposed the Diversion Proposal. MAS submitted that the RH-003-2011 Decision struck an appropriate balance between the Mainline and shippers. MAS were of the view that TransCanada's discretionary pricing tools currently are serving their desired purpose, based on the level of recent FT contracting and IT bid floors set by TransCanada.

MAS expressed concern that the Diversion Proposal will have a negative impact on all shippers, particularly captive shippers, who contract to meet peak demand and therefore have a need to mitigate UDCs because they have excess capacity during non-peak periods. MAS noted that the recent increase in firm contracting amplifies this concern. MAS explained that the Diversion Proposal would significantly limit the market's opportunity to mitigate UDCs. It noted that under the Diversion Proposal the most liquid and transparent trading points are excluded as diversion points for nearly all FT contracts.

MAS recognized TransCanada's concerns about the short-path strategy and suggested that the Tariff could be adjusted to address this concern. MAS recommended that the Board direct TransCanada to consult with the marketplace and develop more appropriate solutions for FT contracting on very short paths. For example, MAS proposed that any paths that are less than 24 kilometres in length would not be permitted diversion and ARP rights outside of the contracted path.

MAS contended that the Diversion Proposal will enable TransCanada to exert undue market power in the secondary market and reduce liquidity in the natural gas commodity market. MAS noted that the Diversion Proposal will reduce the transaction depth in the secondary market which in turn will limit the effectiveness of the secondary market to provide a restraint on TransCanada's ability to exercise its market power.

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[6] MAS consist of: Enbridge Gas Distribution Inc. (Enbridge), Société en commandite Gaz Métro Limitée (Gaz Métro), Union Gas Limited (Union) and Industrial Gas Users Association (IGUA).

Tenaska Marketing Canada, a division of TMV Corp. (Tenaska)

Tenaska objected to the Diversion Proposal. Tenaska submitted that the Diversion Proposal would make diversions essentially useless for mitigating UDCs for the vast majority of FT shippers. Tenaska submitted that in-path diversions are invariably inferior to out-of-path diversions for UDC mitigation, because the market value of transportation to upstream points was almost always less than the value of longer paths to downstream points. Furthermore, Tenaska noted, that under the Diversion Proposal, local distribution company (LDC) shippers would not have access to markets where their capacity might have value, such as at Emerson or Dawn.

Tenaska argued that TransCanada's submission that FT shippers could mitigate UDCs by contracting for IT or STFT service to transport gas to alternative markets is not feasible. Tenaska pointed out that under this approach TransCanada could prevent shippers from mitigating UDCs by pricing the necessary IT at a level that would make the transaction uneconomic.

Tenaska contended that eliminating out-of-path flexibility is fundamentally inconsistent with the Board's RH-003-2011 Decision. Tenaska argued that in the RH-003-2011 Decision, the Board indicated that it based its decision to deregulate IT and STFT pricing in part on its belief that TransCanada's prices will be constrained by competition from FT shippers selling capacity in the secondary market. Eliminating out-of-path diversions, in Tenaska's view, would reduce the amount of competition and this, in Tenaska's view, was ultimately the purpose of TransCanada's Diversion Proposal. Furthermore, Tenaska argued that TransCanada witnesses provided no quantitative evidence to underpin its conclusion that in-path diversions will be sufficiently effective to discipline TransCanada's pricing behaviour for IT and STFT services.

Tenaska proposed that the Board expand, rather than reduce the flexibility that FT shippers have to compete in the secondary market with TransCanada's IT and STFT services (the Tenaska Proposal). The Tenaska Proposal would require TransCanada to provide FT shippers with flexibility to nominate any available alternate path on the Mainline using alternate receipt and delivery points. Tenaska submitted that the Tenaska Proposal would give Mainline FT shippers the same receipt and delivery point flexibility available to firm shippers on United States (U.S.) pipelines. According to Tenaska, the commercial effect of the Tenaska Proposal would be to enable all FT shippers on the Mainline to compete with each other and with the pipeline's IT service on all paths.

In argument, Tenaska contended that out-of-path diversions were part of the RH-003-2011 model and were part of what made the RH-003-2011 tolls and tariff just and reasonable. Tenaska submitted that the Board's direction to TransCanada in the RH-003-2011 Decision to maximize revenues was not intended as an invitation to TransCanada to ask the Board for Tariff adjustments that will benefit the pipeline at the expense of shippers and the rest of the natural gas industry.

Tenaska noted that diversions are not ‘near-firm’ and, at certain times of the year, there is often zero diversion capacity available to some export points. Moreover, Tenaska pointed out that TransCanada has tools that enable it to compete with FT shippers and that TransCanada has in fact competed with FT shippers since the RH-003-2011 Decision was issued. Overall, Tenaska submitted that receipt and delivery point flexibility, including the Mainline's out-of-path downstream diversions, have been an integral part of open-access transportation services in Canada and the U.S. for 20 years. Receipt and delivery point flexibility is an essential element of the modern concept of gas transportation, and it is fundamental to the operation of gas commodity markets across the North American pipeline grid.

Tenaska submitted that none of the alternatives to the Diversion Proposal canvassed by Board counsel should be accepted because all would reduce competition and impair shippers’ abilities to mitigate UDCs. Tenaska also submitted that some of the alternative scenarios could be discriminatory to some shippers.

Union

Union, on behalf of MAS, argued that the RH-003-2011 model appeared to be working due to evidence of new FT contracting and renewals that became available in the course of the proceeding. Union noted that this new evidence showed that TransCanada’s fears of massive shortfalls were groundless. Union also noted while the TSA did not yet show a surplus, the analysis is of an inherently conservative nature. Union stated that it is premature to conclude that TransCanada has been denied a reasonable opportunity to recover its costs such that the Diversion Proposal is required to enable TransCanada to enhance its competitive position.

TransCanada’s Reply

TransCanada contended that the principal mechanism used to mitigate the exercise of its market power is shippers’ recourse to FT service. TransCanada observed that one of the market’s reactions to its pricing of IT and STFT has been to shift to FT and FT-NR contracts, and this recourse has proven to be a very effective alternative to the use of discretionary service.

TransCanada noted that its concern about the short-path strategy has increased since the issuance of the RH-003-2011 Decision. TransCanada noted that, historically, out-of-path diversions have been used on certain FT contracts almost every single day of the winter period; TransCanada expects this use to increase. TransCanada explained that retaining out-of-path access to alternative delivery and receipt points is inconsistent with the cost-based/user-pay principle, and has the potential to grow to the level of being a critical impediment to the effective use of its pricing discretion. TransCanada argued that there is no right to mitigation of demand charges, and that there is no reason why a shipper should have the right to reduce the effective amount they pay for contracted capacity through out-of-path diversions. TransCanada also suggested that intervenors misunderstand the Mainline’s tolling methodology. In TransCanada’s view, FT shippers pay for access between two points. This does not justify having access to a host of other diversion points for the equivalent daily FT cost of the incremental transportation only on the days a shipper wants to use those diversion points.

TransCanada submitted that deferring changes to the diversions and ARPs for one year would invite shippers to use the short-path strategy to its fullest potential for the next year and potentially beyond, increasing the TSA balance by tens of millions of dollars. TransCanada suggested that consciously allowing shippers to circumvent the pricing discretion on paths which the shipper has not elected as its primary path is an attempt to unwind the RH-003-2011 Decision.

TransCanada addressed concerns expressed by shippers about the Diversion Proposal's impact on the secondary market and the removal of constraints on TransCanada's market power. TransCanada indicated that the Diversion Proposal will not distort the secondary market because of the existence of the recourse FT rate, which caps the exposure of any shipper to the tolls for discretionary service, and thereby prevents TransCanada from exploiting its market position for the sale of its existing services. TransCanada also noted that it is likely that the amount of capacity and number of transactions in the secondary market will increase since numerous parties are "firming up" their capacity that can then be resold by shippers in the secondary market to compete against TransCanada's service offerings.

Responding to developments since the issuance of the RH-003-2011 Decision, TransCanada noted that the results from the implementation of that decision are encouraging, but that one should not be unduly influenced by just two and a half months of experience in a 54 month program. TransCanada noted that the RH-003-2011 Decision places it at risk from a cost recovery perspective and re-iterated its evidence that denial of its proposed Tariff amendments will seriously undermine its ability to meet the objectives of the RH-003-2011 Decision to maximize revenues and minimize costs.

Views of the Board

We are not persuaded by TransCanada's submissions that the Diversion Proposal is required to enable TransCanada to effectively use the tools provided in the RH-003-2011 Decision or that it is required to meet the objectives in the Decision to maximize net revenues. Our view is influenced by evidence that became available after the Tariff Amendment Application was filed that demonstrates that the tools provided in the Decision have enabled TransCanada to approach the threshold for sharing in incentive revenues and possibly zero the balance in the TSA in 2013 or 2014.[7]

[7] Union calculated that TransCanada must earn about $15 million in 2013 and $44 million in 2014, more than what TransCanada's current revenue calculations showed for these years to share in incentive revenues. In terms of zeroing the TSA, Union's calculations showed that TransCanada must earn about $53 million in additional revenue to zero the TSA balance in 2013. For 2014, TransCanada would be able to zero the balance in the TSA account if it earned additional revenues that amounted to the shortfall from 2013 plus $117 million. While these amounts may appear to be large, there is a substantial amount of conservatism embedded. In making its revenue calculations,

Moreover, while the Decision directs TransCanada to maximize net revenues over the fixed toll period and provides new tools to help do so, that direction was not unlimited. The ability of TransCanada to maximize net revenues was bounded in the Decision by, among other things, a multi-year fixed FT toll, a view that the secondary market could constrain TransCanada's ability to set the bid floor for IT and STFT pricing and a view that shippers, who may be incented to enter into contracts for firm transportation services at low load factors, would have a reasonable opportunity to mitigate UDCs.

With the incentive for TransCanada to maximize net revenues placed in its proper context, and with evidence demonstrating the effectiveness of the tools provided in the Decision thus far, we are not of the view that the Diversion Proposal is required to implement the Decision. Furthermore, we do not consider TransCanada's argument about remaining "short" or "in the hole" with regard to the LTAA to be relevant. The Decision expected TransCanada to have a certain LTAA balance at the end of 2017. To consider the LTAA balance in this proceeding, as a justification for changing Tariff provisions, is, in our view, inconsistent with the Decision. The Decision expressly contemplated and provided for the accumulation of an annual fixed amount in the LTAA and the slower return of capital to TransCanada through amortization of amounts therein.

We disagree with TransCanada's submission that the current impact of out-of-path diversions and ARPs is on par with the detrimental and distortionary impact of RAM. We observe that, unlike the circumstances preceding the RH-003-2011 Decision, shippers that require guaranteed access to the Mainline are largely contributing the full year's reasonable cost of the capacity they require by using firm transportation services to transport gas to markets where they have a firm requirement. This noticeable shift in contracting behaviour has helped inform our view that the Diversion Proposal is not necessary.

In considering whether modifications to the diversion provisions of the Tariff are currently required, we note that the priority level given to diversions does not guarantee that a diversion will be available on a given path. This capacity risk acts as a check on the ability of shippers to use a short-path strategy to meet a firm requirement. Moreover, TransCanada has the ability, by setting the bid floor for IT and STFT service, to compete with out-of-path diversions and ARPs.

In our opinion, and as set out in the following paragraphs, the detrimental effects of implementing the Diversion Proposal currently outweigh the potential detrimental effects that the Diversion Proposal attempts to remedy.

TransCanada did not assume that contracts for firm services expiring in 2014 would be renewed and did not include any revenues for the future sale of discretionary services in 2013 and 2014.

The Diversion Proposal would leave shippers with little opportunity to mitigate UDCs because, for many Mainline markets, the Diversion Proposal's definition of "path" does not include access to liquid trading points on a year round basis. Access to liquid points is important because it allows shippers to freely service markets where there is demand for natural gas and where the price of natural gas is highest. Under the Diversion Proposal, shippers are unlikely to derive significant value from accessing alternative transportation paths in the domestic market. Therefore, in the Mainline's current context, it is our view that giving shippers a reasonable opportunity to mitigate UDCs includes giving them access to out-of-path receipt and delivery points.

During the proceeding, TransCanada suggested that shippers would continue to have options to mitigate UDCs if the Diversion Proposal were adopted. However, it is our view that these options are not reasonable in the current context. For example, we do not think it is reasonable for a shipper to be required to pay for 365 days of service on a longer path than they actually need and to be required to use in-path diversions to meet their firm needs. Nor do we think it is reasonable to require a shipper who pays for 365 days of service to contract for discretionary services on a longer path to mitigate UDCs. On the other hand, we have decided not to implement the Tenaska Proposal because it could increase use of the short-path strategy and reduce shippers' incentive to contract for firm transportation services to markets where they have a firm requirement.

The ability for the secondary market to act as a fair and necessary check on TransCanada's discretion to set the bid floor for IT and STFT service was integral to the Decision.[8] As Tenaska pointed out in its evidence and argument, the main competition for TransCanada's discretionary services comes from firm transportation service shippers reselling their capacity held under contracts for firm transportation services. Limiting the scope of diversions to the contracted path (as defined by TransCanada's Diversion Proposal), all else equal, limits the number of shippers that would be able to compete with TransCanada's discretionary services on any given path.

We recognize that, if the Diversion Proposal were implemented, there might be higher volumes of firm transportation services contracted on longer paths and, therefore, in theory, TransCanada's discretionary services could face more competition from shippers. However, we are not persuaded that the relative increase in competition arising from the additional contracted volumes of firm transportation services would offset the detrimental effects on competition due to shippers having more limited flexibility in accessing alternative receipt and delivery points.

TransCanada suggested that the Diversion Proposal is necessary to align diversions and ARPs with the cost-based/user pay principle. While we continue to uphold that principle, it should not be applied when its application appears unreasonable and arbitrary, as we find to be evident in these specific circumstances. For example, the Diversion Proposal

[8] RH-003-2011 Decision, p. 127.

would not allow shippers that have certain domestic delivery points, as their primary delivery point, to use diversions to change their delivery point to an export point that is surrounded by an "in-path" DDA.[9] This is because historically, export points were excluded from toll zones (and now DDA calculations) and therefore TransCanada's definition of "path" excludes them as an eligible diversion point. The result is that under the Diversion Proposal, a shipper could divert to points in a DDA that are within a few kilometers of an export point, but not to the export point itself.

We note that there may be other mechanisms to eliminate or mitigate any potential detrimental effects associated with the short-path strategy that achieve a more appropriate balance between the pipeline and shippers. We acknowledge the efforts of all parties to respond to Board counsel's questioning on potential alternatives to the Diversion Proposal and the status quo. We also recognize that there are practical impediments and potentially detrimental effects associated with many of the alternatives that were canvassed.

To conclude, the RH-003-2011 Decision outlined a framework that balances shippers' need for transportation flexibility and TransCanada's need to generate revenue from the Mainline. The Board recognizes that the RH-003-2011 Decision's balance can be adjusted given prevailing circumstances, and that the Decision provided mechanisms to make necessary adjustments. It is our view that now is not the time to make adjustments in view of the absence of evidence that the short-path strategy is occurring and is having a detrimental effect on the Mainline.

With that said, TransCanada should monitor the effects of short-path strategy. If that strategy has demonstrable material detrimental effects on the Mainline, then we expect that TransCanada would apply to the Board for a remedy. Although it is not required, it might be helpful for TransCanada to consult with its shippers in determining an appropriate remedy. We remind all parties that the Board has the ability to act to minimize any detrimental effects on the Mainline. For example, if it became evident that shippers were using the short-path strategy to meet firm requirements, such that the market where they have firm requirements were being de-contracted, then the Board would be able to hear an application that could remedy the situation expeditiously, if needed.

Decision

We have decided to deny the proposed amendments to the Tariff in respect of Diversions and ARPs.

[9] See, for example, the Iroquois export point.

Tab 9

Manitoba Hydro

ORGANIZATION STRUCTURE
EXECUTIVE AND SENIOR MANAGEMENT

- BOARD
  - President and Chief Executive Officer — **Scott Thomson**
    - Vice-President Human Resources & Corporate Services — **Bryan Luce**
      - Division Manager Human Resources — **Gary Maksymyk**
      - Division Manager Workplace Safety & Health and Corporate Services — **Brad Ireland**
      - Division Manager Information Technology Services — **Glen Reitmeier**
      - Corporate Environmental Management
    - Vice-President Generation Operations — **Lorne Midford**
      - Division Manager Engineering Services — **Joel Wortley**
      - Division Manager Generation North — **John Kreml**
      - Division Manager Generation South — **Robert Dandenault**
      - Division Manager Power Planning — **Terry Miles**
      - Division Manager Power Sales & Operations — **David Cormie**
    - Vice-President Major Capital Projects — **Angie Adams**
      - Division Manager Bipole III Project — **Rob Elder**
      - Division Manager Keeyask Project — **Dave Bowen**
      - Division Manager Portfolio Projects Management — **Eduard Wojczynski**
      - Project Services
      - Major Capital Projects
      - Labour Relations
    - Vice-President Transmission — **Shane Mailey**
      - Division Manager Apparatus Maintenance — **Quinn Menec**
      - Division Manager HVDC — **John McNichol**
      - Division Manager Transmission Construction & Line Maintenance — **Glenn Penner**
      - Division Manager Transmission Planning & Design — **Gerald Neufeld**
      - Division Manager Transmission System Operations — **Anthony Clark**
    - Vice-President Customer Care & Energy Conservation — **Lloyd Kuczek**
      - Division Manager Gas Supply — **Vacant**
      - Division Manager Industrial & Commercial Solutions — **Dale Friesen**
      - Division Manager Consumer Marketing & Sales — **Lois Morrison**
      - Division Manager Business Support Services — **Paul Chard**
      - Power Smart Planning/Evaluation & Research
      - Affordable Energy
    - Vice-President General Counsel & Corporate Secretary — **Ken Tennenhouse**
      - Division Manager Internal Audit — **Lawrence Wilson**
      - Division Manager Law — **Patti Ramage**
      - Insurance Services
      - Intellectual Property
      - Human Rights & Respectful Workplace
    - Vice-President Corporate Relations — **Ruth Kristjanson**
      - Division Manager Aboriginal Relations — **Elissa Neville**
      - Division Manager Corporate Planning & Strategic Review — **Ian Page**
      - Division Manager Partnerships & Stakeholder Initiatives — **Vicky Cole**
      - Government Relations & Current Issues
    - Vice-President Customer Service & Distribution — **Brent Reed**
      - Division Manager Distribution Engineering & Construction — **Chuck Steele**
      - Division Manager Customer Service Operations – South Region — **Scott Dunn**
      - Division Manager Customer Service Operations – Winnipeg & North Region — **Dave Case**
      - Division Manager Business Support & Capital Asset Management — **Mark Prydun**
    - Vice-President Finance & Regulatory — **Darren Rainkie**
      - Corporate Controller — **Sandy Bauerlein**
      - Division Manager Rates & Regulatory Affairs — **Greg Barnlund**
      - Corporate Treasurer — **Manny Schulz**
      - Subsidiary Operations — **Shawna Pachal**
      - Corporate Risk Management
      - Financial Planning
    - Vice-President Corporate Communication & Public Affairs — **Siobhan Vinish**
      - Public Affairs
      - Communications & Engagement
      - Creative Services

Tab 10

Section:	Tab 4	**Page No.:**	Appendix 4.1 Table 25,26
Topic:	Natural Gas Volume Forecast		
Subtopic:	FRPGS Customer Forecast		
Issue:	Change in FRPGS customer forecast from 2013 GRA		

PREAMBLE TO IR (IF ANY):

In the 2013 GRA, Centra forecasted 1,351 FRPGS customers by 2016/17 and 1,813 by 2021/22. In the 2014 Forecast, Centra is now forecasting 286 customers by 2016/17 and 187 by 2021/22.

QUESTION:

a) Please explain the reasons for the downward revisions in customer numbers and volumes compared to the 2012 Natural Gas Volume Forecast presented at the 2013 GRA.

b) Please provide a schedule comparing the forecasts from the 2013/14 GRA with the current forecast for both customer numbers and volumes.

RATIONALE FOR QUESTION:

To understand the reasons for a significant change in the Volume Forecast.

RESPONSE:

a) FRPGS provides customers with the opportunity to contract with Centra for a fixed Primary Gas rate for a contract period of either one, three or five years. Centra does not attempt to influence a customer's decision and is indifferent to which product a customer chooses, including the default product.

   Centra reviews and revises its methodology and assumptions on an annual basis regarding the forecast of FRPGS customers. The downward revision in the 2014 forecast is initially based on the knowledge gained from the historical participation in FRPGS, the expected number of customers renewing a new term once their contract expires and also reflects current market conditions as referenced in Centra's response to JEMLP-Centra I-3.

b) The following table compares customer and volume forecasts under the 2012 Natural Gas Volume Forecast with the current 2014 Natural Gas Volume Forecast.

FRPGS Customer Forecast

	2012 Forecast		2014 Forecast	
Fiscal Year	**Customers**	**Volume (m3)**	**Customers**	**Volume (m3)**
2014/15	842	11,327,911	266	1,799,833
2015/16	1,129	14,757,716	295	2,042,147
2016/17	1,351	17,096,202	286	2,189,112
2017/18	1,488	18,506,165	277	2,423,838
2018/19	1,608	20,119,633	241	1,982,799
2019/20	1,704	21,359,224	175	1,362,722
2020/21	1,772	22,005,149	181	1,302,501
2021/22	1,814	22,339,107	187	1,258,502
2022/23			191	1,255,719
2023/24			192	1,204,333

b) The following table shows the FRPGS enrolment period, flow date, fixed rates offered, and the corresponding quarterly rate in effect at the time of the offering for all offerings since the 2013/14 GRA.

FRPGS Enrolment Period & Flow Date	Centra Fixed Rate ($/m^3)	Centra Quarterly Rate ($/m3)
May 7 - June 11, 2013 (August 1, 2013 flow)	1-Year $0.1820 3-Year $0.1838 5-Year $0.1882	$0.1157 (May 1 - July 31)
Aug. 9 - Sept. 10, 2013 (November 1, 2013 flow)	1-Year $0.1669 3-Year $0.1763 5-Year $0.1837	$0.1092 (Aug 1 - Oct 31)
Nov. 12 - Dec. 13, 2013 (February 1, 2014 flow)	1-Year $0.1690 3-Year $0.1743 5-Year $0.1821	$0.1142 (Nov 1 - Jan 31)
Feb. 10 - Mar. 13, 2014 (May 1, 2014 flow)	1-Year $0.2020 3-Year $0.1902 5-Year $0.1910	$0.1382 (Feb 1 - Apr 30)
May 9 - June 12, 2014 (August 1, 2014 flow)	1-Year $0.2225 3-Year $0.2094 5-Year $0.2123	$0.1567 (May 1 - July 31)
Aug. 13 - Sept. 12, 2014 (November 1, 2014 flow)	1-Year $0.1862 3-Year $0.1857 5-Year $0.1898	$0.1551 (Aug 1 - Oct 31)
Nov. 13 - Dec. 15, 2014 (February 1, 2015 flow)	1-Year $0.1808 3-Year $0.1841 5-Year $0.1894	$0.1665 (Nov 1 - Jan 31)
Feb. 10 - Mar 12, 2015 (May 1, 2015 flow)	1-Year $0.1571 3-Year $0.1690 5-Year $0.1768	$0.1252 (Feb 1 - Apr 30)
May 11 – June 12, 2015 (August 1, 2015 flow)	1-Year $0.1481 3-Year $0.1571 5-Year $0.1641	$0.1183 (May 1 - July 31)

c) Please see the attachment to this response detailing the FRPGS billed rate calculations for offerings with initial contract flow dates from November 1, 2013 forward.

d) Centra notes that the risk profile of existing FRPGS contracts is well within the program review thresholds. Up to and including FRPGS contracts with an initial flow date August 1, 2015, the annualized forecast of FRPGS subscribed volumes equates to 0.10% of total annual forecast sales volumes, relative to a program review threshold of 2.5% and the program limit of 5.0%.

As at July 28, 2015, the cumulative settled risk margin position on self-insured FRPGS offerings is a $73,000 gain and the unsettled forward mark-to-market risk margin position is a $64,000 gain, relative to $1 million risk margin loss program review thresholds for each.

Tab 11

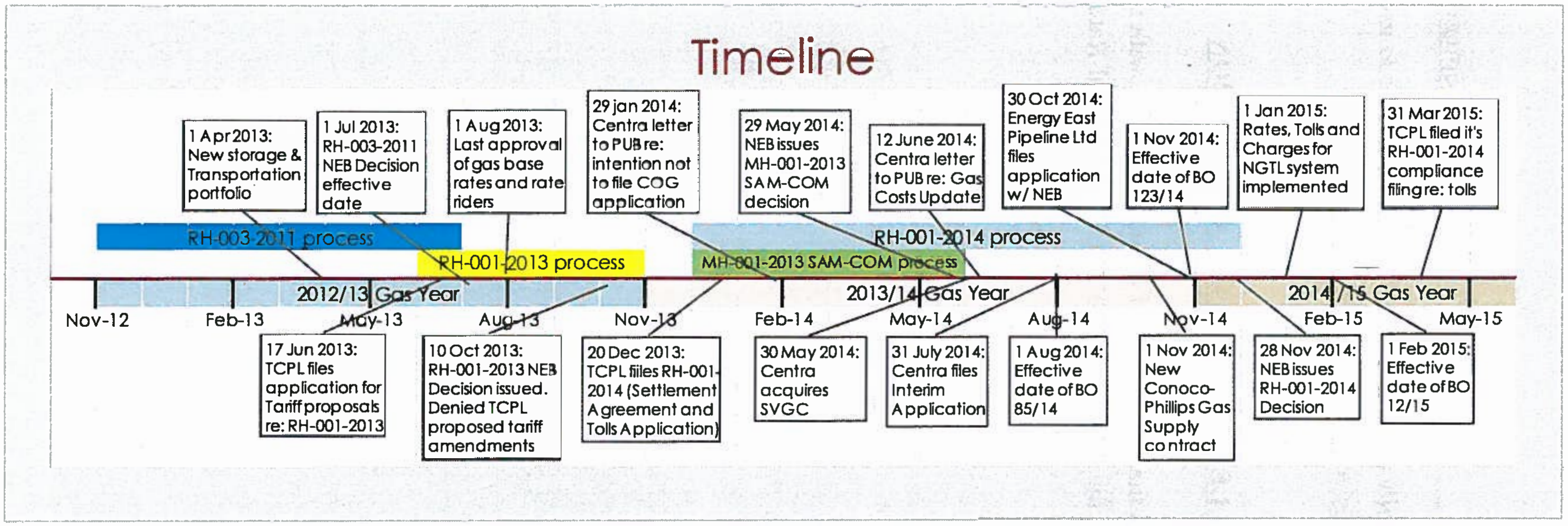
128/09	9e	The use of only statistically independent forecasts; and	Complete	The Corporation has eliminated the use of forecasts that are not statistically independent.
128/09	9f	A proposed process to update the forecasts in advance of the hearing if warranted.	Superseded	This directive has been superseded by Directive 4 of Order 85/13.
128/09	10	Centra to perform a true-up and adjustment on a quarterly basis to ensure there has been no over- or under-recovery of short term finance costs charged to Centra from MH.	Complete	Centra completed the true-up effective April 1, 2009, and an adjustment is performed on a quarterly basis.
128/09	11	Centra to file on or before March 1, 2010 a terms of reference for a study to review the Integrated Cost Allocation Methodology. The study is to be completed in sufficient time to be incorporated within the corporation's next GRA.	Delayed	As noted in a letter to the PUB of September 30, 2010, the implementation of this Directive is impacted by the implementation of International Financial Reporting Standards ("IFRS"). As a result, Centra advised that a response to this Directive would be delayed until post-IFRS implementation. In the proceeding for the 2013/14 GRA, Centra indicated that following the implementation of IFRS, the Corporation will review the current cost allocation methodology with a view to simplifying the methodology prior to reviewing the matter further with the PUB and Intervenors. Centra indicated that it believes that the intent of this directive could be addressed by way of a collaborative process with the PUB and Intervenors, which would provide parties with a better understanding of the methodology. At page 63 of Order 85/13, the PUB indicated that concurrent with the implementation of IFRS, Centra should propose a process to review and simplify the cost allocation methodology.
128/09	12	Centra to calculate its DSM amortization for 2009/10 and thereafter based on a 10-year amortization period, and record its depreciation and amortization expense for rate setting purposes accordingly;	Complete	Centra continues to calculate DSM amortization using a 10-year amortization period.

128/09	13	Centra to file a business plan with respect to the AMI project with the Board for its approval by January 15, 2010, and prior to proceeding beyond the pilot project expenditures. The business plan should include an assessment of the economic and noneconomic benefits of AMI, including safety-related matters, for both the meter reader and for Centra's customers.	Outstanding	A Status Report on AMI was filed with the PUB on February 2, 2010. A business plan will be filed with the PUB prior to proceeding with AMI implementation.
128/09	14	Changes to Centra's Terms and Conditions of Service regarding company labour rates for chargeable services BE AND ARE HEREBY APPROVED;	Complete	Approved in Order.
128/09	15	Changes to Centra's Terms and Conditions of Service relating to new requirements for Interruptible Service class customers BE AND ARE HEREBY APPROVED;	Complete	Approved in Order.
128/09	16	Centra's proposed changes to the Terms and Conditions of Service, including the proposed additional charges for unauthorized over-runs and the requirement for Interruptible customers to maintain a functioning stand-by fuel source BE AND ARE HEREBY APPROVED;	Complete	Approved in Order.
128/09	17	Changes to Centra's Terms and Conditions of Service relating to the Western Transportation Service, specifically the gas loan mechanism and new requirements for natural gas marketers for submission of new customer sign-up lists BE AND ARE HEREBY APPROVED;	Complete	Centra filed revised Terms and Conditions of Service on September 25, 2009 reflecting these changes. By letter of November 5, 2009, the PUB approved the revisions as filed.
128/09	18	The elimination of the volumetric threshold on individual WTS contracts on a final basis BE AND IS HEREBY APPROVED;	Complete	Centra filed revised Terms and Conditions of Service on September 25, 2009 reflecting these changes. By letter of November 5, 2009, the PUB approved the revisions as filed.
128/09	19	Centra's request that it be allowed to aggregate the marketer submissions and process the batch no less frequently than once per week, in addition to requiring marketers to include a date field in their new customer list submissions BE AND IS HEREBY APPROVED;	Complete	Approved in Order.

128/09	25	Centra provide all customers with bill inserts explaining the effects of this Order, the bill inserts to be pre-approved by the Public Utilities Board prior to being distributed, and Centra reference the Board's Order and website in Centra's press release and web postings related to this Order;	Complete	On April 29, 2010, Centra filed a bill insert outlining the impacts of Orders 128/09 and 41/10.
128/09	26	If and when Centra becomes aware of any material change in its financial circumstances, including but not limited to significant changes to accounting, gas supply, or operations, Centra must inform the Board of the change and the resulting impact or anticipated impact on Centra's financial position.	Ongoing	Centra will comply with this Directive should a material change in financial circumstance occur.

Tab 12

1 **Figure 2.2**

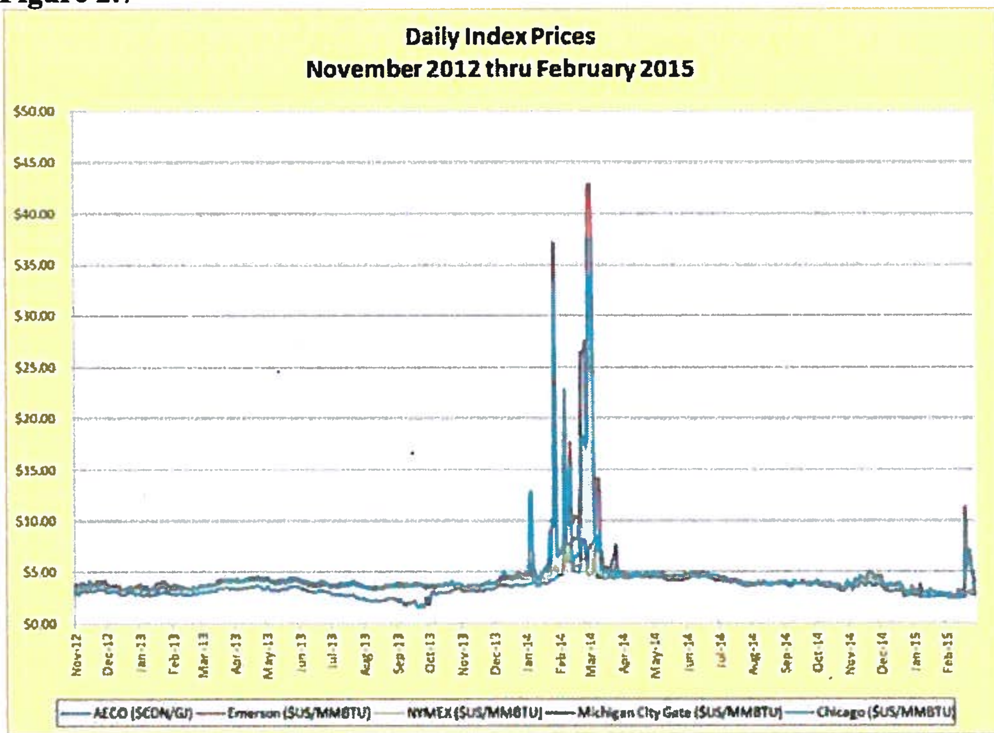

Timeline
1 Apr 2013: New storage & Transportation portfolio
1 Jul 2013: RH-003-2011 NEB Decision effective date
1 Aug 2013: Last approval of gas base rates and rate riders
29 Jan 2014: Centra letter to PUB re: intention not to file COG application
29 May 2014: NEB issues MH-001-2013 SAM-COM decision
12 June 2014: Centra letter to PUB re: Gas Costs Update
30 Oct 2014: Energy East Pipeline Ltd files application w/ NEB
1 Nov 2014: Effective date of BO 123/14
1 Jan 2015: Rates, Tolls and Charges for NGTL system implemented
31 Mar 2015: TCPL filed it's RH-001-2014 compliance filing re: tolls
RH-003-2011 process
RH-001-2013 process
MH-001-2013 SAM-COM process
RH-001-2014 process
2012/13 Gas Year
2013/14 Gas Year
2014/15 Gas Year
Nov-12
Feb-13
May-13
Aug-13
Nov-13
Feb-14
May-14
Aug-14
Nov-14
Feb-15
May-15
17 Jun 2013: TCPL files application for Tariff proposals re: RH-001-2013
10 Oct 2013: RH-001-2013 NEB Decision issued. Denied TCPL proposed tariff amendments
20 Dec 2013: TCPL files RH-001-2014 (Settlement Agreement and Tolls Application)
30 May 2014: Centra acquires SVGC
31 July 2014: Centra files Interim Application
1 Aug 2014: Effective date of BO 85/14
1 Nov 2014: New Conoco-Phillips Gas Supply contract
28 Nov 2014: NEB issues RH-001-2014 Decision
1 Feb 2015: Effective date of BO 12/15

2

months of January through March 2014, TCPL set its minimum Interruptible Transport ("IT") bid floors on the Mainline as high as 55 times its daily equivalent Firm Transportation ("FT") tolls.

To illustrate these dramatic market price increases, please see figure 2.7:

Figure 2.7

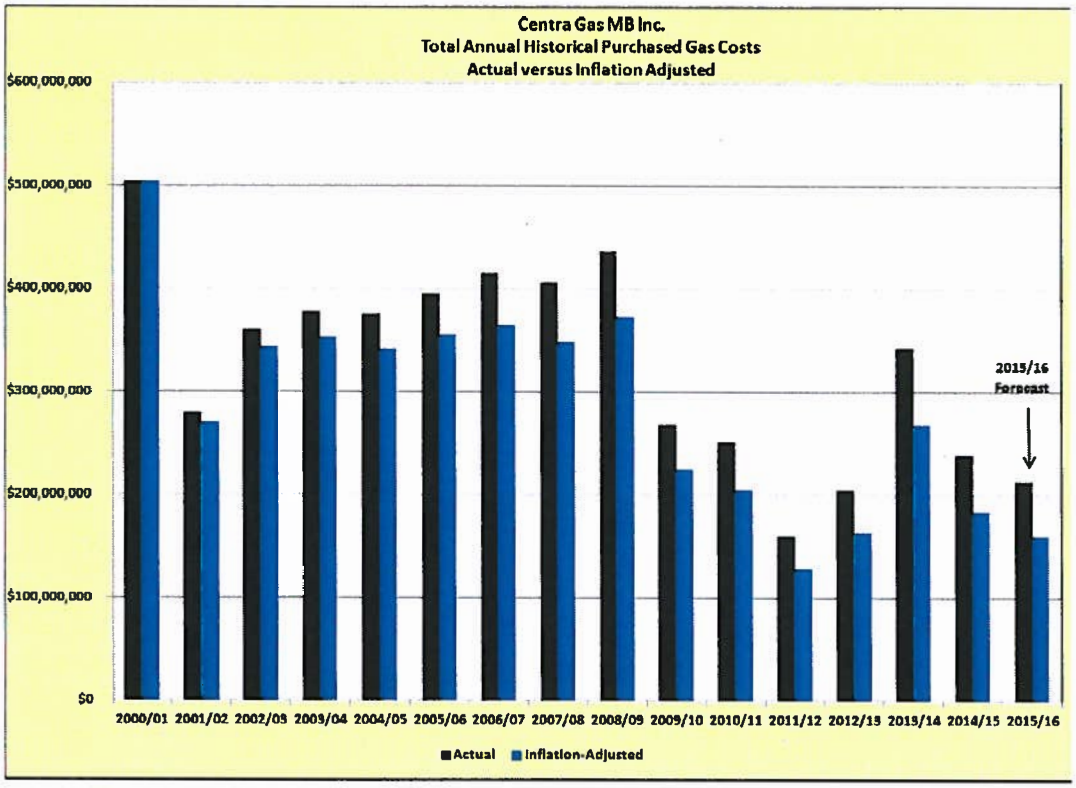


[redacted]

[redacted]

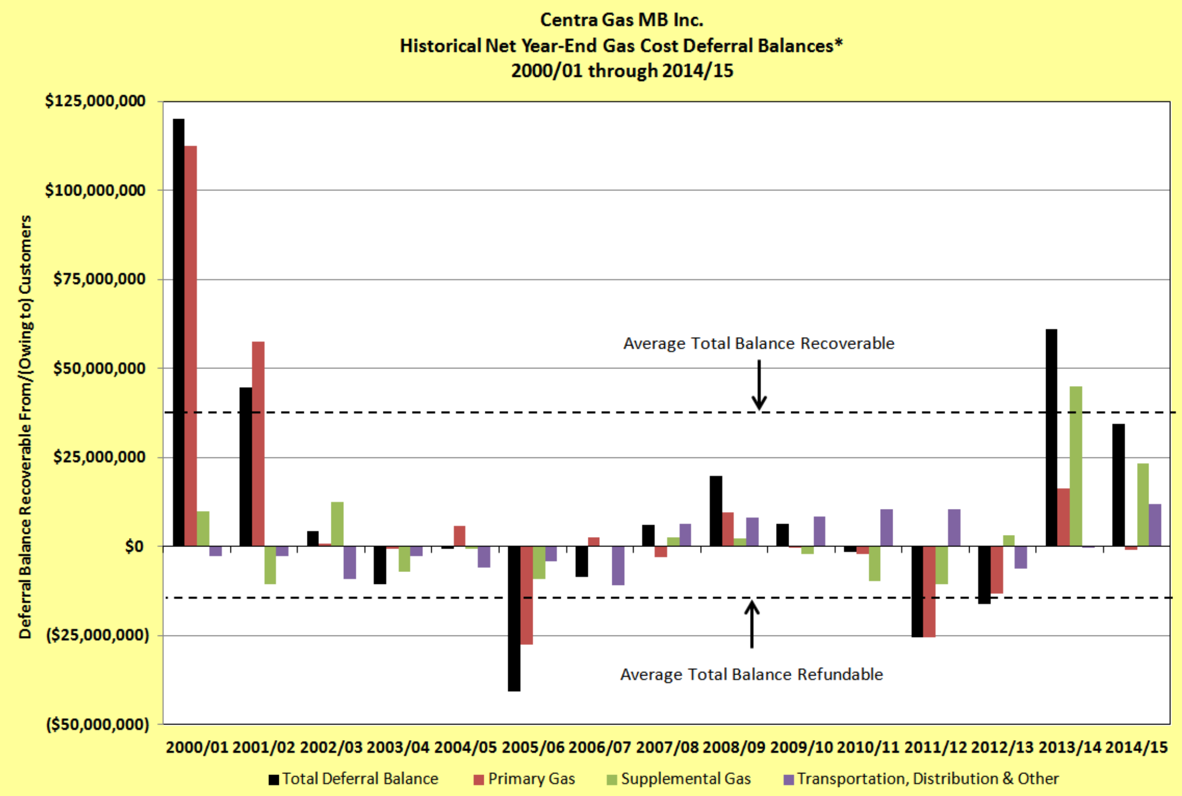
[redacted]

Figure 3.3



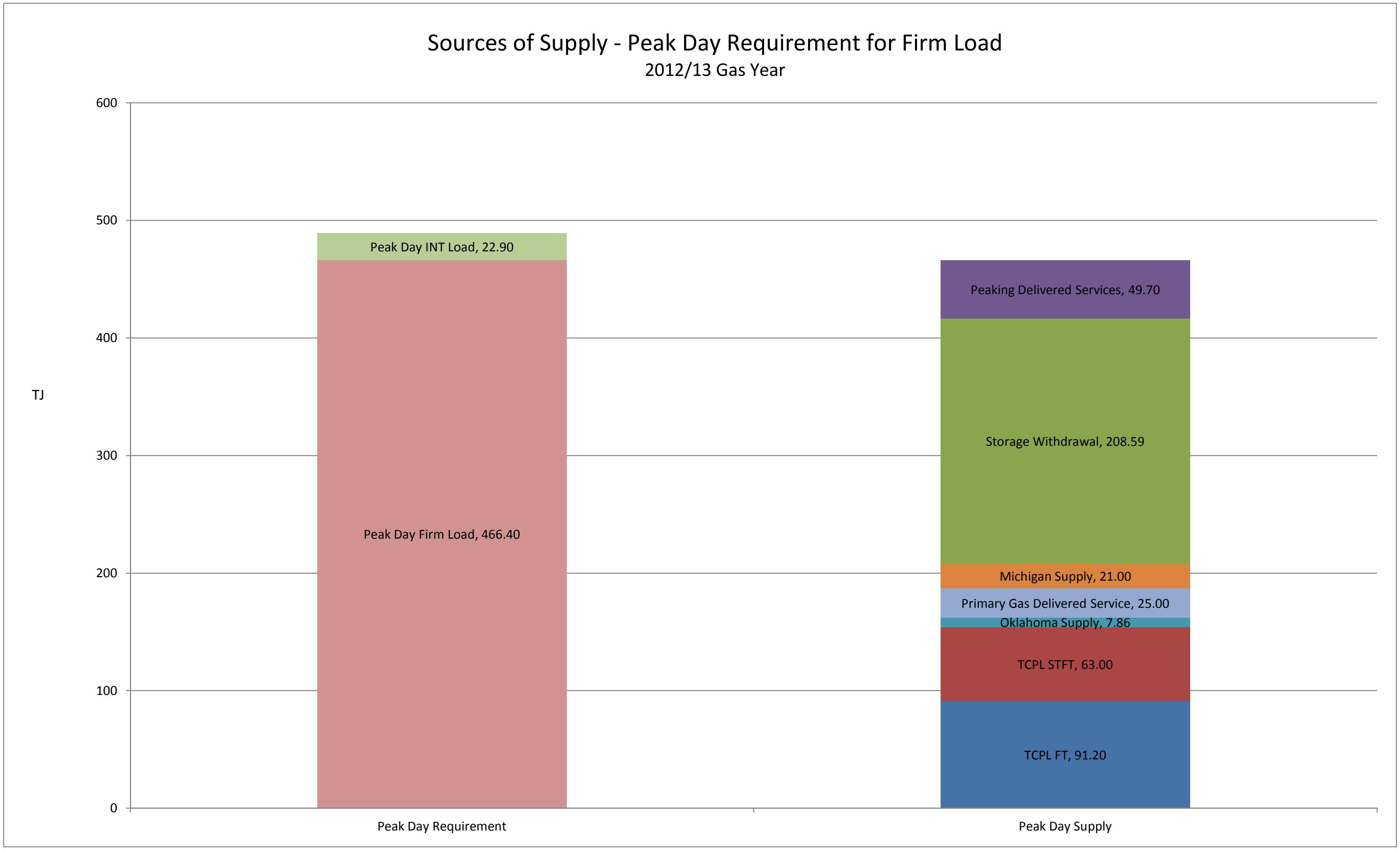
While the Supplemental Gas deferral account balance encountered in 2013/14 is significant, such levels are not unprecedented. The following figure shows the level of all deferral account balances in each of the years since 2000.

Centra Gas Manitoba Inc. 2015/16 Cost of Gas Application
PUB/Centra-I-30

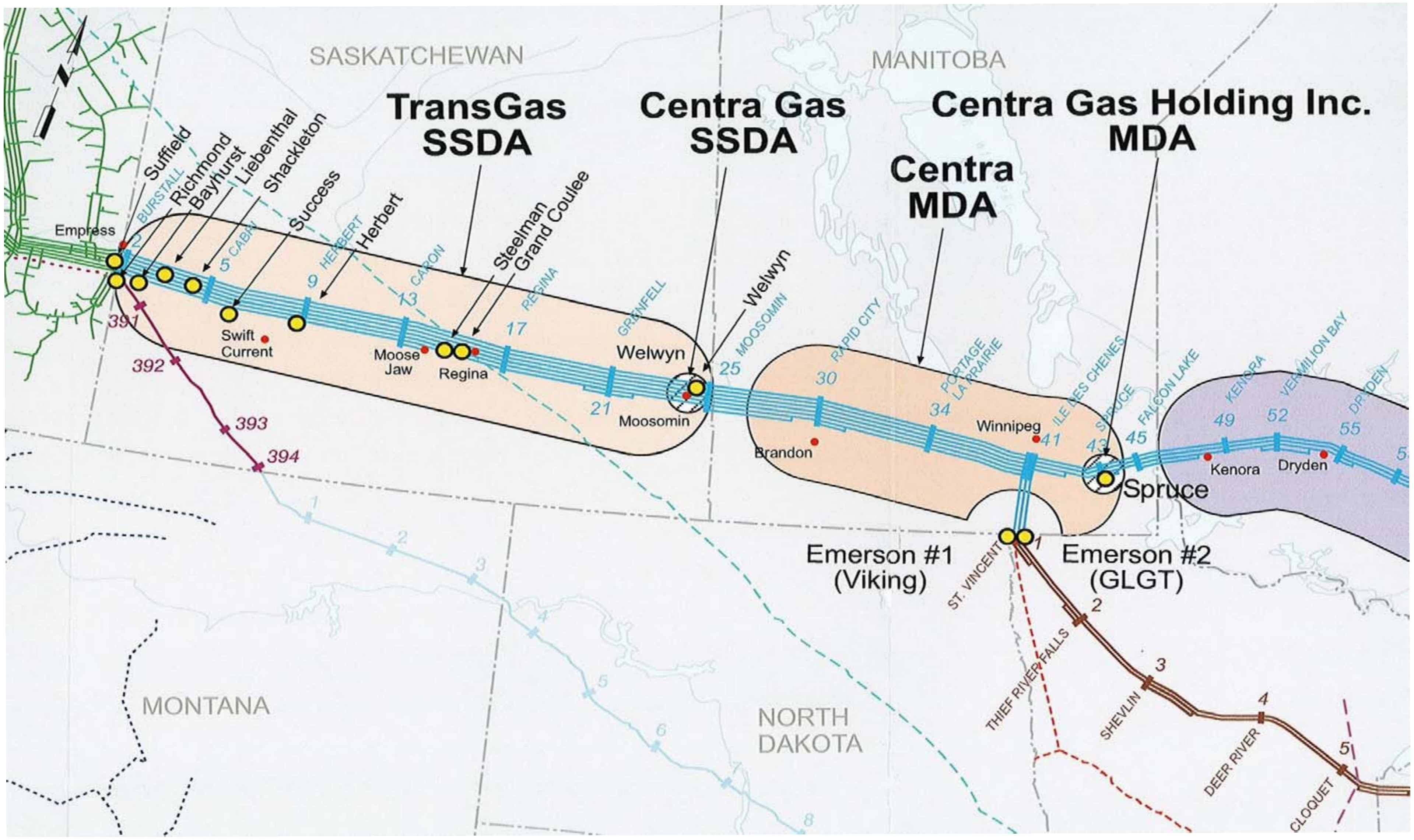


*Figures for the years 2000/01 thru 2006/07 are as at March 31st. Beginning In 2007/08, figures are as at October 31st, when Centra commenced managing its annual gas cost deferral accounts over the November thru October gas year period, as opposed to Centra's April thru March fiscal year period.

Tab 13



Sources of Supply - Peak Day Requirement for Firm Load
2012/13 Gas Year
TJ
600
500
400
300
200
100
0
Peak Day INT Load, 22.90
Peak Day Firm Load, 466.40
Peaking Delivered Services, 49.70
Storage Withdrawal, 208.59
Michigan Supply, 21.00
Primary Gas Delivered Service, 25.00
Oklahoma Supply, 7.86
TCPL STFT, 63.00
TCPL FT, 91.20
Peak Day Requirement
Peak Day Supply


SASKATCHEWAN
MANITOBA
TransGas SSDA
Centra Gas SSDA
Centra Gas Holding Inc. MDA
Centra MDA
Suffield
Richmond
Bayhurst
Liebenthal
Shackleton
Success
Herbert
Steelman
Grand Coulee
Welwyn
Empress
Swift Current
Moose Jaw
Regina
Moosomin
Brandon
Winnipeg
Kenora
Dryden
Spruce
Emerson #1 (Viking)
Emerson #2 (GLGT)
MONTANA
NORTH DAKOTA

Tab 14

Centra Gas Manitoba Inc.
2015/16 Cost of Gas Application
Summary of Gas Costs for 2012/13 Gas Year
Actual vs. Approved

Schedule 3.0.0
September 11, 2015

		2012/2013 Gas Year Actual	2012/2013 Gas Year Approved	Actual vs. Approved
1	**Fixed Costs**			
2	TCPL	$31,695,197	$36,622,387	($4,927,190)
3	Firm transport from counterparties	$1,481,756	$0	$1,481,756
4	ANR	$11,619,971	$11,328,012	$291,959
5	GLGT	$2,153,767	$2,104,963	$48,804
6				
7	**Total Fixed Costs**	**$46,950,690**	**$50,055,362**	**($3,104,671)**
8				
9	**Variable Transportation Costs**			
10	TCPL	$713,478	$1,576,123	($862,646)
11	ANR	$222,299	$262,004	($39,706)
12	GLGT	$28,452	$0	$28,452
13	Storage Gas - Transportation & Delivery Cost	$1,897,895	$2,179,962	($282,067)
14	Primary Gas Delivered Service Imputed Transportation Cost	$1,957,435	$0	$1,957,435
15	Supplemental Gas Peaking Delivered Service Imputed Transportation Cost	$844,994	$0	$844,994
16	Compressor Fuel Cost	$1,145,643	$837,954	$307,688
17	Miscellaneous Transportation Cost	$13	$0	$13
18				
19	**Total Variable Transport Costs**	**$6,810,208**	**$4,856,044**	**$1,954,163**
20				
21	**Supply Costs**			
22	Primary Gas	$120,961,941	$127,597,176	($6,635,235)
23	Supplemental Gas	$30,640,068	$23,164,620	$7,475,447
24	Supplemental Gas - Alternate Supply Service	$2,811,586	$0	$2,811,586
25				
26	**Total Supply Costs**	**$154,413,594**	**$150,761,797**	**$3,651,798**
27				
28	**Other**			
29	Minell Charges	$198,444	$198,444	$0
30	Capacity Management	($3,003,371)	($6,300,000)	$3,296,629
31	Load Balancing Charges	$194,128	$200,000	($5,872)
32				
33	**Total Other**	**($2,610,799)**	**($5,901,556)**	**$3,290,757**
34				
35	**Total Gas Cost Inflows**	**$205,563,694**	**$199,771,646**	**$5,792,047**
36				
37	**Purchased Volumes Excluding Primary WTS Supply (GJ)**			
38	Primary Gas	41,264,846	42,197,929	(933,083)
39	Supplemental Gas	8,357,027	5,748,246	2,608,781
40	Supplemental Gas - Alternate Supply Service	719,762	0	719,762
41	**Total Volumes Excluding Primary WTS Supply (GJ)**	**50,341,635**	**47,946,175**	**2,395,460**

Centra Gas Manitoba Inc.
Purchase Gas Variance Account - 2012/2013 Gas Year Supplemental Gas
2012/13 Gas Year Actual

Schedule 3.1.2 (a)
September 11, 2015

		Actual Nov 2012	Actual Dec 2012	Actual Jan 2013	Actual Feb 2013	Actual Mar 2013	Actual Apr 2013	Actual May 2013	Actual Jun 2013	Actual Jul 2013	Actual Aug 2013	Actual Sep 2013	Actual Oct 2013	TOTAL
	Inflows													
1	Supplemental Supply Direct to the Load	$2,907,088	$2,808,032	$2,687,560	$3,968,726	$8,537,720	$0	$0	$0	$0	$0	$0	$285,254	**$21,194,382**
2	Storage Gas - Supplemental Supply	$0	$0	$0	$0	$4,744,866	$0	$0	$0	$0	$0	$0	$0	**$4,744,866**
3	Supplemental Gas Peaking Delivered Service	$20,000	$0	$53,541	$0	$0	$1,419,829	$579,833	$108,366	$58,816	$82,922	($272)	$2,377,786	**$4,700,820**
4	Alternate Supply Service	$0	$0	$214,674	$0	$0	$1,144,061	$344,233	$145,495	$32,415	$69,164	$48,807	$812,736	**$2,811,586**
6	**Total Inflows**	**$2,927,088**	**$2,808,032**	**$2,955,775**	**$3,968,726**	**$13,282,586**	**$2,563,890**	**$924,066**	**$253,861**	**$91,231**	**$152,086**	**$48,535**	**$3,475,776**	**$33,451,653**
7	Less: UFG Component to Distribution PGVA	($38,357)	($35,175)	($37,445)	($51,024)	($176,307)	($37,219)	($17,915)	($6,637)	($2,492)	($4,256)	($1,195)	($52,607)	**($460,629)**
8	Net UFG True-up Transferred From Distribution PGVA								$159,727					**$159,727**
9	**Net Inflow After UFG Transfer**	**$2,888,732**	**$2,772,857**	**$2,918,330**	**$3,917,703**	**$13,106,279**	**$2,526,671**	**$906,151**	**$406,951**	**$88,739**	**$147,830**	**$47,340**	**$3,423,169**	**$33,150,751**
11	**Outflows**													
12	WACOG Outflows	$2,268,802	$3,183,332	$3,433,917	$2,808,585	$2,626,212	$1,715,724	$1,709,825	$1,231,133	$885,331	$1,546,105	$1,570,914	$4,340,455	**$27,320,337**
13	WACOG on Alternate Supply Service	$0	$0	$214,674	$0	$0	$1,144,061	$344,233	$145,495	$71,033	$30,546	$48,807	$812,736	**$2,811,586**
14	**Total Outflows**	**$2,268,802**	**$3,183,332**	**$3,648,591**	**$2,808,585**	**$2,626,212**	**$2,859,785**	**$2,054,059**	**$1,376,628**	**$956,365**	**$1,576,651**	**$1,619,721**	**$5,153,192**	**$30,131,922**
16	Carrying Costs	$505	$691	($238)	$77	$9,738	$17,880	$17,675	$15,279	$14,784	$12,659	$9,771	$7,506	**$106,327**
18	**Net Inflow**	**$620,434**	**($409,784)**	**($730,499)**	**$1,109,195**	**$10,489,805**	**($315,234)**	**($1,130,232)**	**($954,398)**	**($852,842)**	**($1,416,162)**	**($1,562,610)**	**($1,722,516)**	**$3,125,156**
20	**Net Balance**	**$620,434**	**$210,650**	**($519,849)**	**$589,345**	**$11,079,150**	**$10,763,916**	**$9,633,684**	**$8,679,286**	**$7,826,444**	**$6,410,282**	**$4,847,672**	**$3,125,156**	
22	Supplemental GJ's - System Supply (includes UFG)	837,178	834,488	835,210	1,170,065	3,221,354	391,591	164,243	32,338	21,018	33,778	(114)	815,878	**8,357,027**
23	Alternate Supply Service GJ's	0	0	52,625	0	0	285,009	88,257	38,162	8,482	20,422	13,614	213,191	**719,762**
24	Supplemental Gas Avg. Cost - $/GJ	$3.496	$3.365	$3.329	$3.392	$4.123	$3.789	$3.660	$3.601	$3.093	$2.806	$3.595	$3.378	**$3.685**

		Oct. 31, 2013	Actual Nov 2013	Actual Dec 2013	Actual Jan 2014	Actual Feb 2014	Actual Mar 2014	Actual Apr 2014	Actual May 2014	Actual Jun 2014	Actual Jul 2014	Actual Aug 2014	Actual Sep 2014	Actual Oct 2014	
31	Carrying Cost Rate		1.92%	1.92%	1.89%	1.88%	1.85%	1.91%	1.92%	1.93%	1.94%	1.94%	1.92%	1.89%	
33	Carrying Costs		$5,583	$5,095	$5,025	$4,529	$4,945	$4,949	$5,154	$5,014	$5,211	$5,235	$5,017	$5,100	**$60,857**
35	**Net Inflow**		**$5,583**	**$5,095**	**$5,025**	**$4,529**	**$4,945**	**$4,949**	**$5,154**	**$5,014**	**$5,211**	**$5,235**	**$5,017**	**$5,100**	
37	**Net Balance**	**$3,125,156**	**$3,130,739**	**$3,135,834**	**$3,140,859**	**$3,145,388**	**$3,150,333**	**$3,155,282**	**$3,160,436**	**$3,165,450**	**$3,170,661**	**$3,175,896**	**$3,180,913**	**$3,186,013**	

Centra Gas Manitoba Inc.
Purchase Gas Variance Account - 2012/2013 Gas Year Supplemental
Actual vs. Approved

Schedule 3.1.2 (b)
September 11, 2015

		Actual	Approved	Actual vs. Approved
	Inflows			
1	Supplemental Supply Direct to the Load	$21,194,382	$10,532,402	$10,661,980
2	Storage Gas - Supplemental Supply	$4,744,866	$12,632,218	($7,887,353)
3	Supplemental Gas Peaking Delivered Service	$4,700,820	$0	$4,700,820
4	Alternate Supply Service	$2,811,586	$0	$2,811,586
5	**Total Inflows**	**$33,451,653**	**$23,164,620**	**$10,287,033**
6	Less: UFG Component to Distribution PGVA	($460,629)	($298,631)	($161,998)
7	Less: UFG True-up Transferred from Distribution PGVA	$159,727	$0	$159,727
8	**Net Inflow After UFG Transfer**	**$33,150,751**	**$22,865,989**	**$10,284,762**
9				
10	**Outflows**			
11	WACOG Outflows	$27,320,337	$22,949,716	$4,370,621
12	WACOG on Alternate Supply Service	$2,811,586	$0	$2,811,586
13	**Total Outflows**	**$30,131,922**	**$22,949,716**	**$7,182,206**
14				
15	Carrying Costs	$167,184	$0	$167,184
16				
17	**Net Balance**	**$3,186,013**	**($83,727)**	**$3,269,739**
18				
19	Supplemental GJ's - System Supply (includes UFG)	8,357,027	5,748,246	2,608,781
20	Alternate Supply Service GJ's	719,762	0	719,762
21	Supplemental Gas Avg. Cost - $/GJ	$3.685	$4.030	($0.344)

Centra Gas Manitoba Inc.
Summary of All Non-Primary Gas Cost Deferral Balances
October 31, 2014 Balances Including Carrying Costs

Schedule 3.10.0
September 11, 2015

		Actual Balances	Interim Forecast [1]	Variance	Variance Explanation
1	**July 31, 2013 Prior Period Gas Deferrals**				
2	Supplemental Gas PGVA	$1,166,683	$1,185,743	($19,060)	Mainly relating to prior period billing adjustments recognized in the months of August thru October 2014.
3	Transportation PGVA	($1,653,460)	($1,695,104)	$41,644	Mainly relating to prior period billing adjustments recognized in the months of August thru October 2014.
4	Distribution PGVA	$105,671	$105,254	$417	Mainly relating to prior period billing adjustments recognized in the months of August thru October 2014.
5	Heating Value Margin Deferral	$154,310	$154,586	($276)	Mainly relating to prior period billing adjustments recognized in the months of August thru October 2014.
6					
7	**2012/13 Gas Year Deferral Balances**				
8	Supplemental Gas PGVA	$3,186,013	$3,189,353	($3,341)	May through October carrying costs averaged 1.92% relative to the forecast of 2.15%.
9	Transportation PGVA [2]	($4,451,192)	($4,455,859)	$4,668	May through October carrying costs averaged 1.92% relative to the forecast of 2.15%.
10	Distribution PGVA	($1,646,496)	($1,648,224)	$1,728	May through October carrying costs averaged 1.92% relative to the forecast of 2.15%.
11	Heating Value Margin Deferral	($454,565)	($455,041)	$476	May through October carrying costs averaged 1.92% relative to the forecast of 2.15%.
12					
13	**2013/14 Gas Year Deferral Balances**				
14	Supplemental Gas PGVA	$41,788,922	$42,312,871	($523,949)	$0.8 M of incremental fall 2014 Supplemental commodity purchases, which are more than offset by WACOG Outflows that were ($1.0 M) above forecast during the months of May thru October 2014, a ($0.2 M) UFG True-up impact, and ($0.1 M) due to lower than forecast carrying cost rates.
15	Transportation PGVA [3]	$5,054,313	$5,857,154	($802,841)	($1.0 M) incremental Capacity Management revenues, which are partially offset by $0.1 M of Supplemental Gas Peaking Delivered Service Imputed Transportation Costs and $0.1 M of TCPL Balancing Fees.
16	Distribution PGVA	$1,770,881	$1,385,127	$385,754	$0.4 M UFG True-up, including both Primary and Supplemental Gas components.
17	Heating Value Margin Deferral	($153,805)	($243,912)	$90,106	May, June, August and October 2014 heating values were all above Centra's standard of 37.8 GJ/10^3m^3.
18					
19	**Total All Non-Primary Gas Cost Deferral Account Balances as at October 31, 2014**	**$44,867,275**	**$45,691,949**	**($824,674)**	
20					
21	October 31, 2014 Prior-Period Supplemental Gas Cost Deferral	$46,141,618	$46,687,968	($546,350)	
22	October 31, 2014 Prior-Period Non-Supplemental Gas Cost Deferral	($1,274,344)	($996,019)	($278,324)	
23	**Total All Non-Primary Gas Cost Deferral Account Balances as at October 31, 2014**	**$44,867,275**	**$45,691,949**	**($824,674)**	
24					
25	**Interim Approved October 31, 2014 Prior-Period Deferral Amounts as per Order 123/14**				
26	Interim Approved October 31, 2014 Prior-Period Supplemental Gas Cost Deferral (50% of Forecast)		$23,343,984		
27	Interim Approved October 31, 2014 Prior-Period Non-Supplemental Gas Cost Deferral (100% of Forecast)		($996,019)		
28	**Total Interim Approved October 31, 2014 Prior-Period Non-Primary Gas Cost Deferral Account Balances**		**$22,347,965**		
29					
30	Note 1: Interim Forecast includes actual results to April 2014 and outlook results for May through October 2014 based on May 14, 2014 futures market strip.				
31	Note 2: Includes credit of ($3.0 million) for 2012/13 Gas Year Capacity Management results including carrying costs.				
32	Note 3: Includes credit of ($5.3 million) for 2013/14 Gas Year Capacity Management results including carrying costs.				

CENTRA GAS MANITOBA INC
Summary of All Non-Primary Gas Cost Deferral Balances
To October 31, 2015 Including Carrying Costs

Schedule 3.11.0
September 11, 2015

	Actual	**Actual**	**Actual**	**Actual**	**Actual**	**Outlook**	**Outlook**	**Outlook**	**Outlook**	**Outlook**	**Outlook**	**Outlook**	**Outlook**
October 31, 2014 Prior-Period Supplemental Gas Cost Deferral	**Oct-14**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**
Rate Rider Amortization		($1,611,720)	($1,813,677)	($2,056,578)	($6,050,496)	($4,099,435)	($2,317,734)	($1,377,134)	($844,132)	($645,811)	($667,694)	($913,388)	($2,163,117)
Carrying Costs		$34,764	$70,673	$63,923	$44,576	$53,257	$56,768	$53,336	$51,309	$49,980	$48,817	$47,395	$44,538
Net Balance	**$46,141,618**	**$44,564,663**	**$42,821,658**	**$40,829,004**	**$34,823,084**	**$30,776,906**	**$28,515,940**	**$27,192,142**	**$26,399,319**	**$25,803,488**	**$25,184,611**	**$24,318,618**	**$22,200,039**

	Actual	**Actual**	**Actual**	**Actual**	**Actual**	**Outlook**	**Outlook**	**Outlook**	**Outlook**	**Outlook**	**Outlook**	**Outlook**	**Outlook**
October 31, 2014 Prior-Period Non-Supplemental Gas Cost Deferral	**Oct-14**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**
Rate Rider Amortization		$192,742	$222,069	$406,410	$279,677	$166,561	$25,847	($36,263)	($89,475)	($106,466)	($99,442)	($79,998)	$19,932
Carrying Costs		($845)	($1,573)	($1,008)	($373)	($153)	$4	($6)	($126)	($314)	($512)	($685)	($744)
Net Balance	**($1,274,344)**	**($1,082,446)**	**($861,951)**	**($456,549)**	**($177,245)**	**($10,837)**	**$15,014**	**($21,255)**	**($110,856)**	**($217,637)**	**($317,591)**	**($398,275)**	**($379,087)**

	Outlook
Summary of All October 31, 2015 Non-Primary Gas Cost Deferral Balances	**Oct-15**
October 31, 2014 Prior-Period Supplemental Gas Cost Deferral	$22,200,039
October 31, 2014 Prior-Period Non-Supplemental Gas Cost Deferral	($379,087)
2014/15 Gas Year Balances	
Supplemental PGVA	$1,456,260
Transportation PGVA	$11,193,630
Distribution PGVA	$279,346
Heating Value Margin Deferral	$604,888
Total October 31, 2015 Non-Primary Gas Cost Deferral Balance	**$35,355,076**

Centra Gas Manitoba Inc. **Schedule 3.12.4**
2015/16 Cost of Gas Application Pre-Hearing Update **September 11, 2015**
Difference Between Forecasted Non-Primary Gas Costs
and Non-Primary Gas Costs Recoverable With Existing Base Rates
Supply prices for 2015/16 Gas Year per forward strip as of: July 31, 2015

		(1) Recoverable at Existing Base Rates	(2) Forecast for 2015/16	(3) Difference
1	Primary Gas [1]	$132,710,097	$130,409,732	($2,300,365)
2	Supplemental Gas	$18,215,301	$17,457,312	($757,989)
3	Transportation	$48,099,870	$60,981,569	$12,881,699
4	Distribution	$2,315,798	$2,343,950	$28,151
5				
6				
7	**Totals**	**$201,341,067**	**$211,192,563**	**$9,851,496**
8				
9				
10	**Non-Primary Gas Cost Totals**	**$68,630,970**	**$80,782,831**	**$12,151,861**
11				
12	Note 1: Primary Gas cost recoverable at existing base rates is calculated using the approved August 1, 2015 Primary Gas billed rate.			

Tab 15

Section:	Tab 5	**Page No.:**	Schedule 5.5.1
Topic:	Cost Allocation and Rate Design		
Subtopic:	Proposed Rate Riders		
Issue:	Calculation of Rate Riders		

PREAMBLE TO IR (IF ANY):

Migrations of customers between customer classes and service types affect the volumes and billing determinants used to calculate the Supplemental Gas rate riders.

QUESTION:

Please show calculations of the billing determinants for Supplement Gas on lines 20 and 34 reflecting the migration of customers from Interruptible service to firm service and from Sales service to T-Service.

RATIONALE FOR QUESTION:

To show the migration of customers and how this affects the rate rider calculations.

RESPONSE:

The table below provides the derivation of the billing determinant used in the calculation of the Supplemental Rate Rider (Schedule 5.5.1, line 34) to recover the remaining 50% Supplemental PGVA balance accumulated during the 2013/14 winter and deferred in Order 123/14. The 2015/16 Load Forecast (Schedule 4.4.4) reflects the migration of customers that occurred in 2014. To align the anticipated recovery of that rate rider with its determination, Centra reversed the migration as shown in the table.

No adjustments to the 2015/16 load forecast were necessary for the determination of the 2014/15 Supplemental Rate Rider (Schedule 5.5.1, line 20) as Centra has proposed that the rate treatment be applied only to the material Supplemental PGVA that accumulated during the 2013/14 winter.

10^3M^3	2015/16 Load Forecast Sch 4.4.4	Migration May 1/14	Migration Nov1/14	2015/16 Load Forecast Adjusted Sch 5.5.1, line 34
SGS	659,089			659,089
LGS	511,015			511,015
HVF	166,698	(10,373)	(22,786)	133,539
Mainline	4,083		10,976	15,059
Interruptible	44,670	10,373	23,424	78,467
	1,385,555	-	11,614	1,397,169
HVF-T	45,257		(7,762)	37,495
MLF-T	124,981		(10,976)	114,005
INT-T	11,058		7,124	18,182
PS	14,212			14,212
SC	438,207			438,207
Total (T-service)	633,715	-	(11,614)	622,101
Total	2,019,270	-	-	2,019,270

Schedule 5.5.1 Billing Determinants	Suppl. Rider 2014/15		Suppl. Rider 2013/14	
Firm	1,340,885	line 20	1,318,702	line 34
Int	44,670	line 20	78,467	line 34

Section:	Appendix 7.5	**Page No.:**	PUB/Centra INT-2
Topic:	Gas Supply & Costs		
Subtopic:	Primary Gas / Supplemental Gas billing percentages		
Issue:	Definitions of Primary Gas and Supplemental Gas		

PREAMBLE TO IR (IF ANY):

Centra provides a definition of Primary Gas in Attachment 1 page 9 of PUB/Centra INT-2(a): "Primary Gas is the natural gas received from western Canadian sources at the Alberta border (Empress), whether supplied by Centra or a marketer."

QUESTION:

a) Please provide the Primary Gas / Supplemental Gas billing percentages for May and August 2015.

b) Please confirm whether Centra has always forecasted that Supplemental Gas would be needed in normal weather years. If not confirmed, please identify which years Supplemental Gas was not forecasted under normal weather and explain why it was not expected to be required.

c) Please provide the definitions of Primary Gas and Supplemental Gas (originally proposed as Storage and Peaking Gas) as proposed by Centra in its 1999 application for Western Transportation Service leading to Order 19/00.

d) Please confirm whether the definition of Primary Gas in PUB/Centra INT-2(a) reflects all sources of supply that Centra considers Primary Gas, or whether the definition should be amended to reflect gas supplies delivered to Manitoba on a seasonal basis from Western Canada.

RATIONALE FOR QUESTION:

Update response to PUB/Centra INT-2b. To understand Centra's historical planning for the relative amounts of Primary Gas versus Supplemental Gas, and to understand the differences between Primary Gas and Supplemental Gas.

RESPONSE:

(a) Please see the following table:

May 1, 2015	**Primary Gas Billing %**	**Supplemental Gas Billing %**
Firm	81%	19%
Interruptible	83%	17%
August 1, 2015	**Primary Gas Billing %**	**Supplemental Gas Billing %**
Firm	79%	21%
Interruptible	79%	21%

(b) Not confirmed. For the two gas years commencing November 1, 2006 and November 1, 2007, billing percentages for both Firm and Interruptible customers were set at 100% Primary Gas based upon normal weather assumptions. No Supplemental Gas was forecast to be required under normal weather conditions at the outset of each of these two gas years due to a then recent significant decline in customers' weather-adjusted annual natural gas requirements. For example, in the year following the hurricane-induced natural gas price spikes in the late summer and early fall of 2005, Residential customers' weather-adjusted average natural gas use fell by 5.4%, compared to an average annual decline of 1.7% per year over the prior ten years.

(c) In its Western Transportation Service and Agency Billing and Collection Service Application, Centra proposed the following definitions for "Primary Gas" and "Storage and Peaking Gas":

> ***Primary Gas*** *- Natural gas received by Centra under its TCPL contract from Western Canadian sources. Primary Gas can be provided by either Centra or a broker.*
>
> ***Storage and Peaking Gas (Supplemental Gas) -*** *Natural gas provided from sources other than Primary Gas.*

(d) Generally speaking, Centra is satisfied that its definitions of Primary and Supplemental Gas are appropriate.