REFERENCE:

PUB/Centra I-2 (b)

PREAMBLE TO IR (IF ANY):

QUESTION:

Please update the response to include the Return on Equity for each of the years, including net income and corporate allocation, with the updated information for 2018/19

RESPONSE:

The response to PUB/Centra I-2(b) has been revised to include the Total Return on Equity and the implied ROE % which can be found at the bottom of the projected operating statement below. Targeting an annual net income not to exceed $3 million beyond 2019/20 results in a declining ROE % as the Total Return on Equity does not keep pace with the growth in the rate base. The average ROE % over the 10-year forecast period is 7.2%.

The Corporation is still in the process of finalizing the 2018/19 year-end results and is therefore not in a position to update 2018/19 information at this time.

Once the results have been finalized and made available for public distribution, the financial results for 2018/19 will be filed with the Public Utilities Board.

GAS OPERATIONS (CGM18)
PROJECTED OPERATING STATEMENT
CGM18 - $3M Net Income 2020 - 2028
(In Millions of Dollars)

For the year ended March 31	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
REVENUES										
Domestic Revenue										
Cost of Gas	159	158	166	166	165	165	164	163	162	163
Non-Gas Costs *	152	150	150	151	151	151	151	152	152	151
Furnace Replacement Program Funding	(4)	(1)	-	-	-	-	-	-	-	-
Late Payment Charges and Broker Revenue	1	1	1	1	1	1	1	1	1	1
	308	308	316	317	317	316	316	315	315	315
additional revenue requirement***	-	1	5	7	10	14	18	21	25	29
	308	309	321	324	327	330	334	336	340	344
Weighted Average Cost of Gas Sold **	159	158	166	166	165	165	164	163	162	163
Gross Margin	149	150	155	158	162	166	170	173	178	181
Other	2	2	2	2	2	2	2	2	2	2
	151	152	157	160	164	168	172	175	180	183
EXPENSES										
Operating and Administrative	63	61	62	63	64	65	66	68	69	70
Finance Expense	22	23	25	26	28	29	30	31	33	34
Depreciation and Amortization	24	25	27	28	29	31	31	32	33	34
Capital and Other Taxes	17	17	18	18	19	19	20	20	21	21
Other Expenses	12	13	13	12	12	12	12	12	12	11
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
	150	152	157	160	163	168	171	175	179	182
Net Income before Net Movement in Regulatory Deferral	1	(0)	(0)	(0)	0	0	1	0	0	1
Net Movement in Regulatory Deferral **	3	3	3	3	3	3	2	3	3	2
Net Income	3	3	3	3	3	3	3	3	3	3

* The Non-Gas Costs reflect the proposed discontinuance of FRP funding and removal of associated costs from rates for the SGS class, effective Aug 1, 2019

** The adjusted gross margin reflects the cost of gas charged to customer through rates (WACOG). The PGVA has been reclassified to the gross margin from net movement for rate setting purposes.

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
*****Additional Revenue Requirement**										
Percent Increase	0.00%	0.25%	1.36%	0.40%	1.32%	0.98%	1.17%	0.68%	1.41%	0.94%
Cumulative Percent Increase	0.00%	0.25%	1.61%	2.02%	3.36%	4.37%	5.60%	6.31%	7.81%	8.83%
Equity Ratio (PUB Approved Methodology)	32%	31%	29%	29%	28%	28%	27%	27%	26%	26%
Total Return on Equity										
Net Income	3	3	3	3	3	3	3	3	3	3
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
Return on Equity	15	15	15	15	15	15	15	15	15	15
Return on Equity %	7.7%	7.5%	7.5%	7.4%	7.3%	7.2%	7.1%	7.0%	6.9%	6.8%

GAS OPERATIONS (CGM18)
PROJECTED BALANCE SHEET
CGM18 - $3M Net Income 2020 - 2028
(In Millions of Dollars)

For the year ended March 31	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
ASSETS										
Plant in Service	622	658	698	737	776	814	854	894	935	977
Accumulated Depreciation	(65)	(79)	(95)	(112)	(130)	(148)	(168)	(187)	(208)	(229)
Net Plant in Service	557	579	603	626	646	666	686	707	727	747
Construction in Progress	6	9	6	4	4	4	4	4	4	4
Current and Other Assets	92	92	92	92	92	92	92	92	92	92
Goodwill and Intangible Assets	10	9	9	9	9	9	9	9	9	9
Total Assets before Regulatory Deferral	665	689	710	730	751	771	791	812	832	853
Regulatory Deferral Balance	106	109	113	116	118	121	123	126	128	130
	771	798	823	846	869	891	914	937	960	983
LIABILITIES AND EQUITY										
Long-Term Debt	390	440	480	480	510	540	525	585	585	615
Current and Other Liabilities	122	102	83	102	90	78	110	70	89	77
Deferred Revenue	47	49	49	50	52	55	57	58	59	60
Share Capital	121	121	121	121	121	121	121	121	121	121
Retained Earnings	79	82	85	88	91	94	97	100	103	106
Total Liabilities and Equity before Regulatory Deferral	759	794	818	842	864	887	910	933	957	979
Regulatory Deferral Balance	12	5	4	4	4	4	4	4	4	3
	771	798	823	846	869	891	914	937	960	983
Net Debt	441	472	510	531	551	572	592	612	631	649
Equity (PUB Approved Methodology)	32%	31%	29%	29%	28%	28%	27%	27%	26%	26%

GAS OPERATIONS (CGM18)
PROJECTED CASH FLOW STATEMENT
CGM18 - $3M Net Income 2020 - 2028
(In Millions of Dollars)

For the year ended March 31	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
OPERATING ACTIVITIES										
Net Income	3	3	3	3	3	3	3	3	3	3
Add Back:										
Depreciation and Amortization	24	25	27	28	29	31	31	32	33	34
Finance Expense	22	23	25	26	28	29	30	31	33	34
Net Movement Impacts on Depreciation and Finance Expense	10	10	11	10	10	9	10	10	10	9
Adjustments for Non-Cash Items	11	11	11	11	11	11	11	11	11	11
Adjustments for Changes in Non-Cash Working Capital Accounts	(9)	(9)	(19)	(2)	(2)	(2)	(1)	(1)	0	(0)
Interest Paid	(33)	(35)	(37)	(38)	(39)	(41)	(42)	(44)	(45)	(46)
Cash Provided by Operating Activities	27	29	20	38	40	40	42	42	45	45
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	40	50	40	20	40	30	20	60	10	30
Retirement of Long-Term Debt	-	(20)	-	-	(20)	(10)	-	(35)	-	(10)
Cash Provided by Financing Activities	40	30	40	20	20	20	20	25	10	20
INVESTING ACTIVITIES										
Additions to Property, Plant and Equipment	(42)	(47)	(45)	(46)	(47)	(48)	(49)	(50)	(51)	(52)
Additions to Intangible Assets	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Additions to Regulatory Deferral Balances	(14)	(15)	(16)	(15)	(14)	(14)	(15)	(14)	(15)	(13)
Contributions Received	3	3	3	3	3	2	2	3	3	3
Cash Used for Investing Activities	(54)	(60)	(59)	(58)	(59)	(61)	(62)	(62)	(64)	(63)
Net Increase (Decrease) in Cash	13	(1)	1	(1)	0	(1)	(0)	4	(9)	2
Cash at Beginning of Year	(44)	(31)	(32)	(30)	(31)	(31)	(32)	(32)	(27)	(36)
Cash at End of Year	(31)	(32)	(30)	(31)	(31)	(32)	(32)	(27)	(36)	(34)

REFERENCE:

PUB/Centra I-3

PREAMBLE TO IR (IF ANY):

QUESTION:

Please update the schedule of Quarterly results to include the actual results for Q4 and comment on the reasons for the change from forecast.

RESPONSE:

The Corporation is still in the process of finalizing the 2018/19 year-end results and is therefore not in a position to file this information at this time.

Once the results have been finalized and made available for public distribution, the financial results for 2018/19 will be filed with the Public Utilities Board.

REFERENCE:

PUB/Centra I-5, PUB/Centra I-6 a - b

PREAMBLE TO IR (IF ANY):

QUESTION:

a) File an updated Appendix 3.1 reflecting the changes in financial results once the forecasted financial information beyond 2019/20 has been reviewed and approved by the MHEB. Please include the detail of net movement in regulatory deferral accounts consistent with the updated financial forecast.
b) Please update Appendix 5.8 extended for the 10 year IFF period once the forecasted financial information beyond 2019/20 has been reviewed and approved by the MHEB.

RESPONSE:

An updated financial forecast will not be approved by the Manitoba Hydro-Electric Board during the timeframe of this proceeding. As such, Centra is unable to respond to this request.

REFERENCE:

PUB/Centra I-7

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide the comparative analysis for 2018/19 with 2013/14 when available.

RESPONSE:

The Corporation is still in the process of finalizing the 2018/19 year-end results and is therefore not in a position to file this information at this time.

Once the results have been finalized and made available for public distribution, the financial results for 2018/19 will be filed with the Public Utilities Board.

REFERENCE:

PUB/Centra I-7

QUESTION:

b) Please explain the variances in finance expense for 2013/14 actual vs forecast and 2014/15. Please include the impact related to variances in forecast versus actual interest rates.

RESPONSE:

The following sections highlight the differences in finance expense:

CENTRA GAS MANITOBA INC. **Finance Expense** ($000'S)	PUB Approved 2013/14	Actual 2013/14	Difference
Interest on Long Term Debt/Advances	12,345	12,569	224
Provincial Guarantee Fee on Long Term Debt	2,950	2,950	-
Interest on Short Term Debt	162	267	105
Provincial Guarantee Fee on Short Term Debt	25	193	168
Interest on Common Assets	2,990	1,993	(997)
Interest on Inventory	151	168	17
Interest Capitalized	(1,998)	(2,319)	(321)
Carrying Costs on Furnace Replacement Program	320	322	2
Other	-	(23)	(23)
Finance Expense	16,945	16,120	(825)

2013/14 Actual vs. 2013/14 PUB Approved (CGAAP)

Actual 2013/14 finance expense was lower than forecast predominantly due to a decrease in actual interest expense on common assets resulting from a reduction in gas activity charges, as a percentage of total activity charges, which is the cost driver used to allocate interest on common assets. The 2013/14 PUB Approved forecast assumed gas activity charges at 10% versus 9% on an actual basis.

Higher spending on capital projects contributed to increased capitalized interest which further reduced finance expense. Partially offsetting these variances were higher interest and provincial guarantee fee on greater average volumes of short and long term debt, as well as higher rates on long term debt. Greater detail with particular reference to Order 85/13 is provided below.

IFF12 had forecast long term debt issuance of $40 million on March 31, 2014. Only $10 million was issued to Centra, however this was done earlier in the fiscal year on November 26, 2013, increasing finance expense by $116 thousand over forecast. CG18 was issued at a rate of 3.398% versus a forecast rate of 3.40% as revised by Order 85/13.

All of Centra's existing long term debt was at fixed rates with the exception of CG10. The actual interest cost for variable rate CG10 for 2013/14 was 1.68% versus a forecast rate of 1.58% as revised by Order 85/13, increasing finance expense by $35 thousand over forecast.

Debt Series CG15 was forecast to reflect a downward adjustment of 38 basis points to 2.798% as per Order 85/13. On an actual basis, charges for CG15 were based on the underlying Manitoba Hydro debt issue at a rate of 3.178% increasing finance expense by $76 thousand.

Interest on short term debt was forecast to be at 1.00% as per Order 85/13. On an actual basis, interest on short term debt was charged at 0.95%. The increase of $105 thousand in short term interest expense is volume-related.

CENTRA GAS MANITOBA INC. **Finance Expense** ($000'S)	PUB Approved 2013/14	Actual 2014/15	Difference
Interest on Long Term Debt/Advances	12,345	12,810	465
Provincial Guarantee Fee on Long Term Debt	2,950	3,050	100
Interest on Short Term Debt	162	728	566
Provincial Guarantee Fee on Short Term Debt	25	277	252
Interest on Common Assets	2,990	1,977	(1,013)
Interest on Inventory	151	152	1
Interest Capitalized	(1,998)	(3,230)	(1,232)
Carrying Costs on Furnace Replacement Program	320	336	16
Other	-	88	88
Finance Expense	16,945	16,188	(757)

2014/15 Actual vs. 2013/14 PUB Approved (CGAAP)

Actual 2014/15 finance expense was lower than forecast in large part due to favourable volume variance on deferred gas costs as large purchases of supplemental gas were made in 2013/14 due to the colder than normal winter, which resulted in a large PVGA balance owing to Centra in 2014/15. The 2013/14 PUB Approved forecast had a PGVA balance owing to customers for most of the year.

In addition, there was a decrease in actual interest expense on common assets resulting from a reduction in gas activity charges as a percentage of total activity charges. The 2013/14 PUB Approved forecast assumed gas activity charges at 10% versus 9% on an actual basis.

This was partially offset by higher provincial guarantee fee and interest on greater volumes of short and long term debt as well as a higher actual interest rate on long term debt than the 2013/14 PUB Approved forecast.

On November 26, 2013 CG18 $10 million was issued at a rate of 3.398% versus a forecast rate of 3.40%. As this debt issue was outstanding for the full year in 2014/15, it increased finance expense $340 thousand over 2013/14 PUB Approved forecast.

All of Centra's existing long term debt was at fixed rates with the exception of CG10. The actual interest cost for variable rate CG10 for 2014/15 was 1.62% versus a forecast rate of 1.58%. CG10 matured on February 22, 2015. On March 2, 2015 CG19 was issued to refinance CG10 at a rate of 2.902%. The net impact of these variances increased finance expense by $36 thousand versus the 2013/14 PUB Approved forecast.

Debt Series CG15 was forecast to reflect a downward adjustment of 38 basis points to 2.798% as per Order 85/13. On an actual basis, charges for CG15 were based on the underlying Manitoba Hydro debt issue at a rate of 3.178% increasing finance expense by $76 thousand versus the 2013/14 PUB Approved forecast.

Interest on short term debt was forecast to be at 1.00% as per Order 85/13. On an actual basis, interest on short term debt was charged at 0.85%. The increase of $566 thousand in short term interest expense was volume-related.

REFERENCE:

PUB/Centra I-7

PREAMBLE TO IR (IF ANY):

Centra states that the variance in Depreciation Expense between 2013/14 Approved and 2013/14 actual is primarily due to assets becoming fully depreciated (SCADA related-software costs).

QUESTION:

a) Explain why the reduction in Depreciation Expense due to assets becoming fully depreciated was not known or not included in the 2013/14 requested revenue requirement.
b) Please provide a comparative schedule detail of Depreciation and Amortization expense 2013/14 approved vs. 2015/16 actual.

RESPONSE:

a) The response to PUB/CENTRA I-7 has been revised, as the variance explanation for depreciation and amortization expense as originally filed did not correctly characterize the gas SCADA related difference between the 2013/14 approved vs 2013/14 actual and the 2013/14 approved vs 2014/15 actual depreciation expense.

   The portion of the 2013/14 approved vs actual depreciation & amortization variance pertaining to the gas SCADA computer system development plant account is ($397) thousand, and is due to lower capital costs than forecast for the gas SCADA project, and also to an eight month delay in placing the gas SCADA project in-service. The 2013/14 approved depreciation forecast for gas SCADA computer development assumed a full year of depreciation based on capitalized costs of $3,964 thousand with an expected in-service in November, 2012. The project was actually placed into service July, 2013, with computer development costs of $3 006 thousand.

b) The following schedule provides a detailed comparison of 2013/14 approved vs 2015/16 actual depreciation & amortization expense for rate setting purposes. The decrease is primarily due to the impact of removing net salvage from depreciation rates upon transition to IFRS and a reduction in depreciation on common assets, partially offset by an increase in depreciation due to net plant asset additions.

CENTRA GAS MANITOBA INC.
Depreciation Expense Comparison **($000'S)**

1		2013/14	2015/16	
2		Approved	Actual	Variance
3			Rate Setting	
4		[1]	[2]	[3] = [2] - [1]
5	**Intangible Assets**			
6	Franchises & Consents	1	1	0
7	Land Rights	59	76	17
8	Computer System Development	530	442	(88)
9	Other Distribution Development (SCADA)	793	601	(191)
10		1 384	1 121	(263)
11	**Transmission Plant**			
12	Land	-	-	-
13	Structures & Improvements - M&R	20	19	(2)
14	Structures & Improvements - Other	2	2	(0)
15	Mains - Transmission	1 668	1 545	(123)
16	Measuring & Regulating Equipment	149	162	12
17	Amortization of Customer Contributions: Mains	(502)	56	558
18	Amortization of Customer Contributions: Measuring & Regulating Equipment	(5)	26	31
19		1 333	1 809	476
20	**Distribution Plant**			
21	Land	-	-	-
22	Structures & Improvements	32	24	(9)
23	Structures & Improvements - M&R	70	73	2
24	Services	6 555	3 984	(2 571)
25	Regulators	1 123	1 170	47
26	Mains - Distribution	3 354	2 809	(545)
27	Measuring & Reg. Equipment	1 171	946	(225)
28	Telemetry Equipment	203	205	3
29	Meters	1 999	1 637	(362)
30	Computer Equipment - Hardware	94	80	(14)
31	Amortization of Customer Contributions: Services	(171)	(36)	135
32	Amortization of Customer Contributions: Mains	(229)	(8)	221
33	Amortization of Customer Contributions: Measuring & Regulating Equipment	(91)	(24)	66
34	Amortization of Customer Contributions: Meters	(2)	4	6
35		14 108	10 863	(3 245)
36	**General Plant**			
37	Land	-	-	-
38	Structures & Improvements	137	206	68
39	Office Furniture & Equipment	24	3	(21)
40	Transportation Equipment	26	(7)	(34)
41	Heavy Work Equipment	-	-	-
42	Tools & Work Equipment	119	75	(44)
43		306	276	(30)
44				
45	**Depreciation on Common Assets**	4 621	4 008	(613)
46				
47	Other	1 235	959	(276)
48	Investment in Demand Side Management	7 198	7 878	680
49	**Deferred Asset Amortization**	8 433	8 837	404
50				
51	**Other**			
52	Target Adjustments	(95)	-	95
53		(95)	-	95
54				
55	**Depreciation & Amortization Expense**	30 091	26 913	(3 177)

REFERENCE:

PUB/Centra I-11 b) & c)

QUESTION:

a) Please explain why labour allocated to projects has declined in 2018/19.

b) Please update the table from PUB/Centra I-11 b) & c) Round 1 Response to include the number of meter sets replaced in each year and the cost per meter set repair/replacement and explain the variation.

RESPONSE:

a) The forecast labour for meter sampling, testing and exchange decreased in 2018/19 primarily due to a reduction in the forecast for meter exchanges required under the meter compliance program and a shift to use a higher percentage of trainees who have a lower wage rate. The 2017/18 fiscal year also included additional labour to investigate whether or not the gas meter set was up to current standards prior to a meter exchange which was not required in 2018/19.

b) The table below has been updated from PUB/CENTRA I-11b-c to differentiate the labour costs for meter sampling and testing from meter exchange as well as to include the number of meter exchanges, as per Measurement Canada compliance requirements, and the labour cost per meter exchange. Labour cost per meter exchange is calculated using only the corresponding labour for meter exchanges.

CENTRA GAS MANITOBA INC.
METER SAMPLING, TESTING AND EXCHANGE COSTS
($000's)

	CGAAP			IFRS				
	Actual			Actual			Forecast	Test Year
	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Materials	$ 547	$ 200	$ 547	$ 351	$ 400	$ 542	$ 384	$ 456
Labour	**3,996**	**3,585**	**4,295**	**4,808**	**3,495**	**3,273**	**2,608**	**3,066**
Subtotal	4,544	3,785	4,842	5,159	3,895	3,816	2,992	3,522
Overhead	1,008	904	215	(51)	190	168	104	123
Total	$ 5,551	$ 4,689	$ 5,057	$ 5,107	$ 4,085	$ 3,984	$ 3,097	$ 3,645

Labour:								
Meter Sampling, Testing	1,044	974	882	1,319	1,213	1,134	985	1,244
Meter Exchange	2,952	2,611	3,413	3,489	2,282	2,139	1,623	1,822
Total Labour	**3,996**	**3,585**	**4,295**	**4,808**	**3,495**	**3,273**	**2,608**	**3,066**

Labour: Meter Exchange	2,952	2,611	3,413	3,489	2,282	2,139	1,623	1,822
Meter Exchanges (Compliance Requirements)	29,598	15,605	24,202	22,380	12,653	15,538	14,737	16,206
Labour Cost per Meter Exchange	$ 100	$ 167	$ 141	$ 156	$ 180	$ 138	$ 110	$ 112

Labour required to exchange meters is comprised of the time spent exchanging meters, as per Measurement Canada compliance, as well as exchanging meters for various other reasons not related to compliance requirements. Some non-compliance requirements for exchange include damaged, leaking or noisy meters, meters no longer working and upgrades for added load requirements. Both forms of exchanges are combined and costed together with no discrete mechanism in place to split the costs between compliance and other change reasons. However, the majority of the labour primarily relates to the compliance exchanges.

All meter exchanges may include various tasks that make up the total time spent on an exchange, including meter disconnect, removal and install of a new meter, raising and straightening a meter set, and inspecting and upgrading regulation and piping to the current standard. Centra may also relocate the vent of a regulator to meet clearance requirements. Additional time is also incurred if staff are unable to access the meter for exchange and have to return one or more times to complete the job. All of these tasks are costed as meter exchange labour in the table above.

Meter exchange compliance requirements are based on the results of meter sampling from the previous year. Higher failure rates or failure of samples with a larger lot volume are the primary reason behind variations in meter exchanges between years.

The labour cost per meter exchange can vary for a number of reasons, such as:

- The number and location of meter changes. In years with a greater number of exchanges and in areas that are more concentrated, efficiencies related to the routing of staff will naturally occur.
- The level and mix of resources used to complete the exchanges. In years of higher volumes, junior staff are transferred from non-compliance work functions to assist in meeting the work demand.
- Additional tasks and time, as noted above, can vary for each exchange.

REFERENCE:

PUB/Centra I-11 (d),CAC/Centra 1-6 d), e) & f), CAC/Centra I-16 Page 1, Attachment 1 pg. 68

PREAMBLE TO IR (IF ANY):

In Centra's March 10, 2016 letter with respect to accounting for meter sampling and testing:

"As outlined in the IFRS Status update report filed in Manitoba Hydro's 2015/16 & 2016/17 General Rate Application, Centra will harmonize its accounting treatment with that of the Corporation's electric operations to capitalize the costs associated with meter sampling, testing and exchange activities. Centra intends to apply this change in policy on a prospective basis commencing in the 2015/16 fiscal year (with restatement of the 2014/15 fiscal year for comparative reporting purposes) and is requesting the PUB's confirmation that this approach is appropriate for rate-setting purposes."

In the Board's letter to Manitoba Hydro dated April 4, 2016

"At the outset, the Board clarifies that its mandate with respect to prescribing accounting methods is limited to determining the appropriate accounting for rate-setting purposes, but not for financial reporting purposes. While in the Board's view, it would be preferable for Centra's financial statements to be consistent with the current rate-setting methodology approved by the Board, the Board cannot provide the requested guidance as to how Centra should prepare its financial statements for financial reporting purposes. As such, both Manitoba Hydro and Centra should seek the appropriate guidance from their internal and external accounting advisors with respect to their obligations under IFRS to comply with the directives of Board Order 73/15. This should include a consideration of the risk of the utility having to re-state its financial statements if the financial reporting methodology does not align with the Board-approved rate setting methodology…

In the Board's view, whether each of the accounting changes proposed by Centra in its March 10, 2016 correspondence should be implemented for rate-setting purposes will be examined in the next Centra General Rate Application and does not warrant an interim proceeding at this time. It is the Board's intention to examine and make a final ruling with respect to each of these issues for rate-setting purposes at the hearing of the next General Rate Application in 2017."

Centra proposes to make the change in accounting meter sampling and testing for rate setting purposes effecting 2019/20 although the accounting change was implemented for financial reporting purposes in 2015/16.

With respect to asset removal costs and gains and losses on interim disposals under IFRS, such gains and losses are to be recognized in income in the year incurred. Centra established a regulatory deferral account effective April 1, 2014 to defer both the impact of recognizing asset removal costs on terminal asset retirements and the impact of recognizing asset retirement gains and losses.

QUESTION:

a) Please differentiate and explain why Centra has proposed to deal with IFRS prescribed changes for accounting asset retirement costs and interim gains and losses on disposal of assets for rate setting purposes since 2015/16 differently than in the accounting for the change in meter sampling and testing.
b) Provide an IFF scenario where the difference accumulated related to the change in accounting for meter sampling and testing is treated in a similar manner as the purposed treatment of interim gains and losses on disposal of assets for rate setting purposes.
c) Please assume that the accounting adjustment for meter sampling and testing were made at the subsidiary level when Centra adopted IFRS and was required to have consistent accounting policies with the parent company and provide the following requested scenarios for rate-setting purposes.
    i) A CGM18 financial scenario (including adjustments to the proposed/ indicative rate increases and the financial ratio calculations) assuming the transfer of the cumulative profit adjustment from part (b)) to Centra's balance sheet (retained earnings) effective April 1, 2019 and adjusting the non-gas revenue requirement and required rate increase for 2019/20 and the indicative rate increases for 2020/21 to

2027/28 to result in a projected Equity ratio of 30% in all years of the forecast including 2019/20. If required, please reflect the adjustment as a regulatory deferral account.

ii) Alternate versions of Figure 3.3 and Figure 3.4 of Tab 3, Section 3.3 of the Application assuming that the profit adjustment in part (b) is a component of the Centra net income and retained earnings from 2014/15 to 2018/19 and provide data tables to support the amounts in the alternate Figures 3.3 and 3.4.

d) Please provide scenario(s) whereby the cumulative profit adjustment is set up as a regulatory deferral account and amortized into rates over a 5 year or ten-year period. Please adjust the indicated rate to maintain a 30% equity ratio in each of the scenarios.

e) Please provide scenario(s) whereby the cumulative profit adjustment is set up as a regulatory deferral account and amortized into rates over a 5 year period and also over a ten-year period. Please adjust the indicative rate to maintain $3 million net income in each of the scenarios.

RESPONSE:

a) Prior to transition to IFRS, losses or gains on disposal of assets were historically included in rate base as they were recorded through accumulated depreciation. The losses or gains would remain in accumulated depreciation until future depreciation studies adjusted depreciation rates to recover or refund these costs. Upon transition to IFRS, this treatment was no longer allowed, with losses or gains recorded directly to the statement of income when the asset is retired. To maintain the regulatory accounting principle that had been in place previous to IFRS, Centra is currently recording losses or gains as a regulated debit or credit balance. This ensures that the full cost of the asset is recovered from ratepayers, even if the asset is retired prior to being fully depreciated.

Meter testing costs were historically included in Centra’s operating costs. As such, they were recovered from customers in rates in the period they were incurred. Upon transition to IFRS, Centra sought regulatory approval to capitalize these costs as Centra and its parent, Manitoba Hydro, were required to have harmonized accounting policies for financial statement purposes. The PUB determined that they would review the capitalizing of these costs for rate setting purposes at the next GRA. In the interim, Centra continued to expense these costs on its financial statements. Centra rate payers fully paid for these costs each year. The required change to harmonize accounting policy for financial statement purposes was made at the consolidated level, and does not impact Centra financial statements or accounting for rate setting purposes.

b) through e)

The following schedule which provides the income statement and balance sheet balances related to the meter exchange program, as provided in the response to CAC-CENTRA-I-6b, was used in the development of the responses below.

($000's)	O&A	Depreciation	Net Income	PP&E	Accumulated Depreciation	Net Plant
2014/15 actual	(5 057)	220	4 836	5 057	220	4 836
2015/16 actual	(5 107)	753	4 355	10 164	973	9 191
2016/17 actual	(4 085)	1 207	2 878	14 249	2 180	12 069
2017/18 actual	(3 984)	1 602	2 382	18 233	3 782	14 451
2018/19 forecast	(2 992)	2 101	891	21 225	5 883	15 342
	(21 225)	5 883	15 342			

Further to the above schedule, the following schedule provides the remaining forecasted depreciation relating to the unamortized balance of the meter exchange program:

	($000s)	Depreciation
Actual:	2014/15	220
	2015/16	753
	2016/17	1 207
	2017/18	1 602
Projected:	2018/19	2 101
	Subtotal	**5 883**
Forecast:	2019/20	2 125
	2020/21	2 125
	2021/22	2 125
	2022/23	2 125
	2023/24	2 125
	2024/25	1 905
	2025/26	1 372
	2026/27	918
	2027/28	522
	Total	**21 225**

The following table summarizes the assumptions used for each of the financial scenarios and financial ratio calculations provided in the Attachment to this response:

SCENARIO	ASSUMPTIONS
Part b)	As of April 1, 2019, a regulated asset was established and retained earnings were credited for the amount of the unamortized balance of the meter exchange program ($15.342M). This balance was amortized through net movement according to the projected depreciation schedule provided above.
Part c) i Part c) ii	As of April 1, 2019, Net PP&E and retained earnings were restated by the unamortized balance of meter exchange program ($15.342M). The remaining meter exchange program balance was depreciated through the Depreciation & Amortization line on the income statement according to the schedule provided above. Figures 3.3 and 3.4 of Tab 3, Section 3.3 of the Application have been restated assuming the accounting treatment as outlined in part c) i above.
Part d) i	As of April 1, 2019, a regulated asset was established and retained earnings were credited for the amount of the unamortized balance of the meter exchange program ($15.342M). This balance was amortized through net movement over a 5 year period. The indicative rate increases were not required to be adjusted as the equity ratio remains at or around the 30% equity ratio in each year of the forecast period.
Part d) ii	As of April 1, 2019, a regulated asset was established and retained earnings were credited for the amount of the unamortized balance of the meter exchange program ($15.342M). This balance was amortized through net movement over a 10 year period. The indicative rate increases were not required to be adjusted as the equity ratio remains at or around the 30% equity ratio in each year of the forecast period.
Part e) i	As of April 1, 2019, a regulated asset was established and retained earnings were credited for the amount of the unamortized balance of the meter exchange program ($15.342M). This balance was amortized through net movement over a 5 year period. Starting in 2020/21, indicative rate increases were adjusted to maintain a $3M net income in each year of the forecast.
Part e) ii	As of April 1, 2019, a regulated asset was established and retained earnings were credited for the amount of the unamortized balance of the meter

	exchange program ($15.342M). This balance was amortized through net movement over a 10 year period. Starting in 2020/21, indicative rate increases were adjusted to maintain a $3M net income in each year of the forecast.

Part b)

GAS OPERATIONS (CGM18)
PROJECTED OPERATING STATEMENT
CGM18 - Meter Exchange Unamortized Balance set up in Regulated Asset
(In Millions of Dollars)

For the year ended March 31	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
REVENUES										
Domestic Revenue										
Cost of Gas	159	158	166	166	165	165	164	163	162	163
Non-Gas Costs *	152	150	150	151	151	151	151	152	152	151
Furnace Replacement Program Funding	(4)	(1)	-	-	-	-	-	-	-	-
Late Payment Charges and Broker Revenue	1	1	1	1	1	1	1	1	1	1
	308	308	316	317	317	316	316	315	315	315
additional revenue requirement***	-	-	6	10	14	17	21	24	28	32
	308	308	323	328	331	334	337	340	343	346
Weighted Average Cost of Gas Sold **	159	158	166	166	165	165	164	163	162	163
Gross Margin	149	150	157	162	165	169	173	177	181	184
Other	2	2	2	2	2	2	2	2	2	2
	151	151	158	163	167	171	175	179	183	186
EXPENSES										
Operating and Administrative	63	61	62	63	64	65	66	68	69	70
Finance Expense	22	23	25	26	27	29	30	30	32	33
Depreciation and Amortization	24	25	27	28	29	31	31	32	33	34
Capital and Other Taxes	17	17	18	18	19	19	20	20	21	21
Other Expenses	12	13	13	12	12	12	12	12	12	11
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
	150	152	157	160	163	167	171	174	178	181
Net Income before Net Movement in Regulatory Deferral	1	(1)	1	4	4	4	4	5	4	5
Net Movement in Regulatory Deferral **	3	1	1	1	0	1	0	1	2	2
Net Income	3	0	2	5	5	5	5	6	6	6

* The Non-Gas Costs reflect the proposed discontinuance of FRP funding and removal of associated costs from rates for the SGS class, effective Aug 1, 2019

** The adjusted gross margin reflects the cost of gas charged to customer through rates (WACOG). The PGVA has been reclassified to the gross margin from net movement for rate setting purposes.

***__Additional Revenue Requirement__**										
Percent Increase	0.00%	0.00%	2.25%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
Cumulative Percent Increase	0.00%	0.00%	2.25%	3.27%	4.31%	5.35%	6.40%	7.47%	8.54%	9.63%
Equity Ratio (PUB Approved Methodology)	32%	31%	31%	30%	30%	29%	29%	29%	29%	29%

Part b)

GAS OPERATIONS (CGM18)
PROJECTED BALANCE SHEET
CGM18 - Meter Exchange Unamortized Balance set up in Regulated Asset
(In Millions of Dollars)

For the year ended March 31	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
ASSETS										
Plant in Service	622	658	698	737	776	814	854	894	935	977
Accumulated Depreciation	(65)	(79)	(95)	(112)	(130)	(148)	(168)	(187)	(208)	(229)
Net Plant in Service	557	579	603	626	646	666	686	707	727	747
Construction in Progress	6	9	6	4	4	4	4	4	4	4
Current and Other Assets	92	92	92	92	92	92	92	92	92	92
Goodwill and Intangible Assets	10	9	9	9	9	9	9	9	9	9
Total Assets before Regulatory Deferral	665	689	710	730	751	771	791	812	832	853
Regulatory Deferral Balance	106	123	124	125	125	125	126	127	129	130
	771	812	834	855	876	896	917	939	961	983
LIABILITIES AND EQUITY										
Long-Term Debt	390	440	480	470	500	530	505	565	565	595
Current and Other Liabilities	122	103	82	108	92	76	115	69	85	69
Deferred Revenue	47	49	49	50	52	55	57	58	59	60
Share Capital	121	121	121	121	121	121	121	121	121	121
Retained Earnings	79	94	97	101	106	111	115	121	127	134
Total Liabilities and Equity before Regulatory Deferral	759	807	829	851	871	892	913	935	957	979
Regulatory Deferral Balance	12	5	4	4	4	4	4	4	4	3
	771	812	834	855	876	896	917	939	961	983
Net Debt	441	473	510	526	543	559	576	592	607	622
Equity (PUB Approved Methodology)	32%	31%	31%	30%	30%	29%	29%	29%	29%	29%

Part b)

GAS OPERATIONS (CGM18)
PROJECTED CASH FLOW STATEMENT
CGM18 - Meter Exchange Unamortized Balance set up in Regulated Asset
(In Millions of Dollars)

For the year ended March 31	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
OPERATING ACTIVITIES										
Net Income	3	0	2	5	5	5	5	6	6	6
Add Back:										
Depreciation and Amortization	24	25	27	28	29	31	31	32	33	34
Finance Expense	22	23	25	26	27	29	30	30	32	33
Net Movement Impacts on Depreciation and Finance Expense	10	12	13	12	12	12	12	11	11	10
Adjustments for Non-Cash Items	11	11	11	11	11	11	11	11	11	11
Adjustments for Changes in Non-Cash Working Capital Accounts	(9)	(9)	(19)	(2)	(2)	(2)	(1)	(1)	(0)	(0)
Interest Paid	(33)	(35)	(37)	(38)	(39)	(41)	(42)	(43)	(44)	(45)
Cash Provided by Operating Activities	27	28	22	42	43	44	45	46	48	49
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	40	50	40	10	40	30	10	60	10	30
Retirement of Long-Term Debt	-	(20)	-	-	(20)	(10)	-	(35)	-	(10)
Cash Provided by Financing Activities	40	30	40	10	20	20	10	25	10	20
INVESTING ACTIVITIES										
Additions to Property, Plant and Equipment	(42)	(47)	(45)	(46)	(47)	(48)	(49)	(50)	(51)	(52)
Additions to Intangible Assets	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Additions to Regulatory Deferral Balances	(14)	(15)	(16)	(15)	(14)	(14)	(15)	(14)	(15)	(13)
Contributions Received	3	3	3	3	3	2	2	3	3	3
Cash Used for Investing Activities	(54)	(60)	(59)	(58)	(59)	(61)	(62)	(62)	(64)	(63)
Net Increase (Decrease) in Cash	13	(2)	3	(7)	4	3	(7)	9	(5)	6
Cash at Beginning of Year	(44)	(31)	(33)	(30)	(37)	(33)	(30)	(36)	(27)	(32)
Cash at End of Year	(31)	(33)	(30)	(37)	(33)	(30)	(36)	(27)	(32)	(27)

Part b)

GAS OPERATIONS (CGM18)
PROJECTED FINANCIAL RATIOS
CGM18 - Meter Exchange Unamortized Balance set up in Regulated Asset

For the year ended March 31

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
PUB APPROVED DEBT TO EQUITY RATIO										
Average Long-Term Debt	389.903	424.903	459.903	484.903	499.903	519.903	534.903	552.403	569.903	584.952
Average Due to Parent	37.384	31.706	31.142	33.095	34.643	31.142	32.861	31.700	29.808	29.588
Average Debt	**427.287**	**456.609**	**491.045**	**517.998**	**534.546**	**551.045**	**567.764**	**584.103**	**599.711**	**614.539**
Average Share Capital	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250
Average Retained Earnings	77.225	86.593	95.522	99.088	103.756	108.357	112.950	118.330	124.339	130.393
Average Equity	**198.474**	**207.843**	**216.771**	**220.337**	**225.006**	**229.607**	**234.200**	**239.580**	**245.589**	**251.643**
Average Debt	427.287	456.609	491.045	517.998	534.546	551.045	567.764	584.103	599.711	614.539
Average Equity	198.474	207.843	216.771	220.337	225.006	229.607	234.200	239.580	245.589	251.643
Average Debt and Equity	625.761	664.451	707.816	738.335	759.551	780.652	801.964	823.682	845.300	866.182
PUB Approved Equity Ratio	**31.72%**	**31.28%**	**30.63%**	**29.84%**	**29.62%**	**29.41%**	**29.20%**	**29.09%**	**29.05%**	**29.05%**

Part b)

GAS OPERATIONS (CGM18)
PROJECTED FINANCIAL RATIOS
CGM18 - Meter Exchange Unamortized Balance set up in Regulated Asset

For the year ended March 31

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
INTEREST COVERAGE										
Net Income	3.267	0.127	2.388	4.744	4.592	4.611	4.575	6.184	5.835	6.273
Finance Expense	20.502	22.230	23.946	25.316	26.224	27.724	28.948	29.831	31.559	32.413
Capitalized Interest	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	23.941	22.594	26.585	30.192	30.851	32.370	33.559	36.051	37.432	38.724
Finance Expense	20.502	22.230	23.946	25.316	26.224	27.724	28.948	29.831	31.559	32.413
Capitalized Interest	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	20.674	22.467	24.197	25.448	26.259	27.759	28.984	29.867	31.597	32.451
Interest Coverage	**1.16**	**1.01**	**1.10**	**1.19**	**1.17**	**1.17**	**1.16**	**1.21**	**1.18**	**1.19**
Add: Depreciation and Amortization *	34.899	38.819	40.665	40.936	42.524	43.054	44.000	43.628	44.346	44.354
Total EBITDA	58.840	61.413	67.250	71.128	73.374	75.424	77.559	79.679	81.778	83.078
EBITDA Interest Coverage	**2.85**	**2.73**	**2.78**	**2.80**	**2.79**	**2.72**	**2.68**	**2.67**	**2.59**	**2.56**

* Includes amortization of deferred income tax

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
CAPITAL COVERAGE										
Internally Generated Funds	27.389	27.803	21.883	41.529	43.240	43.998	45.269	46.397	48.372	48.890
Capitalized Interest*	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	27.560	28.040	22.134	41.661	43.275	44.033	45.305	46.433	48.409	48.928
Net Capital Construction Expenditures	35.404	40.075	38.382	38.991	39.800	40.596	41.408	42.236	43.081	43.943
Capital Coverage	**0.78**	**0.70**	**0.58**	**1.07**	**1.09**	**1.08**	**1.09**	**1.10**	**1.12**	**1.11**

*Capitalized interest is removed from gross interest paid in order to maintain a consistent ratio calculation using net interest paid

Part c) i

GAS OPERATIONS (CGM18)
PROJECTED OPERATING STATEMENT
CGM18 - Meter Exchange Unamortized Balance - Restated Net PPE
(In Millions of Dollars)

For the year ended March 31	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
REVENUES										
Domestic Revenue										
Cost of Gas	159	158	166	166	165	165	164	163	162	163
Non-Gas Costs *	152	150	150	151	151	151	151	152	152	151
Furnace Replacement Program Funding	(4)	(1)	-	-	-	-	-	-	-	-
Late Payment Charges and Broker Revenue	1	1	1	1	1	1	1	1	1	1
	308	308	316	317	317	316	316	315	315	315
additional revenue requirement***	-	-	6	10	14	17	21	24	28	32
	308	308	323	328	331	334	337	340	343	346
Weighted Average Cost of Gas Sold **	159	158	166	166	165	165	164	163	162	163
Gross Margin	149	150	157	162	165	169	173	177	181	184
Other	2	2	2	2	2	2	2	2	2	2
	151	151	158	163	167	171	175	179	183	186
EXPENSES										
Operating and Administrative	63	61	62	63	64	65	66	68	69	70
Finance Expense	22	23	25	26	27	29	30	30	32	33
Depreciation and Amortization	24	28	29	30	32	33	33	33	34	35
Capital and Other Taxes	17	17	18	18	19	19	20	20	21	21
Other Expenses	12	13	13	12	12	12	12	12	12	11
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
	150	155	159	162	165	169	173	175	179	182
Net Income before Net Movement in Regulatory Deferral	1	(3)	(1)	2	2	2	2	3	3	4
Net Movement in Regulatory Deferral **	3	3	3	3	3	3	2	3	3	2
Net Income	3	0	2	5	5	5	5	6	6	6

* The Non-Gas Costs reflect the proposed discontinuance of FRP funding and removal of associated costs from rates for the SGS class, effective Aug 1, 2019

** The adjusted gross margin reflects the cost of gas charged to customer through rates (WACOG). The PGVA has been reclassified to the gross margin from net movement for rate setting purposes.

****Additional Revenue Requirement**										
Percent Increase	0.00%	0.00%	2.25%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
Cumulative Percent Increase	0.00%	0.00%	2.25%	3.27%	4.31%	5.35%	6.40%	7.47%	8.54%	9.63%
Equity Ratio (PUB Approved Methodology)	32%	31%	31%	30%	30%	29%	29%	29%	29%	29%

Part c) i

GAS OPERATIONS (CGM18)
PROJECTED BALANCE SHEET
CGM18 - Meter Exchange Unamortized Balance - Restated Net PPE
(In Millions of Dollars)

For the year ended March 31	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
ASSETS										
Plant in Service	622	679	719	759	797	836	875	915	956	998
Accumulated Depreciation	(65)	(87)	(105)	(124)	(144)	(165)	(186)	(207)	(229)	(251)
Net Plant in Service	557	592	614	635	653	671	689	708	728	747
Construction in Progress	6	9	6	4	4	4	4	4	4	4
Current and Other Assets	92	92	92	92	92	92	92	92	92	92
Goodwill and Intangible Assets	10	9	9	9	9	9	9	9	9	9
Total Assets before Regulatory Deferral	665	702	721	739	758	775	794	813	833	853
Regulatory Deferral Balance	106	109	113	116	118	121	123	126	128	130
	771	812	834	855	876	896	917	939	961	983
LIABILITIES AND EQUITY										
Long-Term Debt	390	440	480	470	500	530	505	565	565	595
Current and Other Liabilities	122	103	82	108	92	76	115	69	85	69
Deferred Revenue	47	49	49	50	52	55	57	58	59	60
Share Capital	121	121	121	121	121	121	121	121	121	121
Retained Earnings	79	94	97	101	106	111	115	121	127	134
Total Liabilities and Equity before Regulatory Deferral	759	807	829	851	871	892	913	935	957	979
Regulatory Deferral Balance	12	5	4	4	4	4	4	4	4	3
	771	812	834	855	876	896	917	939	961	983
Net Debt	441	473	510	526	543	559	576	592	607	622
Equity (PUB Approved Methodology)	32%	31%	31%	30%	30%	29%	29%	29%	29%	29%

Part c) i

GAS OPERATIONS (CGM18)
PROJECTED CASH FLOW STATEMENT
CGM18 - Meter Exchange Unamortized Balance - Restated Net PPE
(In Millions of Dollars)

For the year ended March 31

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
OPERATING ACTIVITIES										
Net Income	3	0	2	5	5	5	5	6	6	6
Add Back:										
Depreciation and Amortization	24	28	29	30	32	33	33	33	34	35
Finance Expense	22	23	25	26	27	29	30	30	32	33
Net Movement Impacts on Depreciation and Finance Expense	10	10	11	10	10	9	10	10	10	9
Adjustments for Non-Cash Items	11	11	11	11	11	11	11	11	11	11
Adjustments for Changes in Non-Cash Working Capital Accounts	(9)	(9)	(19)	(2)	(2)	(2)	(1)	(1)	(0)	(0)
Interest Paid	(33)	(35)	(37)	(38)	(39)	(41)	(42)	(43)	(44)	(45)
Cash Provided by Operating Activities	27	28	22	42	43	44	45	46	48	49
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	40	50	40	10	40	30	10	60	10	30
Retirement of Long-Term Debt	-	(20)	-	-	(20)	(10)	-	(35)	-	(10)
Cash Provided by Financing Activities	40	30	40	10	20	20	10	25	10	20
INVESTING ACTIVITIES										
Additions to Property, Plant and Equipment	(42)	(47)	(45)	(46)	(47)	(48)	(49)	(50)	(51)	(52)
Additions to Intangible Assets	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Additions to Regulatory Deferral Balances	(14)	(15)	(16)	(15)	(14)	(14)	(15)	(14)	(15)	(13)
Contributions Received	3	3	3	3	3	2	2	3	3	3
Cash Used for Investing Activities	(54)	(60)	(59)	(58)	(59)	(61)	(62)	(62)	(64)	(63)
Net Increase (Decrease) in Cash	13	(2)	3	(7)	4	3	(7)	9	(5)	6
Cash at Beginning of Year	(44)	(31)	(33)	(30)	(37)	(33)	(30)	(36)	(27)	(32)
Cash at End of Year	(31)	(33)	(30)	(37)	(33)	(30)	(36)	(27)	(32)	(27)

Part c) i

GAS OPERATIONS (CGM18)
PROJECTED FINANCIAL RATIOS
CGM18 - Meter Exchange Unamortized Balance - Restated Net PPE

For the year ended March 31

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
PUB APPROVED DEBT TO EQUITY RATIO										
Average Long-Term Debt	389.903	424.903	459.903	484.903	499.903	519.903	534.903	552.403	569.903	584.952
Average Due to Parent	37.384	31.706	31.142	33.095	34.643	31.142	32.861	31.700	29.808	29.588
Average Debt	**427.287**	**456.609**	**491.045**	**517.998**	**534.546**	**551.045**	**567.764**	**584.103**	**599.711**	**614.539**
Average Share Capital	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250
Average Retained Earnings	77.225	86.593	95.522	99.088	103.756	108.357	112.950	118.330	124.339	130.393
Average Equity	**198.474**	**207.843**	**216.771**	**220.337**	**225.006**	**229.607**	**234.200**	**239.580**	**245.589**	**251.643**
Average Debt	427.287	456.609	491.045	517.998	534.546	551.045	567.764	584.103	599.711	614.539
Average Equity	198.474	207.843	216.771	220.337	225.006	229.607	234.200	239.580	245.589	251.643
Average Debt and Equity	625.761	664.451	707.816	738.335	759.551	780.652	801.964	823.682	845.300	866.182
PUB Approved Equity Ratio	**31.72%**	**31.28%**	**30.63%**	**29.84%**	**29.62%**	**29.41%**	**29.20%**	**29.09%**	**29.05%**	**29.05%**

Part c) i

GAS OPERATIONS (CGM18)
PROJECTED FINANCIAL RATIOS
CGM18 - Meter Exchange Unamortized Balance - Restated Net PPE

For the year ended March 31

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
INTEREST COVERAGE										
Net Income	3.267	0.127	2.388	4.744	4.592	4.611	4.575	6.184	5.835	6.273
Finance Expense	20.502	22.230	23.946	25.316	26.224	27.724	28.948	29.831	31.559	32.413
Capitalized Interest	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	23.941	22.594	26.585	30.192	30.851	32.370	33.559	36.051	37.432	38.724
Finance Expense	20.502	22.230	23.946	25.316	26.224	27.724	28.948	29.831	31.559	32.413
Capitalized Interest	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	20.674	22.467	24.197	25.448	26.259	27.759	28.984	29.867	31.597	32.451
Interest Coverage	**1.16**	**1.01**	**1.10**	**1.19**	**1.17**	**1.17**	**1.16**	**1.21**	**1.18**	**1.19**
Add: Depreciation and Amortization *	34.899	38.819	40.665	40.936	42.524	43.054	44.000	43.628	44.346	44.354
Total EBITDA	58.840	61.413	67.250	71.128	73.374	75.424	77.559	79.679	81.778	83.078
EBITDA Interest Coverage	**2.85**	**2.73**	**2.78**	**2.80**	**2.79**	**2.72**	**2.68**	**2.67**	**2.59**	**2.56**

* Includes amortization of deferred income tax

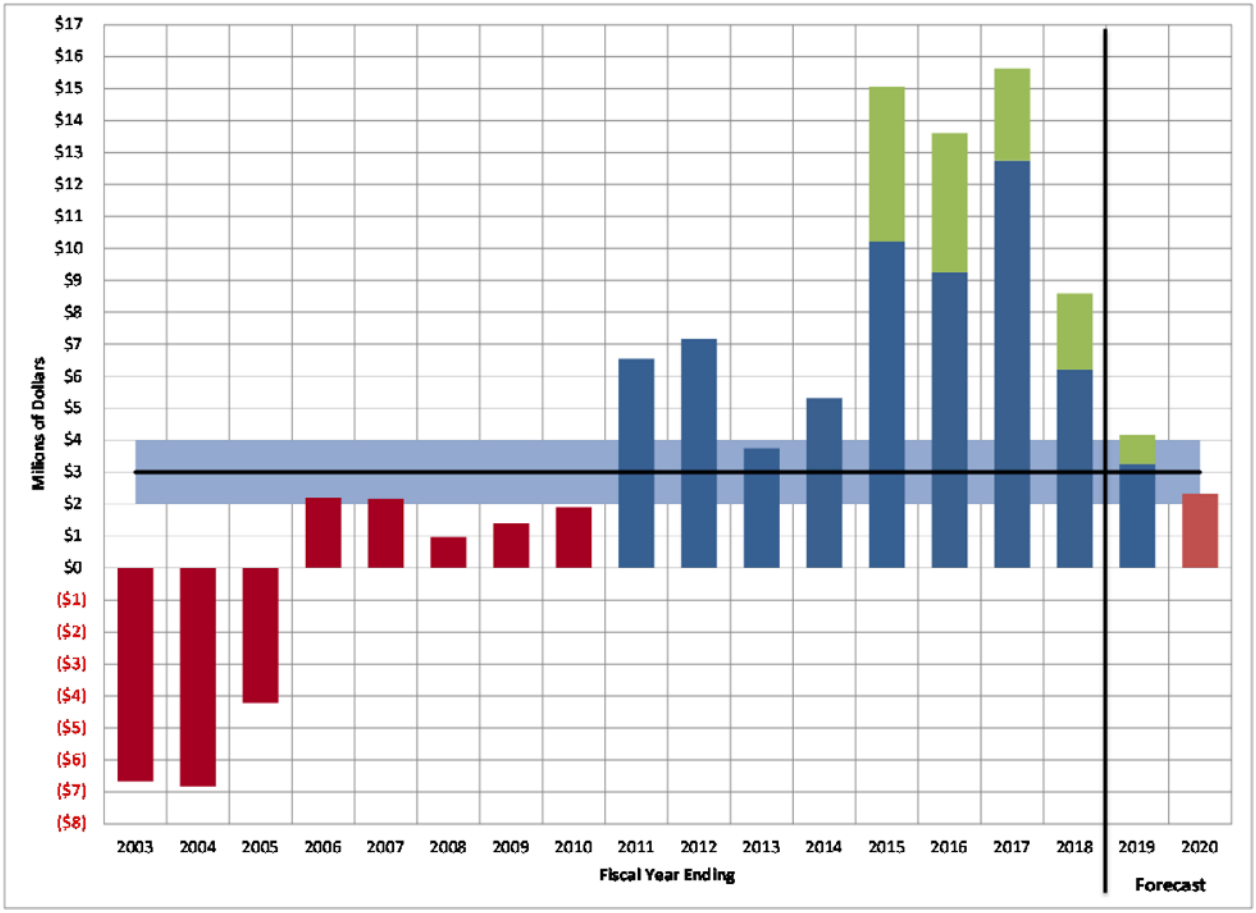
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
CAPITAL COVERAGE										
Internally Generated Funds	27.389	27.803	21.883	41.529	43.240	43.998	45.269	46.397	48.372	48.890
Capitalized Interest*	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	27.560	28.040	22.134	41.661	43.275	44.033	45.305	46.433	48.409	48.928
Net Capital Construction Expenditures	35.404	40.075	38.382	38.991	39.800	40.596	41.408	42.236	43.081	43.943
Capital Coverage	**0.78**	**0.70**	**0.58**	**1.07**	**1.09**	**1.08**	**1.09**	**1.10**	**1.12**	**1.11**

*Capitalized interest is removed from gross interest paid in order to maintain a consistent ratio calculation using net interest paid

part c) ii

Figure 3.3 has been restated below assuming the meter exchange program had been capitalized upon conversion to IFRS beginning in 2014/15. The green bars in the figure show the additional net income that would have been recognized in years 2014/15 through 2018/19. The data supporting the restated figure has been provided below.

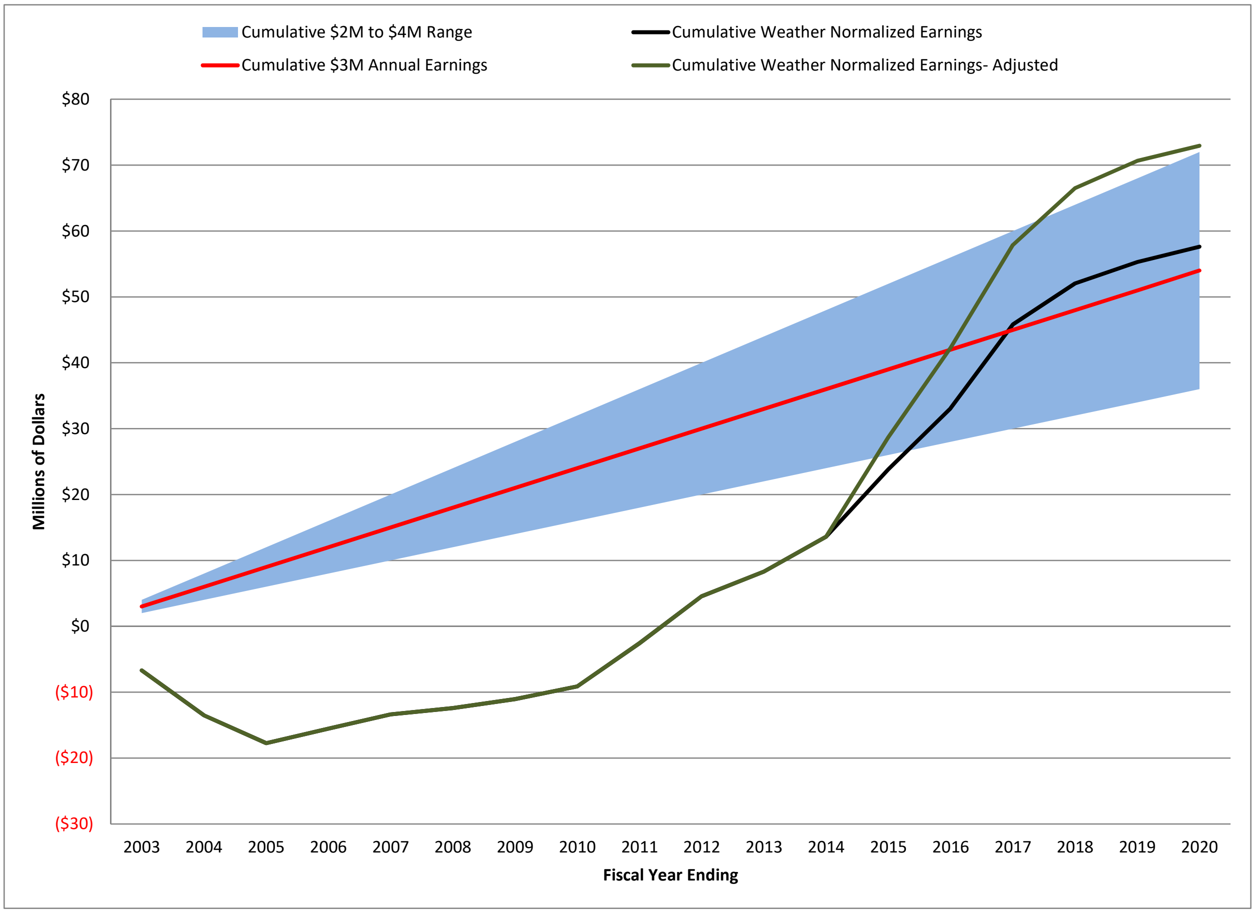
Figure 3.3: Centra's Weather-Normalized Net Income – Restated



(in millions)	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Weather Normalized Net Income	(6.7)	(6.8)	(4.2)	2.2	2.2	1.0	1.4	1.9	6.6	7.2	3.7	5.3	10.2	9.3	12.8	6.2	3.3	2.3
Meter Exchange Net Income Impact	-	-	-	-	-	-	-	-	-	-	-	-	4.8	4.4	2.9	2.4	0.9	-
Adjusted Weather Normalized Net Income	(6.7)	(6.8)	(4.2)	2.2	2.2	1.0	1.4	1.9	6.6	7.2	3.7	5.3	15.1	13.6	15.6	8.6	4.2	2.3

Figure 3.4 has been restated below assuming the meter exchange program had been capitalized upon conversion to IFRS beginning in 2014/15. The green line on the figure shows the cumulative weather normalized net income from 2002/03 to 2019/20 with years 2014/15 to 2018/19 adjusted as if the meter exchange program had been capitalized beginning in 2014/15. The data supporting the restated figure has been provided below.

Figure 3.4: Comparison of Cumulative Weather-Normalized Earnings – Restated



(in millions)	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Cumulative Weather Normalized Net Income	(6.7)	(13.5)	(17.7)	(15.6)	(13.4)	(12.4)	(11.0)	(9.1)	(2.6)	4.6	8.3	13.6	23.8	33.1	45.8	52.0	55.3	57.6
Cumulative Meter Exchange Net Income Impact	-	-	-	-	-	-	-	-	-	-	-	-	4.8	9.2	12.1	14.5	15.3	15.3
Adjusted Cum. Weather Normalized Net Income	(6.7)	(13.5)	(17.7)	(15.6)	(13.4)	(12.4)	(11.0)	(9.1)	(2.6)	4.6	8.3	13.6	28.7	42.3	57.9	66.5	70.7	73.0
Cumulative $2M Range	2.0	4.0	6.0	8.0	10.0	12.0	14.0	16.0	18.0	20.0	22.0	24.0	26.0	28.0	30.0	32.0	34.0	36.0
Cumulative $4M Range	4.0	8.0	12.0	16.0	20.0	24.0	28.0	32.0	36.0	40.0	44.0	48.0	52.0	56.0	60.0	64.0	68.0	72.0

Part d) i

GAS OPERATIONS (CGM18)
PROJECTED OPERATING STATEMENT
CGM18 - Meter Exchange Unamortized Balance set up in Reg Asset, Amort over 5yrs
(In Millions of Dollars)

For the year ended March 31	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
REVENUES										
Domestic Revenue										
Cost of Gas	159	158	166	166	165	165	164	163	162	163
Non-Gas Costs *	152	150	150	151	151	151	151	152	152	151
Furnace Replacement Program Funding	(4)	(1)	-	-	-	-	-	-	-	-
Late Payment Charges and Broker Revenue	1	1	1	1	1	1	1	1	1	1
	308	308	316	317	317	316	316	315	315	315
additional revenue requirement***	-	-	6	10	14	17	21	24	28	32
	308	308	323	328	331	334	337	340	343	346
Weighted Average Cost of Gas Sold **	159	158	166	166	165	165	164	163	162	163
Gross Margin	149	150	157	162	165	169	173	177	181	184
Other	2	2	2	2	2	2	2	2	2	2
	151	151	158	163	167	171	175	179	183	186
EXPENSES										
Operating and Administrative	63	61	62	63	64	65	66	68	69	70
Finance Expense	22	23	25	26	27	29	30	30	32	33
Depreciation and Amortization	24	25	27	28	29	31	31	32	33	34
Capital and Other Taxes	17	17	18	18	19	19	20	20	21	21
Other Expenses	12	13	13	12	12	12	12	12	12	11
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
	150	152	157	160	163	167	171	174	178	181
Net Income before Net Movement in Regulatory Deferral	1	(1)	1	4	4	4	4	5	4	5
Net Movement in Regulatory Deferral **	3	0	0	0	(1)	(0)	2	3	3	2
Net Income	3	(1)	1	4	4	4	6	8	7	7

* The Non-Gas Costs reflect the proposed discontinuance of FRP funding and removal of associated costs from rates for the SGS class, effective Aug 1, 2019

** The adjusted gross margin reflects the cost of gas charged to customer through rates (WACOG). The PGVA has been reclassified to the gross margin from net movement for rate setting purposes.

****Additional Revenue Requirement**										
Percent Increase	0.00%	0.00%	2.25%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
Cumulative Percent Increase	0.00%	0.00%	2.25%	3.27%	4.31%	5.35%	6.40%	7.47%	8.54%	9.63%
Equity Ratio (PUB Approved Methodology)	32%	31%	30%	30%	29%	29%	29%	29%	29%	29%

Part d) i

GAS OPERATIONS (CGM18)
PROJECTED BALANCE SHEET
CGM18 - Meter Exchange Unamortized Balance set up in Reg Asset, Amort over 5yrs
(In Millions of Dollars)

For the year ended March 31

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
ASSETS										
Plant in Service	622	658	698	737	776	814	854	894	935	977
Accumulated Depreciation	(65)	(79)	(95)	(112)	(130)	(148)	(168)	(187)	(208)	(229)
Net Plant in Service	557	579	603	626	646	666	686	707	727	747
Construction in Progress	6	9	6	4	4	4	4	4	4	4
Current and Other Assets	92	92	92	92	92	92	92	92	92	92
Goodwill and Intangible Assets	10	9	9	9	9	9	9	9	9	9
Total Assets before Regulatory Deferral	665	689	710	730	751	771	791	812	832	853
Regulatory Deferral Balance	106	122	122	122	121	121	123	126	128	130
	771	811	832	852	872	891	914	937	960	983
LIABILITIES AND EQUITY										
Long-Term Debt	390	440	480	470	500	530	505	565	565	585
Current and Other Liabilities	122	103	82	108	92	76	115	69	85	79
Deferred Revenue	47	49	49	50	52	55	57	58	59	60
Share Capital	121	121	121	121	121	121	121	121	121	121
Retained Earnings	79	93	95	99	102	106	113	120	127	134
Total Liabilities and Equity before Regulatory Deferral	759	806	827	848	868	887	910	933	957	979
Regulatory Deferral Balance	12	5	4	4	4	4	4	4	4	3
	771	811	832	852	872	891	914	937	960	983
Net Debt	441	473	510	526	543	559	576	592	607	622
Equity (PUB Approved Methodology)	32%	31%	30%	30%	29%	29%	29%	29%	29%	29%

Part d) i

GAS OPERATIONS (CGM18)
PROJECTED CASH FLOW STATEMENT
CGM18 - Meter Exchange Unamortized Balance set up in Reg Asset, Amort over 5yrs
(In Millions of Dollars)

For the year ended March 31	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
OPERATING ACTIVITIES										
Net Income	3	(1)	1	4	4	4	6	8	7	7
Add Back:										
Depreciation and Amortization	24	25	27	28	29	31	31	32	33	34
Finance Expense	22	23	25	26	27	29	30	30	32	33
Net Movement Impacts on Depreciation and Finance Expense	10	13	14	13	13	13	10	10	10	9
Adjustments for Non-Cash Items	11	11	11	11	11	11	11	11	11	11
Adjustments for Changes in Non-Cash Working Capital Accounts	(9)	(9)	(19)	(2)	(2)	(2)	(1)	(1)	(0)	(0)
Interest Paid	(33)	(35)	(37)	(38)	(39)	(41)	(42)	(43)	(44)	(45)
Cash Provided by Operating Activities	27	28	22	42	43	44	45	46	48	49
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	40	50	40	10	40	30	10	60	10	20
Retirement of Long-Term Debt	-	(20)	-	-	(20)	(10)	-	(35)	-	(10)
Cash Provided by Financing Activities	40	30	40	10	20	20	10	25	10	10
INVESTING ACTIVITIES										
Additions to Property, Plant and Equipment	(42)	(47)	(45)	(46)	(47)	(48)	(49)	(50)	(51)	(52)
Additions to Intangible Assets	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Additions to Regulatory Deferral Balances	(14)	(15)	(16)	(15)	(14)	(14)	(15)	(14)	(15)	(13)
Contributions Received	3	3	3	3	3	2	2	3	3	3
Cash Used for Investing Activities	(54)	(60)	(59)	(58)	(59)	(61)	(62)	(62)	(64)	(63)
Net Increase (Decrease) in Cash	13	(2)	3	(7)	4	3	(7)	9	(5)	(4)
Cash at Beginning of Year	(44)	(31)	(33)	(30)	(37)	(33)	(29)	(36)	(27)	(32)
Cash at End of Year	(31)	(33)	(30)	(37)	(33)	(29)	(36)	(27)	(32)	(37)

Part d) i

GAS OPERATIONS (CGM18)
PROJECTED FINANCIAL RATIOS
CGM18 - Meter Exchange Unamortized Balance set up in Reg Asset, Amort over 5yrs

For the year ended March 31

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
PUB APPROVED DEBT TO EQUITY RATIO										
Average Long-Term Debt	389.903	424.903	459.903	484.903	499.903	519.903	534.903	552.403	569.903	579.952
Average Due to Parent	37.384	31.703	31.132	33.073	34.604	31.080	32.777	31.603	29.702	34.477
Average Debt	**427.287**	**456.606**	**491.035**	**517.976**	**534.507**	**550.983**	**567.680**	**584.006**	**599.605**	**614.428**
Average Share Capital	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250
Average Retained Earnings	77.225	86.124	94.116	96.751	100.493	104.173	109.268	116.300	123.463	130.243
Average Equity	**198.474**	**207.373**	**215.366**	**218.000**	**221.742**	**225.423**	**230.518**	**237.550**	**244.713**	**251.493**
Average Debt	427.287	456.606	491.035	517.976	534.507	550.983	567.680	584.006	599.605	614.428
Average Equity	198.474	207.373	215.366	218.000	221.742	225.423	230.518	237.550	244.713	251.493
Average Debt and Equity	625.761	663.980	706.401	735.976	756.249	776.406	798.198	821.555	844.318	865.922
PUB Approved Equity Ratio	**31.72%**	**31.23%**	**30.49%**	**29.62%**	**29.32%**	**29.03%**	**28.88%**	**28.91%**	**28.98%**	**29.04%**

Part d) i

GAS OPERATIONS (CGM18)
PROJECTED FINANCIAL RATIOS
CGM18 - Meter Exchange Unamortized Balance set up in Reg Asset, Amort over 5yrs

For the year ended March 31

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
INTEREST COVERAGE										
Net Income	3.267	(0.812)	1.454	3.816	3.668	3.693	6.497	7.567	6.760	6.800
Finance Expense	20.502	22.230	23.946	25.316	26.223	27.722	28.945	29.827	31.555	32.409
Capitalized Interest	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	23.941	21.655	25.651	29.263	29.926	31.450	35.478	37.431	38.353	39.247
Finance Expense	20.502	22.230	23.946	25.316	26.223	27.722	28.945	29.827	31.555	32.409
Capitalized Interest	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	20.674	22.467	24.197	25.448	26.257	27.757	28.981	29.864	31.593	32.447
Interest Coverage	**1.16**	**0.96**	**1.06**	**1.15**	**1.14**	**1.13**	**1.22**	**1.25**	**1.21**	**1.21**
Add: Depreciation and Amortization *	34.899	39.762	41.609	41.880	43.467	43.998	42.096	42.256	43.428	43.831
Total EBITDA	58.840	61.418	67.260	71.143	73.393	75.448	77.574	79.686	81.781	83.078
EBITDA Interest Coverage	**2.85**	**2.73**	**2.78**	**2.80**	**2.80**	**2.72**	**2.68**	**2.67**	**2.59**	**2.56**

* Includes amortization of deferred income tax

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
CAPITAL COVERAGE										
Internally Generated Funds	27.389	27.808	21.893	41.544	43.260	44.023	45.286	46.407	48.378	48.894
Capitalized Interest*	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	27.560	28.045	22.144	41.676	43.295	44.059	45.322	46.444	48.416	48.932
Net Capital Construction Expenditures	35.404	40.075	38.382	38.991	39.800	40.596	41.408	42.236	43.081	43.943
Capital Coverage	**0.78**	**0.70**	**0.58**	**1.07**	**1.09**	**1.09**	**1.09**	**1.10**	**1.12**	**1.11**

*Capitalized interest is removed from gross interest paid in order to maintain a consistent ratio calculation using net interest paid

Part d) ii

GAS OPERATIONS (CGM18)
PROJECTED OPERATING STATEMENT
CGM18 - Meter Exchange Unamortized Balance set up in Reg Asset, Amort over 10yrs
(In Millions of Dollars)

For the year ended March 31	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
REVENUES										
Domestic Revenue										
Cost of Gas	159	158	166	166	165	165	164	163	162	163
Non-Gas Costs *	152	150	150	151	151	151	151	152	152	151
Furnace Replacement Program Funding	(4)	(1)	-	-	-	-	-	-	-	-
Late Payment Charges and Broker Revenue	1	1	1	1	1	1	1	1	1	1
	308	308	316	317	317	316	316	315	315	315
additional revenue requirement***	-	-	6	10	14	17	21	24	28	32
	308	308	323	328	331	334	337	340	343	346
Weighted Average Cost of Gas Sold **	159	158	166	166	165	165	164	163	162	163
Gross Margin	149	150	157	162	165	169	173	177	181	184
Other	2	2	2	2	2	2	2	2	2	2
	151	151	158	163	167	171	175	179	183	186
EXPENSES										
Operating and Administrative	63	61	62	63	64	65	66	68	69	70
Finance Expense	22	23	25	26	27	29	30	30	32	33
Depreciation and Amortization	24	25	27	28	29	31	31	32	33	34
Capital and Other Taxes	17	17	18	18	19	19	20	20	21	21
Other Expenses	12	13	13	12	12	12	12	12	12	11
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
	150	152	157	160	163	167	171	174	178	181
Net Income before Net Movement in Regulatory Deferral	1	(1)	1	4	4	4	4	5	4	5
Net Movement in Regulatory Deferral **	3	2	2	2	1	1	1	1	1	1
Net Income	3	1	3	5	5	5	5	6	5	5

* The Non-Gas Costs reflect the proposed discontinuance of FRP funding and removal of associated costs from rates for the SGS class, effective Aug 1, 2019

** The adjusted gross margin reflects the cost of gas charged to customer through rates (WACOG). The PGVA has been reclassified to the gross margin from net movement for rate setting purposes.

***__Additional Revenue Requirement__**	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Percent Increase	0.00%	0.00%	2.25%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
Cumulative Percent Increase	0.00%	0.00%	2.25%	3.27%	4.31%	5.35%	6.40%	7.47%	8.54%	9.63%
Equity Ratio (PUB Approved Methodology)	32%	31%	31%	30%	30%	30%	29%	29%	29%	29%

Part d) ii

GAS OPERATIONS (CGM18)
PROJECTED BALANCE SHEET
CGM18 - Meter Exchange Unamortized Balance set up in Reg Asset, Amort over 10yrs
(In Millions of Dollars)

For the year ended March 31	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
ASSETS										
Plant in Service	622	658	698	737	776	814	854	894	935	977
Accumulated Depreciation	(65)	(79)	(95)	(112)	(130)	(148)	(168)	(187)	(208)	(229)
Net Plant in Service	557	579	603	626	646	666	686	707	727	747
Construction in Progress	6	9	6	4	4	4	4	4	4	4
Current and Other Assets	92	92	92	92	92	92	92	92	92	92
Goodwill and Intangible Assets	10	9	9	9	9	9	9	9	9	9
Total Assets before Regulatory Deferral	665	689	710	730	751	771	791	812	832	853
Regulatory Deferral Balance	106	123	125	126	127	128	129	130	131	132
	771	812	835	857	878	899	920	942	963	984
LIABILITIES AND EQUITY										
Long-Term Debt	390	440	480	470	500	530	505	565	565	595
Current and Other Liabilities	122	103	82	108	92	76	115	70	85	70
Deferred Revenue	47	49	49	50	52	55	57	58	59	60
Share Capital	121	121	121	121	121	121	121	121	121	121
Retained Earnings	79	95	98	103	108	114	118	124	130	135
Total Liabilities and Equity before Regulatory Deferral	759	808	831	853	874	895	916	938	960	981
Regulatory Deferral Balance	12	5	4	4	4	4	4	4	4	3
	771	812	835	857	878	899	920	942	963	984
Net Debt	441	473	510	526	543	560	576	592	607	622
Equity (PUB Approved Methodology)	32%	31%	31%	30%	30%	30%	29%	29%	29%	29%

Part d) ii

GAS OPERATIONS (CGM18)
PROJECTED CASH FLOW STATEMENT
CGM18 - Meter Exchange Unamortized Balance set up in Reg Asset, Amort over 10yrs
(In Millions of Dollars)

For the year ended March 31	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
OPERATING ACTIVITIES										
Net Income	3	1	3	5	5	5	5	6	5	5
Add Back:										
Depreciation and Amortization	24	25	27	28	29	31	31	32	33	34
Finance Expense	22	23	25	26	27	29	30	30	32	33
Net Movement Impacts on Depreciation and Finance Expense	10	12	12	11	12	11	12	11	11	11
Adjustments for Non-Cash Items	11	11	11	11	11	11	11	11	11	11
Adjustments for Changes in Non-Cash Working Capital Accounts	(9)	(9)	(19)	(2)	(2)	(2)	(1)	(1)	(0)	(0)
Interest Paid	(33)	(35)	(37)	(38)	(39)	(41)	(42)	(43)	(44)	(45)
Cash Provided by Operating Activities	27	28	22	42	43	44	45	46	48	49
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	40	50	40	10	40	30	10	60	10	30
Retirement of Long-Term Debt	-	(20)	-	-	(20)	(10)	-	(35)	-	(10)
Cash Provided by Financing Activities	40	30	40	10	20	20	10	25	10	20
INVESTING ACTIVITIES										
Additions to Property, Plant and Equipment	(42)	(47)	(45)	(46)	(47)	(48)	(49)	(50)	(51)	(52)
Additions to Intangible Assets	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Additions to Regulatory Deferral Balances	(14)	(15)	(16)	(15)	(14)	(14)	(15)	(14)	(15)	(13)
Contributions Received	3	3	3	3	3	2	2	3	3	3
Cash Used for Investing Activities	(54)	(60)	(59)	(58)	(59)	(61)	(62)	(62)	(64)	(63)
Net Increase (Decrease) in Cash	13	(2)	3	(7)	4	3	(7)	9	(5)	6
Cash at Beginning of Year	(44)	(31)	(33)	(30)	(37)	(33)	(30)	(36)	(27)	(32)
Cash at End of Year	(31)	(33)	(30)	(37)	(33)	(30)	(36)	(27)	(32)	(27)

Part d) ii

GAS OPERATIONS (CGM18)
PROJECTED FINANCIAL RATIOS
CGM18 - Meter Exchange Unamortized Balance set up in Reg Asset, Amort over 10yrs

For the year ended March 31

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
PUB APPROVED DEBT TO EQUITY RATIO										
Average Long-Term Debt	389.903	424.903	459.903	484.903	499.903	519.903	534.903	552.403	569.903	584.952
Average Due to Parent	37.384	31.707	31.148	33.108	34.667	31.181	32.917	31.774	29.899	29.693
Average Debt	**427.287**	**456.610**	**491.051**	**518.011**	**534.570**	**551.084**	**567.820**	**584.177**	**599.802**	**614.645**
Average Share Capital	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250
Average Retained Earnings	77.225	86.887	96.402	100.551	105.799	110.977	116.033	121.498	127.102	132.328
Average Equity	**198.474**	**208.137**	**217.651**	**221.801**	**227.049**	**232.226**	**237.283**	**242.748**	**248.351**	**253.578**
Average Debt	427.287	456.610	491.051	518.011	534.570	551.084	567.820	584.177	599.802	614.645
Average Equity	198.474	208.137	217.651	221.801	227.049	232.226	237.283	242.748	248.351	253.578
Average Debt and Equity	625.761	664.747	708.702	739.812	761.619	783.310	805.102	826.925	848.153	868.223
PUB Approved Equity Ratio	**31.72%**	**31.31%**	**30.71%**	**29.98%**	**29.81%**	**29.65%**	**29.47%**	**29.36%**	**29.28%**	**29.21%**

Part d) ii

GAS OPERATIONS (CGM18)
PROJECTED FINANCIAL RATIOS
CGM18 - Meter Exchange Unamortized Balance set up in Reg Asset, Amort over 10yrs

For the year ended March 31

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
INTEREST COVERAGE										
Net Income	3.267	0.715	2.973	5.326	5.170	5.185	4.927	6.003	5.203	5.250
Finance Expense	20.502	22.230	23.946	25.316	26.225	27.725	28.950	29.833	31.563	32.417
Capitalized Interest	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	23.941	23.182	27.170	30.774	31.429	32.946	33.913	35.874	36.803	37.705
Finance Expense	20.502	22.230	23.946	25.316	26.225	27.725	28.950	29.833	31.563	32.417
Capitalized Interest	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	20.674	22.467	24.197	25.448	26.259	27.760	28.986	29.870	31.600	32.455
Interest Coverage	**1.16**	**1.03**	**1.12**	**1.21**	**1.20**	**1.19**	**1.17**	**1.20**	**1.16**	**1.16**
Add: Depreciation and Amortization *	34.899	38.228	40.075	40.345	41.933	42.464	43.630	43.790	44.962	45.365
Total EBITDA	58.840	61.410	67.244	71.120	73.363	75.409	77.543	79.663	81.765	83.070
EBITDA Interest Coverage	**2.85**	**2.73**	**2.78**	**2.79**	**2.79**	**2.72**	**2.68**	**2.67**	**2.59**	**2.56**

* Includes amortization of deferred income tax

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
CAPITAL COVERAGE										
Internally Generated Funds	27.389	27.800	21.877	41.520	43.228	43.982	45.251	46.378	48.356	48.878
Capitalized Interest*	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	27.560	28.037	22.128	41.652	43.262	44.017	45.287	46.415	48.393	48.916
Net Capital Construction Expenditures	35.404	40.075	38.382	38.991	39.800	40.596	41.408	42.236	43.081	43.943
Capital Coverage	**0.78**	**0.70**	**0.58**	**1.07**	**1.09**	**1.08**	**1.09**	**1.10**	**1.12**	**1.11**

*Capitalized interest is removed from gross interest paid in order to maintain a consistent ratio calculation using net interest paid

Part e) i

GAS OPERATIONS (CGM18)
PROJECTED OPERATING STATEMENT
CGM18 - Meter Exch. Unamort Balance in Reg Asset, Amort over 5yrs, $3M Net Income
(In Millions of Dollars)

For the year ended March 31	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
REVENUES										
Domestic Revenue										
Cost of Gas	159	158	166	166	165	165	164	163	162	163
Non-Gas Costs *	152	150	150	151	151	151	151	152	152	151
Furnace Replacement Program Funding	(4)	(1)	-	-	-	-	-	-	-	-
Late Payment Charges and Broker Revenue	1	1	1	1	1	1	1	1	1	1
	308	308	316	317	317	316	316	315	315	315
additional revenue requirement***	-	-	8	10	13	17	17	20	25	28
	308	308	324	327	330	333	333	336	340	343
Weighted Average Cost of Gas Sold **	159	158	166	166	165	165	164	163	162	163
Gross Margin	149	150	158	161	165	168	169	172	177	181
Other	2	2	2	2	2	2	2	2	2	2
	151	151	160	163	167	170	171	175	179	183
EXPENSES										
Operating and Administrative	63	61	62	63	64	65	66	68	69	70
Finance Expense	22	23	25	26	27	29	30	31	32	33
Depreciation and Amortization	24	25	27	28	29	31	31	32	33	34
Capital and Other Taxes	17	17	18	18	19	19	20	20	21	21
Other Expenses	12	13	13	12	12	12	12	12	12	11
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
	150	152	157	160	163	167	171	174	179	182
Net Income before Net Movement in Regulatory Deferral	1	(1)	3	3	4	3	1	0	0	1
Net Movement in Regulatory Deferral **	3	0	0	0	(1)	(0)	2	3	3	2
Net Income	3	(1)	3	3	3	3	3	3	3	3

* The Non-Gas Costs reflect the proposed discontinuance of FRP funding and removal of associated costs from rates for the SGS class, effective Aug 1, 2019

** The adjusted gross margin reflects the cost of gas charged to customer through rates (WACOG). The PGVA has been reclassified to the gross margin from net movement for rate setting purposes.

***Additional Revenue Requirement**	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Percent Increase	0.00%	0.00%	2.81%	0.01%	1.30%	0.93%	0.07%	0.95%	1.31%	1.02%
Cumulative Percent Increase	0.00%	0.00%	2.81%	2.82%	4.16%	5.13%	5.20%	6.20%	7.59%	8.69%
Equity Ratio (PUB Approved Methodology)	32%	31%	31%	30%	29%	29%	29%	28%	28%	27%

Part e) i

GAS OPERATIONS (CGM18)
PROJECTED BALANCE SHEET
CGM18 - Meter Exch. Unamort Balance in Reg Asset, Amort over 5yrs, $3M Net Income
(In Millions of Dollars)

For the year ended March 31	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
ASSETS										
Plant in Service	622	658	698	737	776	814	854	894	935	977
Accumulated Depreciation	(65)	(79)	(95)	(112)	(130)	(148)	(168)	(187)	(208)	(229)
Net Plant in Service	557	579	603	626	646	666	686	707	727	747
Construction in Progress	6	9	6	4	4	4	4	4	4	4
Current and Other Assets	92	92	92	92	92	92	92	92	92	92
Goodwill and Intangible Assets	10	9	9	9	9	9	9	9	9	9
Total Assets before Regulatory Deferral	665	689	710	730	751	771	791	812	832	853
Regulatory Deferral Balance	106	122	122	122	121	121	123	126	128	130
	771	811	832	852	872	891	914	937	960	983
LIABILITIES AND EQUITY										
Long-Term Debt	390	440	480	470	500	530	515	565	575	605
Current and Other Liabilities	122	103	81	107	92	76	109	78	87	76
Deferred Revenue	47	49	49	50	52	55	57	58	59	60
Share Capital	121	121	121	121	121	121	121	121	121	121
Retained Earnings	79	93	96	99	102	105	108	111	114	117
Total Liabilities and Equity before Regulatory Deferral	759	806	827	848	868	887	910	933	957	979
Regulatory Deferral Balance	12	5	4	4	4	4	4	4	4	3
	771	811	832	852	872	891	914	937	960	983
Net Debt	441	473	508	526	543	560	580	601	620	638
Equity (PUB Approved Methodology)	32%	31%	31%	30%	29%	29%	29%	28%	28%	27%

Part e) i

GAS OPERATIONS (CGM18)
PROJECTED CASH FLOW STATEMENT
CGM18 - Meter Exch. Unamort Balance in Reg Asset, Amort over 5yrs, $3M Net Income
(In Millions of Dollars)

For the year ended March 31	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
OPERATING ACTIVITIES										
Net Income	3	(1)	3	3	3	3	3	3	3	3
Add Back:										
Depreciation and Amortization	24	25	27	28	29	31	31	32	33	34
Finance Expense	22	23	25	26	27	29	30	31	32	33
Net Movement Impacts on Depreciation and Finance Expense	10	13	14	13	13	13	10	10	10	9
Adjustments for Non-Cash Items	11	11	11	11	11	11	11	11	11	11
Adjustments for Changes in Non-Cash Working Capital Accounts	(9)	(9)	(19)	(2)	(2)	(2)	(1)	(1)	0	(0)
Interest Paid	(33)	(35)	(37)	(38)	(39)	(41)	(42)	(43)	(44)	(45)
Cash Provided by Operating Activities	27	28	23	41	43	43	42	42	45	45
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	40	50	40	10	40	30	20	50	20	30
Retirement of Long-Term Debt	-	(20)	-	-	(20)	(10)	-	(35)	-	(10)
Cash Provided by Financing Activities	40	30	40	10	20	20	20	15	20	20
INVESTING ACTIVITIES										
Additions to Property, Plant and Equipment	(42)	(47)	(45)	(46)	(47)	(48)	(49)	(50)	(51)	(52)
Additions to Intangible Assets	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Additions to Regulatory Deferral Balances	(14)	(15)	(16)	(15)	(14)	(14)	(15)	(14)	(15)	(13)
Contributions Received	3	3	3	3	3	2	2	3	3	3
Cash Used for Investing Activities	(54)	(60)	(59)	(58)	(59)	(61)	(62)	(62)	(64)	(63)
Net Increase (Decrease) in Cash	13	(2)	5	(8)	3	3	(0)	(6)	1	2
Cash at Beginning of Year	(44)	(31)	(33)	(28)	(36)	(33)	(30)	(30)	(36)	(35)
Cash at End of Year	(31)	(33)	(28)	(36)	(33)	(30)	(30)	(36)	(35)	(33)

Part e) i

GAS OPERATIONS (CGM18)
PROJECTED FINANCIAL RATIOS
CGM18 - Meter Exch. Unamort Balance in Reg Asset, Amort over 5yrs, $3M Net Income

For the year ended March 31

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
PUB APPROVED DEBT TO EQUITY RATIO										
Average Long-Term Debt	389.903	424.903	459.903	484.903	499.903	519.903	539.903	557.403	574.903	594.952
Average Due to Parent	37.384	31.703	30.351	31.933	34.217	31.370	30.179	33.052	35.311	33.861
Average Debt	**427.287**	**456.606**	**490.254**	**516.836**	**534.120**	**551.273**	**570.082**	**590.455**	**610.214**	**628.812**
Average Share Capital	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250
Average Retained Earnings	77.225	86.124	94.889	97.889	100.889	103.889	106.889	109.889	112.889	115.889
Average Equity	**198.474**	**207.373**	**216.138**	**219.138**	**222.138**	**225.138**	**228.138**	**231.138**	**234.138**	**237.138**
Average Debt	427.287	456.606	490.254	516.836	534.120	551.273	570.082	590.455	610.214	628.812
Average Equity	198.474	207.373	216.138	219.138	222.138	225.138	228.138	231.138	234.138	237.138
Average Debt and Equity	625.761	663.980	706.392	735.975	756.258	776.412	798.221	821.594	844.352	865.951
PUB Approved Equity Ratio	**31.72%**	**31.23%**	**30.60%**	**29.78%**	**29.37%**	**29.00%**	**28.58%**	**28.13%**	**27.73%**	**27.38%**

Part e) i

GAS OPERATIONS (CGM18)
PROJECTED FINANCIAL RATIOS
CGM18 - Meter Exch. Unamort Balance in Reg Asset, Amort over 5yrs, $3M Net Income

For the year ended March 31

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
INTEREST COVERAGE										
Net Income	3.267	(0.812)	3.000	3.000	3.000	3.000	3.000	3.000	3.000	3.000
Finance Expense	20.502	22.230	23.937	25.262	26.206	27.725	29.035	30.162	31.909	33.045
Capitalized Interest	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	23.941	21.655	27.188	28.394	29.241	30.760	32.071	33.199	34.946	36.083
Finance Expense	20.502	22.230	23.937	25.262	26.206	27.725	29.035	30.162	31.909	33.045
Capitalized Interest	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	20.674	22.467	24.188	25.394	26.241	27.760	29.071	30.199	31.946	33.083
Interest Coverage	**1.16**	**0.96**	**1.12**	**1.12**	**1.11**	**1.11**	**1.10**	**1.10**	**1.09**	**1.09**
Add: Depreciation and Amortization *	34.899	39.762	41.609	41.880	43.467	43.998	42.096	42.256	43.428	43.831
Total EBITDA	58.840	61.418	68.797	70.273	72.708	74.758	74.166	75.455	78.374	79.914
EBITDA Interest Coverage	**2.85**	**2.73**	**2.84**	**2.77**	**2.77**	**2.69**	**2.55**	**2.50**	**2.45**	**2.42**

* Includes amortization of deferred income tax

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
CAPITAL COVERAGE										
Internally Generated Funds	27.389	27.808	23.456	40.696	42.601	43.328	41.759	41.838	44.629	45.094
Capitalized Interest*	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	27.560	28.045	23.707	40.828	42.636	43.364	41.795	41.875	44.666	45.132
Net Capital Construction Expenditures	35.404	40.075	38.382	38.991	39.800	40.596	41.408	42.236	43.081	43.943
Capital Coverage	**0.78**	**0.70**	**0.62**	**1.05**	**1.07**	**1.07**	**1.01**	**0.99**	**1.04**	**1.03**

*Capitalized interest is removed from gross interest paid in order to maintain a consistent ratio calculation using net interest paid

Part e) ii

GAS OPERATIONS (CGM18)
PROJECTED OPERATING STATEMENT
CGM18 - Meter Exch. Unamort Balance in Reg Asset, Amort over 10yrs, $3M Net Income
(In Millions of Dollars)

For the year ended March 31	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
REVENUES										
Domestic Revenue										
Cost of Gas	159	158	166	166	165	165	164	163	162	163
Non-Gas Costs *	152	150	150	151	151	151	151	152	152	151
Furnace Replacement Program Funding	(4)	(1)	-	-	-	-	-	-	-	-
Late Payment Charges and Broker Revenue	1	1	1	1	1	1	1	1	1	1
	308	308	316	317	317	316	316	315	315	315
additional revenue requirement***	-	-	6	8	12	15	19	22	26	30
	308	308	323	325	329	332	335	337	341	345
Weighted Average Cost of Gas Sold **	159	158	166	166	165	165	164	163	162	163
Gross Margin	149	150	157	159	163	167	171	174	179	182
Other	2	2	2	2	2	2	2	2	2	2
	151	151	158	161	165	169	173	176	181	184
EXPENSES										
Operating and Administrative	63	61	62	63	64	65	66	68	69	70
Finance Expense	22	23	25	26	27	29	30	31	33	33
Depreciation and Amortization	24	25	27	28	29	31	31	32	33	34
Capital and Other Taxes	17	17	18	18	19	19	20	20	21	21
Other Expenses	12	13	13	12	12	12	12	12	12	11
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
	150	152	157	160	163	167	171	175	179	182
Net Income before Net Movement in Regulatory Deferral	1	(1)	1	1	2	2	2	2	2	2
Net Movement in Regulatory Deferral **	3	2	2	2	1	1	1	1	1	1
Net Income	3	1	3	3	3	3	3	3	3	3

* The Non-Gas Costs reflect the proposed discontinuance of FRP funding and removal of associated costs from rates for the SGS class, effective Aug 1, 2019

** The adjusted gross margin reflects the cost of gas charged to customer through rates (WACOG). The PGVA has been reclassified to the gross margin from net movement for rate setting purposes.

***__Additional Revenue Requirement__										
Percent Increase	0.00%	0.00%	2.26%	0.16%	1.35%	0.92%	1.11%	0.68%	1.40%	0.92%
Cumulative Percent Increase	0.00%	0.00%	2.26%	2.43%	3.81%	4.77%	5.93%	6.65%	8.14%	9.14%
Equity Ratio (PUB Approved Methodology)	32%	31%	31%	30%	29%	29%	29%	28%	28%	27%

Part e) ii

GAS OPERATIONS (CGM18)
PROJECTED BALANCE SHEET
CGM18 - Meter Exch. Unamort Balance in Reg Asset, Amort over 10yrs, $3M Net Income
(In Millions of Dollars)

For the year ended March 31	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
ASSETS										
Plant in Service	622	658	698	737	776	814	854	894	935	977
Accumulated Depreciation	(65)	(79)	(95)	(112)	(130)	(148)	(168)	(187)	(208)	(229)
Net Plant in Service	557	579	603	626	646	666	686	707	727	747
Construction in Progress	6	9	6	4	4	4	4	4	4	4
Current and Other Assets	92	92	92	92	92	92	92	92	92	92
Goodwill and Intangible Assets	10	9	9	9	9	9	9	9	9	9
Total Assets before Regulatory Deferral	665	689	710	730	751	771	791	812	832	853
Regulatory Deferral Balance	106	123	125	126	127	128	129	130	131	132
	771	812	835	857	878	899	920	942	963	984
LIABILITIES AND EQUITY										
Long-Term Debt	390	440	480	480	510	530	515	575	575	605
Current and Other Liabilities	122	103	82	100	87	82	113	71	89	76
Deferred Revenue	47	49	49	50	52	55	57	58	59	60
Share Capital	121	121	121	121	121	121	121	121	121	121
Retained Earnings	79	95	98	101	104	107	110	113	116	119
Total Liabilities and Equity before Regulatory Deferral	759	808	831	853	874	895	916	938	960	981
Regulatory Deferral Balance	12	5	4	4	4	4	4	4	4	3
	771	812	835	857	878	899	920	942	963	984
Net Debt	441	473	510	529	547	566	585	604	621	638
Equity (PUB Approved Methodology)	32%	31%	31%	30%	29%	29%	29%	28%	28%	27%

Part e) ii

GAS OPERATIONS (CGM18)
PROJECTED CASH FLOW STATEMENT
CGM18 - Meter Exch. Unamort Balance in Reg Asset, Amort over 10yrs, $3M Net Income
(In Millions of Dollars)

For the year ended March 31

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
OPERATING ACTIVITIES										
Net Income	3	1	3	3	3	3	3	3	3	3
Add Back:										
Depreciation and Amortization	24	25	27	28	29	31	31	32	33	34
Finance Expense	22	23	25	26	27	29	30	31	33	33
Net Movement Impacts on Depreciation and Finance Expense	10	12	12	11	12	11	12	11	11	11
Adjustments for Non-Cash Items	11	11	11	11	11	11	11	11	11	11
Adjustments for Changes in Non-Cash Working Capital Accounts	(9)	(9)	(19)	(2)	(2)	(2)	(1)	(1)	0	(0)
Interest Paid	(33)	(35)	(37)	(38)	(39)	(41)	(42)	(43)	(45)	(45)
Cash Provided by Operating Activities	27	28	22	39	41	42	43	43	46	47
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	40	50	40	20	40	20	20	60	10	30
Retirement of Long-Term Debt	-	(20)	-	-	(20)	(10)	-	(35)	-	(10)
Cash Provided by Financing Activities	40	30	40	20	20	10	20	25	10	20
INVESTING ACTIVITIES										
Additions to Property, Plant and Equipment	(42)	(47)	(45)	(46)	(47)	(48)	(49)	(50)	(51)	(52)
Additions to Intangible Assets	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Additions to Regulatory Deferral Balances	(14)	(15)	(16)	(15)	(14)	(14)	(15)	(14)	(15)	(13)
Contributions Received	3	3	3	3	3	2	2	3	3	3
Cash Used for Investing Activities	(54)	(60)	(59)	(58)	(59)	(61)	(62)	(62)	(64)	(63)
Net Increase (Decrease) in Cash	13	(2)	3	1	2	(9)	1	6	(7)	3
Cash at Beginning of Year	(44)	(31)	(33)	(30)	(29)	(27)	(36)	(35)	(29)	(36)
Cash at End of Year	(31)	(33)	(30)	(29)	(27)	(36)	(35)	(29)	(36)	(33)

Part e) ii

GAS OPERATIONS (CGM18)
PROJECTED FINANCIAL RATIOS
CGM18 - Meter Exch. Unamort Balance in Reg Asset, Amort over 10yrs, $3M Net Income

For the year ended March 31	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
PUB APPROVED DEBT TO EQUITY RATIO										
Average Long-Term Debt	389.903	424.903	459.903	489.903	509.903	524.903	539.903	562.403	579.903	594.952
Average Due to Parent	37.384	31.707	31.134	29.257	28.072	31.759	35.551	31.877	32.604	34.620
Average Debt	**427.287**	**456.610**	**491.037**	**519.160**	**537.975**	**556.662**	**575.454**	**594.280**	**612.507**	**629.572**
Average Share Capital	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250
Average Retained Earnings	77.225	86.887	96.415	99.415	102.415	105.415	108.415	111.415	114.415	117.415
Average Equity	**198.474**	**208.137**	**217.665**	**220.665**	**223.665**	**226.665**	**229.665**	**232.665**	**235.665**	**238.665**
Average Debt	427.287	456.610	491.037	519.160	537.975	556.662	575.454	594.280	612.507	629.572
Average Equity	198.474	208.137	217.665	220.665	223.665	226.665	229.665	232.665	235.665	238.665
Average Debt and Equity	625.761	664.747	708.702	739.825	761.640	783.327	805.119	826.945	848.172	868.237
PUB Approved Equity Ratio	**31.72%**	**31.31%**	**30.71%**	**29.83%**	**29.37%**	**28.94%**	**28.53%**	**28.14%**	**27.79%**	**27.49%**

Part e) ii

GAS OPERATIONS (CGM18)
PROJECTED FINANCIAL RATIOS
CGM18 - Meter Exch. Unamort Balance in Reg Asset, Amort over 10yrs, $3M Net Income

For the year ended March 31

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
INTEREST COVERAGE										
Net Income	3.267	0.715	3.000	3.000	3.000	3.000	3.000	3.000	3.000	3.000
Finance Expense	20.502	22.230	23.946	25.328	26.489	28.005	29.214	30.321	32.160	33.092
Capitalized Interest	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	23.941	23.182	27.197	28.460	29.524	31.040	32.250	33.358	35.198	36.130
Finance Expense	20.502	22.230	23.946	25.328	26.489	28.005	29.214	30.321	32.160	33.092
Capitalized Interest	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	20.674	22.467	24.197	25.460	26.524	28.040	29.250	30.358	32.198	33.130
Interest Coverage	**1.16**	**1.03**	**1.12**	**1.12**	**1.11**	**1.11**	**1.10**	**1.10**	**1.09**	**1.09**
Add: Depreciation and Amortization *	34.899	38.228	40.075	40.345	41.933	42.464	43.630	43.790	44.962	45.365
Total EBITDA	58.840	61.410	67.271	68.805	71.457	73.504	75.880	77.148	80.160	81.495
EBITDA Interest Coverage	**2.85**	**2.73**	**2.78**	**2.70**	**2.69**	**2.62**	**2.59**	**2.54**	**2.49**	**2.46**

* Includes amortization of deferred income tax

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
CAPITAL COVERAGE										
Internally Generated Funds	27.389	27.800	21.905	39.167	41.069	41.794	43.327	43.364	46.166	46.625
Capitalized Interest*	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	27.560	28.037	22.155	39.299	41.103	41.829	43.363	43.401	46.203	46.663
Net Capital Construction Expenditures	35.404	40.075	38.382	38.991	39.800	40.596	41.408	42.236	43.081	43.943
Capital Coverage	**0.78**	**0.70**	**0.58**	**1.01**	**1.03**	**1.03**	**1.05**	**1.03**	**1.07**	**1.06**

*Capitalized interest is removed from gross interest paid in order to maintain a consistent ratio calculation using net interest paid

REFERENCE:

PUB/Centra I-14, PUB/Centra I-7 (b) 2013/14 GRA

QUESTION:

Please file a schedule in similar format to PUB/Centra I-7 (b) detailing the accounting changes from 2013/14 through 2027/28 and provide a comparison with the accounting changes forecast at the last GRA for comparative years and explain any differences.

RESPONSE:

Please see the following schedules that identify the CGAAP and IFRS related accounting changes for the years 2013/14 through to 2027/28 in accordance with the accounts included in the Statement of Income and in a format similar to that provided in PUB/CENTRA I-7b in the 2013/14 GRA Separate schedules have been prepared specifically for the current 2019/20 GRA amounts and the previous 2013/14 GRA. In addition, a schedule comparing the differences between the two applications has been provided with explanations of the differences following the schedule. For more information on the accounting standards underlying the accounting changes, please see the response to PUB/CENTRA I-10a-c.

CENTRA GAS ACCOUNTING CHANGES - 2019/20 RATE APPLICATION
(In Millions of Dollars)

	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Actual 2018	Current Outlook 2019	Approved Budget 2020	CGM 18 ---> 2021	2022	2023	2024	2025	2026	2027	2028
GAS REVENUE															
IFRS Changes															
Reclass Miscellaneous Revenues from Other Income (i.e. Late Pmt Charges, Broker fees, Non-metered Gas)	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Gas Revenue IFRS Changes	**-**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
OTHER INCOME															
IFRS Changes															
Reclass Miscellaneous Revenues to Gas Revenues (i.e. Late Pmt Charges, Broker fees, Non-metered Gas)	-	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Reclass Miscellaneous Amounts From Other Expenses	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reclass Amortization of Customer Contributions from Depreciation	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Other Income IFRS Changes	**-**	**(0)**	**0**	**0**	**0**	**0**	**0**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
OM&A EXPENSE															
CGAAP Changes															
Reduction to Intangible Assets Capitalized (e.g. DSM research and promotion expensed)	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Reduction in Administrative Overhead Capitalized under CGAAP	3	3	3	4	4	4	4	4	4	4	4	4	4	4	4
Pension & Employee Benefit Changes (e.g. Discount Rate impacts)	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Subtotal CGAAP Changes	**8**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**
IFRS Changes															
Ineligible Administrative Overhead for Capitalization	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Meter Compliance, Exchange and Sampling	-	-	-	-	-	-	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)
Pension and Employee Benefit Changes	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal IFRS Changes	**-**	**3**	**3**	**3**	**3**	**3**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**
Total OM&A Changes	**8**	**12**	**12**	**12**	**12**	**12**	**8**	**8**	**7**	**8**	**8**	**8**	**9**	**9**	**9**
FINANCE EXPENSE															
IFRS Changes															
Reclass Deferred Income Taxes Carrying Costs to Net Movement in Regulatory Deferrals		2	2	2	2	2	1	1	1	1	1	1	1	0	0
Reclass PGVA Carrying Costs to Net Movement in Regulatory Deferrals		1	0	(0)	(0)	(0)	(0)	-	-	-	-	-	-	-	-
Total Finance Expense IFRS Changes	**-**	**3**	**2**	**2**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**0**	**0**
DEPRECIATION & AMORTIZATION EXPENSE															
CGAAP Changes															
Reduce Administrative Overhead Capitalized under CGAAP (Depreciation impact)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)
Average Service Life Changes (2014 Depreciation Study)	-	(1)	(1)	(1)	(1)	(1)	-	-	-	-	-	-	-	-	-
Subtotal CGAAP Changes	**(0)**	**(1)**	**(1)**	**(1)**	**(2)**	**(2)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(2)**	**(2)**	**(2)**
IFRS Changes															
Ineligible Administrative Overhead for Capitalization (Depreciation Impact)	-	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Impact of Change in Gas Meter Rate (from 25 to 20 yr service life)	-	-	0	0	0	0	-	-	-	-	-	-	-	-	-
Meter Compliance, Exchange and Sampling	-	-	-	-	-	-	0	1	1	1	2	2	2	3	3
Removal of Negative Salvage in Depreciation Rates	-	(4)	(4)	(4)	(5)	(5)	(5)	(6)	(6)	(6)	(6)	(7)	(7)	(7)	(7)
Change to ELG method of Depreciation	-	2	2	2	2	2	2	2	3	3	3	3	3	3	3
Loss on Asset Retirements/Disposals	-	3	3	3	2	2	2	2	2	2	2	2	2	2	2
Reclass Amortization of DSM Programs to Net Movement	-	(8)	(8)	(9)	(9)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(11)	(11)
Reclass Amortization of Regulatory Costs to Net Movement	-	(1)	(1)	(1)	(1)	(1)	(1)	(2)	(1)	(2)	(1)	(2)	(1)	(2)	(1)
Reclass Amortization of Site Remediation Costs to Net Movement	-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Reclass Amortization of Customer Contributions to Other Income	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Subtotal IFRS Changes	**-**	**(7)**	**(6)**	**(8)**	**(9)**	**(11)**	**(12)**	**(13)**	**(12)**	**(12)**	**(11)**	**(12)**	**(11)**	**(11)**	**(10)**
Total Depreciation Changes	**(0)**	**(8)**	**(8)**	**(10)**	**(10)**	**(13)**	**(13)**	**(14)**	**(13)**	**(13)**	**(13)**	**(13)**	**(12)**	**(13)**	**(12)**

CENTRA GAS ACCOUNTING CHANGES - 2019/20 RATE APPLICATION
(In Millions of Dollars)

	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Actual 2018	Current Outlook 2019	Approved Budget 2020	CGM 18 ---> 2021	2022	2023	2024	2025	2026	2027	2028
CAPITAL TAX EXPENSE															
IFRS Changes															
Reclass Amortization of Deferred Tax on Acquisition to Net Movement	-	(4)	(4)	(4)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(2)	(2)	(2)	(2)
Total Capital Tax Expense IFRS Accounting Changes	**-**	**(4)**	**(4)**	**(4)**	**(3)**	**(3)**	**(3)**	**(3)**	**(3)**	**(3)**	**(3)**	**(2)**	**(2)**	**(2)**	**(2)**
OTHER EXPENSE															
IFRS Changes															
DSM Expenditures	-	9	10	11	11	9	8	11	11	10	11	10	11	10	9
Regulatory Costs	-	1	1	1	0	2	2	3	1	1	1	1	1	1	1
Site Restoration Expenditures	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-
Reclass Miscellaneous Amounts From Other Expenses	-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Total Other Expenses IFRS Changes	**-**	**10**	**11**	**11**	**11**	**11**	**11**	**13**	**12**	**12**	**12**	**12**	**12**	**12**	**11**
Total Impact of CGAAP changes to Net Income	**(8)**	**(7)**	**(7)**	**(7)**	**(7)**	**(7)**	**(8)**	**(8)**	**(8)**	**(8)**	**(8)**	**(8)**	**(8)**	**(8)**	**(8)**
Total Impact of IFRS Changes to Net Income	**-**	**(4)**	**(5)**	**(3)**	**(3)**	**(0)**	**5**	**3**	**3**	**4**	**3**	**4**	**3**	**3**	**3**
Total Impact to Net Income Before Net Movement Impacts	**(8)**	**(12)**	**(12)**	**(10)**	**(10)**	**(7)**	**(3)**	**(5)**	**(4)**	**(4)**	**(4)**	**(4)**	**(5)**	**(5)**	**(4)**
NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNTS															
IFRS Changes															
Defer Ineligible Administrative Overhead	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Defer DSM Expenditures	-	9	10	11	11	9	8	11	11	10	11	10	11	10	9
Defer Regulatory Costs	-	1	1	1	0	2	2	3	1	1	1	1	1	1	1
Defer Site Restoration Expenditures	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-
Defer (Gains) Losses on Asset Retirements/Disposal	-	3	3	3	2	2	2	2	2	2	2	2	2	2	2
Defer Impact of 2014 Depreciation Study	-	(1)	(1)	(1)	(1)	(1)	-	-	-	-	-	-	-	-	-
Defer Change in Depreciation Rate Meters	-	-	0	0	0	0	-	-	-	-	-	-	-	-	-
Defer Impact of Change to ELG Method	-	2	2	2	2	2	2	2	3	3	3	3	3	3	3
Reclass Deferred Tax Carrying Costs on Acquisition from Finance Expense	-	2	2	2	2	2	1	1	1	1	1	1	1	0	0
Reclass PGVA Carrying Costs from Finance Expense	-	1	0	(0)	(0)	(0)	(0)	-	-	-	-	-	-	-	-
Reclass Amortization of DSM programs from Depreciation and Amortization	-	(8)	(8)	(9)	(9)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(11)	(11)
Reclass Amortization of Regulatory Costs from Depreciation and Amortization	-	(1)	(1)	(1)	(1)	(1)	(1)	(2)	(1)	(2)	(1)	(2)	(1)	(2)	(1)
Reclass Amortization of Site Remediation Costs from Depreciation and Amortization	-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Reclass Amortization of Deferred Tax on Acquisition from Capital and Other Taxes	-	(4)	(4)	(4)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(2)	(2)	(2)	(2)
Amortization of Loss on Asset Retirements/Disposals	-	-	-	-	-	-	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(1)
Amortization of Ineligible Administrative Overhead	-	-	-	-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Amortization of Impact of 2014 Depreciation Study	-	-	-	-	-	-	0	0	0	0	0	0	0	0	0
Amortization of Change in Depreciation Rate - Meters	-	-	-	-	-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Total Net Movement Impact	**-**	**5**	**6**	**5**	**4**	**2**	**1**	**3**	**3**	**3**	**3**	**2**	**3**	**3**	**2**
Total Impact to Net Income After Net Movement Impacts	**(8)**	**(6)**	**(6)**	**(6)**	**(6)**	**(5)**	**(1)**	**(1)**	**(1)**	**(1)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**

CENTRA GAS ACCOUNTING CHANGES - 2013/14 GENERAL RATE APPLICATION

(In Millions of Dollars)

	Actual	Actual	Actual	Actual	Actual	Current Outlook	Approved Budget	CGM18 ---->							
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
GAS REVENUE															
IFRS Changes															
Reclass Miscellaneous Revenues from Other Income (i.e. Late Pmt Charges, Broker fees, Non-metered Gas)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Gas Revenue IFRS Changes	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
OTHER INCOME															
IFRS Changes															
Reclass Miscellaneous Revenues to Gas Revenues (i.e. Late Pmt Charges, Broker fees, Non-metered Gas)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Reclass Miscellaneous Amounts From Other Expenses	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Reclass Amortization of Customer Contributions from Depreciation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Income IFRS Changes	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
OM&A EXPENSE															
CGAAP Changes															
Reduction to Intangible Assets Capitalized (e.g. DSM research and promotion expensed)	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Reduction in Administrative Overhead Capitalized under CGAAP	5	5	5	5	5	6	6	6	6	6	6	6	6	6	7
Pension & Employee Benefit Changes (e.g. Discount Rate impacts)	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Reclass Operating Expense Recoveries to Other Income	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Subtotal CGAAP Changes	**8**	**8**	**8**	**8**	**8**	**8**	**9**	**9**	**9**	**9**	**9**	**9**	**10**	**10**	**10**
IFRS Changes															
Ineligible Administrative Overhead for Capitalization	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Meter Compliance, Exchange and Sampling		(5)	(5)	(5)	(5)	(5)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)
Pension and Employee Benefit Changes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Regulatory Costs		1	0	1	1	1	1	1	1	1	1	1	1	1	1
DSM Expenditures		8	7	7	5	4	3	3	3	3	3	3	3	3	3
Subtotal IFRS Changes	**-**	**6**	**4**	**5**	**3**	**2**	**0**	**0**	**0**	**(0)**	**(0)**	**0**	**(0)**	**0**	**(0)**
Total OM&A Changes	**8**	**14**	**12**	**13**	**11**	**10**	**9**	**9**	**9**	**9**	**9**	**10**	**9**	**10**	**9**
FINANCE EXPENSE															
IFRS Changes															
Eliminate Deferred Taxes carrying Costs	-	2	2	2	2	1	1	1	1	1	1	1	1	0	0
Eliminate PGVA Carrying Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Finance Expense IFRS Changes	**-**	**2**	**2**	**2**	**2**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**0**	**0**

CENTRA GAS ACCOUNTING CHANGES - 2013/14 GENERAL RATE APPLICATION

(In Millions of Dollars)

	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Actual 2018	Current Outlook 2019	Approved Budget 2020	CGM18 ----> 2021	2022	2023	2024	2025	2026	2027	2028
DEPRECIATION & AMORTIZATION EXPENSE															
CGAAP Changes															
Reduce Administrative Overhead Capitalized under CGAAP (Depreciation impact)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Average Service Life Changes (2014 Depreciation Study)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Subtotal CGAAP Changes	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**
IFRS Changes															
Ineligible Administrative Overhead for Capitalization (Depreciation Impact)		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)
Impact of Change in Gas Meter Rate (from 25 to 20 yr service life)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Meter Compliance, Exchange and Sampling	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1
Removal of Negative Salvage in Depreciation Rates	-	(5)	(5)	(5)	(6)	(6)	(6)	(6)	(6)	(6)	(7)	(7)	(7)	(7)	(7)
Change to ELG method of Depreciation	-	2	2	3	3	3	3	3	3	3	3	4	4	4	4
Loss on Asset Retirements/Disposals	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Eliminate Amortization of Deferred DSM Expenditures		(8)	(8)	(8)	(8)	(8)	(8)	(7)	(6)	(6)	(5)	(4)	(4)	(3)	(3)
Eliminate Amortization of Deferred Regulatory Cost Expenditures		(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Eliminate Amortization of Deferred Site Restoration Expenditures		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-	-
Reclass Amortization of Customer Contributions to Other Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal IFRS Changes	**-**	**(12)**	**(12)**	**(11)**	**(12)**	**(12)**	**(11)**	**(10)**	**(9)**	**(9)**	**(9)**	**(8)**	**(8)**	**(7)**	**(7)**
Total Depreciation Changes	**(1)**	**(13)**	**(13)**	**(12)**	**(12)**	**(13)**	**(12)**	**(11)**	**(10)**	**(10)**	**(9)**	**(9)**	**(9)**	**(8)**	**(8)**
CAPITAL TAX EXPENSE															
IFRS Changes															
Eliminate Amortization of Deferred Tax on Acquisition of Centra	-	(4)	(4)	(4)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(2)	(2)	(2)	(2)
Total Capital Tax Expense IFRS Accounting Changes	**-**	**(4)**	**(4)**	**(4)**	**(3)**	**(3)**	**(3)**	**(3)**	**(3)**	**(3)**	**(3)**	**(2)**	**(2)**	**(2)**	**(2)**
OTHER EXPENSE															
IFRS Changes															
DSM Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Regulatory Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Site Restoration Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Reclass Miscellaneous Amounts From Other Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Expenses IFRS Changes	**-**	**-**	**-**	**-**	**-**										
Total Impact of CGAAP changes to Net Income	**(7)**	**(7)**	**(7)**	**(7)**	**(7)**	**(8)**	**(8)**	**(8)**	**(8)**	**(8)**	**(8)**	**(9)**	**(9)**	**(9)**	**(9)**
Total Impact of IFRS Changes to Net Income	**1**	**9**	**11**	**9**	**11**	**13**	**14**	**13**	**12**	**12**	**12**	**10**	**11**	**10**	**11**
Total Impact to Net Income Before Net Movement Impacts	**(6)**	**1**	**4**	**2**	**4**	**6**	**6**	**5**	**4**	**3**	**3**	**2**	**2**	**1**	**2**

CENTRA GAS ACCOUNTING CHANGES - 2013/14 GENERAL RATE APPLICATION

(In Millions of Dollars)

	Actual	Actual	Actual	Actual	Actual	Current Outlook	Approved Budget	CGM18 ---->							
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNTS															
IFRS Changes															
Defer Ineligible Administrative Overhead	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Defer DSM Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Defer Regulatory Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Defer Site Restoration Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Defer (Gains) Losses on Asset Retirements/Disposal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Defer Impact of 2014 Depreciation Study	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Defer Change in Depreciation Rate Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Defer Impact of Change to ELG Method	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Reclass Deferred Tax Carrying Costs on Acquisition from Finance Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Reclass PGVA Carrying Costs from Finance Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Reclass Amortization of DSM programs from Depreciation and Amortization	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Reclass Amortization of Regulatory Costs from Depreciation and Amortization	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Reclass Amortization of Site Remediation Costs from Depreciation and Amortization	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Reclass Amortization of Deferred Tax on Acquisition from Capital and Other Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization of Loss on Asset Retirements/Disposals	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization of Ineligible Administrative Overhead	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization of Impact of 2014 Depreciation Study	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization of Change in Depreciation Rate - Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net Movement Impact	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Total Impact to Net Income After Net Movement Impacts	**(6)**	**1**	**4**	**2**	**4**	**6**	**6**	**5**	**4**	**3**	**3**	**2**	**2**	**1**	**2**

CENTRA GAS ACCOUNTING CHANGES - DIFFERENCES (2019/20 RATE APPLICATION Less 2013/14 GRA)
(In Millions of Dollars)

	Actual	Actual	Actual	Actual	Actual	Current Outlook	Approved Budget	CGM 18 ----->								
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Reference
Gas Revenue:																
IFRS Changes 2019/20 Rate Application	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
IFRS Changes 2013/14 GRA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Difference	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Other Income:																
IFRS Changes 2019/20 Rate Application	-	(0)	0	0	0	0	0	1	1	1	1	1	1	1	1	
IFRS Changes 2013/14 GRA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Difference	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	2
OM&A Expense:																
CGAAP Changes 2019/20 Rate Application	8	9	9	9	9	9	9	9	9	9	9	9	9	9	9	
CGAAP Changes 2013/14 GRA	8	8	8	8	8	8	9	9	9	9	9	9	10	10	10	
Difference	(0)	0	1	1	1	0	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	3
OM&A Expense:																
IFRS Changes 2019/20 Rate Application	-	3	3	3	3	3	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	
IFRS Changes 2013/14 GRA	-	6	4	5	3	2	0	0	0	(0)	(0)	0	(0)	0	(0)	
Difference	-	(3)	(1)	(2)	0	1	(1)	(1)	(1)	(1)	(1)	(1)	(0)	(1)	(0)	4
Finance Expense																
IFRS Changes 2019/20 Rate Application	-	3	2	2	1	1	1	1	1	1	1	1	1	0	0	
IFRS Changes 2013/14 GRA	-	2	2	2	2	1	1	1	1	1	1	1	1	0	0	
Difference	-	1	0	(0)	(0)	(0)	(0)	-	-	-	-	-	-	-	-	5
Depreciation & Amortization Expense:																
CGAAP Changes 2019/20 Rate Application	(0)	(1)	(1)	(1)	(2)	(2)	(1)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)	
CGAAP Changes 2013/14 GRA	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	
Difference	1	(0)	(1)	(1)	(1)	(1)	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(1)	6
Depreciation & Amortization Expense:																
IFRS Changes 2019/20 Rate Application	-	(7)	(6)	(8)	(9)	(11)	(12)	(13)	(12)	(12)	(11)	(12)	(11)	(11)	(10)	
IFRS Changes 2013/14 GRA	-	(12)	(12)	(11)	(12)	(12)	(11)	(10)	(9)	(9)	(9)	(8)	(8)	(7)	(7)	
Difference	-	5	5	3	3	1	(1)	(3)	(2)	(3)	(3)	(4)	(3)	(4)	(3)	7
Capital Tax Expense:																
IFRS Changes 2019/20 Rate Application	-	(4)	(4)	(4)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(2)	(2)	(2)	(2)	
IFRS Changes 2013/14 GRA	-	(4)	(4)	(4)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(2)	(2)	(2)	(2)	
Difference	-	-	0	-	(0)	-	-	-	-	-	-	-	-	-	-	8
Other Expense:																
IFRS Changes 2019/20 Rate Application	-	10	11	11	11	11	11	13	12	12	12	12	12	12	11	
IFRS Changes 2013/14 GRA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Difference	-	10	11	11	11	11	11	13	12	12	12	12	12	12	11	9
Net Movement in Regulatory Deferral Accounts:																
IFRS Changes 2019/20 Rate Application	-	5	6	5	4	2	1	3	3	3	3	2	3	3	2	
IFRS Changes 2013/14 GRA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Difference	-	5	6	5	4	2	1	3	3	3	3	2	3	3	2	10

Explanation of Differences – 2019/20 Rate Application Less 2013/14 GRA

1. **Gas Revenue - IFRS changes:** The IFRS related difference is due to the actual reclassification for amounts such as late payment charges and broker fees from Other Income to Gas Revenues to comply with the IFRS financial statement presentation standard *IAS 1 Presentation of Financial Statements*. Centra had not included this change in its 2013/14 GRA analysis.

2. **Other Income – IFRS changes:** The IFRS related difference is due to the actual reclassification of the amortization of customer contributions for property, plant and equipment assets from Depreciation and Amortization Expense to Other Income. This change was made to comply with the requirements of *IFRIC 18 Transfers of Assets From Customers* which requires contributions to be recognized as revenue. The 2013/14 GRA estimates did not include the impact of reclassifying the amortization of customer contributions to revenue.

3. **OM&A – CGAAP changes:** The annual net CGAAP differences to OM&A are small. There are, however, some larger individual differences between the 2019/20 and 2013/14 application amounts for reductions in administrative overheads capitalized and pension and employee benefit changes.
    - Actual and estimated annual reductions in administrative overheads capitalized for the 2019/20 GRA are approximately $1-$2 million lower than the 2013/14 GRA projections. This difference is due to updated estimates determined subsequent to the completion of the 2013/14 GRA for administrative overheads associated with IT infrastructure and related support and building depreciation and operating costs.
    - Actual annual increases in pension and employee benefit amounts are approximately $2 -$3 million higher than the estimates projected in the 2013/14 GRA due primarily to further discount rate changes that occurred in the years subsequent to the 2013/14 GRA. Notably, discount rates declined from 5.25% in 2012 to 4.25% in 2013, 4.50% in 2014 and 3.70% in 2015.

4. **OM&A – IFRS changes:** The IFRS related differences are due primarily to differences in assumptions with respect to the timing of the recognition of meter exchange and

sampling costs as capital activities and with respect to the recognition of DSM, regulatory and site remediation costs.

- Centra's 2019/20 GRA assumes that the capitalization of meter exchange and sampling activities commences in fiscal 2019/20. In contrast, the CGM12 forecast from the 2013/14 GRA assumed such activities would commence capitalization in 2014/15 following Centra's 2015/16 transition to IFRS. As part of Order 85/13, the PUB did not direct a change in the accounting for meter exchange and sampling activities for rate setting purposes and instead, requested Centra put forward a proposal on harmonizing this accounting policy with Manitoba Hydro in its IFRS Status Update Report. Centra is requesting such harmonization for the accounting for meter exchanges and sampling as part of this application.
- Centra's 2013/14 GRA assumed that expenditures for rate regulated assets such as DSM and regulatory proceedings would no longer be eligible for deferral under IFRS as a rate regulated standard under IFRS did not exist at the time. As such, it was assumed that such costs would be required to be expensed as incurred under OM&A. Subsequent to the 2013/14 GRA, interim standard *IFRS 14 Regulatory Deferral Accounts* was issued which permitted the continued deferral of expenditures for rate regulated accounts. Centra's 2019/20 GRA reflects what actually transpired upon its transition to IFRS whereby rate regulated amounts are first recorded in Other Expenses and then subsequently deferred and amortized through the Net Movement in Regulatory Deferrals account.
- The $1 million annual difference between the 2013/14 and 2019/20 application amounts regarding administrative and overhead costs no longer eligible for capitalization is due to updated information at the time of Centra's transition to IFRS. This annual $1 million difference is deferred ($0.7 million) as a regulatory deferral in the Net Movement in Regulatory Deferral Account and is proposed to be amortized over 34 years.

5. **Finance Expense – IFRS Changes:** The IFRS related difference regarding finance expense changes is due to the deferred interest on the PGVA balance as recorded for 2014/15 actuals. This information would not have been available at the time of the 2013/14 GRA.

6. **Depreciation and Amortization – CGAAP Changes:** The CGAAP related difference pertains to the 2019/20 reduction in depreciation for the reduction in administrative overhead capitalized. This small dollar impact was not included in the estimates proposed in the 2013/14 GRA.

7. **Depreciation and Amortization – IFRS Changes:** The IFRS related differences for the years 2014/15 through to 2017/18 are primarily the result of the recognition of asset retirement gains and losses in depreciation which is what actually occurred upon Centra's transition to IFRS. Notably, these amounts are subsequently deferred in the Net Movement in Regulatory Deferrals Account. The CGM12 forecast underlying Centra's 2013/14 GRA did not forecast asset retirement gains and losses. In addition, 2013/14 GRA estimates did not include the impact of reclassifying the amortization of customer contributions to revenue.

   For the forecast years 2022/23 and beyond, 2019/20 GRA estimates project a higher reduction in depreciation and amortization expense compared to the 2013/14 GRA as reductions for the reclassification of the amortization of DSM and regulatory deferrals are much higher compared to those projected in the 2013/14 GRA. The reduction in the projected amortization of DSM expenditures in the 2013/14 GRA is due to the fact that CGM12 assumed a much lower level of spending on DSM programs in the later years of the forecast compared to the CGM18 forecast.

8. **Capital and Other Taxes – IFRS Changes:** there is no difference in the IFRS related changes between the 2013/14 and 2019/20 application amounts.

9. **Other Expenses – IFRS Changes:** The difference in IFRS related changes is the result of recognizing expenditures for regulated assets such as DSM and regulatory costs immediately in Other Expenses for actuals and in the CGM18 forecast. These amounts are subsequently deferred and amortized through the Net Movement in Regulatory Deferrals account. The 2013/14 GRA analysis assumed that rate regulated accounting would not be available on transition to IFRS and as such, these amounts would be recognized immediately in OM&A.

10. **Net Movement in Regulatory Deferral Accounts – IFRS Changes:** The IFRS related difference is due to the fact that the 2013/14 GRA forecast assumed that expenditures for regulated assets would be expensed as incurred with no opportunity for deferral and amortization. Notably, IFRS interim standard *IFRS14* Regulatory *Deferral Accounts* was not issued until January, 2014 which was subsequent to the timing of the 2013/14 GRA. The 2019/20 GRA amounts reflect the deferral and amortization of rate regulated accounts through the Net Movement Account as recorded for actuals and as required by interim standard IFRS14.

REFERENCE:

PUB/Centra I-15

QUESTION:

Please restate the table assuming that the accounting for capitalizing meter sampling, testing and exchange activities were applied in 2014/15 when IFRS was adopted and provide a comparison of total actual and forecast O&A expense.

RESPONSE:

Centra adopted IFRS on April 1, 2015 and restated its 2014/15 financial statements for comparative reporting purposes only. The table in PUB/Centra I-15, as well as all tables in Appendix 5.9, show 2014/15 O&A expenditures under CGAAP and do not include a restatement under IFRS.

The table below adjusts the total Business Operations Capital ("BOC") expenditures, the total Capitalized Activity Charges & Overhead and the total Operating & Administrative ("O&A") expense to simulate the movement of meter sampling, testing and exchange activities from O&A to BOC upon the adoption of IFRS in 2015/16 through to 2018/19 (2019/20 assumed capitalization of meters). The table also reflects a correction of forecast capitalized activity charges for 2018/19 and 2019/20 for Human Resources & Corporate Services, which was shown as General Counsel & Corporate Secretary in PUB/CENTRA I-15 in error.

CENTRA GAS MANITOBA INC.
ADJUSTED CAPITALIZED ACTIVITY CHARGES & OVERHEAD
($000s)

	CGAAP			IFRS				
	2012/13 Actual	**2013/14 Actual**	**2014/15 Actual**	**2015/16 Actual**	**2016/17 Actual**	**2017/18 Actual**	**2018/19 Forecast**	**2019/20 Test Year**
Total Gas Business Operations Capital (BOC) Expenditures	$ 29 793	$ 32 615	$ 27 320	$ 40 441	$ 54 445	$ 32 880	$ 35 404	$ 40 075
BOC Requested Adjustments				*5 107*	*4 085*	*3 984*	*3 097*	
Total Gas BOC Expenditures - Adjusted	29 793	32 615	27 320	45 548	58 530	36 864	38 501	40 075
Capitalized Activity Charges and Overhead								
Total Capitalized Overhead	2 526	2 576	2 701	592	933	720	824	839
General Counsel & Corporate Secretary	5	-	-	-	-	-	-	-
Human Resources & Corporate Services	156	277	372	328	391	308	70	46
Generation & Wholesale	45	70	130	163	84	54	-	-
Transmission	224	111	133	204	292	165	-	-
Marketing & Customer Service	8 736	9 063	9 671	9 022	10 302	9 849	9 607	12 610
Total Capitalized Activity Charges	9 166	9 520	10 306	9 718	11 069	10 376	9 677	12 656
*Capitalized Activity Charges/Overhead Requested Adjustments**				*4 756*	*3 685*	*3 441*	*2 713*	
Total Capitalized Activity Charges & Overhead Adjusted	11 692	12 096	13 007	15 066	15 686	14 537	13 214	13 495
Program Costs								
Customer Service & Corporate Relations	31 161	32 458	31 789	30 514	29 701	29 183	28 918	30 008
Operations and Maintenance	16 845	18 439	20 490	20 001	19 621	19 266	18 841	16 165
Organizational Support	16 858	17 250	17 405	18 386	17 818	16 757	16 012	16 408
Total Program Costs	64 863	68 147	69 684	68 901	67 140	65 206	63 770	62 581
Adjustments:								
Total Adjustments	(1 128)	(1 337)	(2 226)	(2 294)	(1 756)	(2 093)	(455)	(1 331)
Total Operating & Administrative (O&A) Expenses	$ 63 735	$ 66 810	$ 67 458	$ 66 607	$ 65 384	$ 63 113	$ 63 315	$ 61 250
O&A Requested Adjustments				*(5 107)*	*(4 085)*	*(3 984)*	*(3 097)*	
Total O&A Expenses - Adjusted	$ 63 735	$ 66 810	$ 67 458	$ 61 500	$ 61 299	$ 59 129	$ 60 218	$ 61 250
Capitalized Activity Charges & Overhead as a percentage of Adjusted O&A Expenses	**18%**	**18%**	**19%**	**24%**	**26%**	**25%**	**22%**	**22%**

*Approximately $0.4 million of the expenditures to be capitalized are materials and are therefore excluded from this line item

REFERENCE:

PUB/Centra I-18

PREAMBLE TO IR (IF ANY):

Manitoba Hydro has indicated that it would realize $92.6M in savings related to O&A of which 60% was O&A and 40% related to capital activities. Centra has assumed its share of the VDP O&A savings to be 4% based on an allocator of percentage of total assets.

QUESTION:

a) Please provide an explanation for the following variances on O&A by cost element:
   - Consulting and professional fees
   - Office expenses

b) Please provide an update to the comparison for the 2018/19 annual versus forecast by cost element and program for the fourth quarter and explain all material variances.

c) Please provide an explanation for the following Q3 variances on O&A by program:
   - Customer and public relations
   - Customer safety services
   - Metering
   - System performance & reliability

RESPONSE:

a) Explanations for the cost element variances requested for the nine months ended December 31, 2018 are shown below:

   Consulting & professional fees – the over expenditure is primarily related to additional environmental investigations required at 35 Sutherland, including the parking lot and river.

Office expenses – the under expenditure is primarily related to discontinuing the use of traditional land-based phone lines and using wireless communications for monitoring field equipment.

b) The Corporation is still in the process of finalizing the 2018/19 year-end results and is therefore not in a position to update 2018/19 information at this time.

Once the results have been finalized and made available for public distribution the financial results for 2018/19 will be filed with the Public Utilities Board.

While Centra's overall Operating & Administrative Expense target for 2019/20 continues to be $61.2 million, consistent with the original Application and the Supplement to the Application filed on March 22, 2019, Centra can advise the PUB that it has recently finalized an updated detailed O&A budget for gas operations for 2019/20. The updated detailed O&A budget will be reflected in Centra's Pre-hearing Update scheduled to be filed in July 2019. Centra can advise at this time that from an overall revenue requirement perspective, the updated detailed O&A budget for gas operations for 2019/20 will have no material impact on the current Application. The impacts to cost of service have not yet been calculated but will be included in the Pre-hearing Update.

c) Explanations for the program variances requested for the nine months ended December 31, 2018 are shown below:

Customer & Public Relations – the under expenditure is primarily due to less gas system expansion initiatives and the absence of advertising for Power Smart, due to the transition to Efficiency Manitoba, partially offset by higher participation for the Neighbours Helping Neighbours program.

Customer Safety Services – the over expenditure is partially related to a new carbon monoxide alarm awareness campaign, as well as increased safety watch requests and odour related calls.

Metering – The over expenditure is primarily due to a greater number of meter exchanges required by Measurement Canada than planned, partially offset by less time spent on meter shop activities due to lower staffing levels.

System Performance & Reliability – the over expenditure is related to new coating, shielding & corrosion expenditures incurred to identify and quantify the extent of pipeline corrosion.

REFERENCE:

PUB/Centra 1-19 b) & c), PUB/MH I-21 (2019/20 Manitoba Hydro GRA), CAC/Centra I-12(d)

QUESTION:

a) Please explain how Centra determined the total asset allocator was appropriate for allocation of savings related to the VDP.
b) Why did Centra not utilize the corporate activity charge ratio of 8% for allocating the labour savings related to VDP?
c) Please indicate how much of labour is allocated based on activity charges versus other allocators.
d) Please explain how the Corporation determined that the restructuring costs should be based on 6%. Please provide the determination of this allocation.
e) Please file the headcount analysis demonstrating the $92.6M in salary and benefit savings related to the VDP.
f) Please add an additional column to the schedule (d) indicating the number of staff that worked only on or primarily on natural gas specific work. Include additional columns for the wages and benefits related to those individuals.

RESPONSE:

a) and b):

The total assets driver is a general driver used to allocate costs and savings to Centra that represents the relative size of the electric and gas utility. The VDP was a corporate wide offering to all Manitoba Hydro staff, regardless of their age, jurisdiction, years of service, etc. As such, without knowing the full impact of the VDP, a general driver based upon the size of each utility was determined to be the most appropriate for this initiative.

c) As shown in the table below, approximately 85% of labour and benefits are allocated to Centra based on direct activity charges while the remaining 15% are allocated using other allocation processes.

CENTRA GAS MANITOBA INC.
ALLOCATION OF LABOUR & BENEFITS
(in millions)

		2017/18	%
Activity Charges (Timecarding)	$	39.8	85%
Other Allocation Processes		7.2	15%
Total	**$**	**47.1**	**100%**

d) As discussed in PUB/CENTRA I-28c, a new cost driver was introduced in 2016/17 to allocate restructuring expenditures associated with the VDP. The restructuring costs were not anticipated to impact the Business Operations Capital for the natural gas segment. As a result, the driver reflects the percentage of gas operating activity charges over total activity charges as shown in the table below.

CENTRA GAS MANITOBA INC.
RESTRUCTURING DRIVER
(in millions)

		2016 Study
Gas Operating Activity Charges	$	37.8
Total Activity Charges		628.5
Gas Percentage		**6%**

e) The following table provides the headcount analysis demonstrating the $92.6 million in salary and benefit savings related to the VDP. This table was filed in PUB/MH I-21b of the Manitoba Hydro 2019/20 Electric Rate Application.

VOLUNTARY DEPARTURE PROGRAM
($ in millions)

	Headcount	Annual Salary	Benefits	Total
President & CEO	1	$ 0.1	$ 0.0	$ 0.1
General Counsel & Corporate Secretary	5	0.6	0.2	0.8
Human Resources & Corporate Services	147	12.3	4.3	16.6
Indigenous Relations	9	0.7	0.2	0.9
Finance & Strategy	33	3.0	1.1	4.1
Generation & Wholesale	157	13.9	4.9	18.8
Transmission	198	16.7	5.8	22.5
Marketing & Customer Service	267	20.8	7.3	28.1
Subsidiary Secondments	4	0.5	0.2	0.6
Total	821	$ 68.6	$ 24.0	$ 92.6

f) Manitoba Hydro’s electric and natural gas lines of business are fully integrated and all employees are employed by Manitoba Hydro. Centra does not have employees and as such is unable to indicate the number of staff for natural gas work and their associated wages and benefits.

REFERENCE:

PUB/Centra I-20 (a)

QUESTION:

a) Please provide a schedule that details the costs and the costs per square foot for 360 Portage and the amounts allocated to Centra for each of the years 2013/14 through 2017/18 and the forecast or actual (if available) for 2018/19 and forecast for 2019/20.
b) Please provide the detail of the determination of interest expense in (a) related to the head office for 2013/14 approved and 2019/20 forecast and explain the difference.

RESPONSE:

a) The following table provides the total costs and cost per square foot for 360 Portage Avenue, as well as the actual amounts allocated to Centra for each of the years 2013/14 through 2017/18 and forecast amounts for 2018/19 and 2019/20.

CENTRA GAS MANITOBA INC.
360 PORTAGE AVENUE COSTS AND ALLOCATION TO CENTRA

(In Millions)	2012/13 Actual	2013/14 Actual	2014/15 Actual	2015/16 Actual	2016/17 Actual	2017/18 Actual	2018/19 Forecast	2019/20 Forecast
Gross Costs								
Operating & Maintenance	$ 2.9	$ 3.7	$ 3.8	$ 4.2	$ 3.8	$ 4.1	$ 4.3	$ 4.4
Interest	18.5	17.0	16.5	15.6	14.8	14.0	13.8	14.1
Depreciation	3.6	3.7	4.2	4.3	4.3	4.3	4.3	4.4
Property Tax	4.0	4.2	4.2	4.3	5.0	4.0	4.3	4.4
Total	**29.1**	**28.7**	**28.6**	**28.4**	**27.9**	**26.4**	**26.7**	**27.2**
Square Feet	697,609	697,609	697,609	697,609	697,609	697,609	697,609	697,609
Cost per Square Foot	$ 42	$ 41	$ 41	$ 41	$ 40	$ 38	$ 38	$ 39
Allocation to Centra	10%	9%	9%	9%	8%	8%	8%	8%
Allocation to Centra								
Operating & Maintenance	$ 0.3	$ 0.3	$ 0.3	$ 0.4	$ 0.3	$ 0.3	$ 0.3	$ 0.4
Interest	1.9	1.5	1.5	1.4	1.2	1.1	0.3	0.4
Depreciation	0.4	0.3	0.4	0.4	0.3	0.3	1.1	1.1
Property Tax	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3
Total	**2.9**	**2.6**	**2.6**	**2.6**	**2.2**	**2.1**	**2.1**	**2.2**
Credit	$ (2.2)	$ (2.2)	$ (2.2)	$ (2.2)	$ (2.2)	$ (1.6)	$ (1.6)	$ (1.7)
Allocation to Centra after Credit	**$ 0.7**	**$ 0.4**	**$ 0.4**	**$ 0.3**	**$ 0.0**	**$ 0.5**	**$ 0.5**	**$ 0.5**
Square Feet	69,761	62,785	62,785	62,785	55,809	55,809	55,809	55,809
Cost per Square Foot	$ 10	$ 6	$ 6	$ 5	$ 0	$ 9	$ 10	$ 9

The purpose of the 360 Portage credit is to ensure the overall costs charged to Centra for administrative buildings is in line with the costs charged prior to the construction of the 360 Portage building. Please refer to PUB/Centra I-20 a-d Revised for additional information.

b) The table below provides the details of the interest expense calculation for the 2013/14 Approved Forecast and the 2019/20 Test Year.

	2013/14 Approved	2019/20 Test Year
Average Net Book Value	$ 292,987	$ 271,346
Weighted Average Cost of Capital	6.5%	5.2%
Interest Expense	$ 19,073	$ 14,056

Interest expense is lower in the 2019/20 Test Year due to a reduction in the average net book value of Centra assets, as well as a lower weighted average cost of capital.

REFERENCE:

PUB/Centra I-20 b & c) PUB/Centra II-155 (b) (2013/14 GRA)

QUESTION:

a) Provide a schedule detailing the determination of the $2.2 million 360 Portage credit.
b) Please provide the same approach in (a) for determining the credit for 2019/20 and compare the results with the proposed $1.7 million adjustment for that year.
c) Please update the schedule 'Analysis of Facilities' costs by including the approved allocation to Centra of administrative building facility costs for 2013/14 of $3.8 million and indicate the difference between actual and approved for each of the years 2013/14 through 2019/20 and the cumulative total difference.

RESPONSE:

a) and b)

The table below provides a breakdown of the details of the 360 Portage Credit for 2010/11 (the first year of the credit at $2.2 million), as well as a similar calculation for 2019/20 with a comparison to the $1.7million credit implemented.

As discussed in PUB/CENTRA I-20c, in order to ensure that Centra pays its fair share of consolidated facilities costs while still complying with Order 99/07, the credit was decreased to $1.7 million to align the annualized compound growth of Centra's facilities costs after credit to -1.3% with the annualized compound growth of Centra's gross facilities costs over the same timeframe.

Analysis of Centra 360 Portage Credit	($ millions)	
	2010/11	2019/20
Consolidated Facilities Costs		
Actuals	$ 59.3	
Estimated[1]		$ 70.0
Baseline[2]	36.2	42.7
Difference	23.1	27.2
Corporate Activity Allocation %	10%	8%
360 Portage Credit	2.2	2.2
360 Portage Credit (PUB-CENTRA I-20b)		1.7
Difference		0.5

[1]2010/11 actuals adjusted for inflation.

[2]The baseline is an estimate of the total consolidated facilities costs prior to the construction of 360 Portage, calculated as 2008/09 actuals adjusted for inflation and estimated lease rate increases.

c) The following table provides a comparison of the facility cost allocation to Centra to the 2013/14 approved amount of $3.8 million.

Schedule of Consolidated Facilities Costs	2013/14 Approved	2013/14 Actual	2014/15 Actual	2015/16 Actual	2016/17 Actual	2017/18 Actual	2018/19 Forecast	2019/20 Test Year ($ millions)
Consolidated Facilities Costs	$ 60.0	$ 55.5	$ 55.7	$ 56.4	$ 57.1	$ 56.2	$ 55.8	$ 56.9
Corporate Activity Allocation %	10%	9%	9%	9%	8%	8%	8%	8%
Centra Gross Facilites Costs	6.0	5.0	5.0	5.1	4.6	4.5	4.5	4.5
360 Portage Credit	(2.2)	(2.2)	(2.2)	(2.2)	(2.2)	(1.6)	(1.6)	(1.7)
Centra Facilities Costs After Credit	$ 3.8	$ 2.8	$ 2.8	$ 2.9	$ 2.4	$ 2.9	$ 2.9	$ 2.8
Difference to 2013/14 approved		$ (1.0)	$ (1.0)	$ (0.9)	$ (1.4)	$ (0.9)	$ (0.9)	$ (1.0)
Cumulative Difference								$ (7.1)

The cumulative allocation to Centra from 2013/14 to 2019/20 is projected to be lower than the approved forecast of 2013/14 by approximately $7 million primarily due to consolidated facilities costs that have not grown at the rate of inflation as well as a decrease in the corporate activity allocation percentage.

REFERENCE:

PUB/Centra I-26 b)

QUESTION:

File a schedule detailing the key performance metrics utilized by Centra, a description of what is being measured and the results for the last five fiscal years together with a narrative description of the results.

RESPONSE:

The requested schedule is not readily available and would require an extensive and lengthy effort to produce. Instead of the requested schedule, please see the attachment to this response for the Q4 reports on Key Performance Indicators ("KPIs") from 2014-15 to 2018-19, the measures of which of were listed in the response to PUB/CENTRA I-162g.

DAMAGE MEASURES

PROGRAM MEASURES

LEAK SURVEY PROGRESS

Natural Gas Operations

Key Performance Indicators

Q4 - 2014/15 January 1 – March 31

Fiscal Yearly Comparisons

Total Locates:

- ***2014/15 – 45,912(-587)***
- ***2013/14 – 46,499***

Total Gas Below Grade Damage:

- ***2014/15 – 90(-7)***
- ***2013/14 – 97***

Total Gas Above Grade Damages:

- ***2014/15 – 30(-6)***
- ***2013/14 – 36***

- ***Manitoba Hydro outperformed the CGA average in every category in 2014/15!***
- ***1 damage measure was missed for Q4, 3 program measures and 1 leak survey measure were missed***

2014/2015 Q4 Results January - March			Measure			2013/2014 Q4 Results January - March			Measure
Below Grade Damages per 1000 locates	**Q4 Staking Requests**	**Q4 Damages**	**Number of damages per 1000 locates**	**CGA Average 2013 4,913/1,615,251**	**Status**	Below Grade Damages per 1000 locates	**Q4 Staking Requests**	**Q4 Damages**	**Number of damages per 1000 locates**
Winnipeg	3041	7	2.63		✔	*Winnipeg*	2,902	8	2.76
Westman	538	0	0			*Westman*	652	1	1.53
Eastman	555	1	1.80			*Eastman*	562	0	0
Parkland	200	0	0			*Parkland*	176	0	0
Interlake	362	0	0			*Interlake*	262	0	0
Provincial	**4769**	**8**	1.68	**3.04**		***Provincial***	**4,639**	**9**	1.94
Below Grade Damages per 1000 locates - excluding "Did Not Call"	**Q4 Staking Requests**	**Q4 Damages**	**Number of damages per 1000 locates**	**CGA Average 3.04 x 52%**		Below Grade Damages per 1000 locates - excluding "Did Not Call"	**Q4 Staking Requests**	**Q4 Damages**	**Number of damages per 1000 locates**
Winnipeg	3041	7	2.63		✘	*Winnipeg*	2,902	7	2.41
Westman	538	0	0			*Westman*	652	1	1.53
Eastman	555	1	1.80			*Eastman*	562	0	0
Parkland	200	0	0			*Parkland*	176	0	0
Interlake	362	0	0			*Interlake*	262	0	0
Provincial	**4769**	**8**	1.68(ytd 1.50)	**1.58**		***Provincial***	**4,639**	**8**	1.72
Below Grade Damages per 1000 customers	Number of Customers	Rolling 12 month period	**Number of damages per 1000 customers**	**CGA Average 4913/6,538,399**		Below Grade Damages per 1000 customers	Number of Customers		**Number of damages per 1000 customers**
Provincial	272228	90	0.33	**0.75**	✔	***Provincial***	**278735**	97	**0.35**
Below Grade Damages per 1000 Km of main.	Kilometres of Distribution Main including HP	Rolling 12 month period	**Number of damages per 1000 Km of main**	**CGA Average 4913/243,819**		Below Grade Damages per 1000 Km of main.	Kilometres of Distribution Main including HP		**Number of damages per 1000 Km of main**
Winnipeg					✔	*Winnipeg*			
Westman						*Westman*			
Eastman						*Eastman*			
Parkland						*Parkland*			
Interlake						*Interlake*			
Provincial	9580	90	9.39	**20.15**		***Provincial***	**9580**	97	10.13
Below Grade Damages per 1000 Km of main and services.	Kilometres of Main & Services	Rolling 12 month period	**Number of damages per 1000 Km of main & services**	**CGA Average 4913/378,682**		Below Grade Damages per 1000 Km of main and services.	Kilometres of Main & Services		**Number of damages per 1000 Km of main & services**
Winnipeg					✔	*Winnipeg*			
Westman						*Westman*			
Eastman						*Eastman*			
Parkland						*Parkland*			
Interlake						*Interlake*			
Provincial	15357	90	5.86	**12.97**		***Provincial***	**15,357**	97	6.32

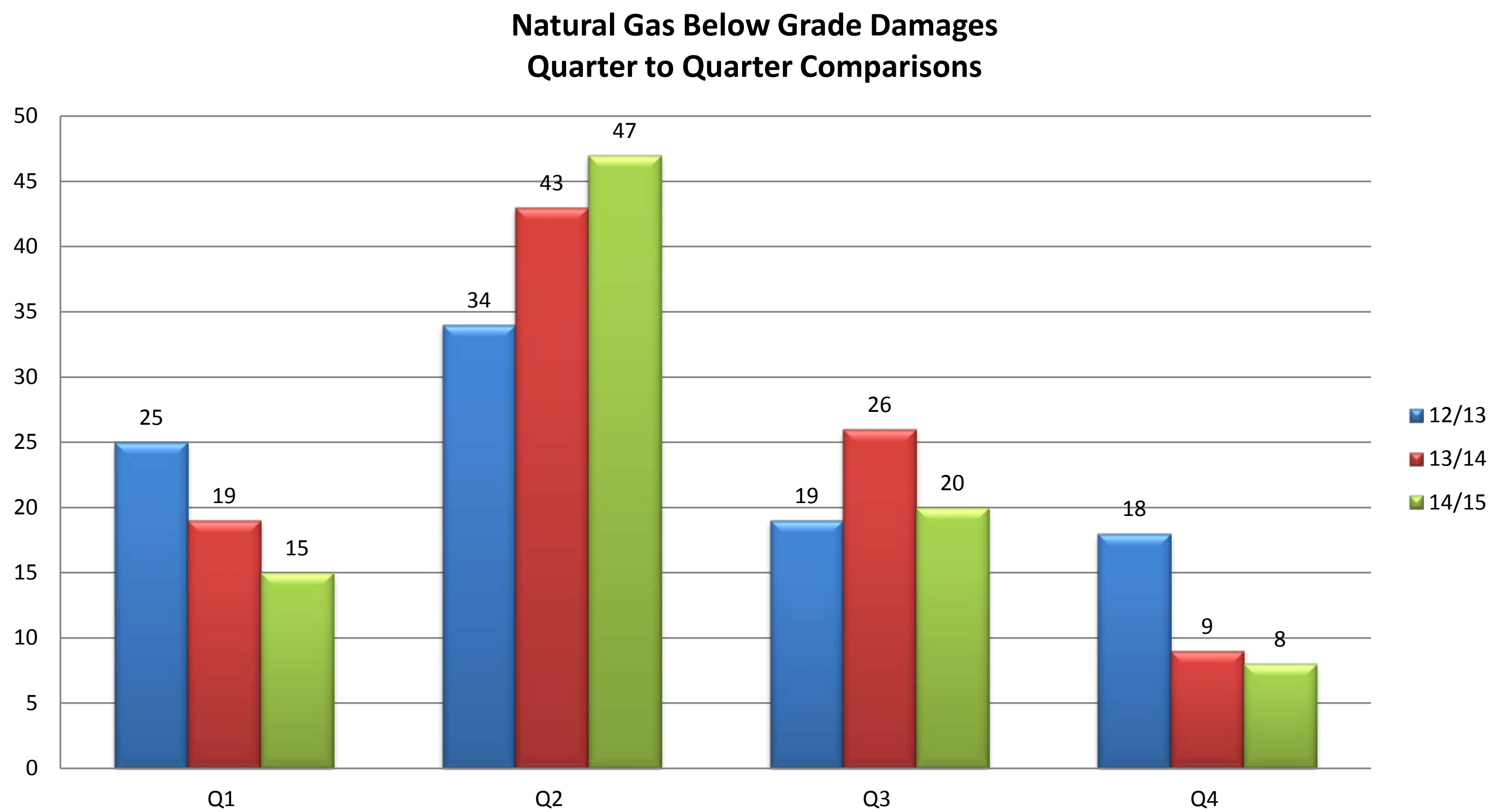
2014/15 Results

Below Grade Damages per 1000 locates	Staking Requests				Damages				Number of damages per 1000 locates				CGA Average
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
Winnipeg	8,939	10,328	5,058	3041	7	25	7	7	.78	2.42	1.38	2.30	
Westman	1,602	1,999	1284	538	0	6	1	0	0	3.00	0.78	0	
Eastman	2,192	2,557	1489	555	6	11	5	1	2.74	4.3	3.36	1.80	
Parkland	674	767	512	200	1	0	3	0	1.48	0	5.86	0	
Interlake	1,103	1,410	827	362	1	5	4	0	0.91	3.55	4.84	0	
Provincial	**14,510**	**17,318**	**9315**	**4769**	15	47	**20**	8	1.03	2.71	2.15	1.68	
	12 month total		45912		**12 month total**		90		**12 month average**		1.96		**3.04**
Below Grade Damages per 1000 Km of main.	**Kilometres of Distribution Main**								**Number of damages per 1000 Km of main**				**CGA Average**
Winnipeg	9580				7	25	7	7					
Westman					0	6	1	0					
Eastman					6	11	5	1					
Parkland					1	0	3	0					
Interlake					1	5	4	0					
Provincial					15	47	**20**	8	1.57	4.90	**2.09**	0.84	
					12 month total		90		**12 month average**			9.39	**20.15**
Below Grade Damages per 1000 Km of main and services.	**Kilometres of Main & Services**								**Number of damages per 1000 Km of main & services**				**CGA Average**
Winnipeg	15357				7	25	7	7					
Westman					0	6	1	0					
Eastman					6	11	5	1					
Parkland					1	0	3	0					
Interlake					1	5	4	0					
Provincial					15	47	**20**	8	0.98	3.06	**1.30**	0.52	
					12 month total		90		**12 month average**			5.86	**12.97**
Below Grade Damages- f damages to Four Party Trench plant									**Percent of damages to 4 party trench plant**				
Winnipeg					2	4	2	4	29%	16%	28%	57%	
Westman						1			0%	17%	0%	0%	
Eastman					1	3	1	1	14%	27%	20%	100%	
Parkland						0			0%	0%	0%	0%	
Interlake						0			05	0%	0%	0%	
Provincial					**3**	**8**	**3**	5	20%	17%	15%	63%	
					Yearly total 4 party		19		Yearly total damages	90	AVG	21%	

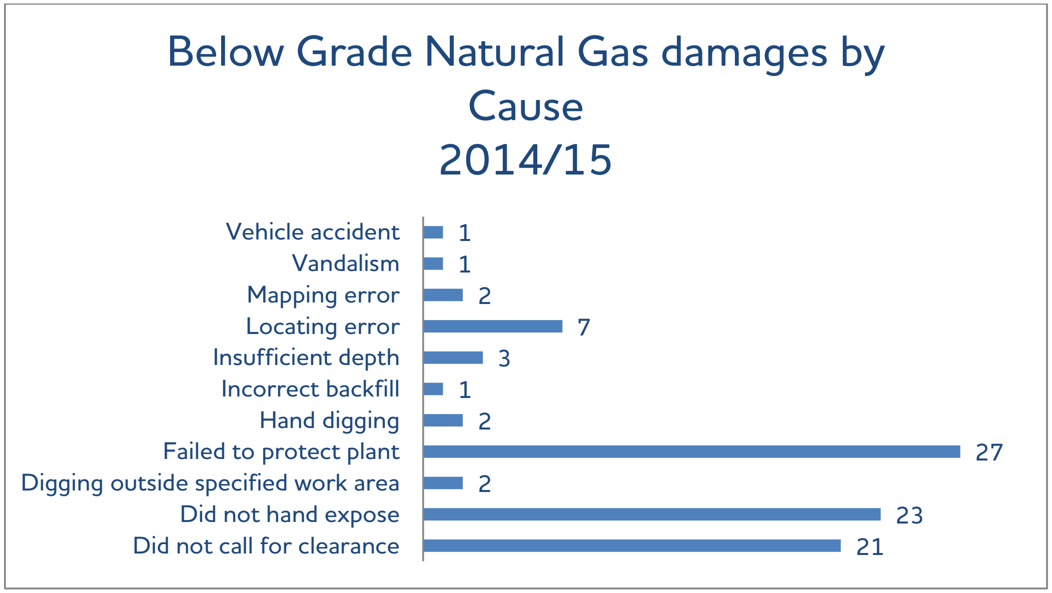
***Note:** Fortis BC data is removed from the CGA Average as their operational model differs from the rest of the CGA members*

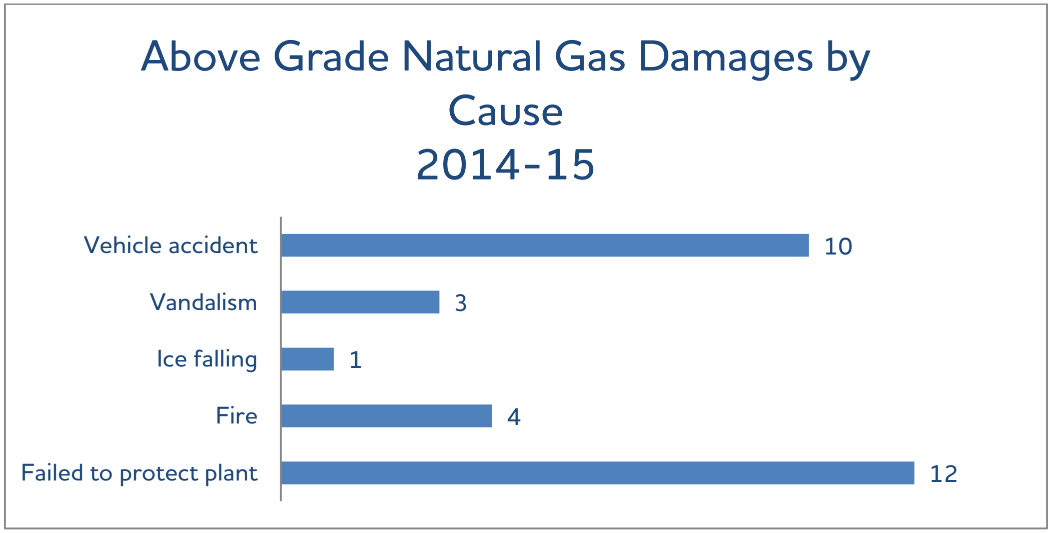
2013/14 Results

Below Grade Damages per 1000 locates	Staking Requests				Damages				Number of damages per 1000 locates			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Winnipeg	9321	11,331	5,279	2,902	8	22	10	19	0.86	1.94	1.89	6.55
Westman	1884	2,383	1,267	652	2	2	4	1	1.06	0.84	3.15	1.53
Eastman	2075	2,381	1,526	562	6	15	7	0	2.89	6.30	4.59	0.00
Parkland	670	915	371	176	1	1	1	1	1.49	1.09	2.70	5.68
Interlake	1067	1,380	776	262	2	3	4	0	1.87	2.17	5.15	0.00
Provincial	15017	**17,624**	9,219	4,639	19	**43**	26	9	1.27	**2.49**	2.82	1.94
	YTD		**46,499**		**YTD**		**97**		**YTD**		**2.09**	
Below Grade Damages per 1000 Km of main.	**Kilometres of Distribution Main**								**Damages per 1000 Km of main**			
Winnipeg	9580				8	22	10	8				
Westman					2	2	4	1				
Eastman					6	15	7	0				
Parkland					1	1	1	0				
Interlake					2	3	4	0				
Provincial					19	**43**	26	9	1.98	4.49	2.71	0.939
					YTD		**97**		**YTD**	**97**	**Avg**	**10.125**
Below Grade Damages per 1000 Km of main and services.	**Kilometres of Main & Services**								**Number of damages per 1000 Km of main & services**			
Winnipeg	**15,357**				8	22	10	8				
Westman					2	2	4	1				
Eastman					6	15	7	0				
Parkland					1	1	1	0				
Interlake					2	3	4	0				
Provincial					19	**43**	26	9	**1.24**	2.08	1.69	0.59
					YTD		96		**YTD**	97	**Avg**	**6.31**
Below Grade Damages- Percent of damages to Four Party Trench plant									**2012/13 Percent of damages to 4 party trench plant**			
Winnipeg						3		3	0%	14%	0%	37%
Westman								1	0%	0%	0%	100%
Eastman					1	1	1		17%	7%	14%	0%
Parkland									0%	0%	0%	0%
Interlake									0%	0%	0%	0%
Provincial					**1**	4	1	4	**5%**	**9%**	**4%**	**44%**
					YTD		10		YTD	97	AVG	10.3%



	14/15				13/14				12/13			
	Q1	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**
Winnipeg	7	25	7	7	8	22	10	8	8	12	8	13
Westman	0	6	1	0	2	2	4	1	6	2	0	2
Eastman	6	11	5	1	6	15	7	0	9	14	7	2
Parkland	1	0	3	0	1	1	1	0	1	3	1	0
Interlake	1	5	4	0	2	3	4	0	1	3	3	1
	15	**47**	**20**	**8**	**19**	**43**	**26**	**9**	**25**	**34**	**19**	**18**
YTD	**15**	**62**	**82**	**90**	**19**	**62**	**88**	**97**	**25**	**59**	**78**	**96**


Below Grade Natural Gas damages by Cause 2014/15
Vehicle accident
1
Vandalism
1
Mapping error
2
Locating error
7
Insufficient depth
3
Incorrect backfill
1
Hand digging
2
Failed to protect plant
27
Digging outside specified work area
2
Did not hand expose
23
Did not call for clearance
21


Above Grade Natural Gas Damages by Cause 2014-15
Vehicle accident
10
Vandalism
3
Ice falling
1
Fire
4
Failed to protect plant
12

Gas Operations Key Performance Indicators

Program Measures

Procedure	Frequency	KPI		
Odorization Testing Procedure # 4.500.11				
Odorant Intensity Testing	The current practice is to perform these tests on a weekly basis.	Performed once per week.	**January - March Q4**	
Winnipeg			Complete	✔
Westman			Complete	
Eastman			Complete	
Parkland			Complete	
Interlake			Complete	
Equipment Testing				
Combustible Gas Indicator Testing Standard 711.01				
Monthly Inspection and Calibration	Monthly	Testing of CGI units is complete by the last day of the month.	**January - March Q4**	
Winnipeg			98%	✔
Westman			100%	
Eastman			100%	
Parkland			100%	
Interlake			100%	
Flame Ionization Equipment Calibration	Monthly	Testing of FI units are complete by the last day of the month.	**January - March Q4**	
Winnipeg	Most areas now have DP-IR equipment that is self calibrating. Log books are kept for all DP-IRs.		100%	✔
Westman			100%	
Eastman			100%	
Parkland			100%	
Interlake			100%	

Gas Operations Key Performance Indicators

Procedure	Frequency	KPI		
Emergency Equipment Testing - Squeezers	100% of squeezers are tested twice each year		**January - March Q4**	
Winnipeg			Complete	✗
Westman			Complete	
Eastman			Complete	
Parkland			Complete	
Interlake			PLP did not complete	
Emergency Equipment Inventory List Review	To be reviewed annually	Completed once each year.	**January - March Q4**	
Winnipeg			Complete	✗
Westman			Complete	
Eastman			Complete	
Parkland			Complete	
Interlake			PLP did not Complete	
Pre-Tested Pipe Inventory Procedure 5000.1 and Standard 720.07	To be reviewed annually	Completed once each year.	**January - March Q4**	
Winnipeg	Completed Q4 2014/15		Complete	✓
Parkland	Gladstone Aluminum		Complete	
Line Marker Signs	Ongoing annual survey		**January - March Q4**	
Winnipeg	Survey completed July 15, 2014. Discrepancies forwarded to Districts.		Complete	✓
Westman			Complete	
Eastman			Complete	
Parkland			Complete	
Interlake			Complete	
Vegetation Management Standard 723.01	Surveyed at not more than 3 year intervals. Done with Transmission Survey	Deficiencies resolved prior to the next survey	**January - March Q4**	
Winnipeg	Survey completed July 15, 2014. Discrepancies forwarded to Districts And Forestry.		Complete	✓
Westman			Complete	
Eastman			Complete	
Parkland			Complete	
Interlake			Complete	

Program Measures

2014/15

Procedure	KPI Frequency	Number of Kilometres Surveyed	Above Grade Leaks			Below Grade Leaks			Result	
Outside Leak Surveys Procedure #4.004.23									**Jan-Mar Q4**	
Distribution System										
Transmission and High Pressure Pipeline Survey	Entire line to be surveyed once per year, not to exceed 15 months	Completed in Q3	**A**	**B**	**C**	**A**	**B**	**C**		
Winnipeg									Complete	
Westman										
Eastman										
Parkland										
Interlake										
Total		2086	0	0	0	0	0	0		
Mains and Services	Mains to be surveyed every 3 years	**Number of Services Surveyed**	**Above Grade Leaks**			**Below Grade Leaks Reported**				
		Completed in Q2	**A**	**B**	**C**	**A**	**B**	**C**		
Winnipeg	One third of the distribution mains and services surveyed each year									
Westman										
Eastman										
Parkland										
Interlake										
Total		50,706	1295			53		3		

Above Grade piping at bridge crossings	Survey completed once each year	**Date Complete**		**Above Grade Leaks**		
Interlake	Lockport Bridge			**A**	**B**	**C**
(Included in annual Transmission survey)		July 2014		**0**	**0**	**0**
Regulator - Valve Maintenance Procedure # 4.500.16						
All Valves associated with the gas distribution system will be maintained on a yearly basis.	Completed once each year.	**# Completed**	**Total**			
Emergency Sectional Downtown Valve Maintenance Program		56	56	**Jan-Mar Q4**		✔
Distribution Buried Valves			**Total**	**Completed**		☐
Winnipeg	Portage did not complete		402	402		✘
Westman			63	63		
Eastman			93	93		
Parkland			22	22		
Interlake			?	0		

Leak Classification Criteria

Class A Leak

Due to the location or intensity, is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous. Class A leaks are repaired through regular maintenance.

Class B Leak

Due to the location or intensity, is recognized as being non-hazardous at the time of detection, but justifies scheduled repair due to probability of future hazards. That is, if conditions changed that would re-classify the leak to a level that requires immediate action such as, migration or customer concern.

Class C Leak

Due to the location or intensity, represents an existing or potential hazard to persons or property, and requires immediate or continuous action until the conditions are no longer hazardous.

Q4 2014/15

Business District Mains & Services							
	Frequency	**Number of Buildings Surveyed**				**Survey Results**	
A Business District is defined as any area in which the Public Right of Way (laneway or road allowance) is entirely covered with a permanent surface of concrete or asphalt extending from the building wall to the center line of the right of way and beneath which runs a gas main or service	Three times per year outside and once inside building annually	Number Surveyed Q4	Leaks found	Leaks Repaired	Open Orders		
Winnipeg	Total number of buildings fluctuates with additions and deletions due to new construction, building sales etc.	935	9	0	9	Survey 1(2015)	X
Westman		234	0	0	0	6 remaining from Survey 3	
Eastman		213	0	0	0	Survey 3 complete	
Parkland		0	0	0	0		
Interlake	Selkirk completed with Wpg, PLP missed survey 3 Survey 2 –Q1, Survey 1 –Q3	0	0	0	0		

Q4 2014/15

Public Building Leak Survey Procedure 5.000.24	*Public Buildings Survey*							
	Frequency	**KPI**						
A building served by natural gas, which is used as a place of public assembly for a common purpose. Such buildings include: - Hospitals, nursing and senior citizens homes, schools, daycare centres, churches and recreation complexes.	Annually	Identified buildings are surveyed each year.	Number Surveyed	Leaks found on company piping	Leaks Repaired	Open Orders	**Survey Results**	
Winnipeg	Total number of buildings fluctuates with additions and deletions due to new construction, building sales etc.		246	7	2	0	Complete	✔
Westman			171	0	0	0	Complete	
Eastman			137	1	1	0	Complete	
Parkland			151	0	0	0	Complete	
Interlake			50	0	0	0	Complete	

Buildings With Inside Regulators			**Q4**	
Any building in which a company regulator is located.	Yearly, not to exceed 15 months, generally done concurrently with the inside business district survey.		Identified buildings are surveyed once each year.	
Winnipeg		350 St Mary Ave	Completed July 11, 2014	✔

Winnipeg

Total # of PBI's 2015	Total 246	
Complete - No Leak on company piping(CPNL)	226	92 %
Complete - "A leak found and repaired	2	1 %
Complete – leak found Company Piping	5	2 %
Complete – Leak found Customer Piping	9	4%
Other Infractions found	4	2%

High Pressure Transmission, Mains and Services Survey Results

Fiscal Year 2014/15

Procedure	Frequency	KPI	
Outside Leak Surveys Procedure #4.004.23	Entire line to be surveyed once per year, not to exceed 15 months	Survey completed once each year	
GAMC - Gate Stations yard piping	Total Number of Stations	Number of Stations Surveyed this quarter	Remaining
Apr 1 to Jun 30 Q1	199	0	199
Jul 1 to Sept 30 Q2	199	14	185
Oct 1 to Dec 31 Q3	199	185	0
Jan 1 to Mar 31 Q4	199	0	0
GAMC Maintenance Standards 1 & 2			
Valves associated with the gas distribution system will be maintained on a yearly basis.	Yearly, not to exceed 18 months	Completed once each year.	
Pipeline Valves	Total Number of Valves	Number Completed this quarter	Remaining
Apr 1 to Jun 30 Q1	862	322	540
Jul 1 to Sept 30 Q2	862	469	71
Oct 1 to Dec 31 Q3	862	71	0
Jan 1 to Mar 31 Q4	862	0	0
Station Valves	Number of valves	Number Completed this quarter	Remaining
Apr 1 to Jun 30 Q1	1626	997	629
Jul 1 to Sept 30 Q2	1626	588	41
Oct 1 to Dec 31 Q3	1626	41	0
Jan 1 to Mar 31 Q4	1626	0	0

DAMAGE MEASURES
PROGRAM MEASURES
LEAK SURVEY PROGRESS

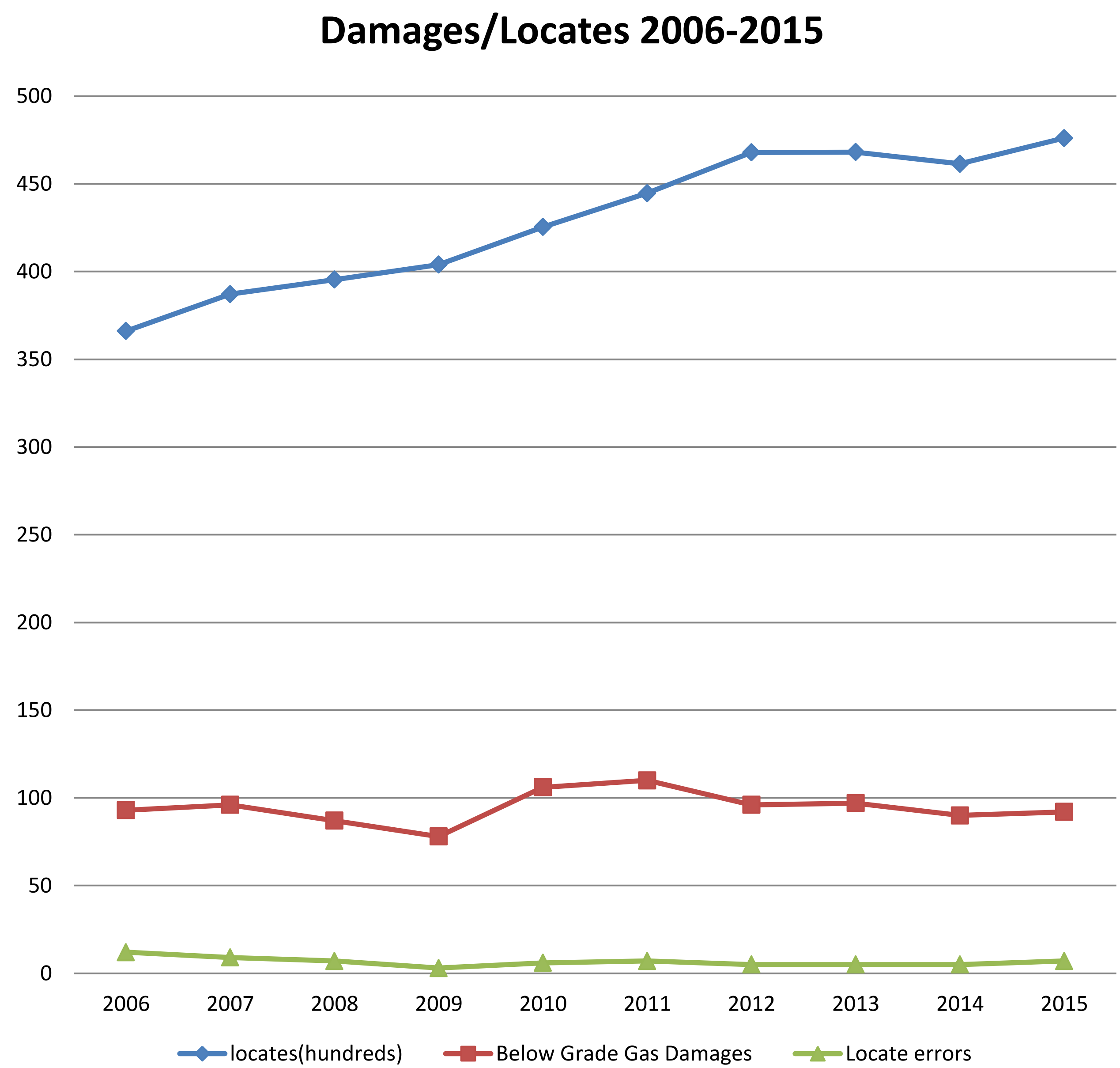
Q4 - 2015/16 January 1– March 31

Natural Gas Operations Key Performance

- 2015/16 below grade damages increased from 90 to 92 as compared to a year earlier

- Averaged 94 damages per year in the past 10 years . The trend is downward despite locate volumes increasing

Manitoba Hydro


Damages/Locates 2006-2015
500
450
400
350
300
250
200
150
100
50
0
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
locates(hundreds)
Below Grade Gas Damages
Locate errors

2015-2016 Q4 Results January - March			Measure			2014-2015 Q4 Results January - March			Measure
Below Grade Damages Per 1000 locates Q4									
2015-2016 Q4	Q4 Staking Requests	Q4 BG Damages	BG damages per 1000 locates	CGA Average 2014 4,832/1,758,482	Status	2014-2015 Q4	Q4 Staking Requests	Q4 BG Damages	BG damages per 1000 locates
Winnipeg	3,176	5	1.57			*Winnipeg*	3041	7	2.30
Westman	557	0	0.00			*Westman*	538	0	0.00
Eastman	546	1	1.83			*Eastman*	555	1	1.80
Parkland	194	2	10.31			*Parkland*	200	0	0.00
Interlake	418	0	0.00			*Interlake*	362	0	0.00
Provincial	4,891	8	1.64	2.75		*Provincial*	4,696	8	1.70
Below Grade Damages per 1000 locates excluding "did not call" Q4									
2015-2016 Q4	Q4 Staking Requests	Q4 Damages	BG damages per 1000 locates	CGA Average 2.75x58%	Status	2014-2015 Q4	Q4 Staking Requests	Q4 Damages	BG damages per 1000 locates
Winnipeg	3,176	5	1.57			Winnipeg	3,041	7	2.30
Westman	557	0	0.00			*Westman*	538	0	0.00
Eastman	546	1	1.83			*Eastman*	555	1	1.80
Parkland	194	2	10.31			*Parkland*	200	0	0.00
Interlake	418	0	0.00			*Interlake*	362	0	0.00
Provincial	4,891	8	1.64	1.60		*Provincial*	4,696	8	1.70
Below Grade Damages per 1000 Customers									
2015-2016 Q4	Number of Customers	Rolling 12 month period damages	Number of damages per 1000 customers	CGA Average 4832/6,658,306	Status	2014-2015 Q4	Number of Customers		Number of damages per 1000 customers
Provincial	274,817	92	0.33	0.73		*Provincial*	274,084	90	0.33
Below Grade Damages per 1000 km of Main									
2015-2016 Q4	Kilometres of Distribution Main including HP	Rolling 12 month period damages	Number of damages per 1000 Km of main	CGA Average 4832/248,275	Status	2014-2015 Q4	Kilometres of Distribution Main including HP		Number of damages per 1000 Km of main
Provincial	10,074	92	9.13	19.46		*Provincial*	9,580	90	9.39
Below Grade Damages per 1000 Km of main and services.									
2015-2016 Q4	Kilometres of Main & Services	Rolling 12 month period damages	Number of damages per 1000 Km of main & services	CGA Average 4832/385056	Status	2014-2015 Q4	Kilometres of Main & Services		Number of damages per 1000 Km of main & services
Provincial	17,146	92	5.37	12.55		*Provincial*	15,357	90	5.86

Below Grade Damages per 1000 Locates

2015-2016 Results

	Staking Requests				Damages				Number of damages per 1000 locates				CGA Average
	Q4 15/16	Q3 15/16	Q2 15/16	Q1 15/16	Q4 15/16	Q3 15/16	Q2 15/16	Q1 15/16	Q4 15/16	Q3 15/16	Q2 15/16	Q1 15/16	
Winnipeg	3,176	5,251	9,958	10,770	5	3	27	12	1.57	0.57	2.71	1.11	
Westman	557	1,317	1,925	1,681	0	3	2	5	0.00	2.28	1.04	2.97	
Eastman	546	1,197	2,072	2,119	1	3	7	8	1.83	2.51	3.38	3.78	
Parkland	194	450	740	747	2	1	3	1	10.31	2.22	4.05	1.34	
Interlake	418	877	1,473	1,445	0	4	5	0	0.00	4.56	3.39	0.00	
Provincial	4,891	9092	16168	16,762	8	14	44	26	1.64	1.54	2.72	1.55	
	12 month total		46,913		12 month total		92		12 month avg		1.96		2.75

2014-2015 Results

2014-2015	Staking Requests				Damages				Number of damages per 1000 locates			
	Q4 14/15	Q3 14/15	Q2 14/15	Q1 14/15	Q4 14/15	Q3 14/15	Q2 14/15	Q1 14/15	Q4 14/15	Q3 14/15	Q2 14/15	Q1 14/15
Winnipeg	3041	5,058	10,328	8,939	7	7	25	7	2.30	1.38	2.42	0.78
Westman	538	1,284	1,999	1,602	0	1	6	0	0.00	0.78	3.00	0.00
Eastman	555	1,489	2,557	2,192	1	5	11	6	1.80	3.36	4.30	2.74
Parkland	200	512	767	674	0	3	0	1	0.00	5.86	0.00	1.48
Interlake	362	827	1,410	1,103	0	4	5	1	0.00	4.84	3.55	0.91
Provincial	4696	9,170	17,061	14,510	8	20	47	15	1.70	2.18	2.75	1.03
	12 month total		45,437		12 month total		90		12 month avg		1.98	

Below Grade Damages per 1000 Km of main

2015-2016

	Kilometres of Distribution Main	Damages				Number of damages per 1000 Km of main				CGA Average
		Q4 15/16	Q3 15/16	Q2 15/16	Q1 15/16	Q4 15/16	Q3 15/16	Q2 15/16	Q1 15/16	
Winnipeg	10,074	5	3	27	12					
Westman		0	3	2	5					
Eastman		1	3	7	8					
Parkland		2	1	3	1					
Interlake		0	4	5	0					
Provincial		8	14	44	26	0.79	1.39	4.37	2.58	
		12 month total		92		12 month avg			9.13	19.46

2014-2015

2014-2015	Kilometres of Distribution Main	Damages				Damages per 1000 Km of main			
		Q4 14/15	Q3 14/15	Q2 14/15	Q1 14/15	Q4 14/15	Q3 14/15	Q2 14/15	Q1 14/15
Winnipeg	9,580	7	7	25	7				
Westman		0	1	6	0				
Eastman		1	5	11	6				
Parkland		0	3	0	1				
Interlake		0	4	5	1				
Provincial		8	20	47	15	0.84	2.09	4.91	1.57
		12 month total		90		12 month avg			9.39

Below Grade Damages per 1000 km of mains & services

2015-2016

	Kilometres of Main & Services	Damages				Number of damages per 1000 Km of main & services				CGA Average
		Q4 15/16	Q3 15/16	Q2 15/16	Q1 15/16	Q4 15/16	Q3 15/16	Q2 15/16	Q1 15/16	
Winnipeg	17,146	5	3	27	12					
Westman		0	3	2	5					
Eastman		1	3	7	8					
Parkland		2	1	3	1					
Interlake		0	4	5	0					
Provincial		8	14	44	26	0.47	0.82	2.57	1.52	
		12 month total		92		12 month average			5.37	12.55

2014-2015

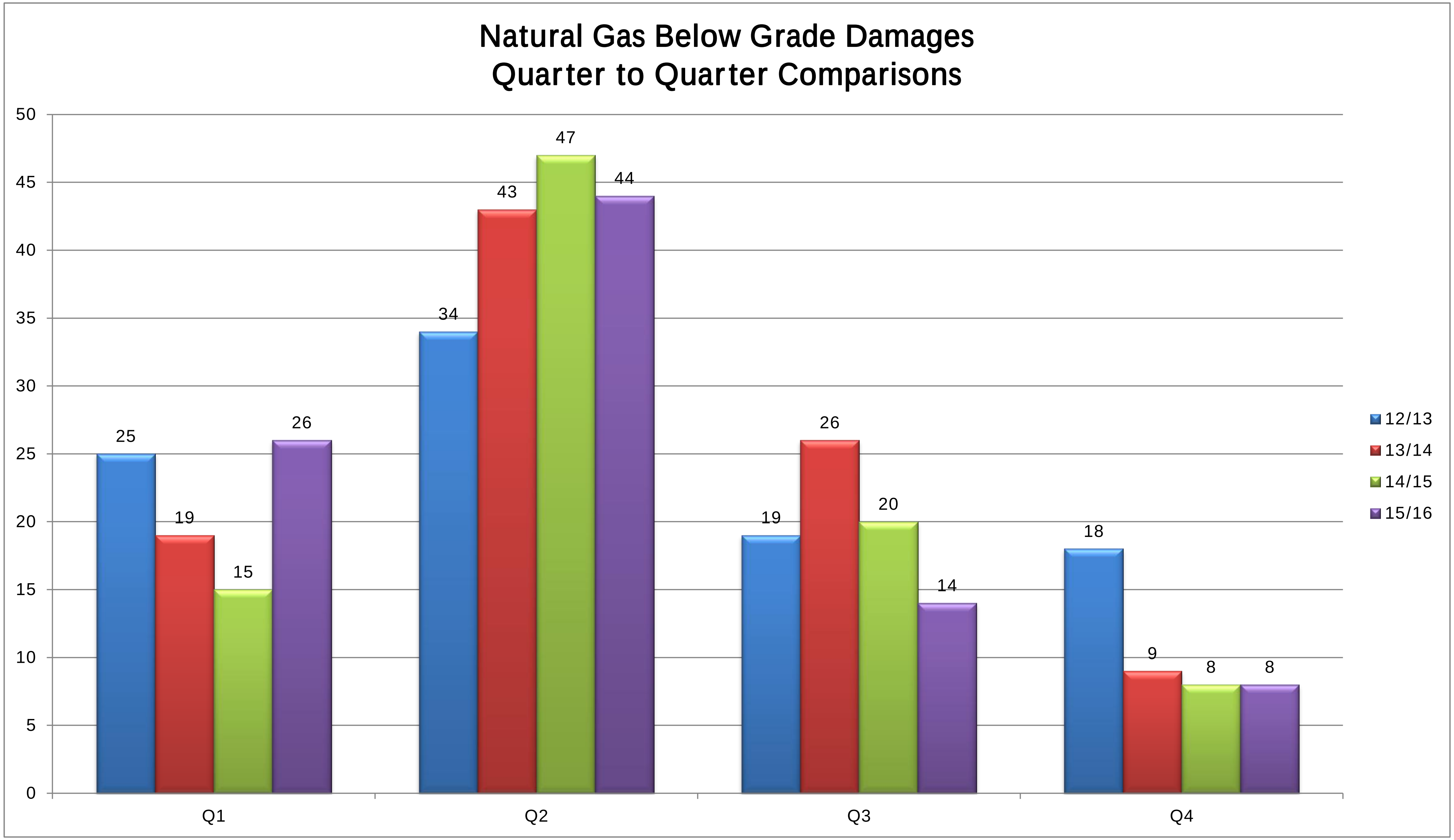
2014-2015	Kilometres of Main & Services	Damages				Number of damages per 1000 Km of main & services			
		Q4 14/15	Q3 14/15	Q2 14/15	Q1 14/15	Q4 14/15	Q3 14/15	Q2 14/15	Q1 14/15
Winnipeg	15,357	7	7	25	7				
Westman		0	1	6	0				
Eastman		1	5	11	6				
Parkland		0	3	0	1				
Interlake		0	4	5	1				
Provincial		8	20	47	15	0.52	1.30	3.06	0.98
		12 month total		90		12 month avg			5.86

Percent of Below Grade Damages that are four party trench area

2015-2016	4 Party Damages				Percent of damages to 4 party trench plant			
	Q4 15/16	Q3 15/16	Q2 15/16	Q1 15/16	Q4 15/16	Q3 15/16	Q2 15/16	Q1 15/16
Winnipeg	1	1	3	1	20%	33%	11%	8%
Westman	0	0	0	1	0%	0%	0%	20%
Eastman	1	0	0	2	100%	0%	0%	25%
Parkland	0	0	0	0	0%	0%	0%	0%
Interlake	0	0	0	0	0%	0%	0%	0%
Provincial	2	1	3	4	25%	7%	7%	15%
	12 month total	10			damages	92	AVG	11%

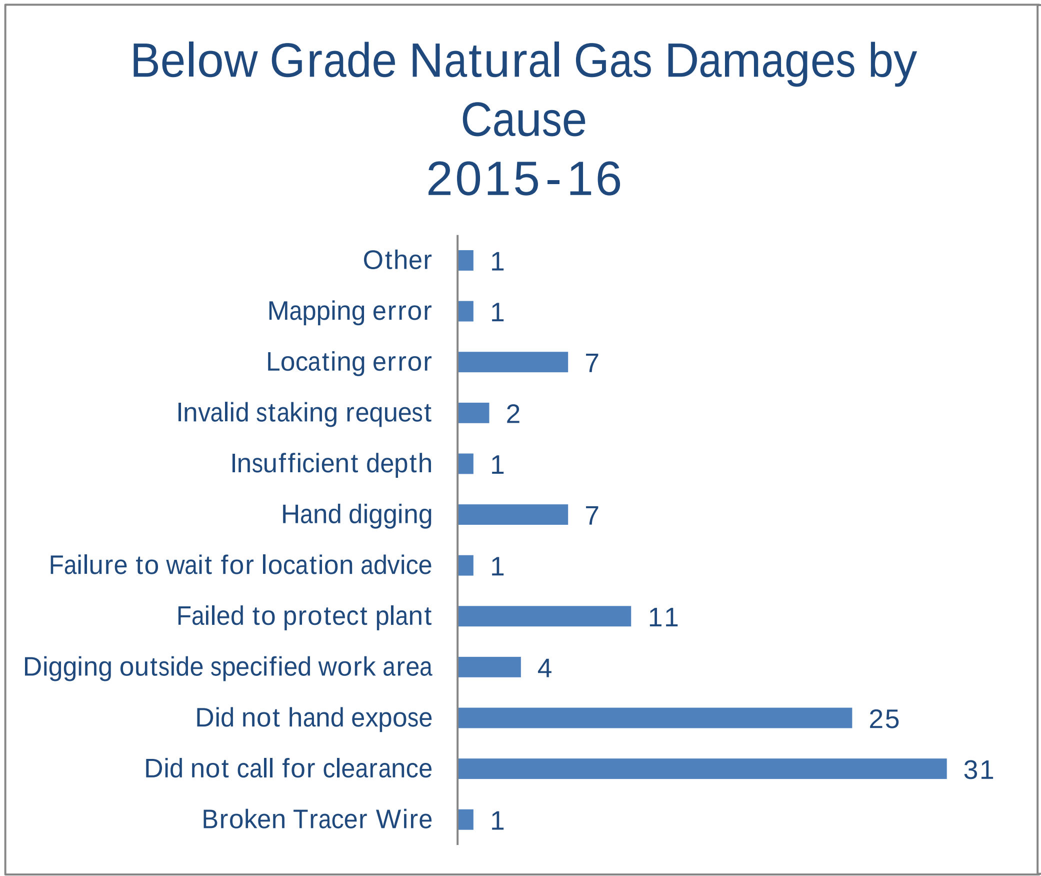
2014-2015	4 Party Damages				Percent of damages to 4 party trench plant			
	Q4 14/15	Q3 14/15	Q2 14/15	Q1 14/15	Q4 14/15	Q3 14/15	Q2 14/15	Q1 14/15
Winnipeg	4	4	4	2	57%	57%	16%	29%
Westman	0	1	1	0	0%	100%	17%	0%
Eastman	1	3	3	1	100%	60%	27%	17%
Parkland	0	0	0	0	0%	0%	0%	0%
Interlake	0	0	0	0	0%	0%	0%	0%
Provincial	5	8	8	3	63%	40%	17%	20%
	12 month total	24			damages	90	AVG	26.67%

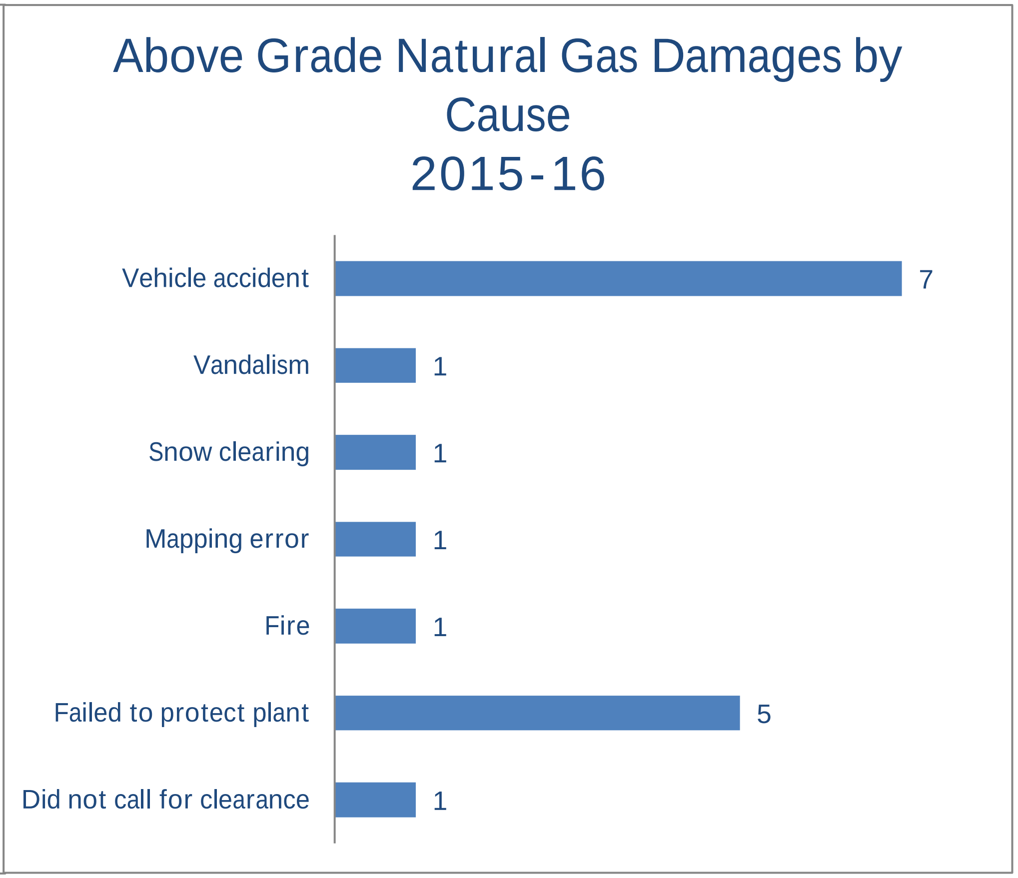
****Note:*** *Fortis BC data is removed from the CGA Average as their operational model differs from the rest of the CGA members*



	2015-2016				2014-2015				2013-2014				2012-2013			
	Q1	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**
Winnipeg	12	27	3	5	7	25	7	7	8	22	10	8	8	12	8	13
Westman	5	2	3	0	0	6	1	0	2	2	4	1	6	2	0	2
Eastman	8	7	3	1	6	11	5	1	6	15	7	0	9	14	7	2
Parkland	1	3	1	2	1	0	3	0	1	1	1	0	1	3	1	0
Interlake	0	5	4	0	1	5	4	0	2	3	4	0	1	3	3	1
	26	**44**	**14**	**8**	**15**	**47**	**20**	**8**	**19**	**43**	**26**	**9**	**25**	**34**	**19**	**18**
YTD	**26**	**70**	**84**	**92**	**15**	**62**	**82**	**90**	**19**	**62**	**88**	**97**	**25**	**59**	**78**	**96**

2015/16 Natural Gas Damages





Gas Operations Key Performance Indicators			
Odorization Testing Procedure # 4.500.35			
Odorant Intensity Testing	Performed once per week.	**Q4 Jan-Mar**	
Winnipeg		Complete	🟢
Westman		Complete	🟢
Eastman		Complete	🟢
Parkland		Complete	🟢
Interlake		Complete	🟢
Equipment Testing			
Combustible Gas Indicator Testing Standard 711.01			
Monthly Inspection and Calibration	Monthly	**Q4 Jan-Mar**	
Winnipeg	1 unit at Sutherland, 1 at Notre Dame missing	98%	
Westman		100%	🟢
Eastman	Winkler is using MSA's with auto calibrate feature	100%	🟢
Parkland		100%	🟢
Interlake		100%	🟢
Flame Ionization Equipment Calibration	Monthly	**Q4 Jan-Mar**	
Winnipeg	Parkland and WestMan now use DP-IR equipment that is self calibrating. Log books are kept for all DP-IRs.	100%	🟢
Eastman		100%	🟢
Interlake		100%	🟢
Emergency Equipment Testing - Squeezers	Squeezer test 1 to be completed by the end of Q2 Squeezer test 2 to be completed by the end of Q4	**Q4 Jan-Mar**	
Winnipeg		Test 2 Comp in Q3/4	🟢
Westman		Test 2 Comp in Q4	🟢
Eastman		Test 2 Comp in Q3	🟢
Parkland		Test 2 Comp in Q3	🟢
Interlake		Test 2 Comp in Q3/4	🟢

Gas Operations Key Performance Indicators			
Emergency Equipment Inventory List Review	To be reviewed annually	**Q4 Jan-Mar**	
Winnipeg	Sutherland completed in Q1, N.D. Completed in Q3	Complete	
Westman	Completed in Q3	Complete	
Eastman	Steinbach comp in Q1, Winkler completed in Q3	Complete	
Parkland	completed in Q3	Complete	
Interlake	completed in Q1	Complete	
Pre-Tested Pipe Inventory Procedure 5.000.1 and Standard 720.07	To be reviewed annually	**Q4 Jan-Mar**	
Winnipeg	Completed November 2015	Complete	
Parkland	Gladstone Aluminum - June 2015	Complete	
Line Marker Signs	Checked with leak survey in Q2, work orders to be submitted to districts in Q4 for scheduled repair	**Q4 Jan-Mar**	
Winnipeg		Scheduled	
Westman		Scheduled	
Eastman		Scheduled	
Parkland		Scheduled	
Interlake		Scheduled	
Vegetation Management Standard 723.01	Surveyed at not more than 3 year intervals. Done with Transmission Survey Deficiencies resolved prior to the next survey,	**Q4 Jan-Mar**	
	Checked with leak survey in Q2, 34 locations submitted to Forestry in Q4 for remediation in Spring/Summer		
Winnipeg		Scheduled	
Westman		Scheduled	
Eastman		Scheduled	
Parkland		Scheduled	
Interlake		Scheduled	

Outside Leak Survey Procedure 4.004.23	KPI Frequency	Number of Kilometres Surveyed	Q4 Above Grade Leaks			Q4 Below Grade Leaks			Result	
Q4 January - March										
Transmission and High Pressure Pipeline Survey	once per year, not to exceed 15 months	Completed YTD	A	B	C	A	B	C		
Provincial Total	2,294	2,294	0	0	0	0	0	0	complete in Q2	
YTD Results			0	0	0	0	0	0	complete in Q2	
Mains and Services	every 3 years	Number of Services Surveyed	Q4 Above Grade Leaks			Q4 Below Grade Leaks				
	2015/16 services to be surveyed	Completed YTD	A	B	C	A	B	C		
Provincial Total	100,865	100,865	0	0	0	0	0	0	complete in Q2	
YTD Results			1,902	0	0	32	0	9		

Leak Classification Criteria

Class A Leak

Due to the location or intensity, is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous. Class A leaks are repaired through regular maintenance.

Class B Leak

Due to the location or intensity, is recognized as being non-hazardous at the time of

Class C Leak

Due to the location or intensity, represents an existing or potential hazard to persons or

Above Grade piping at bridge crossings	Survey completed once each year	Date Complete	Above Grade Leaks		
			A	B	C
Interlake (Included in annual Transmission survey)	Lockport Bridge	Completed in Q2 8/14/2015	0	0	0
Valve Maintenance					
All Valves associated with the gas distribution system will be maintained on a yearly basis.	**Total**	**Completed YTD**			
Emergency Sectional Downtown Valve Maintenance Program	56	56	Completed		
Distribution Buried Valves	**Total**	**Completed YTD**			
Winnipeg	393	392	Scheduled		
Westman	63	63	complete		
Eastman	100	100	complete		
Parkland	22	22	complete		
Interlake	28	28	complete		

* one valve could not be located in West St Paul, expected to be resolved in April

Business District Mains & Services (Wall to Wall Leak Survey) A Business District is defined as any area in which the Public Right of Way (laneway or road allowance) is entirely covered with a permanent surface of concrete or asphalt extending from the building wall to the centre line of the right of way and beneath which runs a gas main or service Three times per year outside and once inside building annually. Total number of buildings fluctuates with additions and deletiions due to new construction, building sales, etc.										
	Number of Buildings Surveyed			Cumulative Leaks					Survey Results	
	Survey 1	Survey 2	Survey 3			Leaks found	Leaks Repaired	Open Orders		
Winnipeg & Selkirk	2397/2397	2397/2397	2397/2397			92	36	56		
Westman	412/412	412/412	412/412			23	17	6		
Eastman	273/273	276/276	276/276			39	6	33		
Parkland	134/134	134/134	134/134			9	9	0		
Interlake (Portage)	89/89	89/89	89/89			11	8	3		

Public Building Leak Survey Procedure 5.000.24	***Public Buildings Survey*** A building served by natural gas, which is used as a place of public assembly for a common purpose. Such buildings include: - Hospitals, nursing and senior citizens homes, schools, daycare centres, churches and recreation complexes. Total number of buildings fluctuates with additions and deletions due to new construction, building sales etc.					
	Annual Requirement	Completed YTD	Leaks found on company piping YTD	Leaks Repaired YTD	Open Orders	per cent complete	
Winnipeg	1017	1017	43	43	0	100%	
Westman	170	170	0	0	0	100%	
Eastman	307	307	20	16	4	100%	
Parkland	167	167	4	4	0	100%	
Interlake	184	184	19	15	4	100%	

Buildings With Inside Regulators		
Any building in which a company regulator is located.	Yearly, not to exceed 15 months, generally done concurrently with the inside business district survey.	
Winnipeg	350 St Mary Ave	Completed July 15

Winnipeg

Total # of PBI's completed 2015	1017	
Complete - No Leak on company piping(CPNL)	898	88%
Complete - "A leak found and repaired	20	2%
Complete – leak found Company Piping	23	2%
Complete – Leak found Customer Piping	66	6%
Other Infractions found	9	1%

High Pressure Transmission, Mains and Services Survey Results

Outside Leak Surveys Procedure #4.004.23	Frequency	KPI	
	Entire line to be surveyed once per year, not to exceed 15 months	Survey completed once each year	
Gate Stations and Yard Piping	Total Number of Stations	Number of Stations Surveyed YTD	Remaining
Apr 1 to Jun 30 Q1	199	0	199
Jul 1 to Sept 30 Q2	199	0	199
Oct 1 to Dec 31 Q3	199	199	0
Jan 1 to Mar 31 Q4	199	0	0
GAMC Maintenance Standards 1 & 2	**Frequency**	**KPI**	
Pipeline and Station valve maintenance	Yearly, not to exceed 18 months	Inspections Completed	
Pipeline Valves	**Total Number of Valves**	**Number Checked YTD**	**Remaining**
Apr 1 to Jun 30 Q1	913	427	486
Jul 1 to Sept 30 Q2	913	360	126
Oct 1 to Dec 31 Q3	913	88	38
Jan 1 to Mar 31 Q4	913	38	0
Station Valves	**Number of valves**	**Number Completed this quarter**	**Remaining**
Apr 1 to Jun 30 Q1	1,626	995	631
Jul 1 to Sept 30 Q2	1,626	432	199
Oct 1 to Dec 31 Q3	1,626	199	0
Jan 1 to Mar 31 Q4	1,626	0	0

DAMAGE MEASURES
PROGRAM MEASURES
LEAK SURVEY PROGRESS

Natural Gas Operations Key Performance Indicators

Q4 - 2016/17 January 1– March 31

2016 vs 2015

· BG damages were reduced by 21% in 2016 vs 2017 fiscal year (73 vs 92)

• Locates increased by 20% in 2016 from 46913 to 56263

Manitoba Hydro

2016-2017 Q4 Results October - December			Measure			2015-2016 Q4 Results October - December			Measure
Below Grade Damages Per 1000 locates Q4									
2016-2017 Q4	Q4 Staking Requests	Q4 BG Damages	BG damages per 1000 locates	2015 CGA Average 5019/1839380	Status	2015-2016 Q4	Q4 Staking Requests	Q4 BG Damages	BG damages per 1000 locates
Winnipeg	4,275	6	1.40			*Winnipeg*	3,176	5	1.57
Westman	663	0	0.00			*Westman*	557	0	0.00
Eastman	768	1	1.30			*Eastman*	546	1	1.83
Parkland	347	0	0.00			*Parkland*	194	2	10.31
Interlake	660	1	1.52			*Interlake*	418	0	0.00
Provincial	6,713	8	1.19	2.73		*Provincial*	4,891	8	1.64
Below Grade Damages per 1000 locates excluding "did not call" Q4									
2016-2017 Q4	Q4 Staking Requests	Q4 Damages	BG damages per 1000 locates	2015 CGA Average 2.73x58%	Status	2015-2016 Q4	Q4 Staking Requests	Q4 Damages	BG damages per 1000 locates
Winnipeg	4,275	6	1.40			Winnipeg	3,176	5	1.57
Westman	663	0	0.00			*Westman*	557	0	0.00
Eastman	768	1	1.30			*Eastman*	546	1	1.83
Parkland	347	0	0.00			*Parkland*	194	2	10.31
Interlake	660	1	1.52			*Interlake*	418	0	0.00
Provincial	6,713	8	1.19	1.58		*Provincial*	4,891	8	1.64
Below Grade Damages per 1000 Customers									
2016-2017 Q4	Number of Customers	Rolling 12 month period damages	Number of damages per 1000 customers	2015 CGA Average 5019/6,761,083	Status	2015-2016 Q4	Number of Customers	Rolling 12 month period damages	Number of damages per 1000 customers
Provincial	281,236	73	0.26	0.74		*Provincial*	274,817	92	0.33
Below Grade Damages per 1000 km of Main									
2016-2017 Q4	Kilometres of Distribution Main including HP/TP	Rolling 12 month period damages	Number of damages per 1000 Km of main	2015 CGA Average 5019/315,886	Status	2015-2016 Q4	Kilometres of Distribution Main including HP	Rolling 12 month period damages	Number of damages per 1000 Km of main
Provincial	10,324	73	7.07	15.90		*Provincial*	10,074	92	9.13
Below Grade Damages per 1000 Km of main and services.									
2016-2017 Q4	Kilometres of Main & Services	Rolling 12 month period damages	Number of damages per 1000 Km of main & services	2015 CGA Average 5019/454256	Status	2015-2016 Q4	Kilometres of Main & Services	Rolling 12 month period damages	Number of damages per 1000 Km of main & services
Provincial	17,543	73	4.16	11.04		*Provincial*	17,146	92	5.37

Below Grade Damages per 1000 Locates

2016-2017 Results

	Staking Requests				Damages				Number of damages per 1000 locates				CGA Average
	Q4 16/17	Q3 16/17	Q2 16/17	Q1 16/17	Q4 16/17	Q3 16/17	Q2 16/17	Q1 16/17	Q4 16/17	Q3 16/17	Q2 16/17	Q1 16/17	
Winnipeg	4,275	6,985	12,240	11,462	6	8	14	5	6	8	1.14	0.44	
Westman	663	1,507	2,251	2,147	0	2	4	1	0	2	1.78	0.47	
Eastman	768	1,730	2,585	2,538	1	2	4	12	1	2	1.55	4.73	
Parkland	347	748	1,241	1,079	0	1	1	0	0	1	0.81	0.00	
Interlake	660	1,274	1,879	1,706	1	4	3	4	1	4	1.60	2.34	
Provincial	6,713	12,244	20,196	18,932	8	17	26	22	1.19	1.39	1.29	1.16	
	12 month total		58,085		12 month total		73		12 month avg		1.26		2.73

2015-2016 Results

	Staking Requests				Damages				Number of damages per 1000 locates			
	Q4 15/16	Q3 15/16	Q2 15/16	Q1 15/16	Q4 15/16	Q3 15/16	Q2 15/16	Q1 15/16	Q4 15/16	Q3 15/16	Q2 15/16	Q1 15/16
Winnipeg	3,176	5,251	9,958	10,770	5	3	27	12	1.57	0.57	2.71	1.11
Westman	557	1,317	1,925	1,681	0	3	2	5	0.00	2.28	1.04	2.97
Eastman	546	1,197	2,072	2,119	1	3	7	8	1.83	2.51	3.38	3.78
Parkland	194	450	740	747	2	1	3	1	10.31	2.22	4.05	1.34
Interlake	418	877	1,473	1,445	0	4	5	0	0.00	4.56	3.39	0.00
Provincial	4,891	9,092	16,168	16,762	8	14	44	26	1.64	1.54	2.72	1.55
	12 month total		46,913		12 month total		92		12 month avg		1.96	

Below Grade Damages per 1000 Km of main

2016-2017 Results

	Kilometres of Distribution Main	Damages				Number of damages per 1000 Km of main				CGA Average
		Q4 16/17	Q3 16/17	Q2 16/17	Q1 16/17	Q4 16/17	Q3 16/17	Q2 16/17	Q1 16/17	
Winnipeg	10,324	6	8	14	5					
Westman		0	2	4	1					
Eastman		1	2	4	12					
Parkland		0	1	1	0					
Interlake		1	4	3	4					
Provincial		8	17	26	22	0.77	1.65	2.52	2.13	
		12 month total		73		12 month avg			7.07	15.90

2015-2016 Results

	Kilometres of Distribution Main	Damages				Damages per 1000 Km of main			
		Q4 15/16	Q3 15/16	Q2 15/16	Q1 15/16	Q4 15/16	Q3 15/16	Q2 15/16	Q1 15/16
Winnipeg	10,074	5	3	27	12				
Westman		0	3	2	5				
Eastman		1	3	7	8				
Parkland		2	1	3	1				
Interlake		0	4	5	0				
Provincial		8	14	44	26	0.79	1.39	4.37	2.58
		12 month total		92		12 month avg			9.13

Below Grade Damages per 1000 km of mains & services

2016-2017 Results

	Kilometres of Main & Services	Damages				Number of damages per 1000 Km of main & services				CGA Average
		Q4 16/17	Q3 16/17	Q2 16/17	Q1 16/17	Q4 16/17	Q3 16/17	Q2 16/17	Q1 16/17	
Winnipeg	17,543	6	8	14	5					
Westman		0	2	4	1					
Eastman		1	2	4	12					
Interlake		1	4	3	4					
Provincial		8	16	25	22	0.46	0.91	1.43	1.25	
		12 month total		71		12 month average			4.05	11.04

2015-2016 Results

	Kilometres of Main & Services	Damages				Number of damages per 1000 Km of main & services			
		Q4 15/16	Q3 15/16	Q2 15/16	Q1 15/16	Q4 15/16	Q3 15/16	Q2 15/16	Q1 15/16
Winnipeg	17,146	5	3	27	12				
Westman		0	3	2	5				
Eastman		1	3	7	8				
Interlake		0	4	5	0				
Provincial		8	14	44	26	0.47	0.82	2.57	1.52
		12 month total		92		12 month avg			5.37

Percent of Below Grade Damages that are four party trench area

2016-2017

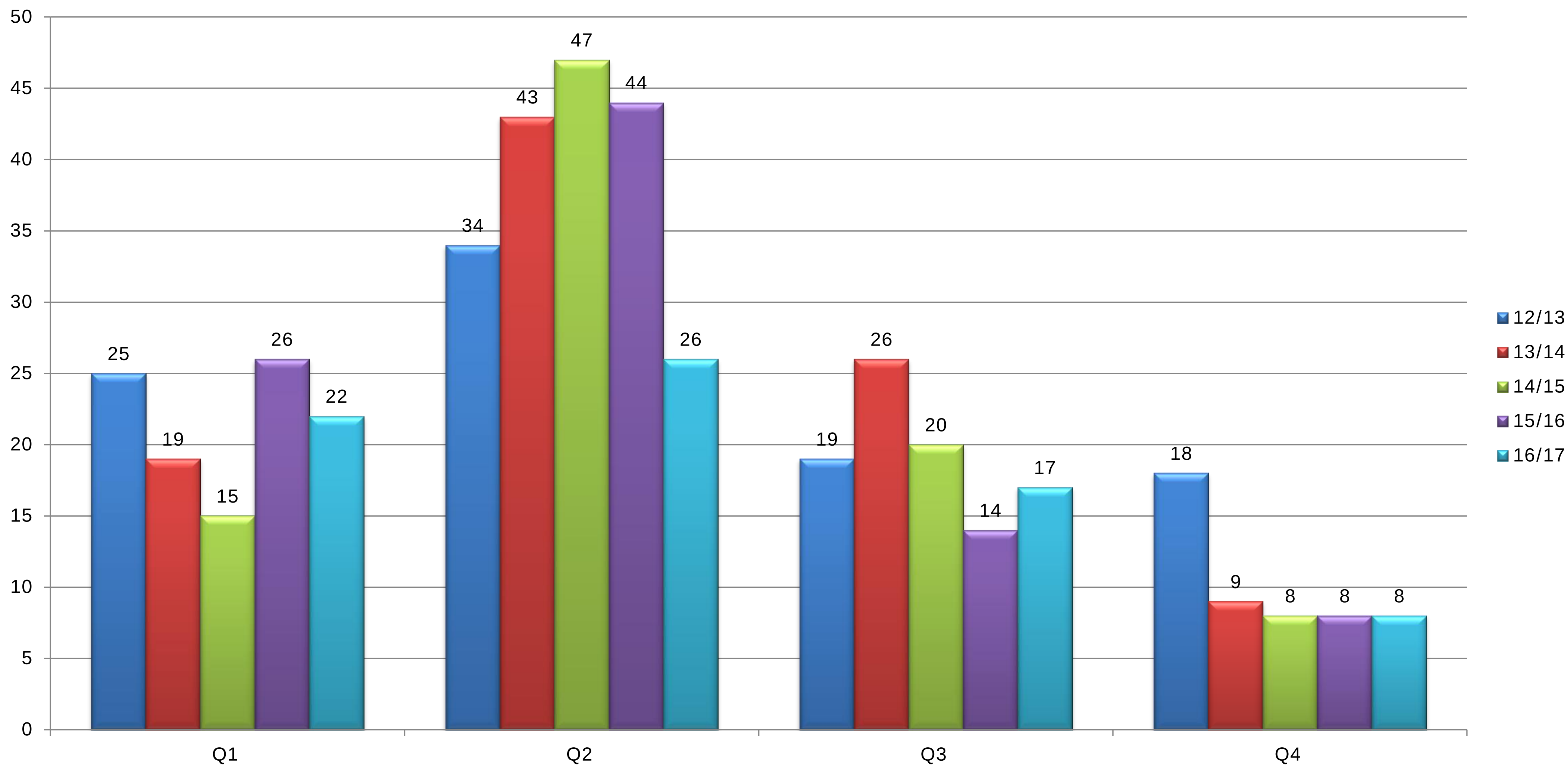
	4 Party Damages				Percent of damages to 4 party trench plant			
	Q4 16/17	Q3 16/17	Q2 16/17	Q1 16/17	Q4 16/17	Q3 16/17	Q2 16/17	Q1 16/17
Winnipeg	2	3	3	3	33%	38%	21%	60%
Westman	0	0	0	0	0%	0%	0%	0%
Eastman	1	0	0	0	100%	0%	0%	0%
Parkland	0	0	0	0	0%	0%	0%	0%
Interlake	0	0	0	0	0%	0%	0%	0%
Provincial	3	3	3	3	38%	19%	12%	14%
	12 month total		12		damages	71	AVG	17%

2015-2016

	4 Party Damages				Percent of damages to 4 party trench plant			
	Q4 15/16	Q3 15/16	Q2 15/16	Q1 15/16	Q4 15/16	Q3 15/16	Q2 15/16	Q1 15/16
Winnipeg	1	1	3	1	20%	33%	11%	8%
Westman	0	0	0	1	0%	0%	0%	20%
Eastman	1	0	0	2	100%	0%	0%	25%
Parkland	0	0	0	0	0%	0%	0%	0%
Interlake	0	0	0	0	0%	0%	0%	0%
Provincial	2	1	3	4	25%	7%	7%	15%
	12 month total		10		damages	92	AVG	11%

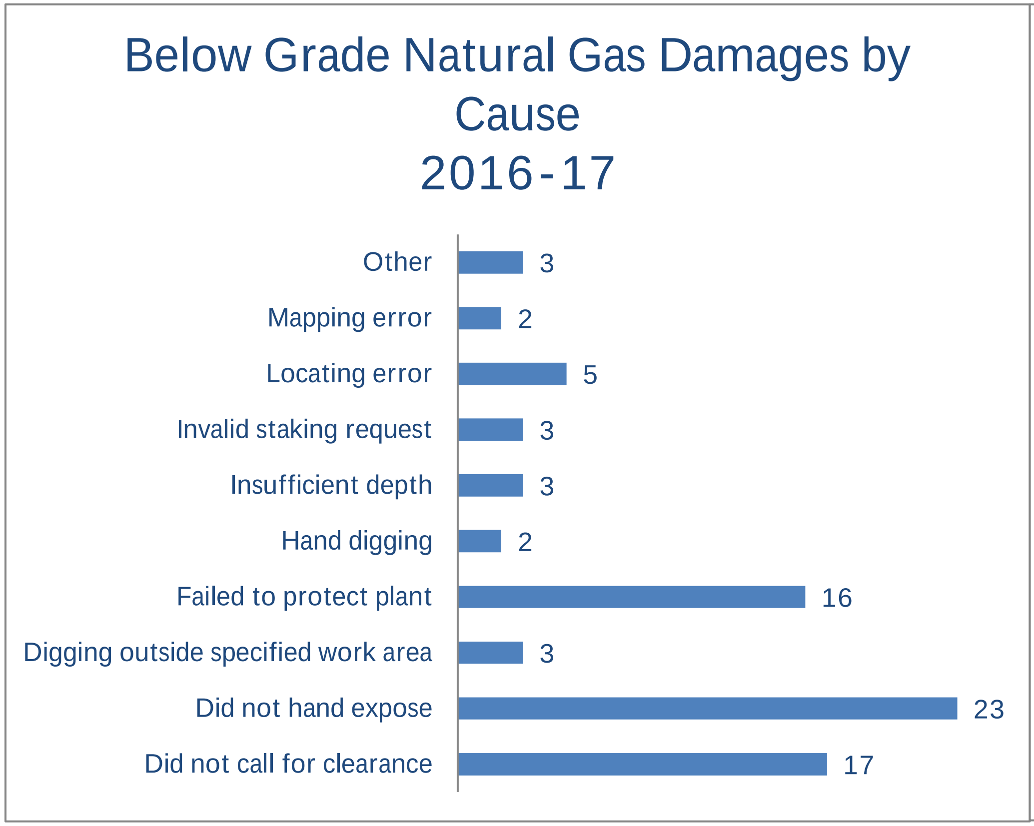
****Note:*** *Fortis BC data is removed from the CGA Average as their operational model differs from the rest of the CGA members*

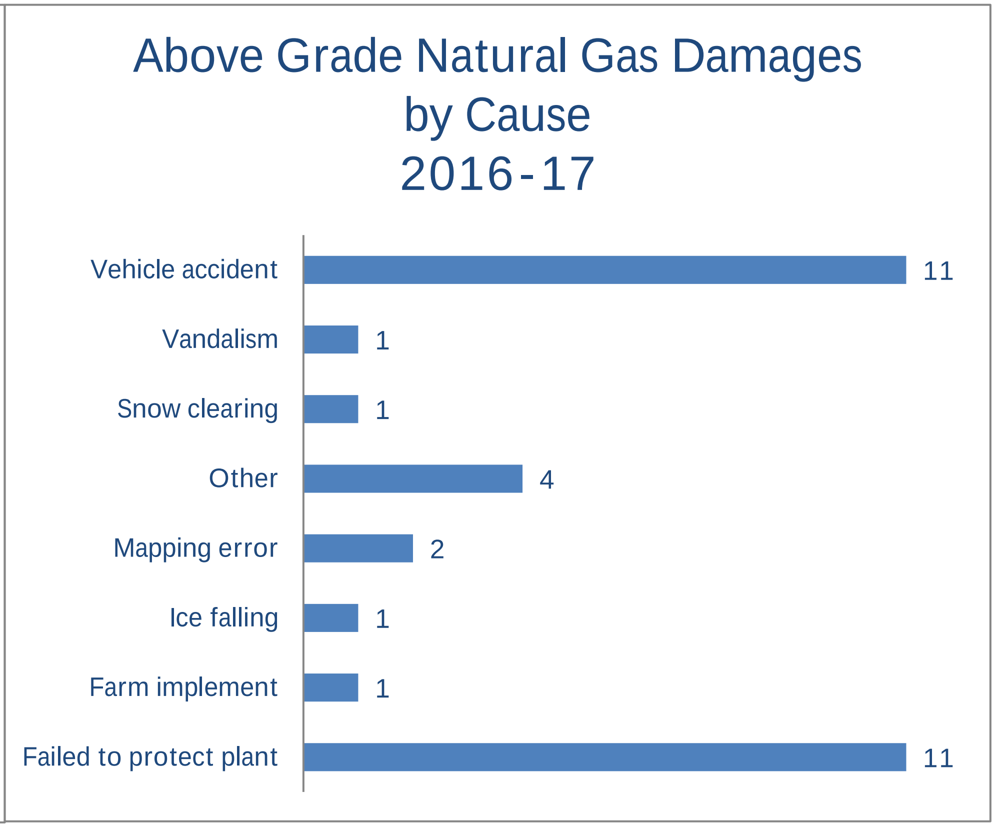
Natural Gas Below Grade Damages
Quarter to Quarter Comparisons



	2016-2017				2015-2016				2014-2015				2013-2014			
	Q1	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**
Winnipeg	5	14	8	6	12	27	3	5	7	25	7	7	8	22	10	8
Westman	1	4	2	0	5	2	3	0	0	6	1	0	2	2	4	1
Eastman	12	4	2	1	8	7	3	1	6	11	5	1	6	15	7	0
Parkland	0	1	1	0	1	3	1	2	1	0	3	0	1	1	1	0
Interlake	4	3	4	1	0	5	4	0	1	5	4	0	2	3	4	0
	22	**26**	**17**	**8**	**26**	**44**	**14**	**8**	**15**	**47**	**20**	**8**	**19**	**43**	**26**	**9**
YTD	**22**	**48**	**65**	**73**	**26**	**70**	**84**	**92**	**15**	**62**	**82**	**90**	**19**	**62**	**88**	**97**

2016/17 Natural Gas Damages





Gas Operations Key Performance Indicators			
Odorization Testing Procedure # 4.500.35			
Odorant Intensity Testing	Performed once per week.	**Q4 Jan-Mar**	
Winnipeg		Complete	●
Westman		Complete	●
Eastman		Complete	●
Parkland		Complete	●
Interlake		Complete	●
Equipment Testing			
Combustible Gas Indicator Testing Standard 711.01			
Monthly Inspection and Calibration	Monthly	**Q4 Jan-Mar**	
Winnipeg	64/64 in Jan, 64/64 in Feb, 67/67 in March	100%	
Westman	19/19 completed each month	100%	●
Eastman	Morden has MSA's with auto calibrate, Stnb 6/6	100%	●
Parkland	Parkland is using MSA's with auto calibrate	100%	●
Interlake	Selkirk completed 6/6, Portage completed 5/5	100%	●
Flame Ionization Equipment Calibration	Monthly (Winnipeg, Morden,Parkland and WestMan now use DP-IR equipment that is self calibrating. Log books are kept for all DP-IRs.)	**Q4 Jan-Mar**	
Eastman	Morden is using DPIR's, Stnb completed 3/3	100%	●
Interlake	Selkirk 2/2, Portage,1/1	100%	●
Emergency Equipment Testing - Squeezers	Squeezer test 1 to be completed by the end of Q2 Squeezer test 2 to be completed by the end of Q4	**Q4 Jan-Mar**	
Winnipeg	Test #2 complete in Q4, 196/196	100%	●
Westman	Test #2, 59/59 completed in Q4	100%	●
Eastman	Test #2, Stnbch 32/32 in Q3, Winkler 37/37 in Q3	100%	●
Parkland	Test 2 52/52 completed in Q3	100%	●
Interlake	Test #2, Portage 9/9, Selkirk 5/5, completed Q3	100%	●
Winnipeg	completed January 2017	Complete	●
Westman	completed Feb 13, 2017	Complete	●

Gas Operations Key Performance Indicators			
Eastman	Stnbch comp June 16, Winkler comp Dec 2016	Complete	●
Parkland	completed in October 2016	Complete	●
Interlake	Portage completed May 2016, BAGS June 2016	Complete	●
Pre-Tested Pipe Inventory Procedure 5.000.1 and Standard 720.07	To be reviewed annually	**Q4 Jan-Mar**	
Winnipeg	completed May 2016	Complete	●
Parkland	Gladstone Aluminum completed May 2016	Complete	●
Line Marker Signs	Signs have been identified and sent to the districts for remediation. Work is ongoing	**Q4 Jan-Mar**	
Winnipeg		Scheduled	●
Westman		Scheduled	●
Eastman		Scheduled	●
Parkland		Scheduled	●
Interlake		Scheduled	●
Vegetation Management Standard 723.01	Surveyed at not more than 3 year intervals. Done with Transmission Survey Deficiencies resolved prior to the next survey,	**Q4 Jan-Mar**	
	locations requiring vegetation management have been identified in Q2 and sent to forestry for remediation		
Winnipeg		Scheduled	●
Westman		Scheduled	●
Eastman		Scheduled	●
Parkland		Scheduled	●
Interlake		Scheduled	●

Outside Leak Survey Procedure 4.004.23	KPI Frequency	Number of Kilometres Surveyed	Q4 Above Grade Leaks			Q4 Below Grade Leaks			Result	
Q4 October - December										
Transmission and High Pressure Pipeline Survey	once per year, not to exceed 15 months	Completed YTD	A	B	C	A	B	C		
Provincial Total	2,219	2,219	0	0	0	0	0	0	complete Jun 23	
YTD Results			2	0	0	0	0	3		
Mains and Services	every 3 years	Number of Services Surveyed	Q3 Above Grade Leaks			Q4 Below Grade Leaks				
	2016/17 services to be surveyed	Completed YTD	A	B	C	A	B	C		
Provincial Total	93,846	93,846	0	0	0	0	0	0	complete Sep 21	
YTD Results			146	2	0	5	0	11		

Leak Classification Criteria

Class A Leak

Due to the location or intensity, is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous. Class A leaks are repaired through regular maintenance.

Class B Leak

Due to the location or intensity, is recognized as being non-hazardous at the time of

Class C Leak

Due to the location or intensity, represents an existing or potential hazard to persons or

Above Grade piping at bridge crossings	Survey completed once each year	Date Complete	Above Grade Leaks		
			A	B	C
Interlake (Included in annual Transmission survey)	Lockport Bridge	Completed in Q1 May 26, 2016	0	0	0
Valve Maintenance					
All Valves associated with the gas distribution system will be maintained on a yearly basis.	**Total**	**Completed YTD**			
Emergency Sectional Downtown Valve Maintenance Program	56	56	Complete in Q2		
Distribution Buried Valves	**Total**	**Completed YTD**			
Winnipeg	414	414	Complete in Q3		
Westman	72	72	Complete in Q2		
Eastman	101	101	Complete in Q3		
Parkland	22	22	Complete in Q3		
Interlake	28	28	complete in Q4		

Business District Mains & Services (Wall to Wall Leak Survey)

A Business District is defined as any area in which the Public Right of Way (laneway or road allowance) is entirely covered with a permanent surface of concrete or asphalt extending from the building wall to the centre line of the right of way and beneath which runs a gas main or service

Three times per year outside and once inside building annually. Total number of buildings fluctuates with additions and deletiions due to new construction, building sales, etc.

	Number of Buildings Surveyed			Cumulative Leaks					Survey Results	
	Survey 1	Survey 2	Survey 3			Leaks found	Leaks Repaired	Open Orders		
Winnipeg & Selkirk	2397/2397	2397/2397	2397/2397			64	34	30		
Westman	295/295	295/295	295/295			0	0	0		
Eastman	281/281	280/280	288/288			41	33	8		
Parkland	134/134	134/134	134/134			13	13	0		
Interlake (Portage)	84/87	87/87	87/87			4	4	0		

Public Building Leak Survey Procedure 5.000.24	***Public Buildings Survey*** A building served by natural gas, which is used as a place of public assembly for a common purpose. Such buildings include: - Hospitals, nursing and senior citizens homes, schools, daycare centres, churches and recreation complexes. Total number of buildings fluctuates with additions and deletions due to new construction, building sales etc.					
	Annual Requirement	Completed YTD	Leaks found on company piping YTD	Leaks Repaired YTD	Open Orders	per cent complete	
Winnipeg	1039	1039	66	66	0	100%	
Westman	142	142	0	0	0	100%	
Eastman	299	299	39	39	0	100%	
Parkland	167	167	2	2	0	100%	
Interlake	213	213	4	3	1	100%	

Winnipeg

Total # of PBI's completed 2016	1039	
Complete - No Leak on company piping(CPNL)	917	88%
Complete - "A leak found and repaired	41	4%
Complete – leak found Company Piping	25	2%
Complete – Leak found Customer Piping	51	5%
Other Infractions found	5	0%

High Pressure Transmission, Mains and Services Survey Results

Outside Leak Surveys Procedure #4.004.23	Frequency	KPI	
	Entire line to be surveyed once per year, not to exceed 15 months	Survey completed once each year	
Gate Stations and Yard Piping	Total Number of Stations	Number of Stations Surveyed quaterly	Remaining
Apr 1 to Jun 30 Q1	200	0	200
Jul 1 to Sept 30 Q2	200	23	177
Oct 1 to Dec 31 Q3	200	177	0
Jan 1 to Mar 31 Q4	200	0	0
GAMC Maintenance Standards 1 & 2	**Frequency**	**KPI**	
Pipeline and Station valve maintenance	Yearly, not to exceed 18 months	Inspections Completed	
Pipeline Valves	**Total Number of Valves**	**Number Checked quarterly**	**Remaining**
Apr 1 to Jun 30 Q1	1,045	526	519
Jul 1 to Sept 30 Q2	1,045	340	179
Oct 1 to Dec 31 Q3	1,045	179	0
Jan 1 to Mar 31 Q4	1,045	0	0
Station Valves	**Number of valves**	**Number Completed this quarter**	**Remaining**
Apr 1 to Jun 30 Q1	1,650	1,242	408
Jul 1 to Sept 30 Q2	1,650	314	94
Oct 1 to Dec 31 Q3	1,650	94	0
Jan 1 to Mar 31 Q4	1,650	0	0

DAMAGE MEASURES
PROGRAM MEASURES
LEAK SURVEY PROGRESS

Natural Gas Operations Key Performance Indicators

Q4 - 2017/18 January - March

2017/18 saw a 5% increase in the number of locate requests as compared to 2016/17

There were 12 different contractors that had reported damages in Q4

36% of damages in Q3 were classified as "did not call for clearance"

Manitoba Hydro

2017-2018 Q4 Results January - March			Measure			2016-2017 Q4 Results January - March			Measure
Below Grade Damages Per 1000 locates Q3									
2017-2018 Q4 Results January - March	**Q4 Staking Requests**	**Q4 BG Damages**	**BG damages per 1000 locates**	**2016 CGA Average 4781/1,834,591**	**Status**	**2016-2017 Q4 Results**	**Q4 Staking Requests**	**Q4 BG Damages**	**BG damages per 1000 locates**
Winnipeg	3,897	8	2.05			*Winnipeg*	4,275	6	1.40
South Central	800	1	1.25			*South Central*	663	0	0.00
Eastman	866	2	2.31			*Eastman*	768	1	1.30
Parkland West	648	0	0.00			*Parkland West*	347	0	0.00
Interlake	295	0	0.00			*Interlake*	660	1	1.52
Provincial	**6,506**	**11**	**1.69**	**2.60**		*Provincial*	**6,713**	**8**	**1.19**
Below Grade Damages per 1000 locates excluding "did not call" Q3									
2017-2018 Q4	**Q4 Staking Requests**	**Q4 Damages**	**BG damages per 1000 locates**	**2016 CGA Average* 2.60x59%**	**Status**	**2016-2017 Q4**	**Q4 Staking Requests**	**Q4 Damages**	**BG damages per 1000 locates**
Winnipeg	3,897	4	1.03			*Winnipeg*	4,275	6	1.40
South Central	800	1	1.25			*South Central*	663	0	0.00
Eastman	866	2	2.31			*Eastman*	768	1	1.30
Parkland West	648	0	0.00			*Parkland West*	347	0	0.00
Interlake	295	0	0.00			*Interlake*	660	1	1.52
Provincial	**6,506**	**7**	**1.08**	**1.53**		*Provincial*	**6,713**	**8**	**1.19**
Below Grade Damages per 1000 Customers									
2017-2018 Q4	**Number of Customers**	**Rolling 12 month period damages**	**Number of damages per 1000 customers**	**2016 CGA Average 4781/6,843,102**	**Status**	**2016-2017 Q4**	**Number of Customers**	**Rolling 12 month period damages**	**Number of damages per 1000 customers**
Provincial	**283,258**	**100**	**0.35**	**0.70**		*Provincial*	**281,236**	**73**	**0.26**
Below Grade Damages per 1000 km of Main									
2017-2018 Q4	**Kilometres of Distribution Main including HP/TP**	**Rolling 12 month period damages**	**Number of damages per 1000 Km of main**	**2016 CGA Average 4781/316,591**	**Status**	**2016 -2017 Q4**	**Kilometres of Distribution Main including HP**	**Rolling 12 month period damages**	**Number of damages per 1000 Km of main**
Provincial	**10,383**	**100**	**9.63**	**15.10**		*Provincial*	**10,324**	**73**	**7.07**
Below Grade Damages per 1000 Km of main and services.									
2017-2018 Q4	**Kilometres of Main & Services**	**Rolling 12 month period damages**	**Number of damages per 1000 Km of main & services**	**2016 CGA Average 4781/456,658**	**Status**	**2016 -2017 Q4**	**Kilometres of Main & Services**	**Rolling 12 month period damages**	**Number of damages per 1000 Km of main & services**
Provincial	**17,684**	**100**	**5.65**	**10.47**		*Provincial*	**17,543**	**73**	**4.16**

*Incidents when no locate was requested by the excavator compared to incidents when a locate was requested by the excavator as a percentage of total third party damage incidents.

Below Grade Damages per 1000 Locates

2017-2018 Results

	Staking Requests				Damages				Number of damages per 1000 locates				CGA Average
	Q4 17/18	Q3 17/18	Q2 17/18	Q1 17/18	Q4 17/18	Q3 17/18	Q2 17/18	Q1 17/18	Q4 17/18	Q3 17/18	Q2 17/18	Q1 17/18	
Winnipeg	3,897	6,738	12,191	12,384	8	10	21	18	2.05	1.48	1.72	1.45	
South Central	600	1,587	2,319	2,503	0	3	4	1	0.00	1.89	1.72	0.40	
Eastman	866	2,134	2,873	2,808	2	5	8	9	2.31	2.34	2.78	3.21	
Parkland West	648	1,221	1,532	1,400	1	0	0	2	1.54	0.00	0.00	1.43	
Interlake	295	1,204	2,020	1,774	0	1	6	1	0.00	0.83	2.97	0.56	
Provincial	**6,306**	**12,884**	**20,935**	**20,869**	**11**	**19**	**39**	**31**	**1.74**	**1.47**	**1.86**	**1.49**	
	12 month total		60,994		12 month total		100		12 month avg		1.64		2.60

2016-2017 Results

	Staking Requests				Damages				Number of damages per 1000 locates			
	Q4 16/17	Q3 16/17	Q2 16/17	Q1 16/17	Q4 16/17	Q3 16/17	Q2 16/17	Q1 16/17	Q4 16/17	Q3 16/17	Q2 16/17	Q1 16/17
Winnipeg	4,275	6,985	12,240	11,462	6	8	14	5	1.40	1.15	1.14	0.44
South Central	663	1,507	2,251	2,147	0	2	4	1	0.00	1.33	1.78	0.47
Eastman	768	1,730	2,585	2,538	1	2	4	12	1.30	1.16	1.55	4.73
Parkland West	347	748	1,241	1,079	0	1	1	0	0.00	1.34	0.81	0.00
Interlake	660	1,274	1,879	1,706	1	4	3	4	1.52	3.14	1.60	2.34
Provincial	**6,713**	**12,244**	**20,196**	**18,932**	**8**	**17**	**26**	**22**	**1.19**	**1.39**	**1.29**	**1.16**
	12 month total		58,085		12 month total		73		12 month avg		1.26	

Below Grade Damages per 1000 Km of main

2017-2018 Results

	Kilometres of Distribution Main	Damages				Number of damages per 1000 Km of main				CGA Average
		Q4 17/18	Q3 17/18	Q2 17/18	Q1 17/18	Q4 17/18	Q3 17/18	Q2 17/18	Q1 17/18	
Winnipeg	10,383	8	10	21	18					
South Central		0	3	4	1					
Eastman		2	5	8	9					
Parkland West		1	0	0	2					
Interlake		0	1	6	1					
Provincial		**11**	**19**	**39**	**31**	**1.06**	**1.83**	**3.76**	**2.99**	
		12 month total		100		12 month avg			9.63	15.10

2016-2017 Results

	Kilometres of Distribution Main	Damages				Damages per 1000 Km of main			
		Q4 16/17	Q3 16/17	Q2 16/17	Q1 16/17	Q4 16/17	Q3 16/17	Q2 16/17	Q1 16/17
Winnipeg	10,324	6	8	14	5				
South Central		0	2	4	1				
Eastman		1	2	4	12				
Parkland West		0	1	1	0				
Interlake		1	4	3	4				
Provincial		8	17	26	22	0.77	1.65	2.52	2.13
		12 month total		73		12 month avg			7.07

Below Grade Damages per 1000 km of mains & services

2017-2018 Results

	Kilometres of Main & Services	Damages				Number of damages per 1000 Km of main & services				CGA Average
		Q4 17/18	Q3 17/18	Q2 17/18	Q1 17/18	Q4 17/18	Q3 17/18	Q2 17/18	Q1 17/18	
Winnipeg	17,684	8	10	21	18					
South Central		0	3	4	1					
Eastman		2	5	8	9					
Parkland West		1	0	0	2					
Interlake		0	1	6	1					
Provincial		**11**	**19**	**39**	**31**	**0.62**	**1.07**	**2.21**	**1.75**	
		12 month total		100		12 month average			5.65	10.47

2016-2017 Results

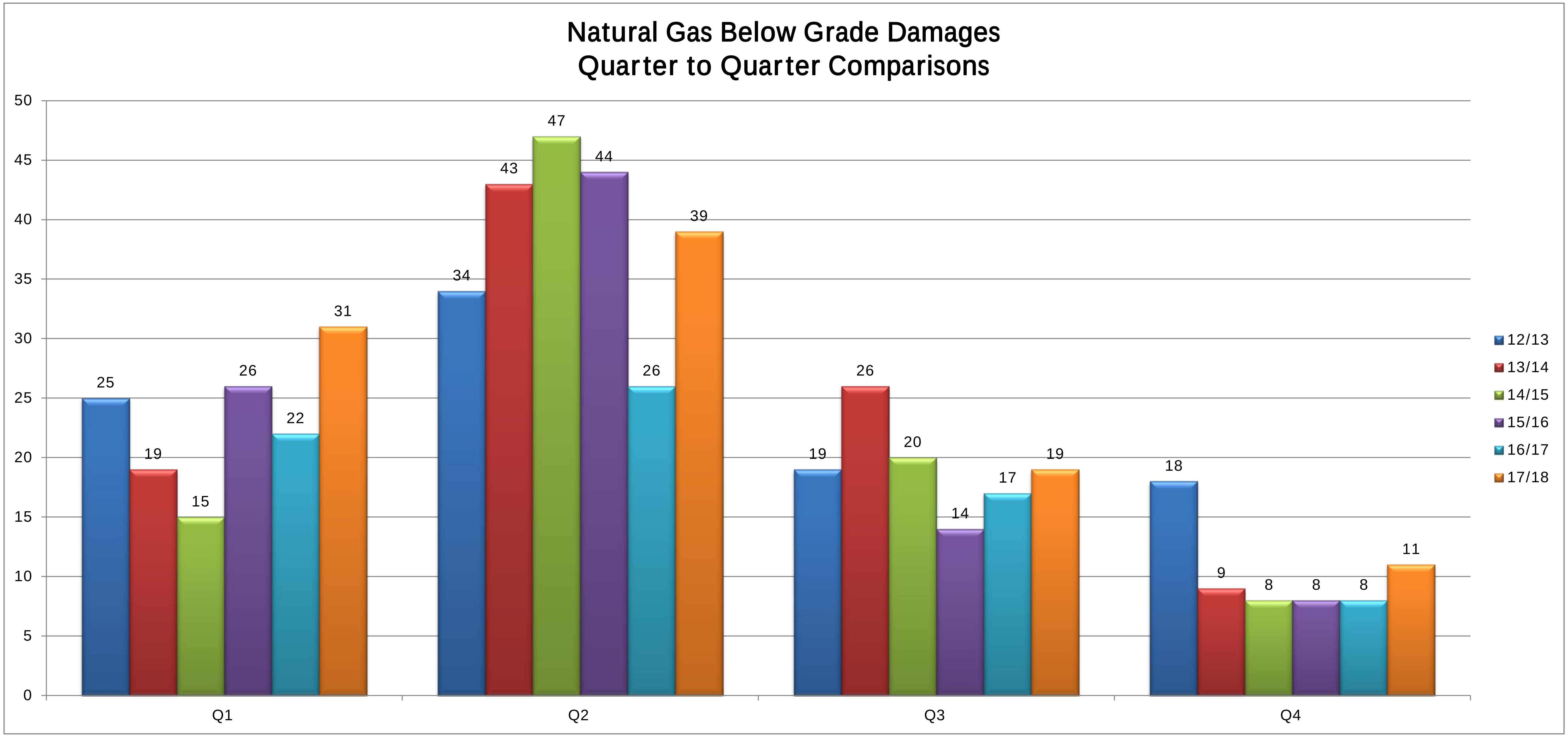
	Kilometres of Main & Services	Damages				Number of damages per 1000 Km of main & services			
		Q4 16/17	Q3 16/17	Q2 16/17	Q1 16/17	Q4 16/17	Q3 16/17	Q2 16/17	Q1 16/17
Winnipeg	17,543	6	8	14	5				
South Central		0	2	4	1				
Eastman		1	2	4	12				
Parkland West		0	1	1	0				
Interlake		1	4	3	4				
Provincial		8	17	26	22	0.46	0.97	1.48	1.25
		12 month total		73		12 month avg			4.16

Percent of Below Grade Damages that are four party trench area

2017-2018	4 Party Damages				Percent of damages to 4 party trench plant			
	Q4 17/18	Q3 17/18	Q2 17/18	Q1 17/18	Q4 17/18	Q3 17/18	Q2 17/18	Q1 17/18
Winnipeg	3	1	6	2	38%	10%	29%	11%
South Central	0	0	0	0	0%	0%	0%	0%
Eastman	0	1	2	2	0%	20%	25%	22%
Parkland West	0	0	0	0	0%	0%	0%	0%
Interlake	0	0	0	0	0%	0%	0%	0%
Provincial	**3**	**2**	**8**	**4**	**27%**	**11%**	**21%**	**13%**
	12 month total		17		damages	100	AVG	17%

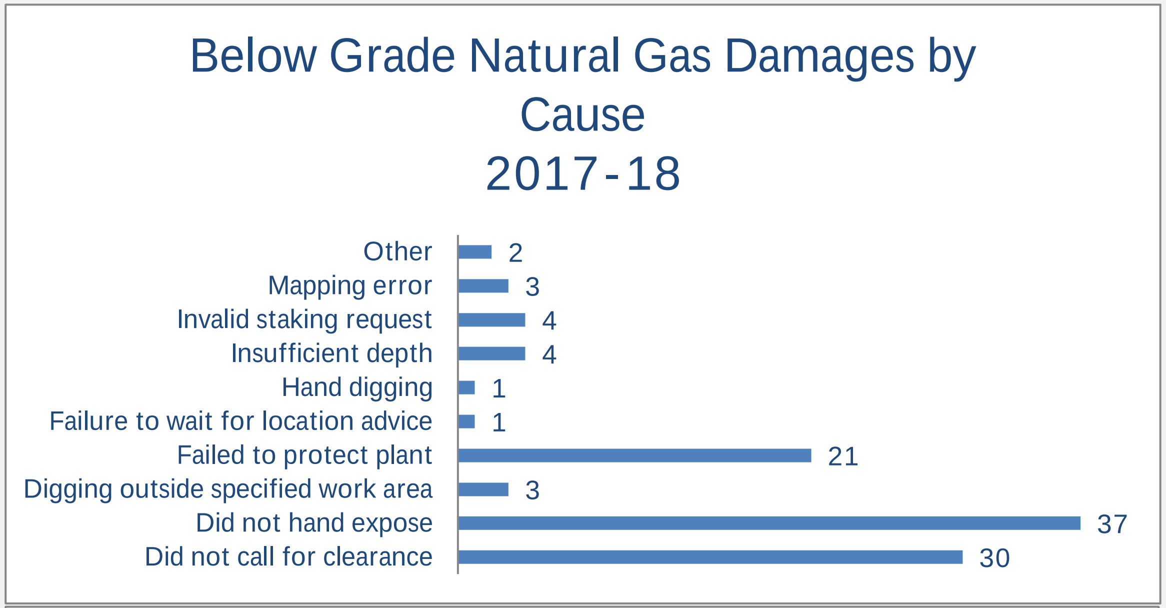
2016-2017	4 Party Damages				Percent of damages to 4 party trench plant			
	Q4 16/17	Q3 16/17	Q2 16/17	Q1 16/17	Q4 16/17	Q3 16/17	Q2 16/17	Q1 16/17
Winnipeg	2	3	3	3	33%	38%	21%	60%
South Central	0	0	0	0	0%	0%	0%	0%
Eastman	1	0	0	0	100%	0%	0%	0%
Parkland West	0	0	0	0	0%	0%	0%	0%
Interlake	0	0	0	0	0%	0%	0%	0%
Provincial	3	3	3	3	38%	18%	12%	14%
	12 month total		12		damages	73	AVG	16%

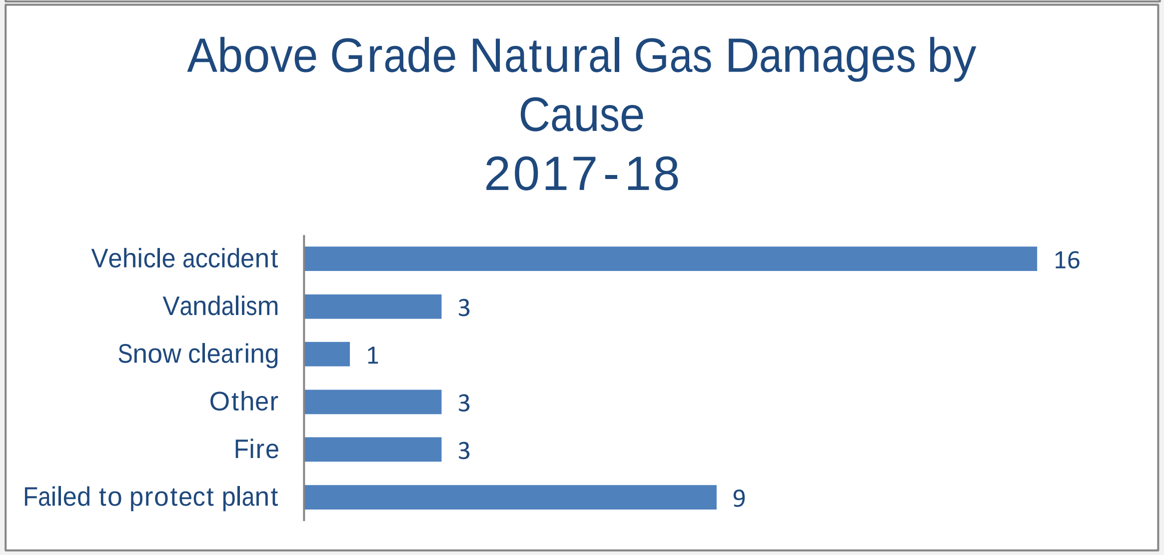
****Note:** Fortis BC data is removed from the CGA Average as their operational model differs from the rest of the CGA members*



	2017-2018				2016-2017				2015-2016				2014-2015				2013-2014			
	Q1	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**
Winnipeg	18	21	10	8	5	14	8	6	12	27	3	5	7	25	7	7	8	22	10	8
South Central	1	4	3	0	1	4	2	0	5	2	3	0	0	6	1	0	2	2	4	1
Eastman	9	8	5	2	12	4	2	1	8	7	3	1	6	11	5	1	6	15	7	0
Parkland West	2	0	0	1	0	1	1	0	1	3	1	2	1	0	3	0	1	1	1	0
Interlake	1	6	1	0	4	3	4	1	0	5	4	0	1	5	4	0	2	3	4	0
	31	**39**	**19**	**11**	**22**	**26**	**17**	**8**	**26**	**44**	**14**	**8**	**15**	**47**	**20**	**8**	**19**	**43**	**26**	**9**
YTD	**31**	**70**	**89**	**100**	**22**	**48**	**65**	**73**	**26**	**70**	**84**	**92**	**15**	**62**	**82**	**90**	**19**	**62**	**88**	**97**

2017/2018 Natural Gas Damages





Gas Operations Key Performance Indicators			
Odorization Testing Procedure # 4.500.35			
Odorant Intensity Testing	Performed once per week.	**Q4 January - March**	
Winnipeg		Complete	
Westman		Complete	
Eastman		Complete	
Parkland		Complete	
Interlake		Complete	
Equipment Testing			
Combustible Gas Indicator Testing Standard 711.01			
Monthly Inspection and Calibration	Monthly	**Q4 January - March**	
Winnipeg	44/57 in Jan, 72/72 in Feb, 42/73 in March*	78%	
Westman	16/16 completed each month	100%	
Eastman	Morden has MSA's with auto calibrate, Stnb 6/6	100%	
Parkland	Parkland is using MSA's with auto calibrate	100%	
Interlake	Selkirk completed 5/5, Portage completed 5/5	100%	
Flame Ionization Equipment Calibration	Monthly (Winnipeg, Morden, Parkland, and WestMan now DP-IR equipment that is self calibrating. Log books are kept for all DPIR)	**Q4 January - March**	
Eastman	Morden is using DPIR's, Stnb completed 3/3	100%	
Interlake	Selkirk 2/2, Portage,1/1	100%	
Emergency Equipment Testing - Squeezers	Squeezer test 1 to be completed by the end of Q2 Squeezer test 2 to be completed by the end of Q4	**Q4 January - March**	
Winnipeg	Test #2; Complete	100%	
Westman	Test #2; 61/61 tested in Q3	100%	
Eastman	Test #2; Stnbch 31/31 in Q3, Winkler 37/37 in Q3	100%	
Parkland	Test #2; 52/52 completed in Q3	100%	
Interlake	Test #2; Portage 9/9, Selkirk 5/5, completed Q4	100%	

Gas Operations Key Performance Indicators			
Emergency Equipment Inventory List Review	To be reviewed annually	**Q4 January - March**	
Winnipeg	Last completed Jan 2017	Scheduled	🟢
Westman	Completed Feb 13, 2017 - Scheduled for Q4	Scheduled	🟢
Eastman	Stnbch complete Q1, Winkler complete Q4	Complete	🟢
Parkland	Completed Oct 2017	Complete	🟢
Interlake	Portage completed Q1, BAGSS completed Q1	Complete	🟢
Pre-Tested Pipe Inventory Procedure 5.000.1 and Standard 720.07	To be reviewed annually	**Q4 January - March**	
Winnipeg	Completed Feb 2017	Scheduled	🟢
Parkland	Gladstone Aluminum completed June 2017	Complete	🟢
Line Marker Signs	Signs have been identified and sent to CSCs for remediation. Work is ongoing	**Q4 January - March**	
Winnipeg		Complete	🟢
Westman		Scheduled	🟢
Eastman		Scheduled	🟢
Parkland		Complete	🟢
Interlake		Scheduled	🟢
Vegetation Management Standard 723.01	Surveyed at not more than 3 year intervals. Done with Transmission Survey.	**Q4 January - March**	
	Locations requiring vegetation management have been identified		
Winnipeg		Scheduled	🟢
Westman		Scheduled	🟢
Eastman		Scheduled	🟢
Parkland		Scheduled	🟢
Interlake		Scheduled	🟢

* Daily bump tests were completed as required.

Outside Leak Survey Procedure 4.004.23	KPI Frequency	Number of Kilometres Surveyed	Q4 Above Grade Leaks			Q4 Below Grade Leaks			Result	
Q3 October - December										
Transmission and High Pressure Pipeline Survey	once per year, not to exceed 15 months	Completed YTD	A	B	C	A	B	C		
Provincial Total	2,219	2,156	0	0	0	0	0	0		
Annual Results (Completed Q2)			20	0	0	0	0	0		
Mains and Services	every 3 years	Number of Services Surveyed	Q3 Above Grade Leaks			Q3 Below Grade Leaks				
	2017/18 services to be surveyed	Completed YTD	A	B	C	A	B	C		
Provincial Total	93,846	93,846	60	0	0	2	2	1		
Annual Results			488	3	1	20	3	14		

Leak Classification Criteria

Class A Leak

Due to the location or intensity, is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous. Class A leaks are repaired through regular maintenance.

Class B Leak

Due to the location or intensity, is recognized as being non-hazardous at the time of detection, but justifies scheduled repair due to probability of future hazards. That is, if conditions changed that would re-classify the leak to a level that requires immediate action such as, migration or customer concern.

Class C Leak

Due to the location or intensity, represents an existing or potential hazard to persons or property, and requires immediate or continuous action until the conditions are no longer hazardous.

Above Grade piping at bridge crossings	Survey completed once each year	Date Complete	Above Grade Leaks		
			A	B	C
Interlake (Included in annual Transmission survey)	Lockport Bridge	Completed in Q1 May 2017	1	0	0
Valve Maintenance					
All Valves associated with the gas distribution system will be maintained on a yearly basis.	**Total**	**Completed YTD**			
Emergency Sectional Downtown Valve Maintenance Program	56	56	Complete		
Distribution Buried Valves	**Total**	**Completed YTD**			
Winnipeg	448	448	Complete		
Westman	40	40	Complete		
Eastman	106	106	Complete		
Parkland	22	22	Complete		
Interlake	29	29	Complete		

Wall to Wall Leak Survey

A Wall to Wall (Business District Leak Survey) is defined as any area in which the Public Right of Way (laneway or road allowance) is entirely covered with a permanent surface of concrete or asphalt extending from the building wall to the centre line of the right of way and beneath which runs a gas main or service

Three times per year outside and once inside building annually. Total number of buildings fluctuates with additions and deletions due to new construction, building sales, etc.

	Number of Buildings Surveyed			Cumulative Leaks					Survey Results	
	Survey 1	Survey 2	Survey 3			Leaks found	Leaks Repaired	Open Orders		
Winnipeg & Selkirk	2183/2381	2271/2381	2380/2381			26	16	10		
Westman	295/295	281/295*	41/295*			4	4	0		
Eastman	288/288	289/289	286/286			29	16	13		
Parkland	146/146	147/147	147/147			1	1	0		
Interlake (Portage)	61/87	87/87	87/87			16	4	12		

** Reduction of staff through VDP and non-qualified staff could not perform these inspections.*

Public Building Leak Survey Procedure 5.000.24	***Public Buildings Survey*** A building served by natural gas, which is used as a place of public assembly for a common purpose. Such buildings include: - Hospitals, nursing and senior citizen's homes, schools, daycare centres, churches and recreation complexes. Total number of buildings fluctuates with additions and deletions due to new construction, building sales etc.					
	Annual Requirement	Completed YTD	Leaks found on company piping YTD	Leaks Repaired YTD	Open Orders	per cent complete	
Winnipeg	1034	1034	47	39	8	100%	●
Westman	142	116	0	0	0	82%	●
Eastman	297	290	24	18	6	98%	●
Parkland	188	188	5	5	0	100%	●
Interlake	190	190	7	7	0	100%	●

*Westman: Reduction of staff through VDP and non-qualified staff could not perform these inspections.

Winnipeg

Total # of PBI's completed 2017	1034	
Complete - No Leak on company piping(CPNL)	805	78%
Complete - "A leak found and repaired	29	3%
Complete – leak found Company Piping	39	4%
Complete – Leak found Customer Piping	142	14%
Other Infractions found	19	2%

High Pressure Transmission, Mains and Services Survey Results

Outside Leak Surveys Procedure #4.004.23	Frequency	KPI	
	Entire line to be surveyed once per year, not to exceed 15 months	Survey completed once each year	
Gate Stations and Yard Piping	**Total Number of Stations**	**Number of Stations Surveyed quaterly**	**Remaining**
Apr 1 to Jun 30 Q1	203	0	203
Jul 1 to Sept 30 Q2	203	29	174
Oct 1 to Dec 31 Q3	203	174	0
Jan 1 to Mar 31 Q4	203	0	0
GAMC Maintenance Standards 1 & 2	**Frequency**	**KPI**	
Pipeline and Station valve maintenance	Yearly, not to exceed 18 months	Inspections Completed	
Pipeline Valves	**Total Number of Valves**	**Number Checked quarterly**	**Remaining**
Apr 1 to Jun 30 Q1	1,112	549	563
Jul 1 to Sept 30 Q2	1,112	276	277
Oct 1 to Dec 31 Q3	1,102*	277	0
Jan 1 to Mar 31 Q4	1,102	0	0
Station Valves	**Number of valves**	**Number Completed this quarter**	**Remaining**
Apr 1 to Jun 30 Q1	1,662	1,049	613
Jul 1 to Sept 30 Q2	1,662	407	206
Oct 1 to Dec 31 Q3	1,662	206	0
Jan 1 to Mar 31 Q4	1,662	0	0

* Valves removed from maintenance due to system upgrades

Natural Gas Operations Key Performance Indicators

DAMAGE MEASURES
PROGRAM MEASURES
LEAK SURVEY PROGRESS

Q4 - 2018/19 October - December

Below grade damages decreased by 20% compared to 2017/18 fiscal year.

2018/19, 32% of below grade damages were caused by "did not had expose" followed by 22% identified as "did not call for clearance". "Locating error" accounted for 12% of damages.

2018/19 saw a minimal increase (2.4%) in the number of line locate requests compared to 2017/18.

Manitoba Hydro

2018-2019 Q3 Results October - December			Measure			2017-2018 Q3 Results October - December			Measure
Below Grade Damages Per 1000 locates Q4									
2018-2019 Q4 Results January - March	**Q4 Staking Requests**	**Q4 BG Damages**	**BG damages per 1000 locates**	**2017 CGA Average 4905/2,124,033**	**Status**	**2017-2018 Q4 Results**	**Q4 Staking Requests**	**Q4 BG Damages**	**BG damages per 1000 locates**
Winnipeg	3,879	8	2.06			*Winnipeg*	3,841	8	2.08
South Central	1,240	1	0.81			*South Central*	791	2	2.53
Eastman	1,684	1	0.59			*Eastman*	854	2	2.34
Parkland West	716	0	0.00			*Parkland West*	744	0	0.00
Interlake North	340	0	0.00			*Interlake*	295	0	0.00
Provincial	**7,859**	**10**	**1.27**	**2.30**		*Provincial*	**6,525**	**12**	**1.84**
Below Grade Damages per 1000 locates excluding "did not call" Q3									
2018-2019 Q4	**Q4 Staking Requests**	**Q4 Damages**	**BG damages per 1000 locates**	**2017 CGA Average* 2.3x61%**	**Status**	**2017-2018 Q4 Results**	**Q4 Staking Requests**	**Q4 Damages**	**BG damages per 1000 locates**
Winnipeg	3,879	8	2.06			*Winnipeg*	3,841	8	1.21
South Central	1,240	1	0.81			*South Central*	791	2	0.00
Eastman	1,684	1	0.59			*Eastman*	854	2	1.07
Parkland West	716	0	0.00			*Parkland West*	744	0	0.71
Interlake North	340	0	0.00			*Interlake*	295	0	0.00
Provincial	**7,859**	**10**	**1.27**	1.40		*Provincial*	**6,525**	**12**	**1.84**
Below Grade Damages per 1000 Customers									
2018-2019 Q4	**Number of Customers**	**Rolling 12 month period damages**	**Number of damages per 1000 customers**	**2017 CGA Average 4905/7,053,679**	**Status**	**2017-2018 Q4**	**Number of Customers**	**Rolling 12 month period damages**	**Number of damages per 1000 customers**
Provincial	**287,136**	**85**	**0.30**	**0.60**		*Provincial*	**283,258**	**106**	**0.37**
Below Grade Damages per 1000 km of Main									
2018-2019 Q4	**Kilometres of Distribution Main including HP/TP**	**Rolling 12 month period damages**	**Number of damages per 1000 Km of main**	**2017 CGA Average 4905/363,710**	**Status**	**2017-2018 Q4**	**Kilometres of Distribution Main including HP**	**Rolling 12 month period damages**	**Number of damages per 1000 Km of main**
Provincial	**10,558**	**85**	8.05	**13.40**		*Provincial*	**10,383**	**106**	**10.21**
Below Grade Damages per 1000 Km of main and services.									
2018-2019 Q4	**Kilometres of Main & Services**	**Rolling 12 month period damages**	**Number of damages per 1000 Km of main & services**	**2017 CGA Average 4905/550,452**	**Status**	**2017-2018 Q4**	**Kilometres of Main & Services**	**Rolling 12 month period damages**	**Number of damages per 1000 Km of main & services**
Provincial	**17,935**	**85**	4.74	**8.90**		*Provincial*	**17,684**	**106**	**5.99**

*Incidents when no locate was requested by the excavator compared to incidents when a locate was requested by the excavator as a percentage of total third party damage incidents.

Below Grade Damages per 1000 Locates

2018-2019 Results

	Staking Requests				Damages				Number of damages per 1000 locates				CGA Average
	Q4 18/19	Q3 18/19	Q2 18/19	Q1 118/19	Q4 18/19	Q3 18/19	Q2 18/19	Q1 118/19	Q4 18/19	Q3 18/19	Q2 18/19	Q1 118/19	
Winnipeg	3,879	6,852	11,967	10,944	8	8	24	7	2.06	2.01	1.17	2.01	
South Central	1,240	2,717	4,120	3,881	1	4	2	7	0.81	0.49	1.47	0.49	
Eastman	1,684	1,513	2,571	2,534	1	6	7	6	0.59	2.72	3.97	2.72	
Parkland West	716	1,667	2,542	2,168	0	0	2	1	0.00	0.79	0.00	0.79	
Interlake	340	398	717	701	0	0	0	1	0.00	0.00	0.00	0.00	
Provincial	**7,859**	**13,147**	**21,917**	**20,228**	**10**	**18**	**35**	**22**	**1.27**	**1.37**	**1.60**	**1.09**	
	12 month total		63,151		12 month total		85		12 month avg		1.35		2.30

2017-2018 Results

	Staking Requests				Damages				Number of damages per 1000 locates			
	Q4 17/18	Q3 17/18	Q2 17/18	Q1 17/18	Q4 17/18	Q3 17/18	Q2 17/18	Q1 17/18	Q4 17/18	Q3 17/18	Q2 17/18	Q1 17/18
Winnipeg	3,841	6,643	12,030	12,259	8	10	23	18	1.48	1.51	1.91	1.47
South	791	2,370	3,467	3,547	2	2	14	4	1.89	0.84	4.04	1.13
Eastman	854	1,672	2,533	2,458	2	5	5	6	2.34	2.99	1.97	2.44
Parkland	744	1,884	2,261	2,104	0	2	1	4	0.00	1.06	0.44	1.90
Interlake	295	468	842	589	0	0	0	0	0.83	0.00	0.00	0.00
Provincial	**6,525**	**13,037**	**21,133**	**20,957**	**12**	**19**	**43**	**32**	**1.84**	**1.46**	**2.03**	**1.53**
	12 month total		61,652		12 month total		106		12 month avg		1.72	

Below Grade Damages per 1000 Km of main

2018-2019 Results

	Kilometres of Distribution Main	Damages				Number of damages per 1000 Km of main				CGA Average
		Q4 18/19	Q3 18/19	Q2 18/19	Q1 18/19	Q4 18/19	Q3 18/19	Q2 18/19	Q1 18/19	
Winnipeg	10,558	8	8	24	7					
South Central		1	4	2	7					
Eastman		1	6	7	6					
Parkland West		0	0	2	1					
Interlake		0	0	0	1					
Provincial		**10**	**18**	**35**	**22**	**0.95**	**1.70**	**3.31**	**2.08**	
		12 month total		85		12 month avg			8.05	13.40

2017-2018 Results

	Kilometres of Distribution Main	Damages				Damages per 1000 Km of main			
		Q4 17/18	Q3 17/18	Q2 17/18	Q1 17/18	Q4 17/18	Q3 17/18	Q2 17/18	Q1 17/18
Winnipeg	10,383	8	10	23	18				
South Central		2	2	14	4				
Eastman		2	5	5	6				
Parkland West		0	2	1	4				
Interlake		0	0	0	0				
Provincial		**12**	19	43	32	1.16	1.83	4.14	3.08
		12 month total		106		12 month avg			10.21

Below Grade Damages per 1000 km of mains & services

2018-2019 Results

	Kilometres of Main & Services	Damages				Number of damages per 1000 Km of main & services				CGA Average
		Q4 18/19	Q3 18/19	Q2 18/19	Q1 18/19	Q4 18/19	Q3 18/19	Q2 18/19	Q1 18/19	
Winnipeg	17,935	8	8	24	7					
South Central		1	4	2	7					
Eastman		1	6	7	6					
Parkland West		0	0	2	1					
Interlake		0	0	0	1					
Provincial		**10**	**18**	**35**	**22**	**0.56**	**1.00**	**1.95**	**1.23**	
		12 month total		85		12 month average			4.74	8.90

2017-2018 Results

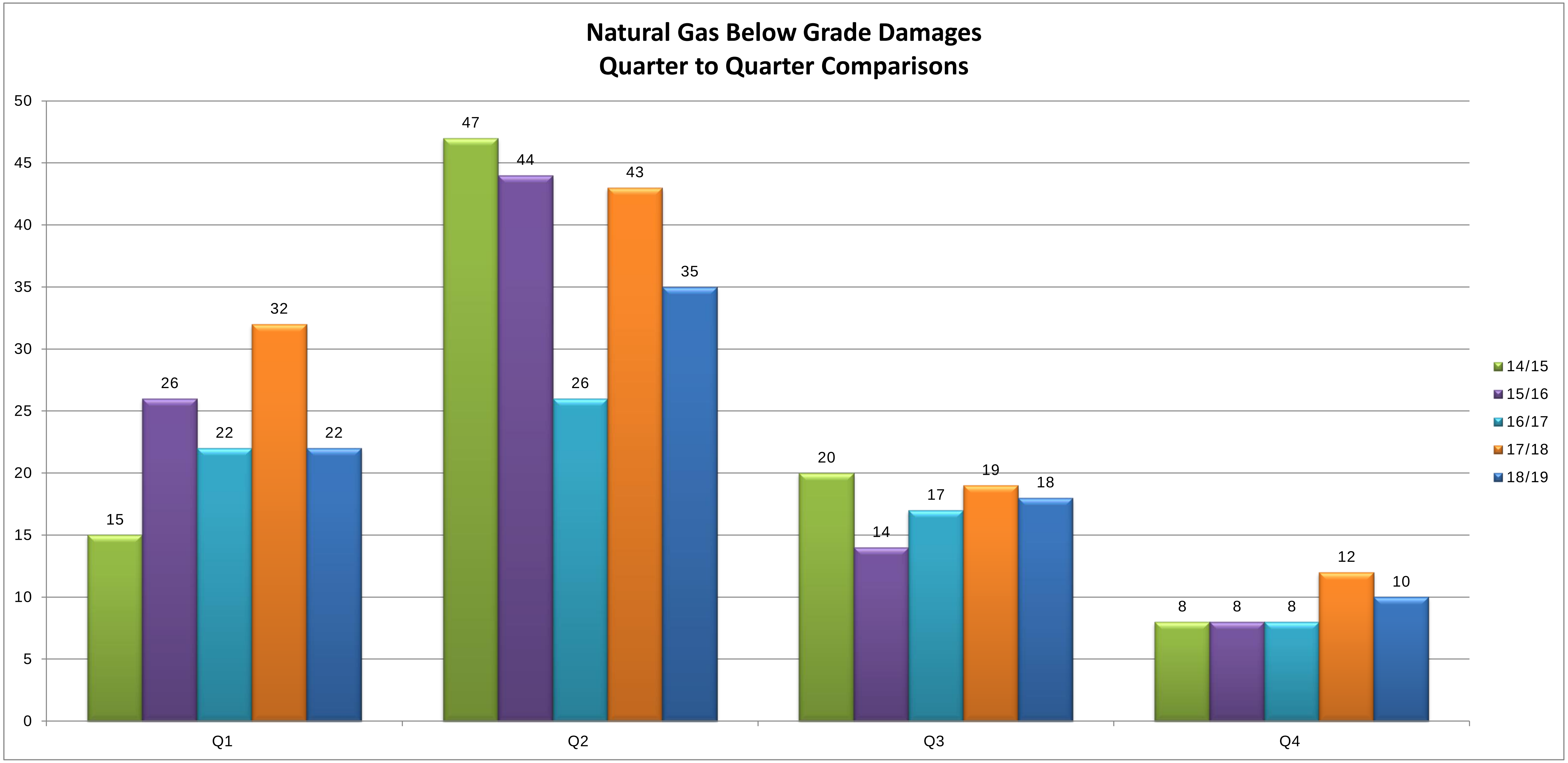
	Kilometres of Main & Services	Damages				Number of damages per 1000 Km of main & services			
		Q4 18/19	Q3 18/19	Q2 18/19	Q1 18/19	Q4 18/19	Q3 18/19	Q2 18/19	Q1 18/19
Winnipeg	17,684	8	10	23	18				
South Central		2	2	14	4				
Eastman		2	5	5	6				
Parkland West		0	2	1	4				
Interlake		0	0	0	0				
Provincial		**12**	19	43	32	0.68	1.07	2.43	1.81
		12 month total		106		12 month avg			5.99

Percent of Below Grade Damages that are four party trench area

2018-2019		4 Party Damages				Percent of damages to 4 party trench plant			
		Q4 18/19	Q3 18/19	Q2 18/19	Q1 18/19	Q4 18/19	Q3 18/19	Q2 18/19	Q1 18/19
Winnipeg		2	2	0	1	25%	25%	0%	14%
South Central		0	0	0	0	0%	0%	0%	0%
Eastman		0	0	0	0	0%	0%	0%	0%
Parkland West		0	0	0	0	0%	0%	0%	0%
Interlake		0	0	0	0	0%	0%	0%	0%
Provincial		**2**	**2**	**0**	**1**	**20%**	**11%**	**0%**	**5%**
		12 month total		5		damages	85	AVG	6%

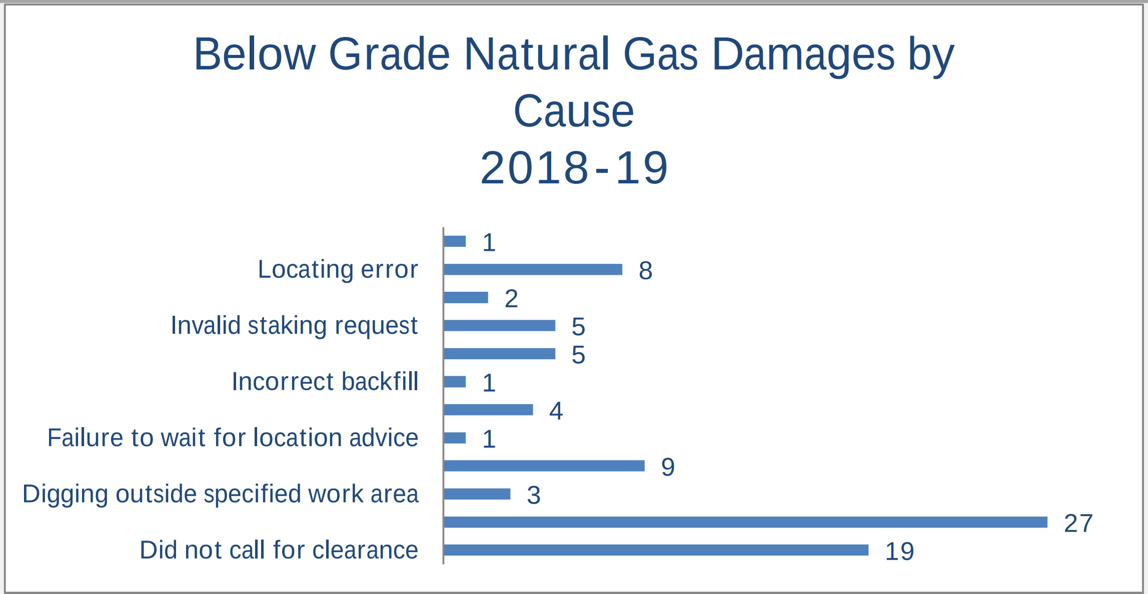
2017-2018		4 Party Damages				Percent of damages to 4 party trench plant			
		Q4 18/19	Q3 18/19	Q2 18/19	Q1 18/19	Q4 18/19	Q3 18/19	Q2 18/19	Q1 18/19
Winnipeg		2	3	6	2	25%	30%	26%	11%
South Central		0	0	1	0	0%	0%	25%	0%
Eastman		0	1	1	2	0%	20%	20%	33%
Parkland West		0	0	0	0	0%	0%	0%	0%
Interlake		0	0	0	0	0%	0%	0%	0%
Provincial		2	4	8	4	11%	9%	25%	13%
		12 month total		18		damages	106	AVG	17%

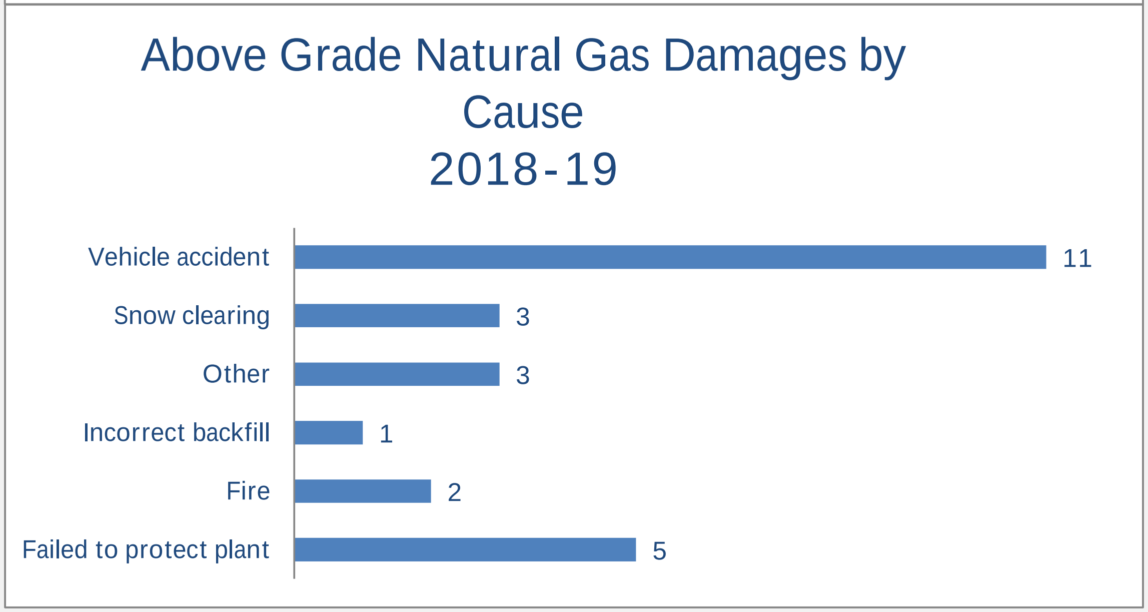
****Note:*** *Fortis BC data is removed from the CGA Average as their operational model differs from the rest of the CGA members*



	2018-2019				2017-2018				2016-2017				2015-2016				2014-2015			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Winnipeg	7	24	8	8	18	23	10	8	5	14	8	6	12	27	3	5	7	25	7	7
South Central	7	2	4	1	4	14	2	2	1	4	2	0	5	2	3	0	0	6	1	0
Eastman	6	7	6	1	6	5	5	2	12	4	2	1	8	7	3	1	6	11	5	1
Parkland West	1	2	0	0	4	1	2	0	0	1	1	0	1	3	1	2	1	0	3	0
Interlake North	1	0	0	0	0	0	0	0	4	3	4	1	0	5	4	0	1	5	4	0
	22	**35**	**18**	**10**	**32**	**43**	**19**	**12**	**22**	**26**	**17**	**8**	**26**	**44**	**14**	**8**	**15**	**47**	**20**	**8**
YTD	**22**	**57**	**75**	**85**	**32**	**75**	**94**	**106**	**22**	**48**	**65**	**73**	**26**	**70**	**84**	**92**	**15**	**62**	**82**	**90**

2018/2019 Natural Gas Damages





Gas Operations Key Performance Indicators			
Odorization Testing Procedure # 4.500.35			
Odorant Intensity Testing	Performed once per week.	**Q4 January - March**	
Winnipeg		Complete	●
South Central		Complete	●
Eastman		Complete	●
Parkland West		Complete	●
Interlake North		Complete	●
Equipment Testing			
Combustible Gas Indicator Testing Standard 711.01			
Monthly Inspection and Calibration	Monthly	**Q4 January - March**	
Winnipeg	83/85 January, 79/79 February, 83/84 March	100%	
South Central	PLP 4/4 , MRD/BRA using MSA's	100%	●
Eastman	Selkirk 5/5, Steinbach 7/7	100%	●
Parkland West	Parkland using MSA's	100%	●
Interlake North	N/A covered out of Selkirk	100%	●
Flame Ionization Equipment Calibration	Monthly All CSO Departments LSI equipment is self calibrating.	**Q4 January - March**	●
Emergency Equipment Testing - Squeezers	Squeezer test 1 to be completed by the end of Q2 Squeezer test 2 to be completed by the end of Q4	**Q4 January - March**	
Winnipeg	Test #1 Complete; Test #2 Complete Q4	100%	●
South Central	Test #1; 145/145, Test#2 145/145 completed Q3	100%	●
Eastman	Test #1 37/37, Test #2 32/37 completed Q3	100%	●
Parkland West	Test #1; 52/52, Test #2 52/52 Completed Q3	100%	●
Interlake North	N/A covered out of Selkirk	100%	●
Emergency Equipment Inventory List Review	To be reviewed annually	**Q4 January - March**	

Gas Operations Key Performance Indicators			
Winnipeg	Completed Q3 2018/19	Complete	●
South Central	Completed Q4 2018/19	Complete	●
Eastman	Completed Q1, 2018/19	Complete	●
Parkland West	Completed Q3 2018/19	Complete	●
Interlake North	N/A covered out of Selkirk	Complete	●
Pre-Tested Pipe Inventory Procedure 5.000.1 and Standard 720.07	To be reviewed annually	**Q4 January - March**	
Winnipeg	Completed May 13, 2018	Complete	●
South Central	Brandon Aluminum completed May 2018	Complete	●
Line Marker Signs	Signs have been identified and sent to CSCs for remediation. Work is ongoing	**Q4 January - March**	
Winnipeg	Complete	Complete	●
South Central	Complete	Complete	●
Eastman	Complete	Complete	●
Parkland West	Complete	Complete	●
Interlake North	Complete	Complete	●
Vegetation Management Standard 723.01	Surveyed at not more than 3 year intervals. Done with Transmission Survey.	**Q4 January - March**	
	Locations requiring vegetation management have been identified.		
Winnipeg	Complete	Complete	●
South Central	Complete	Complete	●
Eastman	Complete	Complete	●
Parkland West	Complete	Complete	●
Interlake North	Complete	Complete	●

* Daily bump tests were completed as required.

Outside Leak Survey Procedure 4.004.23	**KPI Frequency**	**Number of Kilometres Surveyed**	**Q2 Above Grade Leaks**			**Q2 Below Grade Leaks**			**Result**	
Q4 October - December										
Transmission and High Pressure Pipeline Survey	once per year, not to exceed 15 months	Completed YTD	**A**	**B**	**C**	**A**	**B**	**C**		
Provincial Total	2,219	2,152	0	0	0	0	0	0		
Annual Results (Completed Q1)			15	0	0	0	0	0		
Mains and Services	every 3 years	**Number of Services Surveyed**	**Q4 Above Grade Leaks**			**Q4 Below Grade Leaks**				
	2017/18 services to be surveyed	Completed YTD	**A**	**B**	**C**	**A**	**B**	**C**		
Provincial Total	93,846	91,333	0	0	0	0	0	0		
Annual Results			530	23	3	8	12	11		

<u>Leak Classification Criteria</u>

<u>Class A Leak</u>

Due to the location or intensity, is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous. Class A leaks are repaired through regular maintenance.

<u>Class B Leak</u>

Due to the location or intensity, is recognized as being non-hazardous at the time of detection, but justifies scheduled repair due to probability of future hazards. That is, if conditions changed that would re-classify the leak to a level that requires immediate action such as, migration or customer concern.

<u>Class C Leak</u>

Due to the location or intensity, represents an existing or potential hazard to persons or property, and requires immediate or continuous action until the conditions are no longer hazardous.

Above Grade piping at bridge crossings	**Survey completed once each year**	**Date Complete**	**Above Grade Leaks**		
			A	**B**	**C**
Interlake (Included in annual Transmission survey)	Lockport Bridge	8/23/2018	1	0	0
Valve Maintenance					
All Valves associated with the gas distribution system will be maintained on a yearly basis.	**Total**	**Completed YTD**			
Emergency Sectional Downtown Valve Maintenance Program	56	56	Complete		
Distribution Buried Valves	**Total**	**Completed YTD**			
Winnipeg	451	451	Complete		
South Central	89	80	Scheduled		
Eastman	97	97	Complete		
Parkland West	22	22	Complete		
Interlake North	6	6	Complete		

Wall to Wall Leak Survey

A Wall to Wall (Business District Leak Survey) is defined as any area in which the Public Right of Way (laneway or road allowance) is entirely covered with a permanent surface of concrete or asphalt extending from the building wall to the centre line of the right of way and beneath which runs a gas main or service

Three times per year outside and once inside building annually. Total number of buildings fluctuates with additions and deletions due to new construction, building sales, etc.

	Number of Buildings Surveyed			**Cumulative Leaks**					**Survey Results**	
	Survey 1	Survey 2	Survey 3			Leaks found	Leaks Repaired	Open Orders		
Winnipeg & Selkirk	2360/2360	2356/2360	2341/2360			49	7	42		
South Central	487/487	521/522	521/521			34	25	9		
Eastman	171/171	171/171	171/171			22	20	2		
Parkland West	156/156	156/156	156/156			2	2	0		
Interlake North	0/0	0/0	0/0			0	0	0		

Public Building Leak Survey Procedure 5.000.24	***Public Buildings Survey*** A building served by natural gas, which is used as a place of public assembly for a common purpose. Such buildings include: - Hospitals, nursing and senior citizen's homes, schools, daycare centres, churches and recreation complexes. Total number of buildings fluctuates with additions and deletions due to new construction, building sales etc.						
	Annual Requirement	Completed YTD	per cent complete	Leaks found on company piping YTD	Leaks Repaired on company pipingYTD	Open Leak Orders on company piping	
Winnipeg	1032	1032	100%	35	33	2	
South Central	456	456	100%	16	13	3	
Eastman	245	245	100%	9	9	0	
Parkland West	285	285	100%	2	2	0	
Interlake North	22	14	64%	0	0	0	

Winnipeg

Total # of PBI's completed 2018	1032	
Complete - No Leak on company piping(CPNL)	783	76%
Complete - "A" leaks found and repaired	68	7%
Complete - "B" leaks found and repaired	2	0%
Complete – leak found Company Piping	35	3%
Complete – Leak found Customer Piping	132	13%
Other Infractions found	12	1%

High Pressure Transmission, Mains and Services Survey Results

Outside Leak Surveys Procedure #4.004.23	Frequency	KPI	
	Entire line to be surveyed once per year, not to exceed 15 months	Survey completed once each year	
Gate Stations and Yard Piping	**Total Number of Stations**	**Number of Stations Surveyed quarterly**	**Remaining**
Apr 1 to Jun 30 Q1	207	0	207
Jul 1 to Sept 30 Q2	207	0	207
Oct 1 to Dec 31 Q3	207	207	0
Jan 1 to Mar 31 Q4	207	0	0
GAMC Maintenance Standards 1 & 2	**Frequency**	**KPI**	
Pipeline and Station valve maintenance	Yearly, not to exceed 18 months	Inspections Completed	
Pipeline Valves	**Total Number of Valves**	**Number Checked quarterly**	**Remaining**
Apr 1 to Jun 30 Q1	1,111	735	376
Jul 1 to Sept 30 Q2	1,102	230	146
Oct 1 to Dec 31 Q3	1,101	146	0
Jan 1 to Mar 31 Q4	1,159	58	0
Station Valves	**Number of valves**	**Number Completed this quarter**	**Remaining**
Apr 1 to Jun 30 Q1	1,685	1,368	317
Jul 1 to Sept 30 Q2	1,663	92	125
Oct 1 to Dec 31 Q3	1,660	125	0
Jan 1 to Mar 31 Q4	1,676	16	0

* Valves removed from maintenance due to system upgrades

REFERENCE:

PUB/Centra I-28 a)

QUESTION:

Please explain what factors led the percentage of O&A costs allocated to gas operations declining from 12% pre IFRS to 11% post IFRS implementation.

RESPONSE:

With the adoption of IFRS in 2015/16, overhead costs can no longer be capitalized unless directly attributable to a construction project or an intangible asset. As a result, O&A expenditures increased by $59 million for the electric segment (Manitoba Hydro 2016 Financial Statements, Note 6C, p. 67) and $3 million for the natural gas segment, as discussed in Note C on page 20 of Appendix 5.4 – Centra Financial Statements Year Ended March 31, 2016.

The table below illustrates that overhead costs previously capitalized are more heavily weighted to the electric segment, resulting in Electric O&A increasing proportionately greater than Gas O&A. In addition, the 2015/16 percentage allocated to Centra would have remained unchanged at 12%, absent the IFRS accounting change for overhead costs no longer eligible for capitalization.

CENTRA GAS MANITOBA INC
TOTAL O&A COSTS ALLOCATED TO CENTRA
($000's)

	CGAAP 2014/15 Actual	IFRS 2015/16 Actual	Accounting Change for Ineligible Overhead		2015/16 without Accounting Change
Electric O&A	$ 480,472	$ 542,714	$ (59,000)	*95%*	$ 483,714
Gas O&A	67,458	66,607	(3,000)	*5%*	$ 63,607
Total O&A	$ 547,930	$ 609,321	$ (62,000)	*100%*	$ 547,321
% Allocated to Centra	12%	11%			12%

REFERENCE:

PUB/Centra I-28 b)

QUESTION:

a) Please update the schedule to incorporate columns for total expenditures and the relative percentage of indirect costs to total cost for each year and comment on variations.

b) Please explain which Direct costs of Operations & Maintenance have declined from $18.251 million in 2013/14 to $16.036 million in 2019/20.

c) Please discuss the factors that resulted in indirect costs declining from $29.167M in 2013/14 to 25.959M in 2019/20.

d) Please explain how the Corporation determined the allocation of comprehensive general liability insurance.

RESPONSE:

a) The table from PUB/CENTRA I-28b has been updated below to include total expenditures and the relative percentage of indirect costs to total cost for each year. In addition, Centra has made minor adjustments to the direct costs of Customer Service & Corporate Relations ($3k) and Operations and Maintenance ($78k) in 2019/20 for costs inadvertently missed, as well as adjustments to the Customer Service & Corporate Relations amount for 2012/13 as bad debt was inadvertently included as an indirect cost rather than a direct cost in the first table, and liability insurance was marked as direct as opposed to indirect in the second table.

CENTRA GAS MANITOBA INC.
DIRECT/INDIRECT COSTS BY PROGRAM
($000's)

	CGAAP								
	2012/13 Actual			2013/14 Actual			2014/15 Actual		
	Direct	Indirect	Total	Direct	Indirect	Total	Direct	Indirect	Total
Customer Service & Corporate Relations	$19 564	$11 597		$20 423	$12 035		$20 264	$11 525	
Operations and Maintenance	16 579	266		18 251	188		20 157	333	
Organizational Support	399	16 459		306	16 944		398	17 007	
Total Program Costs	**$36 542**	**$28 322**	**$64 864**	**$38 980**	**$29 167**	**$68 147**	**$40 819**	**$28 865**	**$69 684**
Indirect Percentage		**44%**			**43%**			**41%**	

CENTRA GAS MANITOBA INC.
DIRECT/INDIRECT COSTS BY PROGRAM
($000's)

	IFRS														
	2015/16 Actual			2016/17 Actual			2017/18 Actual			2018/19 Forecast			2019/20 Test Year		
	Direct	Indirect	Total	Direct	Indirect	Total	Direct	Indirect	Total	Direct	Indirect	Total	Direct	Indirect	Total
Customer Service & Corporate Relations	$19,739	$10,775		$19,300	$10,401		$18,702	$10,482		$19,250	$ 9,667		$20,150	$ 9,861	
Operations and Maintenance	19,779	222		19,388	234		$19,073	$ 193		18,713	127		16,114	130	
Organizational Support	284	18,102		221	17,596		$ 280	$16,478		255	15,757		253	16,074	
Total Program Costs	**$39,802**	**$29,099**	**$68,901**	**$38,909**	**$28,231**	**$67,140**	**$38,054**	**$27,152**	**$65,206**	**$38,219**	**$25,551**	**$63,770**	**$36,517**	**$26,064**	**$62,581**
Indirect Percentage		**42%**			**42%**			**42%**			**40%**			**42%**	

The percentage of indirect costs decreased during the CGAAP years from 44% in 2012/13 to 41% in 2014/15 and remained constant under IFRS at 42%. The decline in the indirect cost percentage from 2012/13 to 2014/15 is primarily due to:

- An increase in Operations and Maintenance direct costs related to:
  - The distribution maintenance program as a result of an increase in time spent on above grade and below grade cathodic protection work; and
  - The system performance & reliability program as a result of higher labour requirements for cathodic protection work, external corrosion assessments, depth of cover investigations, close interval surveys and pipeline river crossing inspections.

b) The decline in direct costs in Operations & Maintenance from $18.251M in 2013/14 to $16.114M (as per PUB/Centra I-28b Updated) in 2019/20 is primarily due to:

- A decrease in the metering program as a result of the proposed capitalization of metering costs in 2019/20 as well as a reduction in the necessary sampling and refurbishment requirements resulting from Measurement Canada testing in 2015/16 through 2018/19.

Partially offset by:

- An increase in the distribution maintenance program primarily related to an increase in time spent on above grade and below grade cathodic protection work.

c) The decrease in indirect costs from $29.167M in 2013/14 to $26.064M in 2019/20 is primarily related to:

- A decrease in Organizational Support costs due to a reduction in staff related to the VDP and senior management reductions, and
- A decrease in Customer Service & Corporate Relations costs related to the billing & collections program costs as a result of staffing reductions and the customer & public relations program attributable to decrease in advertising, donations and consulting services for Power Smart marketing, as well as a decrease in call volumes in the customer contact centre.

d) Insurance costs are allocated between Manitoba Hydro and Centra based on a pro-rata premium breakdown that represents the exposure and risk associated with the insurance requirements for each line of business.

The combined 2005 insurance premium [redacted] for Manitoba Hydro and [redacted] for Centra Gas have been used as the allocation basis going forward as illustrated below. 4b, 5a

	2005 Actuals (000s)	Comprehensive General Liability Insurance Allocation %
Manitoba Hydro	[redacted]	45%
Centra Gas	[redacted]	55%

4b, 5a

Insurers underwrite risks based on their exposures. It was deemed appropriate to use the 2005 pro-rata premium breakdown to allocate future premiums as the overall insurance coverage for each line of business was comparable and these amounts represented the insurer's opinion of risk. The risk exposures have not changed since the two policies were amalgamated and as such is still the best driver for allocation of costs.

Based on this methodology the allocation is 55% to Centra and 45% to Manitoba Hydro.

REFERENCE:

PUB/Centra I-28 pg. 3, PUB/Centra I-33

QUESTION:

a) Please file a full table indicating all cost drivers, the details of the common costs, total corporate amount subject to allocation by the cost driver and the amount of the costs attributable gas operations for 2019/20.

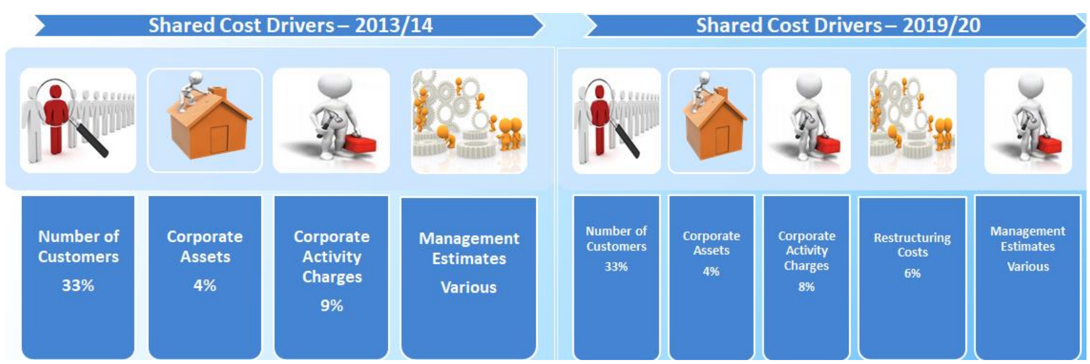
b) Please provide a similar table for 2013/14 approved and identify in each case in (a) any changes in the allocator utilized and provide an explanation for the change.

c) Please provide a detailed description and illustrative calculation of the new cost driver to allocate restructuring expenditures.

RESPONSE:

a) to c)

The following diagram provides the shared cost drivers and the percentage charged to Centra for 2013/14 and 2019/20.



Please see the response to PUB/CENTRA II-23a-f for the details of common costs, total corporate amount subject to allocation by the cost driver and the amount of the costs attributable to gas operations for 2019/20.

The Number of Customers and Corporate Assets shared cost drivers remained unchanged between 2013/14 and 2019/20.

The percentage of Corporate Activity Charges directly related to the Natural Gas segment dropped by 1% from 2013/14 to 2019/20.

As discussed in PUB/CENTRA I-28c, the Restructuring cost driver was introduced to allocate restructuring expenditures associated with the Voluntary Departure Program ("VDP"). Please refer to the response to PUB/CENTRA II-11d for the calculation of the cost driver.

REFERENCE:

PUB/Centra I-29 a)

QUESTION:

Please provide a schedule detailing the total salaries by corporate group, the headcount, the number of EFT's, and the average salary per EFT for each of the years 2013/14 through 2019/20.

RESPONSE:

The following table provides the total salaries by Operating / Corporate group of the integrated utility, based upon the current organizational structure from 2013/14 through 2019/20. Salaries of staff that support the gas operations are imbedded in activity rates, which are used to allocate operating costs to Centra.

MANITOBA HYDRO
SALARIES BY OPERATING/CORPORATE GROUP
(000's)

	2013/14 Actual	2014/15 Actual	2015/16 Actual	2016/17 Actual	2017/18 Actual	2018/19 Forecast	2019/20 Forecast
President & CEO	$ 2 715	$ 3 133	$ 3 634	$ 3 216	$ 2 612	$ 2 537	$ 2 624
General Counsel & Corporate Secretary	2 785	2 670	2 937	2 944	2 641	2 512	2 969
Human Resources & Corporate Services	63 174	63 736	65 805	65 794	61 484	57 265	58 462
Indigenous Relations	7 847	8 046	7 376	7 369	6 716	7 072	6 914
Finance & Strategy	15 043	15 253	15 562	15 614	13 775	12 767	12 571
Generation & Wholesale	112 591	109 314	110 269	111 693	107 402	102 212	103 354
Transmission	123 341	134 809	140 351	145 126	139 994	133 987	127 238
Marketing & Customer Service	149 196	153 042	157 576	161 870	156 209	148 545	151 676
Total	**$476 693**	**$490 004**	**$ 503 509**	**$ 513 627**	**$ 490 835**	**$ 466 896**	**$ 465 808**

The following table provides a summary of the straight time EFT's by Operating / Corporate group of the integrated utility from 2013/14 through 2019/20.

MANITOBA HYDRO
STRAIGHT TIME EFT'S BY OPERATING/CORPORATE GROUP

	2013/14 Actual	2014/15 Actual	2015/16 Actual	2016/17 Actual	2017/18 Actual	2018/19 Forecast	2019/20 Forecast
President & CEO	14	15	14	14	10	9	9
General Counsel & Corporate Secretary	27	25	27	26	24	23	26
Human Resources & Corporate Services	823	807	806	792	725	669	669
Indigenous Relations	99	99	88	86	80	79	77
Finance & Strategy	176	171	166	163	141	133	127
Generation & Wholesale	1 466	1 330	1 282	1 264	1 186	1 103	1 120
Transmission	1 574	1 668	1 663	1 665	1 557	1 475	1 387
Marketing & Customer Service	2 193	2 172	2 176	2 191	2 055	1 949	1 908
Total	**6 374**	**6 287**	**6 223**	**6 201**	**5 778**	**5 440**	**5 324**

The following table provides a summary of the average salary per EFT by Operating / Corporate group of the integrated utility from 2013/14 through 2019/20.

MANITOBA HYDRO
AVERAGE SALARY PER EFT BY OPERATING/CORPORATE GROUP

	2013/14 Actual	2014/15 Actual	2015/16 Actual	2016/17 Actual	2017/18 Actual	2018/19 Forecast	2019/20 Forecast
President & CEO	$ 189 657	$ 212 588	$ 251 263	$ 231 258	$ 261 178	$ 281 889	$ 291 535
General Counsel & Corporate Secretary	103 041	107 236	110 747	114 019	112 288	108 267	114 208
Human Resources & Corporate Services	76 789	78 997	81 644	83 038	84 778	85 551	87 328
Indigenous Relations	79 269	81 499	83 413	85 637	84 452	89 764	89 281
Finance & Strategy	85 246	89 396	93 913	96 066	97 959	96 106	99 172
Generation & Wholesale	76 783	82 165	86 017	88 378	90 542	92 696	92 250
Transmission	78 343	80 800	84 381	87 156	89 896	90 815	91 765
Marketing & Customer Service	68 020	70 463	72 410	73 868	75 998	76 219	79 498
Corporate Average Salary	**$ 74 791**	**$ 77 944**	**$ 80 917**	**$ 82 831**	**$ 84 951**	**$ 85 824**	**$ 87 500**

Headcount data is an actual only, point in time count based on the number of employees excluding seasonal staff and summer students, regardless of the employees' work schedule (full time or part time). As such, actual headcount will differ from actual EFT which is an annualized statistic calculated on hours worked, (*on an annual basis 1 916 hours equates to 1 EFT*) for all staff. Headcount tracking was implemented on April 10, 2017 with a corporation target of 5 242 as of March 31, 2020.

The following table provides a summary of actual headcount information by Operating / Corporate group for the integrated utility as of April 10, 2017, March 31, 2018 and March 31, 2019.

MANITOBA HYDRO
HEADCOUNT BY OPERATING/CORPORATE GROUP
(000's)

	April 10 2017	**March 31 2018**	**March 31 2019**
President & CEO	10	9	8
General Counsel & Corporate Secretary	28	24	26
Human Resources & Corporate Services	786	643	642
Indigenous Relations	70	61	62
Finance & Strategy	163	130	124
Generation & Wholesale	1 259	1 102	1 086
Transmission	1 638	1 446	1 355
Marketing & Customer Service	2 163	1 893	1 894
Total	**6 117**	**5 308**	**5 197**

REFERENCE:

PUB/Centra I-30

QUESTION:

a) Please provide a separate schedule that provides the ST activity hours and ST activity rate by function for each of the years 2015/16 to 2019/20.

b) Please explain why the back/middle office ST average rate increased from $64 in 2015/16 to $94 in 2016/17. Please provide a schedule which compares a breakdown of the cost components with narrative explaining the changes.

c) Please provide an explanation for the changes in ST hours on billing and collection which was 111,280 in 2015/16 and is forecast to be 89,773 in 2019/20 a decrease of 21,507 hours.

d) Please explain the change in the average activity ST rate for customer inspections from 2017/18 actual of $81 average rate to $74 for the test year. Please provide a schedule which compares a breakdown of the cost components with narrative explaining the changes.

e) Please explain the reasons for the forecast increase in ST hours for distribution maintenance from 2017/18 to 2019/20 and provide explanation for the variation in the average rate. Provide the detailed calculations for the average activity rate for 2017/18 and 2019/20 and explain the changes.

RESPONSE:

a) By email on June 2, 2019, PUB Counsel has advised that part a) of this request has been withdrawn by the Public Utilities Board.

b) The 2015/16 average straight time activity rate for the back/middle office services program should have been $89/hour and the total straight time activity charges should have been $246K. An error occurred when an incorrect activity type was used in the time allocation process which had a nil activity rate. As such, the hours were included in the table in PUB/CENTRA I-30, but the dollars were understated and not charged to Centra. The true increase from 2015/16 to 2016/17 is only $5/hour as compared to

$30/hour as shown. Controls have subsequently been established to disallow posting of hours with a nil activity rate.

c) The decrease of 21,507 straight time hours for billing and collections from 2015/16 to 2019/20 reflects a decline in hours worked due to staff reductions related to an internal hiring freeze, the voluntary departure program as well as the closure of front desks at customer service centres for billing inquiries.

d) Please see the response to PUB/CENTRA II-21b for a discussion on the breakdown of the cost components within an activity rate. As the customer inspection program has approximately 40 work groups involved in the program, an extensive and very time consuming work effort is required to provide the requested breakdown of the component changes in the activity rate for each work group. Accordingly, Centra is unable to provide the requested breakdown within the time frame of the current proceeding.

e) The increase in straight time hours for distribution maintenance from 2017/18 to 2019/20 is due to greater work requirements anticipated for both above and below ground maintenance. The hours charged to this program fluctuate based on competing priorities for resources. Please see the response to PUB/CENTRA II-21 for a discussion on the breakdown of the cost components within an activity rate. As the distribution maintenance program has approximately 25 work groups who allocate time to the program, an extensive and very time consuming work effort is required to provide the requested breakdown of the component changes in the activity rate for each work group. Accordingly, Centra is unable to provide the requested breakdown within the time frame of the current proceeding

REFERENCE:

PUB/Centra I-30, PUB/Centra I-21 f) (2013/14 GRA)

QUESTION:

a) Please provide a comparison between the actual activity hours, activity rates and charges for 2013/14 provide in this application with the 2013/14 forecast test year provided at the last GRA and reconcile and explain the differences.
b) Please file in the same format as the last GRA the actual for 2012/13, 2013/14 and 2014/15 and identify and explain the changes made in the ICAM.

RESPONSE:

a) The table below provides a comparison of the actual activity hours, activity rates and activity charges by program between the actual results for 2013/14 and the forecast filed in the 2013/14 General Rate Application.

CENTRA GAS MANITOBA INC.
TOTAL ACTIVITY HOURS, RATES AND CHARGES

	2013/14 Actual			2013/14 Test Year			Variance		
	Hours	Avg. Activity Rate ($)	Activity Charges ($000s)	Hours	Avg. Activity Rate ($)	Activity Charges ($000s)	Hours	Avg. Activity Rate ($)	Activity Charges ($000s)
Customer Service & Corporate Relations									
Back/middle office services	2 792	83	233	3 070	91	279	278	8	46
Billing & collections	117 524	53	6 185	115 701	50	5 793	(1 823)	(3)	(392)
Customer & public relations	63 413	71	4 502	77 987	68	5 330	14 574	(3)	828
Customer information systems (Banner)	10 268	84	865	10 479	81	844	211	(3)	(21)
Customer inspections	87 896	80	7 057	93 964	77	7 194	6 068	(3)	137
Customer safety services	15 507	87	1 357	20 818	82	1 713	5 311	(5)	356
Dispatch	26 408	72	1 894	36 832	61	2 239	10 424	(11)	345
Energy supply, planning & support	23 935	78	1 861	22 269	77	1 705	(1 666)	(1)	(156)
Environment	758	92	70	-	-	-	(758)	(92)	-*
Meter reading	479	84	40	549	77	42	70	(7)	2
Rate and regulatory affairs	13 048	82	1 066	14 958	79	1 183	1 910	(3)	117
	362 027	69	25 130	396 627	66	26 321	34 600	(3)	1 191
Operations and Maintenance									
Communication systems	1 942	83	161	1 650	87	144	(292)	4	(17)
Distribution maintenance	56 097	86	4 849	61 295	82	5 004	5 198	(4)	155
Load forecast	1 835	72	132	2 096	75	158	261	3	26
Metering	54 616	72	3 959	65 482	73	4 812	10 866	1	853
Plant failures & emergencies	11 210	97	1 082	1 321	70	92	(9 889)	(27)	(990)
Quality assessment	3 789	76	290	6 210	72	449	2 421	(4)	159
Station maintenance	36 120	91	3 282	38 516	96	3 687	2 396	5	405
System performance & reliability	21 695	87	1 878	16 215	84	1 357	(5 480)	(3)	(521)
	187 305	83	15 633	192 785	81	15 701	5 480	(2)	68
Organizational Support	3 811	63	240	3 426	76	259	(385)	13	19
TOTAL	**553 143**	**74**	**41 003**	**592 837**	**71**	**42 282**	**39 694**	**(3)**	**1 279**

* No change reflected as hours charged were nil.

Activity charges for Customer Service & Corporate Relations expenditures were $1.2 million or 5% lower than forecast of $26.3 million, reflecting an overall reduction of 34,600 hours charged primarily in the customer & public relations, customer inspection, customer safety services and dispatch programs, as explained below.

Customer & public relations – the decrease in hours and charges is primarily due to less time spent on customer inquiries and service calls.

Customer inspections – the decrease in hours and charges is primarily due to vacancies, lower customer requests for appliance inspections and fewer customer calls for burner tip and conversion burner work.

Customer safety services – the lower than forecast hours and charges is primarily due to fewer customer odourant related inquiries than expected.

Dispatch – the lower than forecast hours and charges is primarily the result of a greater number of vacancies and lower than planned shift coverage required by staff due to Mobile Workforce Management synergies.

Activity charges for Operations and Maintenance expenditures were on target with the forecast of $15.7M; however, a reduction of 5,480 hours as compared to the forecast of 192,785 hours or 3% was experienced. Material hour variances have been explained below.

Distribution maintenance – the lower than forecast hours are due to a reduction in time spent on equipment maintenance and lower activities in gas distribution mains & services due to vacancies. This program fluctuates based on competing priorities for resources.

Metering – the lower than forecast hours is primarily due to less overtime required than expected.

Plant failures & emergencies – the increased hours is due to the TCPL pipeline explosion near Otterbourne, Manitoba.

Quality assessment – the lower than planned hours is primarily due to decreased staffing levels.

Station maintenance – the lower than planned hours is due to the deferral of non-critical work to focus on the SCADA system upgrade.

System performance & reliability – the increase in hours is primarily related to more work in design and technical support functions.

b) The table below provides a comparison of 2012/13 and 2013/14 actual activity hours, activity rates and activity charges and the change in the activity rate in the same format as PUB/CENTRA I-21f from the 2013/14 GRA.

CENTRA GAS MANITOBA INC.
COMPARISON OF ACTIVITY RATES

	2012/13 Actual			2013/14 Actual				
	Hours	Avg. Activity Rate ($)	Activity Charges ($000s)	Hours	Avg. Activity Rate ($)	Activity Charges ($000s)	Inc/(Dec) in Activity Rate	%
Customer Service & Corporate Relations								
Back/middle office services	3 127	79	246	2 792	83	233	4	5%
Billing & collections	110 267	49	5 435	117 524	53	6 185	4	8%
Customer & public relations	73 795	67	4 949	63 413	71	4 502	4	6%
Customer information systems (Banner)	10 209	78	793	10 268	84	865	6	7%
Customer inspections	87 191	76	6 601	87 896	80	7 057	4	5%
Customer safety services	14 364	84	1 209	15 507	87	1 357	3	3%
Dispatch	27 062	63	1 694	26 408	72	1 894	9	13%
Energy supply, planning & support	24 481	76	1 849	23 935	78	1 861	2	3%
Environment	572	88	50	758	92	70	4	4%
Meter reading	440	81	36	479	84	40	3	4%
Rate and regulatory affairs	11 724	77	900	13 048	82	1 066	5	6%
	363 234	64	23 762	362 027	69	25 130	5	7%
Operations and Maintenance								
Communication systems	1 058	87	92	1 942	83	161	(4)	-5%
Distribution maintenance	50 555	81	4 106	56 097	86	4 849	5	6%
Load forecast	2 142	71	153	1 835	72	132	1	1%
Metering	61 438	69	4 251	54 616	72	3 959	3	4%
Plant failures & emergencies	1 305	55	72	11 210	97	1 082	42	44%
Quality assessment	3 654	78	286	3 789	76	290	(2)	-3%
Station maintenance	38 808	92	3 568	36 120	91	3 282	(1)	-1%
System performance & reliability	16 699	81	1 361	21 695	87	1 878	6	7%
	175 658	79	13 888	187 305	83	15 633	4	5%
Organizational Support	3 413	63	215	3 811	63	240	-	0%
TOTAL	542 304	70	37 865	553 143	74	41 003	4	5%

As shown above, the overall change in average activity rate from 2012/13 to 2013/14 was $4/hour. The most notable increase was in the plant failures & emergencies program of $42/hour due to the TCPL pipeline explosion near Otterbourne, Manitoba which was not planned.

The table below provides a comparison of 2013/14 and 2014/15 actual activity hours, activity rates and activity charges and the change in the activity rate in the same format as PUB/CENTRA I-21f from the 2013/14 GRA.

CENTRA GAS MANITOBA INC.
COMPARISON OF ACTIVITY RATES

	2013/14 Actual			2014/15 Actual				
	Hours	Avg. Activity Rate ($)	Activity Charges ($000s)	Hours	Avg. Activity Rate ($)	Activity Charges ($000s)	Inc/(Dec) in Activity Rate	%
Customer Service & Corporate Relations								
Back/middle office services	2 792	83	233	3 117	75	235	(8)	-11%
Billing & collections	117 524	53	6 185	113 779	54	6 132	1	2%
Customer & public relations	63 413	71	4 502	58 003	72	4 202	1	1%
Customer information systems (Banner)	10 268	84	865	7 821	86	675	2	2%
Customer inspections	87 896	80	7 057	84 335	85	7 152	5	6%
Customer safety services	15 507	87	1 357	13 998	93	1 307	6	6%
Dispatch	26 408	72	1 894	27 369	68	1 870	(4)	-6%
Energy supply, planning & support	23 935	78	1 861	26 024	80	2 092	2	2%
Environment	758	92	70	911	102	93	10	10%
Meter reading	479	84	40	294	89	26	5	6%
Rate and regulatory affairs	13 048	82	1 066	7 935	82	653	-	0%
	362 027	69	25 130	343 585	71	24 437	2	3%
Operations and Maintenance								
Communication systems	1 942	83	161	2 486	87	215	4	5%
Distribution maintenance	56 097	86	4 849	58 912	89	5 239	3	3%
Load forecast	1 835	72	132	1 950	81	158	9	11%
Metering	54 616	72	3 959	57 492	82	4 717	10	12%
Plant failures & emergencies	11 210	97	1 082	3 860	57	218	(40)	-71%
Quality assessment	3 789	76	290	6 060	82	497	6	7%
Station maintenance	36 120	91	3 282	39 151	94	3 676	3	3%
System performance & reliability	21 695	87	1 878	22 387	93	2 072	6	6%
	187 305	83	15 633	192 298	87	16 792	4	5%
Organizational Support	3 811	63	240	3 908	83	323	20	24%
TOTAL	553 143	74	41 003	539 791	77	41 552	3	4%

The overall change in average activity rate from 2013/14 to 2014/15 was an increase of $3/hour. The most notable changes in the average activity rate was the decrease in the plant failures & emergencies program of $40/hour due to the TCPL pipeline explosion near Otterbourne, Manitoba which occurred in 2013/14 and the increase in Organizational support of $20/hour.

As discussed in Appendix 5.9 of Tab 5, the primary change made to the integrated cost allocation methodology following the implementation of IFRS was to improve transparency by removing common overhead as a percentage add-on to all gas programs. Unique organizational support programs were established with costs allocated to each using various natural gas cost drivers. For reporting consistency, the programs were restated back to 2011/12 to reflect the functional view created in

2015/16 with overhead removed from Customer Service & Corporate Relations and Operations and Maintenance programs and reflected in Organizational Support. However, the individual programs within organizational support were created effective 2015/16 and as such, a breakdown of the organizational support category is not available prior to 2015/16. No other changes impacting activity hours, rates or charges were made in the ICAM.

REFERENCE:

PUB/Centra I-30

QUESTION:

a) Please provide a comparison of the Actual activity rates for 2015/16 (IFRS) with 2014/15 (CGAAP).
b) For the five (5) greatest decreases in average activity rates as determined in (a), and provide a schedule which compares a breakdown of the cost components and explain the change.
c) Please provide a comparison of the average activity rates for 2017/18 Actual with that forecast for 2019/20.
d) For the ten (5) greatest increases and decreases in average activity rates as determined in (c), please provide a schedule which compares a breakdown of the cost components with narrative explaining the changes.

RESPONSE:

a) The table below provides a comparison of the average actual straight time activity rates by program for 2015/16 (IFRS) with 2014/15 (CGAAP).

CENTRA GAS MANITOBA INC.
STRAIGHT TIME ACTIVITY RATE COMPARISON

	Straight Time Average Activity Rate		
	2014/15	**2015/16**	**Inc/(Dec)**
Customer Service & Corporate Relations			
Back/middle office services	75	64	(11)
Billing & collections	54	55	1
Customer information systems (Banner)	86	85	(1)
Customer inspections	81	78	(3)
Customer safety services	80	77	(3)
Dispatch	66	67	1
Energy supply, planning & support	77	80	3
Environment	102	107	5
Meter reading	89	88	(1)
Rate and regulatory affairs	82	81	(1)
	69	69	-
Operations and Maintenance			
Communication systems	86	90	4
Distribution maintenance	86	84	(2)
Load forecast	81	85	4
Plant failures & emergencies	54	56	2
Quality assessment	82	83	1
Station maintenance	89	91	2
System performance & reliability	92	90	(2)
	85	84	(1)
Organizational Support*	82	81	(1)
TOTAL STRAIGHT TIME ACTIVITY RATES	75	75	-

* Individual programs within Organizational Support were created effective 2015/16 and are not available for 2014/15.

The table below provides a comparison of the average actual overtime activity rates by program for 2015/16 (IFRS) with 2014/15 (CGAAP).

CENTRA GAS MANITOBA INC.
OVERTIME ACTIVITY RATE COMPARISON

	Overtime Average Activity Rate		
	2014/15	**2015/16**	**Inc/(Dec)**
Customer Service & Corporate Relations			
Billing & collections	96	95	(1)
Customer & public relations	108	106	(2)
Customer information systems (Banner)	132	130	(2)
Customer inspections	132	130	(2)
Customer safety services	143	137	(6)
Dispatch	103	104	1
Energy supply, planning & support	142	112	(30)
Meter reading	132	-	-*
	130	126	(4)
Operations and Maintenance			
Communication systems	137	139	2
Distribution maintenance	126	123	(3)
Load forecast	174	-	-*
Metering	123	105	(18)
Plant failures & emergencies	105	115	10
Quality assessment	129	-	-*
Station maintenance	143	148	5
System performance & reliability	138	132	(6)
	132	134	2
Organizational Support**	121	127	6
TOTAL OVERTIME ACTIVITY RATES	131	129	(2)

* No change reflected as hours charged were nil or ≤3.

** Individual programs within Organizational Support were created effective 2015/16 and are not available for 2014/15.

b) As shown in the tables in part a) above, the overall average straight time activity rate remained unchanged at $75/hour and the overall average overtime activity rate declined by only $2/hour or 1.5% from $131 to $129.

The majority of programs include labour from numerous work groups (in some programs, the work groups involved are close to 50), each with their own activity rate.

As discussed in the ICAM presentation in Appendix 5.9, each activity rate is comprised of wages, salaries and benefits, motor vehicles, small tools, safety clothing and travel.

The total costs of the work group are divided by the capacity hours of the workgroup (available hours to work less hours such as vacation and sick time not specific to a job) to derive the activity rate. Each employee working on a function within the program timecards their hours worked and the system posts an activity charge calculated as hours x activity rate. A change in either the cost component or the capacity hours of the work group can have an impact on the activity rate. As such, given the extensive work effort required to provide a breakdown of the component changes in activity rates for each work group within each program, Centra is unable to provide this breakdown within the time frame of the current proceeding.

c) The following table provides a comparison of the average actual straight time activity rates by program for 2017/18 with that forecast for 2019/20.

CENTRA GAS MANITOBA INC.
STRAIGHT TIME ACTIVITY RATE COMPARISON

	Straight Time Average Activity Rate		
	2017/18 Actual	**2019/20 Forecast**	**Inc/Dec)**
Customer Service & Corporate Relations			
Back/middle office services	92	93	1
Billing & collections	57	57	-
Customer & public relations	76	78	2
Customer information systems (Banner)	86	83	(3)
Customer inspections	81	74	(7)
Customer safety services	80	73	(7)
Dispatch	76	93	17
Energy supply, planning & support	84	98	14
Environment	103	111	8
Meter reading	93	79	(14)
Rate and regulatory affairs	101	100	(1)
	73	74	1
Operations and Maintenance			
Communication systems	85	88	3
Distribution maintenance	88	75	(13)
Load forecast	81	89	8
Metering	92	75	(17)
Plant failures & emergencies	60	59	(1)
Quality assessment	90	97	7
Station maintenance	97	90	(7)
System performance & reliability	96	94	(2)
	91	82	(9)
Organizational Support			
Corporate governance	89	99	10
Corporate infrastructure	86	87	1
Corporate services	91	117	26
Departmental support	85	85	-
	85	87	2
TOTAL STRAIGHT TIME ACTIVITY RATES	80	78	(2)

The following table provides a comparison of the average actual overtime activity rates by program for 2017/18 with that forecast for 2019/20.

CENTRA GAS MANITOBA INC.
OVERTIME ACTIVITY RATE COMPARISON

	Overtime Average Activity Rate		
	2017/18 Actual	**2019/20 Forecast**	**Inc/Dec)**
Customer Service & Corporate Relations			
Billing & collections	90	85	(5)
Customer & public relations	103	127	24
Customer information systems (Banner)	136	115	(21)
Customer inspections	135	124	(11)
Customer safety services	141	133	(8)
Dispatch	116	139	23
Energy supply, planning & support	112	168	56
Environment	143	-	-*
Meter reading	-	119	-*
	129	131	2
Operations and Maintenance			
Communication systems	155	147	(8)
Distribution maintenance	135	118	(17)
Metering	-	124	124
Plant failures & emergencies	151	128	(23)
Quality assessment	144	191	47
Station maintenance	156	150	(6)
System performance & reliability	140	86	(54)
	145	130	(15)
Organizational Support			
Corporate governance	143	162	19
Corporate infrastructure	131	137	6
Corporate services	147	161	14
Departmental support	142	130	(12)
	136	134	(2)
TOTAL OVERTIME ACTIVITY RATES	135	131	(4)

* No change reflected as hours charged/planned are nil or ≤3.

d) As shown in the tables in part c) above, the overall average straight time activity rate decreased by only \$2/hour or 3% from \$80 to \$78 and the overall average overtime activity rate declined by only \$4/hour or 3% from \$135 to \$131. Please see the response in part b) above with respect to the component change.

REFERENCE:

PUB/Centra I-31 a) & b)

QUESTION:

Please file the EBO study demonstrating how the external billable overhead percentage was determined in 2014/15 and 2015/16.

RESPONSE:

Please see the attachment to this response for the 2014/15 and 2015/16 approved Benefit and Overhead Rate recommendations, including the related supporting documentation for the external billing overhead percentage of 28% in 2014/15 and 48% in 2015/16 As noted in PUB/Centra I-31 a) & b) and in the 2015/16 approved rate recommendation, the 2015/16 external billing overhead percentage was based on 2014/15 data as a detailed review of the external billing overhead study was underway during the 2015/16 fiscal year.

2014/15 BENEFIT AND OVERHEAD RATE RECOMMENDATION

SUBJECT:

Corporate Overhead, Material and Employee Benefit Rates.

RECOMMENDATION:

That the following revision to Employee Benefit Rates be approved effective April 1, 2014:

	Approved	Proposed
Employee Benefit Rates:		
Straight-Time	34%	35%
Overtime	3%	3%

Previously approved overhead rates will remain in effect for 2014/15.

	Proposed
Corporate Overhead:	
Common	20%
Tool & Procurement	5%
Third Party Billing	28%
Material Overhead:	
General Material	11%
Serialized Equipment	4%

BACKGROUND:

Overhead studies are performed annually to calculate overhead and benefit rates. Previous year actual results are used in forecasting expected rates. The calculations also consider upcoming accounting changes and Manitoba Hydro internal policies. The rates are tested throughout the fiscal year to ensure reasonability, which may result in changes to the recommendations.

JUSTIFICATION:

The 2014/15 recommended rates ensure that an appropriate amount of overhead, employee benefits and material handling costs are charged to the income and capital assets of each utility.

Please refer to Appendix A for further details of recommended Employee Benefit Rates. Appendices B and C provide further details to support the overhead rates.

Approved By:

Darren Rainkie – VP Finance & Regulatory

Bryan Luce – VP HR & Corporate Services

Appendix B

Common Overhead, Tool & Procurement and Third Party Billing Rate Calculations

Tools & Procurement Rate – A Tools & Procurement rate of 5% will be charged to capital networks and operating orders. This rate recovers costs of small tools, such as personal computers and costs associated with the procurement process. These costs were previously charged through activity or overhead rates and will be recovered as a percentage add-on to activity charges.

Common Overhead Rate – The common overhead rate recovers corporate services and departmental support costs, such as HR and IT that are required by the corporation to support its various activities. These costs were previously charged through activity or overhead rates and will be recovered as a percentage add-on to activity charges.

Third Party Billing Overhead – General and administrative costs are required by the corporation to support its various activities. Although these costs will no longer be allocated to capital networks and operating orders through activity or general overhead rates, they should be continued to be applied to third party billings for cost recovery purposes.

Description	2014/15 Tool & Procurement (millions)	2014/15 Common Overhead (millions)	2014/15 3rd Party Billing Add-On (millions)
Corporate Governance: - Executive, general counsel, corporate accounting	0	0	36
Corporate Infrastructure: - Buildings, IT & communication infrastructure (operating, finance expense, depreciation and property taxes)	0	0	139
Corporate Services: - Finance, HR, Safety	0	29	0
Departmental Support: - Division & Department Managers, administrative staff, training	0	100	0
Tools & Procurement: - Technical design and mapping software, PC's, accounts payable, purchasing & moves.	29	0	0
Total Expenses	29	129	175
Total Activity	632	632	632
Projected Rate 2013/14	**5%**	**20%**	**28%**

2015/16 BENEFIT AND OVERHEAD RATE RECOMMENDATION

SUBJECT:

Corporate Overhead, Material and Employee Benefit Rates.

RECOMMENDATION:

That the following Corporate Overhead, Material, and Employee Benefit Rates be approved effective April 1, 2015:

	Approved	Proposed
Employee Benefit Rates:		
Straight-Time	35%	35%
Overtime	3%	3%
Corporate Overheads:		
Common	20%	n/a
Tool & Procurement*	5%	5%
External Billing	28%	48%
Material Overheads:		
General Material	11%	10%
Serialized Equipment	4%	4%

* ***Effective fiscal 2015-16 the tool & procurement rate is ONLY applied on capital networks.***

BACKGROUND:

Overhead studies are performed annually to calculate overhead and benefit rates. Previous year actual results are used in forecasting expected rates. The calculations also consider upcoming accounting changes and Manitoba Hydro internal policies. The rates are tested throughout the fiscal year to ensure reasonability, which may result in changes to the recommendations.

JUSTIFICATION:

The 2015/16 recommended rates ensure that an appropriate amount of overhead, employee benefits and material handling costs are charged to the income and capital assets of each utility.

Please refer to Appendix A for further details regarding the recommended employee benefit rate. Appendices B and C provide further details to support the recommended overhead rates.

Approved By:

Darren Rainkie – VP Finance & Regulatory

Bryan Luce – VP HR & Corporate Services

3) **External Billing Overhead Rate:**

General and administrative costs are required by the corporation to support its various activities. Although these costs will no longer be allocated to capital networks and operating orders through activity charges or common overhead rates, they should continue to be applied to external party billings for cost recovery purposes.

Based on the annual external billing overhead study, the rate for 2015/16 was projected to be 40%. The increase over 2014/15 was largely due to the elimination of corporate services and departmental support costs that can no longer be recovered through the common overhead rate and charged to capital projects.

However, a detailed review is currently being performed on the external billing overhead study, including an evaluation of what other Canadian utilities include in equivalent rates. As this study is still in progress, it is recommended to hold the rate at 28%, based upon the 2014/15 study and add the costs removed from the common overhead rate at a further 20%.

A rate of 48% is therefore recommended for the external billing overhead for 2015/16. It is noted that the 5% Tools & Procurement rate is also applied to all external billings.

Description	2014/15 External Billing Overhead (millions)	2015/16 External Billing Overhead (millions)
Corporate Governance: - Executive, general counsel, corporate accounting	36	33
Corporate Infrastructure: - Buildings, IT & communication infrastructure (operating, finance expense, depreciation and property taxes)	139	122
Corporate Services: - Finance, HR, Safety	0	24
Departmental Support: - Division & Department Managers, administrative staff, training	0	93
Total Expenses	175	272
Total Activity	632	658
Rate	**28%**	**40%***

* Rate is rounded to the nearest 5 %

REFERENCE:

PUB/Centra I-33 a)

QUESTION:

a) Please file the analysis that supports the number of customers allocated to Centra for each of the years 2013/14 to 2019/20.
b) Please provide the analysis that supports the Corporate Asset Driver for each of the years 2013/14 through 2019/20 and provide the detail of total costs allocated to Gas vs. Electric operations on this basis.
c) Please provide the analysis that supports the Corporate Activity Charge driver for each of the years 2013/14 through 2019/20 and provide the detail of total costs allocated to Gas vs. Electric operations allocated on this basis.
d) Please provide a table listing the Management estimate cost drivers employed In each case indicate the amount of costs allocated to Gas vs. Electric operations for each of the drivers for the years 2013/14 through 2019/20.
e) Please include detailed calculation for the top five management cost drivers from the list in (d) (in terms of dollars allocated based on the driver) with a descriptive narrative.
f) Please file a copy of all studies prepared for 2019/20 and that were prepared in support of costs allocated to Centra for 2013/14 approved and comment on any changes to allocators.

RESPONSE:

By email on June 2, 2019, PUB Counsel advised that it was acceptable to the Public Utilities Board for this response to be prepared from 2015/16 forward, corresponding with the transition to IFRS.

a) The following table provides the information that supports the Number of Customers driver from 2015/16 through 2019/20. Number of Customers for 2019/20 remains consistent with 2018/19.

	2015/16		2016/17		2017/18		2018/19		2019/20	
Number of Customers	#	%	#	%	#	%	#	%	#	%
Electric	557,041	67%	565,442	67%	572,218	67%	[redacted]			
Gas	272,659	33%	275,888	33%	278,617	33%	[redacted]			
Total	829,700	100%	841,330	100%	850,835	100%	[redacted]			

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The following tables provide the breakdown of costs allocated by the Number of Customers driver for O&A and Finance Depreciation & Taxes ("FD&T") from 2015/16 through 2019/20.

	O&A - Number of Customers				
($millions)	**Actuals 2015/16**	**Actuals 2016/17**	**Actuals 2017/18**	**Forecast 2018/19**	**Test Year 2019/20**
O&A Costs Allocated by Driver	**18.3**	**17.5**	**17.6**	**17.3**	**17.6**
Less: Allocated to Centra	**6.1**	**5.8**	**5.8**	**5.7**	**5.8**
Billing & collections	4.7	4.4	4.4	4.2	4.3
Customer & public relations	0.3	0.3	0.3	0.4	0.4
Customer Information Systems (Banner)	0.4	0.5	0.6	0.5	0.5
Customer Service & Corporate Relations	*5.4*	*5.1*	*5.2*	*5.1*	*5.2*
Load Forecast	0.1	0.1	0.0	0.0	0.0
Operations & Maintenance	*0.1*	*0.1*	*0.0*	*0.0*	*0.0*
Corporate Governance	0.6	0.6	0.5	0.5	0.6
Organizational Support	*0.6*	*0.6*	*0.5*	*0.5*	*0.6*
Balance remaining in Electric	**12.3**	**11.8**	**11.8**	**11.6**	**11.8**
Gas % Allocation	33%	33%	33%	33%	33%

($millions)	**FD&T - Number of Customers**				
	Actuals 2015/16	Actuals 2016/17	Actuals 2017/18	Forecast 2018/19	Test Year 2019/20
FD&T Costs Allocated by Driver	**1.9**	**1.8**	**1.8**	**1.7**	**1.6**
Less: Allocated to Centra	**0.6**	**0.6**	**0.6**	**0.6**	**0.5**
Finance	0.1	0.0	(0.0)	(0.0)	(0.1)
Depreciation	0.6	0.6	0.6	0.6	0.6
Balance remaining in Electric	**1.3**	**1.2**	**1.2**	**1.1**	**1.1**
Gas % Allocation	33%	33%	33%	33%	33%

b) The following table provides the details for the Corporate Assets driver from 2015/16 through 2019/20. The asset values declined in 2017/18 reflecting the move to a 5 year average calculation of corporate assets as compared to an annual value. Corporate Assets for 2019/20 remains consistent with 2018/19.

	2015/16		2016/17		2017/18		2018/19		2019/20	
Corporate Assets	$ (millions)	%	$ (millions)	%	$ (millions)	%	$ (millions)	%	$ (millions)	%
Electric	15,781	96%	19,150	96%	17,151	96%	19,025	96%	19,025	96%
Gas	678	4%	703	4%	681	4%	709	4%	709	4%
Total	16,459	100%	19,854	100%	17,832	100%	19,734	100%	19,734	100%

The table below provides a breakdown of costs allocated by the Corporate Assets driver for O&A. There are no costs in FD&T allocated using the Corporate Assets driver from 2015/16 through 2019/20.

	O&A - Corporate Assets				
($millions)	Actuals 2015/16	Actuals 2016/17	Actuals 2017/18	Forecast 2018/19	Test Year 2019/20
O&A Costs Allocated by Driver	45.1	41.1	35.8	33.2	33.9
Less: Allocated to Centra	1.8	1.6	1.4	1.3	1.3
Customer & public relations	0.1	0.1	0.1	0.1	0.1
Customer Service & Corporate Relations	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*
Corporate Governance	1.4	1.3	1.0	0.9	0.9
Corporate Services	0.3	0.2	0.3	0.3	0.3
Organizational Support	*1.7*	*1.5*	*1.3*	*1.2*	*1.3*
Balance remaining in Electric	43.3	39.5	34.3	31.9	32.5
Gas % Allocation	4%	4%	4%	4%	4%

c) The table below provides the details for the Corporate Activity Charges driver from 2015/16 through 2019/20. Corporate Activity Charges for 2019/20 remains consistent with 2018/19.

	2015/16		2016/17		2017/18		2018/19		2019/20	
Corporate Activity Charges	$ (millions)	%	$ (millions)	%	$ (millions)	%	$ (millions)	%	$ (millions)	%
Electric	557	91%	578	92%	600	92%	585	92%	585	92%
Gas	53	9%	50	8%	50	8%	51	8%	51	8%
Total	610	100%	628	100%	650	100%	636	100%	636	100%

The following tables provide a breakdown of costs allocated by the Corporate Activity Charges driver for O&A and FD&T from 2015/16 through 2019/20.

	O&A - Corporate Activity Charges				
($millions)	**Actuals 2015/16**	**Actuals 2016/17**	**Actuals 2017/18**	**Forecast 2018/19**	**Test Year 2019/20**
O&A Costs Allocated by Driver	**95.2**	**99.0**	**95.4**	**90.8**	**92.6**
Less: Allocated to Centra	**8.3**	**7.6**	**7.5**	**6.8**	**7.0**
Environment	0.1	0.0	0.0	0.0	0.0
Dispatch	0.0	0.1	0.1	0.0	0.0
Customer Safety Services	0.0	0.1	0.0	0.0	0.0
Customer Service & Corporate Relations	*0.2*	*0.2*	*0.1*	*0.1*	*0.1*
Corporate Infrastructure	5.4	4.7	4.8	4.5	4.6
Corporate Services	2.2	2.0	1.9	1.7	1.7
Departmental Support	0.9	0.8	0.7	0.8	0.8
Organizational Support	*8.5*	*7.5*	*7.4*	*7.0*	*7.1*
Other	(0.4)	(0.1)	(0.1)	(0.2)	(0.2)
Balance remaining in Electric	**86.9**	**91.4**	**87.9**	**83.9**	**85.6**
Gas % Allocation	9%	8%	8%	8%	8%

($millions)	**FD&T - Corporate Activity Charges**				
	Actuals 2015/16	Actuals 2016/17	Actuals 2017/18	Forecast 2018/19	Test Year 2019/20
FD&T Costs Allocated by Driver	**81.9**	**84.4**	**83.8**	**86.0**	**83.7**
Less: Allocated to Centra	**7.1**	**6.5**	**6.4**	**6.6**	**6.4**
Finance	3.3	2.9	2.8	2.7	2.5
Depreciation	3.1	2.8	2.9	3.2	3.2
Taxes Property & Payroll	0.7	0.8	0.7	0.8	0.8
Balance remaining in Electric	**74.8**	**77.9**	**77.4**	**79.4**	**77.3**
Gas % Allocation	9%	8%	8%	8%	8%

d) The following tables provide a breakdown of costs allocated by the Management Estimate cost drivers for O&A and FD&T from 2015/16 through 2019/20.

($millions)	O&A - Management Estimates				
	Actuals 2015/16	Actuals 2016/17	Actuals 2017/18	Forecast 2018/19	Test Year 2019/20
O&A Costs Allocated by Driver	**49.9**	**53.4**	**51.1**	**47.4**	**48.3**
Less: Allocated to Centra	**12.5**	**13.1**	**12.4**	**11.5**	**11.7**
Billing & collections	1.9	1.8	1.7	1.6	1.6
Customer & public relations	0.9	0.7	0.8	0.4	0.5
Customer Inspections	2.2	2.4	2.5	2.3	2.4
Rate and regulatory affairs	0.1	0.2	0.1	0.1	0.1
Customer Service & Corporate Relations	*5.1*	*5.0*	*5.1*	*4.4*	*4.5*
Plant Failures & Emergencies	0.0	0.0	0.1	0.0	0.0
Operations & Maintenance	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*
Corporate Governance	0.4	0.4	0.4	0.4	0.4
Departmental Support	4.3	5.1	5.0	4.9	5.0
Operational Management	2.7	2.5	1.8	1.8	1.8
Organizational Support	*7.3*	*8.0*	*7.2*	*7.0*	*7.2*
Balance remaining in Electric	**37.4**	**40.3**	**38.7**	**35.9**	**36.6**
Gas % Allocation	25%	25%	24%	24%	24%

($millions)	FD&T - Management Estimates				
	Actuals 2015/16	Actuals 2016/17	Actuals 2017/18	Forecast 2018/19	Test Year 2019/20
FD&T Costs Allocated by Driver	**0.2**	**0.1**	**0.1**	**0.1**	**0.1**
Less: Allocated to Centra	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**
Depreciation	0.1	0.0	0.0	0.0	0.0
Balance remaining in Electric	**0.1**	**0.1**	**0.1**	**0.1**	**0.0**
Gas % Allocation	27%	24%	25%	27%	32%

e) The following table provides a breakdown of costs for the top five management cost drivers from 2015/16 through 2019/20, followed by a description of each estimate.

	Top 5 Management Estimates				
($)millions	Actuals 2015/16	Actuals 2016/17	Actuals 2017/18	Forecast 2018/19	Test Year 2019/20
Marketing & Customer Service Activity Charges	6.9	7.6	6.8	6.7	6.8
Relative % of Time	2.7	2.9	3.1	2.7	2.7
Customer Counts	2.0	1.9	1.8	1.5	1.5
DSM electric/gas savings from Power Smart Plan	0.5	0.4	0.3	0.3	0.3
Comprehensive General Liability Risk Exposures	0.3	0.3	0.3	0.3	0.3

Marketing & Customer Service ("M&CS") Activity Charges - Represents the total activity charges of the M&CS organizational unit, of which 20% is allocated to Gas. Training and administrative time for M&CS staff are allocated using this driver.

Relative % of Time - This driver is based upon the relative estimate of time required to perform the task. The majority of the costs allocated are for line locates which are allocated 50% to Gas and 50% to Electric.

Customer Counts - This driver is based on the number of customers per customer service centre. The allocation to gas will vary from 4% to 44% by area. For example, customer service operations work required for disconnect/reconnects use this driver.

DSM electric/gas savings from Power Smart Plan – This driver is based on the ratio of gas vs electric DSM program savings, of which 20% is currently allocated to gas for operational costs associated with DSM/Efficiency Manitoba programs.

Comprehensive General Liability Risk Exposures – Insurance costs are based on the exposures and risk associated with the insurance requirements of each utility, 55% is allocated to gas (see response PUB/CENTRA II-16d for additional information).

The following table provides the detail in support of costs allocated to Centra for 2013/14 Approved and the 2019/20 Test Year.

	2013/14		2019/20	
Number of Customers	#	%	#	%
Electric	545,807	67%	578,697	[redacted]
Gas	268,607	33%	[redacted]	
Total	814,414	100%		

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	2013/14		2019/20	
Corporate Assets	$ (millions)	%	$ (millions)	%
Electric	14,234	96%	19,025	96%
Gas	593	4%	709	4%
Total	14,827	100%	19,734	100%

	2013/14		2019/20	
Corporate Activity Charges	$ (millions)	%	$ (millions)	%
Electric	496	91%	585	92%
Gas	49	9%	51	8%
Total	545	100%	636	100%

	2013/14		2019/20	
Corporate Restructuring Driver	$ (millions)	%	$ (millions)	%
Electric			569	94%
Gas			33	6%
Total	N/A		602	100%

f) The Number of Customers and Corporate Assets drivers have remained constant from 2013/14 through to 2019/20. The Corporate Activity Charges driver dropped from a 9% allocation to Gas to 8% as a result of the percentage of activity charges to the Natural Gas segment declining overall in relation to the total activity charges. As discussed in PUB/CENTRA I-28c, the Restructuring driver was introduced to allocate restructuring expenditures associated with the Voluntary Departure Program.

REFERENCE:

PUB/Centra I-37 b) & c)

QUESTION:

a) Please confirm that the changes made to the currently approved ICAM were limited to the allocation of Common Overheads which are now allocated to Centra through organizational support programs.
b) Please indicate how much in corporate overhead costs were allocated via a percentage add on in 2013/14 and compare with the total costs now allocated through organizational support programs for 2019/20.
c) Please file a copy of the Overhead Study Report mentioned at the ICAM techanical conference, which compared the new common overhead allocation to the previously Board approved ICAM.

RESPONSE:

a) Confirmed. As discussed in Appendix 5.9, the primary change made in the ICAM following the implementation of IFRS was to remove common overhead as a percentage add-on to gas programs and create unique organization support programs using various natural gas cost drivers to allocate the costs.

b) In 2013/14, $17.2 million (see Appendix 5.9, p.7) of organizational support costs, which are primarily corporate overhead, were allocated to Centra via a percentage add-on and various cost drivers; in 2019/20, $16.4 million (see Appendix 5.9, p.10) of organizational support costs were allocated using various cost drivers. Please note that the 2013/14 CGAAP overhead costs are not comparable to the 2019/20 IFRS overhead costs as 2019/20 also includes administrative (overhead) costs no longer eligible for capitalization.

c) The tables below are a copy of the analysis showing the simulated 2015/16 common overhead rate calculation and allocation of overhead as a percent add-on to activity charges:

Simulated Common Overhead Rate Calculation

Description	2015/16 Common Overhead (millions)
Corporate Services: - Finance, HR, Safety	24
Departmental Support: - Division & Department Managers, administrative staff, training	93
Total Expenses*	117
Total Activity	658
Simulated Common Overhead Rate	**18%**

*2015/16 Benefit & Overhead Recommendation PUB/CENTRA II-22, EBO table

Simulated Common Overhead Allocated as % Add-On to Activity	2015/16
Simulated Common Overhead Rate (from above)	18%
Actual Gas Activity Charges ($ millions)	54.1
Simulated Common Overhead % Add-On ($ millions)	9.7

The table below provides a summary of the actual overhead allocated to Centra using the new allocation discussed in the ICAM, with a comparison to simulated results shown in the tables above. As shown, the minor difference between the simulation and the current allocation methodology is shown below (rounded) and demonstrates there is no significant change with the new methodology.

Actual Common Overhead Allocated to Programs using Cost Drivers ($ millions)	2015/16
Corporate Services	2.2
Departmental Support	5.0
Operational Management	2.7
Actual Program Costs	9.9
Simulated Common Overhead % Add-On (from above)	9.7
Difference	(0.1)

REFERENCE:

PUB/Centra I-45

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide an update to the schedule based on the updated interest rate forecast for both short and long term interest rates with the rebuttal evidence to be filed in August.

b) File an table reflecting the updated interest rate forecasts and the assumed interest rate for debt to be issued during each year of the forecast and the weighted average interest rate in each of those years.

RESPONSE:

a) The following table provides the forecast finance expense details for the budget year updated for the summer 2019 interest rate forecast and all actual long term debt activity up to July 24, 2019. All other forecast assumptions have remained unchanged.

CENTRA GAS MANITOBA INC.
Finance Expense - Budget Scenario with Summer 2019 Rates
($000'S)

	2019/20 Forecast
Interest on Long Term Debt/Advances	15,261
Provincial Guarantee Fee on Long Term Debt	3,899
Amortization of Debt Discounts	-
Interest on Short Term Debt	693
Provincial Guarantee Fee on Short Term Debt	213
Interest on Common Assets	1,220
Interest on Inventory	125
Interest Capitalized	(237)
Carrying Costs on Furnace Replacement Program	716
Other	-
Total Finance Expense	21,890

The following table provides the forecast finance expense details for a 9 year period for the CGM18 scenario based updated for the summer 2019 interest rate forecast and all actual long term debt activity to July 24, 2019. All other forecast assumptions have remained unchanged.

CENTRA GAS MANITOBA INC.
Finance Expense - CGM18 Scenario with Summer 2019 Rates
($000'S)

	2019/20 Forecast	2020/21 Forecast	2021/22 Forecast	2022/23 Forecast	2023/24 Forecast	2024/25 Forecast	2025/26 Forecast	2026/27 Forecast	2027/28 Forecast
Interest on Long Term Debt/Advances	15,961	16,826	18,060	17,940	18,971	19,692	19,317	20,842	21,306
Provincial Guarantee Fee on Long Term Debt	4,099	4,399	4,799	4,899	5,099	5,199	5,299	5,449	5,649
Amortization of Debt Discounts	-	-	-	-	-	-	-	-	-
Interest on Short Term Debt	747	732	667	1,072	883	895	1,591	980	938
Provincial Guarantee Fee on Short Term Debt	240	249	206	261	207	255	300	286	208
Interest on Common Assets	1,220	1,000	1,050	1,104	1,160	1,211	1,263	1,317	1,371
Interest on Inventory	125	128	130	133	136	138	141	144	146
Interest Capitalized	(237)	(251)	(132)	(35)	(35)	(36)	(37)	(37)	(38)
Carrying Costs on Furnace Replacement Program	716	708	194	146	104	64	25	2	1
Other	-	-	-	-	-	-	-	-	-
Total Finance Expense	22,871	23,791	24,974	25,520	26,525	27,418	27,899	28,983	29,581
Year over year $ change		920	1,183	546	1,005	893	481	1,084	598
Year over year % change		4.0%	5.0%	2.2%	3.9%	3.4%	1.8%	3.9%	2.1%

b) The following tables provide the updated interest rate forecast beginning in 2019/20, the assumed interest rate for debt to be issued during each forecast year and the forecasted weighted average interest rate of the portfolio for the budget year scenario with the summer 2019 interest rate forecast and all actual long term debt activity to July 24, 2019. All other forecast assumptions have remained unchanged.

BUDGET SCENARIO WITH SUMMER 2019 RATES

INTEREST RATE FORECAST
The rates on debt shown below do not include the 1.00% Provincial Guarantee Fee

	2019/20
CAN T-Bill Rate (Short Term Debt)	1.65%
CAN BA Rate	2.00%
New CAN Floating (BA + 0.50%)	2.50%
CAN Long Term Debt	2.70%

NEW LONG TERM DEBT ISSUED IN FISCAL YEAR

	Type	**Issue Date**	**Maturity Date**	**Principal Value**	**Rate**
2019/20					
New Long Term Debt Issue	Floating	3/31/2020	3/31/2040	$20,000,000.00	2.50%
New Long Term Debt Issue	Fixed	3/31/2020	3/31/2040	$20,000,000.00	2.70%

WEIGHTED AVERAGE INTEREST RATE OF DEBT PORTFOLIO

	Average Debt (millions)	Weighted Average Interest Rate (%)	Interest Expense (thousands)
2019/20			
Interest on Long Term Debt	$391	3.90	15,261
Provincial Guarantee Fee - LTD			3,899
Interest on Short Term Debt	$42	1.65	$693
Provincial Guarantee Fee - STD			$213
Total Debt, Interest & WAIR	$433	4.63	$20,066

The following tables provide the updated interest rate forecast beginning in 2019/20, the assumed interest rate for debt to be issued during each forecast year and the forecasted weighted average interest rate of the portfolio for a 9 year period for the CGM18 scenario with the summer 2019 interest rate forecast and all actual long term debt activity to July 24, 2019. All other forecast assumptions have remained unchanged.

CGM18 SCENARIO WITH SUMMER 2019 RATES

INTEREST RATE FORECAST
The rates on debt shown below do not include the 1.00% Provincial Guarantee Fee

	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26 & on
CAN T-Bill Rate (Short Term Debt)	1.65%	1.75%	1.85%	1.90%	2.00%	2.15%	2.20%
CAN BA Rate	2.00%	2.10%	2.20%	2.25%	2.35%	2.50%	2.55%
New CAN Floating (BA + 0.50%)	2.50%	2.60%	2.70%	2.75%	2.85%	3.00%	3.05%
CAN Long Term Debt	2.70%	3.05%	3.30%	3.35%	3.45%	3.35%	3.35%

NEW LONG TERM DEBT ISSUED IN FISCAL YEAR

	Type	Issue Date	Maturity Date	Principal Value	Rate
2019/20					
New Long Term Debt Issue	Floating	3/31/2020	3/31/2040	$20,000,000.00	2.50%
New Long Term Debt Issue	Fixed	3/31/2020	3/31/2040	$20,000,000.00	2.70%
2020/21					
New Long Term Debt Issue	Floating	3/31/2021	3/31/2041	$10,000,000.00	2.60%
New Long Term Debt Issue	Fixed	3/31/2021	3/31/2041	$30,000,000.00	3.05%
2021/22					
New Long Term Debt Issue	Fixed	3/31/2022	3/31/2042	$10,000,000.00	3.30%
2022/23					
New Long Term Debt Issue	Floating	3/31/2023	3/31/2043	$20,000,000.00	2.75%
New Long Term Debt Issue	Fixed	3/31/2023	3/31/2043	$40,000,000.00	3.35%
2023/24					
New Long Term Debt Issue	Fixed	3/31/2024	3/31/2044	$20,000,000.00	3.45%
2024/25					
New Long Term Debt Issue	Fixed	3/31/2025	3/31/2045	$10,000,000.00	3.35%
2025/26					
New Long Term Debt Issue	Fixed	3/31/2026	3/31/2046	$50,000,000.00	3.35%
2026/27					
New Long Term Debt Issue	Floating	3/31/2027	3/31/2047	$10,000,000.00	3.05%
New Long Term Debt Issue	Fixed	3/31/2027	3/31/2047	$10,000,000.00	3.35%
2027/28					
New Long Term Debt Issue	Floating	3/31/2028	3/31/2048	$10,000,000.00	3.05%
New Long Term Debt Issue	Fixed	3/31/2028	3/31/2048	$10,000,000.00	3.35%

WEIGHTED AVERAGE INTEREST RATE OF DEBT PORTFOLIO

	Average Debt (millions)	Weighted Average Interest Rate (%)	Interest Expense (thousands)
2019/20			
Interest on Long Term Debt	$411	3.88	$15,961
Provincial Guarantee Fee - LTD			$4,099
Interest on Short Term Debt	$45	1.65	$747
Provincial Guarantee Fee - STD			$240
Total Debt, Interest & WAIR	$457	4.61	$21,047
2020/21			
Interest on Long Term Debt	$440	3.82	$16,826
Provincial Guarantee Fee - LTD			$4,399
Interest on Short Term Debt	$42	1.75	$732
Provincial Guarantee Fee - STD			$249
Total Debt, Interest & WAIR	$482	4.61	$22,206
2021/22			
Interest on Long Term Debt	$480	3.76	$18,060
Provincial Guarantee Fee - LTD			$4,799
Interest on Short Term Debt	$36	1.85	$667
Provincial Guarantee Fee - STD			$206
Total Debt, Interest & WAIR	$516	4.60	$23,732
2022/23			
Interest on Long Term Debt	$474	3.79	$17,940
Provincial Guarantee Fee - LTD			$4,899
Interest on Short Term Debt	$56	1.90	$1,072
Provincial Guarantee Fee - STD			$261
Total Debt, Interest & WAIR	$530	4.56	$24,172
2023/24			
Interest on Long Term Debt	$503	3.77	$18,971
Provincial Guarantee Fee - LTD			$5,099
Interest on Short Term Debt	$44	2.00	$883
Provincial Guarantee Fee - STD			$207
Total Debt, Interest & WAIR	$547	4.60	$25,160
2024/25			
Interest on Long Term Debt	$520	3.79	$19,692
Provincial Guarantee Fee - LTD			$5,199
Interest on Short Term Debt	$42	2.15	$895
Provincial Guarantee Fee - STD			$255
Total Debt, Interest & WAIR	$562	4.64	$26,041
2025/26			
Interest on Long Term Debt	$501	3.86	$19,317
Provincial Guarantee Fee - LTD			$5,299
Interest on Short Term Debt	$72	2.20	$1,591
Provincial Guarantee Fee - STD			$300
Total Debt, Interest & WAIR	$573	4.62	$26,507
2026/27			
Interest on Long Term Debt	$545	3.82	$20,842
Provincial Guarantee Fee - LTD			$5,449
Interest on Short Term Debt	$45	2.20	$980
Provincial Guarantee Fee - STD			$286
Total Debt, Interest & WAIR	$590	4.67	$27,557
2027/28			
Interest on Long Term Debt	$560	3.80	$21,306
Provincial Guarantee Fee - LTD			$5,649
Interest on Short Term Debt	$43	2.20	$938
Provincial Guarantee Fee - STD			$208
Total Debt, Interest & WAIR	$603	4.66	$28,101

REFERENCE:

PUB/Centra I-46

QUESTION:

Please provide the bad debt expense and receivable write offs for the last five fiscal years.

RESPONSE:

The following table provides bad debt expense and uncollectable accounts written off for 2014 to 2018 fiscal years.

	2014	**2015**	**2016**	**2017**	**2018**
($ thousands)					
Bad debt expense	1 028	1 010	1 409	836	575
Write off of uncollectable accounts	996	1 304	1 478	1 189	1 086

REFERENCE:

PUB/CENTRA II - 27 Reference: PUB/Centra I-47

QUESTION:

Please provide a detailed table indicating Centra's weighted average interest rate ("WAIR") from the years 2013/014 to 2019/20.

RESPONSE:

The following table depicts Centra's weighted average interest rate ("WAIR") for fiscal years 2013/14 to 2019/20 (actuals, with forecasts for 2018/19 - 2019/20).

	Average Debt (millions)	Weighted Average Interest Rate (%)	Interest Expense (thousands)
2013/14 Actuals			
Interest on Long Term Debt	$298	4.21	$12,569
Provincial Guarantee Fee - LTD			$2,950
Interest on Short Term Debt	$28	0.95	$267
Provincial Guarantee Fee - STD			$193
Total Debt, Interest & WAIR	$327	4.89	$15,979
2014/15 Actuals			
Interest on Long Term Debt	$304	4.21	$12,810
Provincial Guarantee Fee - LTD			$3,050
Interest on Short Term Debt	$86	0.84	$728
Provincial Guarantee Fee - STD			$277
Total Debt, Interest & WAIR	$390	4.32	$16,864
2015/16 Actuals			
Interest on Long Term Debt	$334	4.17	$13,941
Provincial Guarantee Fee - LTD			$3,050
Interest on Short Term Debt	$44	0.49	$218
Provincial Guarantee Fee - STD			$726
Total Debt, Interest & WAIR	$378	4.74	$17,935
2016/17 Actuals			
Interest on Long Term Debt	$347	4.04	$14,033
Provincial Guarantee Fee - LTD			$3,400
Interest on Short Term Debt	$27	0.50	$136
Provincial Guarantee Fee - STD			$356
Total Debt, Interest & WAIR	$375	4.78	$17,926
2017/18 Actuals			
Interest on Long Term Debt	$361	3.99	$14,410
Provincial Guarantee Fee - LTD			$3,600
Interest on Short Term Debt	$42	0.95	$397
Provincial Guarantee Fee - STD			$263
Total Debt, Interest & WAIR	$403	4.63	$18,670
2018/19 Forecast			
Interest on Long Term Debt	$370	3.99	$14,765
Provincial Guarantee Fee - LTD			$3,699
Interest on Short Term Debt	$39	1.55	$598
Provincial Guarantee Fee - STD			$373
Total Debt, Interest & WAIR	$409	4.76	$19,435
2019/20 Forecast			
Interest on Long Term Debt	$384	4.01	$15,398
Provincial Guarantee Fee - LTD			$3,899
Interest on Short Term Debt	$49	2.20	$1,073
Provincial Guarantee Fee - STD			$213
Total Debt, Interest & WAIR	$433	4.76	$20,583

REFERENCE:

PUB/Centra I-49

QUESTION:

a) Please restate 2018/19 to actual results and provide an update to the tables for each years in the 10 year forecast based on the August update.
b) Please update the continuity of equity schedule consistent with (a).
c) Please file a version of (a) & (b) maintaining the approved net income at $3 million annually.

RESPONSE:

Response to a) and b):

The information provided in the following tables reflects the results of a CGM18 scenario incorporating the following:

- Summer 2019 interest rates (as provided in the response to PUB/CENTRA I-44a-c (Update)),
- Debt activity up to July 2019, and
- Additional funding of the FRP until October 31, 2019.

No other assumptions were changed.

CENTRA GAS MANITOBA INC.

	2012/13 Actual	2013/14 Actual	2014/15 Actual	2015/16 Actual	2016/17 Actual	2017/18 Actual	2018/19 Forecast	2019/20 Forecast	2020/21 Forecast	2021/22 Forecast	2022/23 Forecast	2023/24 Forecast	2024/25 Forecast	2025/26 Forecast	2026/27 Forecast	2027/28 Forecast
Capital Structure (000s)																
Long Term Debt	296 244	298 452	304 233	333 210	347 178	361 085	373 465	410 204	439 903	479 903	473 465	501 624	519 903	500 944	544 903	558 761
Short Term Debt	19 613	31 414	57 322	52 066	39 222	42 321	53 798	45 859	49 459	35 047	56 545	43 121	39 465	72 445	41 399	39 370
Equity (mid-year average)	159 455	173 257	188 256	186 915	188 140	193 460	198 450	201 532	205 989	213 149	221 528	230 111	238 833	248 176	258 028	267 801
Total Capitalization	475 312	503 122	549 811	572 192	574 540	596 865	625 713	657 594	695 351	728 100	751 538	774 857	798 200	821 565	844 330	865 932
Weighting																
Long Term Debt	62.3%	59.3%	55.3%	58.2%	60.4%	60.5%	59.7%	62.4%	63.3%	65.9%	63.0%	64.7%	65.1%	61.0%	64.5%	64.5%
Short Term Debt	4.1%	6.2%	10.4%	9.1%	6.8%	7.1%	8.6%	7.0%	7.1%	4.8%	7.5%	5.6%	4.9%	8.8%	4.9%	4.5%
Equity	33.5%	34.4%	34.2%	32.7%	32.7%	32.4%	31.7%	30.6%	29.6%	29.3%	29.5%	29.7%	29.9%	30.2%	30.6%	30.9%
Total Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

CENTRA GAS EQUITY
in millions of dollars

		2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast
	Opening Retained Earnings	34	42	62	66	65	69	76	79	82	88	96	104	113	122	132	142
	Restatement (1)	-	-	(7)	-	-	-	-	-	-	-	-	-	-	-	-	-
	Restated Opening Retained Earnings	34	42	55	66	65	69	76	79	82	88	96	104	113	122	132	142
	Net Income	8	20	11	(1)	4	7	3	3	6	8	8	9	9	10	10	10
A	**Closing Retained Earnings**	**42**	**62**	**66**	**65**	**69**	**76**	**79**	**82**	**88**	**96**	**104**	**113**	**122**	**132**	**142**	**151**
B	**Share Capital**	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**
A+B	**Total Equity**	**163**	**183**	**187**	**186**	**190**	**197**	**200**	**203**	**209**	**217**	**226**	**234**	**243**	**253**	**263**	**273**

(1) Restatement of employee pensions and benefits of $7M upon transition to IFRS

c) The information provided in the following tables reflects the results of a CGM18 scenario incorporating the following:
   - Summer 2019 interest rates (as provided in the response to PUB/CENTRA I-44a-c (Update)),
   - Debt activity up to July 2019,
   - Additional funding of the FRP until October 31, 2019, and
   - Rate increases to maintain a net income of $3M per year.

   No other assumptions were changed.

CENTRA GAS MANITOBA INC.

	2012/13 Actual	2013/14 Actual	2014/15 Actual	2015/16 Actual	2016/17 Actual	2017/18 Actual	2018/19 Forecast	2019/20 Forecast	2020/21 Forecast	2021/22 Forecast	2022/23 Forecast	2023/24 Forecast	2024/25 Forecast	2025/26 Forecast	2026/27 Forecast	2027/28 Forecast
Capital Structure (000s)																
Long Term Debt	296 244	298 452	304 233	333 210	347 178	361 085	373 465	410 204	439 903	479 903	483 465	511 624	539 903	530 944	584 903	588 761
Short Term Debt	19 613	31 414	57 322	52 066	39 222	42 321	53 798	45 832	50 907	40 681	57 563	49 721	41 785	71 112	36 920	51 660
Equity (mid-year average)	159 455	173 257	188 256	186 915	188 140	193 460	198 450	201 558	204 558	207 558	210 558	213 558	216 558	219 558	222 558	225 558
Total Capitalization	475 312	503 122	549 811	572 192	574 540	596 865	625 713	657 594	695 368	728 143	751 586	774 904	798 246	821 615	844 381	865 979
Weighting																
Long Term Debt	62.3%	59.3%	55.3%	58.2%	60.4%	60.5%	59.7%	62.4%	63.3%	65.9%	64.3%	66.0%	67.6%	64.6%	69.3%	68.0%
Short Term Debt	4.1%	6.2%	10.4%	9.1%	6.8%	7.1%	8.6%	7.0%	7.3%	5.6%	7.7%	6.4%	5.2%	8.7%	4.4%	6.0%
Equity	33.5%	34.4%	34.2%	32.7%	32.7%	32.4%	31.7%	30.7%	29.4%	28.5%	28.0%	27.6%	27.1%	26.7%	26.4%	26.0%
Total Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

CENTRA GAS EQUITY
in millions of dollars

		2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast
	Opening Retained Earnings	34	42	62	66	65	69	76	79	82	85	88	91	94	97	100	103
	Restatement (1)	-	-	(7)	-	-	-	-	-	-	-	-	-	-	-	-	-
	Restated Opening Retained Earnings	34	42	55	66	65	69	76	79	82	85	88	91	94	97	100	103
	Net Income	8	20	11	(1)	4	7	3	3	3	3	3	3	3	3	3	3
A	**Closing Retained Earnings**	**42**	**62**	**66**	**65**	**69**	**76**	**79**	**82**	**85**	**88**	**91**	**94**	**97**	**100**	**103**	**106**
B	**Share Capital**	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**	**121**
A+B	**Total Equity**	**163**	**183**	**187**	**186**	**190**	**197**	**200**	**203**	**206**	**209**	**212**	**215**	**218**	**221**	**224**	**227**

(1) Restatement of employee pensions and benefits of $7M upon transition to IFRS

REFERENCE:

PUB/Centra I-53

QUESTION:

Please update the schedule for weather normal basis to include forecast for 2018/19 and 2019/20 based on the August update.

RESPONSE:

The following schedule has been updated to include the 2018/19 and 2019/20 forecast based on the updated 2019/20 Approved Budget with 2019 Summer interest rates, as provided in the response to PUB/CENTRA I-44a-c (Update), and all debt activity up to July 2019.

Calculated Return on Equity - Weather Normalized Net Income **($000s)**

		CGAAP 2012/13 Actual	CGAAP 2013/14 Actual	CGAAP 2014/15 Actual	IFRS 2015/16 Actual	IFRS 2016/17 Actual	IFRS 2017/18 Actual	IFRS 2018/19 Forecast *	IFRS 2019/20 Forecast *
A	Rate Base	477 906	486 677	509 823	529 035	559 303	601 750	622 556	645 623
B	Equity Weighting	33.5%	34.4%	34.2%	32.7%	32.7%	32.4%	32.4%	31.8%
C	Weather Normalized Net Income	3 738	5 314	9 379	9 255	12 755	6 205	2 652	3 636
D	Corporate Allocation	12 000	12 000	12 000	12 000	12 000	12 000	12 000	12 000
E = (C+D)	Total Return on Equity	15 738	17 314	21 379	21 255	24 755	18 205	14 652	15 636
F=E/A/B	Actual ROE	9.8%	10.3%	12.2%	12.3%	13.5%	9.3%	7.3%	7.6%

* Based on the Current Outlook and Approved budget with Summer 2019 interest rate forecast

REFERENCE:

PUB/Centra I-54 b)

QUESTION:

Please provide any insight into how SaskEnergy determined its normal effective heating degree budget (geographically) and results and compare that with how Centra determines its forecast and results.

RESPONSE:

The following response was provided by Mr. Drazen:

SaskEnergy uses weather data from Regina and Saskatoon. It measures Heating Degree Days ("HDD") relative to a base temperature of 18°C. If the average temperature on a given day is 18°C or more, the HDD for that day is zero. If the average temperature is lower than 18° then for that date:

$$\mathbf{HDD_{date} = 18°C - Temperature_{date}}$$

For example, if the average temperature on March 1 was 3°C then the HDD for that date Is 18°C - 3°C = 15 HDD. If the average temperature on January 1 was -15°C then the HDD for that date is 33 HDD. The HDD for all days is summed to get the annual HDD.
"Normal" weather is defined as the latest ten year average.

Centra Gas Manitoba measures HDD relative to a base temperature of [redacted]°C. Temperature is 1d
measured in Winnipeg and Brandon, Centra defines normal weather as [redacted].

REFERENCE:

IGU/Centra I-2 d) Attachment 1 pg. 3

QUESTION:

Please provide the details as to when and how the return on equity of 8.3% was established for SaskEnergy.

RESPONSE:

The following response was provided by Mr. Drazen:

The Minister's Terms of Reference (May 19, 2016) to the Saskatchewan Rate Review Panel regarding the 2016 SaskEnergy Commodity and Delivery Service application stated that one of the given parameters was:

> *[T]he long-term target rate of return on equity of 8.30%, as approved in the 2016/17 business plan.*

https://www.saskratereview.ca/docs/saskenergy2016/mo-saskenergy.pdf

The previous return on equity as stated in the Terms of Reference (June 2, 2015) for the 2015 application was 8.75%.
https://www.saskratereview.ca/docs/saskenergy2015/2015-06-02-saskenergy-srrp-delivery-and-commodity-rate-change.pdf

Therefore, the 8.30% return on equity was established sometime between mid-2015 and mid-2016.

The Terms of Reference (September 26, 2018) for the latest application maintain the 8.30% return on equity.
http://saskratereview.ca/docs/saskenergy2018/saskenergy-to-september-2018-signed.pdf

As discussed in the DCGI evidence (Q&A 18, page 11), the basis for the return on equity, going back at least to 2008 and continuing to the present, was to be "comparable to industry average" as determined by regulators in other Canadian jurisdictions.

REFERENCE:

PUB/Centra I-50 & I-57, PUB/MH I-38 a-e Updated (Manitoba Hydro 2019/20 GRA)

QUESTION:

a) Please file the amortization schedule for the Centra Acquisition including the split of the amount related to Centra and Manitoba Hydro.

RESPONSE:

Please see the following schedule that was last provided at the 2009/10 & 2010/11 Gas GRA.

The corporate allocation currently totals $20.3 million, of which $12 million is allocated to Centra Gas and $8.3 million is allocated to Manitoba Hydro.

Amortization Schedule for Costs Associated with Acquisition of Centra **($000's)**

	1999/2000 Actual	2000/01 Actual	2001/02 Actual	2002/03 Actual	2003/04 Actual	2004/05 Plan	2005/06 Test Year	2006/07 Test Year	2007/08 Plan	2008/09 Plan	2009/10 Plan
Beginning Balance	253 861	252 132	249 415	246 503	243 381	240 035	236 448	232 604	228 482	224 064	219 328
Carrying Costs	12 196	18 169	17 974	17 765	17 540	17 299	17 041	16 765	16 468	16 150	15 809
Amortization	(13 924)	(20 886)	(20 886)	(20 886)	(20 886)	(20 886)	(20 886)	(20 886)	(20 886)	(20 886)	(20 886)
Ending Balance	252 132	249 415	246 503	243 381	240 035	236 448	232 604	228 482	224 064	219 328	214 251

	2010/11 Plan	2011/12 Plan	2012/13 Plan	2013/14 Plan	2014/15 Plan	2015/16 Plan	2016/17 Plan	2017/18 Plan	2018/19 Plan	2019/20 Plan	2020/21 Plan
Beginning Balance	214 251	208 808	202 974	196 719	190 015	182 827	175 121	166 861	158 005	148 511	138 333
Carrying Costs	15 444	15 052	14 632	14 181	13 698	13 181	12 626	12 031	11 392	10 708	9 975
Amortization	(20 886)	(20 886)	(20 886)	(20 886)	(20 886)	(20 886)	(20 886)	(20 886)	(20 886)	(20 886)	(20 886)
Ending Balance	208 808	202 974	196 719	190 015	182 827	175 121	166 861	158 005	148 511	138 333	127 422

	2021/22 Plan	2022/23 Plan	2023/24 Plan	2024/25 Plan	2025/26 Plan	2026/27 Plan	2027/28 Plan	2028/29 Plan	2029/30 Plan	Total
Beginning Balance	127 422	115 724	103 183	89 738	75 323	59 869	43 301	25 538	6 494	
Carrying Costs	9 188	8 345	7 441	6 472	5 432	4 318	3 123	1 842	468	372 726.5
Amortization	(20 886)	(20 886)	(20 886)	(20 886)	(20 886)	(20 886)	(20 886)	(20 886)	(6 962)	
Ending Balance	115 724	103 183	89 738	75 323	59 869	43 301	25 538	6 494	0	

REFERENCE:

PUB/Centra I-50 & I-57, PUB/MH I-38 a-e Updated (Manitoba Hydro 2019/20 GRA)

QUESTION:

b) Please indicate which debt issues specifically relates to the acquisition of Centra.

RESPONSE:

The original financing strategy for Centra acquisition costs was to target 30 year fixed rate financing. At the time of issue in August 1999, 30 year fixed rate financing had an all in yield cost to Manitoba Hydro of 6.61%. In view of market conditions, a $250 million 10 year debenture was issued at a fixed rate of 6.25% and was immediately swapped to floating rate financing at a rate of 3 month BA's – 0.0003%. This financing structure provided Manitoba Hydro the opportunity to execute a 30 year fixed rate interest swap at a future point in time when market conditions were more favourable.

Manitoba Hydro executed three interest swaps which mature on September 1, 2029 and have locked in 30 year fixed rate financing at weighted average interest rates which have been in the range of 6.19% to 6.48% over the course of the last 20 years. Currently, the following debt issues are associated with the Centra acquisition 30 year swaps:

Series	Maturity	Coupon Rate	Par Value
C119-1	2029-09-01	6.575%	$100,000,000
FA-1	2037-03-05	6.211%	$25,000,000
FA-2	2037-03-05	6.311%	$75,000,000
FA-3	2037-03-05	6.266%	$50,000,000

The weighted average interest rate for the Centra acquisition debt is currently 6.40%.

REFERENCE:

PUB/Centra I-58

QUESTION:

Please update the table including 2018/19 actual results and 2019/20 forecast based on the update filed with rebuttal evidence and provide a narrative description of the results.

RESPONSE:

The following table has been updated to include the 2018/19 and 2019/20 forecast based on the updated 2019/20 Approved Budget with 2019 Summer interest rates, as provided in the response to PUB/CENTRA I-44a-c (Update), and all debt activity up to July 2019.

Centra is not in a position to publicly release its financial results for 2018/19 until they have been tabled with the Legislative Assembly and released publicly by the Province.

Net Earnings and Return on Equity

in millions of dollars

Year	Actual Net Earnings	Weather Normalized Net Earnings	Corporate Allocation	Actual Return on Equity	Weather Norm. Return on Equity	Rate Base	Equity Weighting %	Calculated ROE % Actual NI	Calculated ROE % Weather Norm. NI
	A	B	C	D = A+C	E = B+C	F	G	H=D/F/G	I=E/F/G
2002/03	($2.0)	($6.7)	$12.0	$10.0	$5.3	$329.5	35.4%	8.6%	4.5%
2003/04	(7.9)	(6.8)	12.0	4.1	5.2	359.8	34.3%	3.3%	4.2%
2004/05	(1.6)	(4.2)	12.0	10.4	7.8	377.7	35.4%	7.8%	5.8%
2005/06	(5.4)	2.2	12.0	6.6	14.2	414.5	32.0%	5.0%	10.7%
2006/07	1.1	2.2	12.0	13.1	14.2	431.6	30.0%	10.1%	10.9%
2007/08	5.9	1.0	12.0	17.9	13.0	430.8	30.1%	13.8%	10.0%
2008/09	8.6	1.4	12.0	20.6	13.4	462.0	30.9%	14.4%	9.4%
2009/10	(1.0)	1.9	12.0	11.0	13.9	437.7	31.8%	7.9%	10.0%
2010/11	6.6	6.6	12.0	18.6	18.6	451.5	33.1%	12.5%	12.4%
2011/12	(5.8)	7.2	12.0	6.2	19.2	464.9	33.5%	4.0%	12.3%
2012/13	7.8	3.7	12.0	19.8	15.7	477.9	33.5%	12.4%	9.8%
2013/14	19.8	5.3	12.0	31.8	17.3	486.7	34.4%	19.0%	10.3%
2014/15	11.0	10.2	12.0	23.0	22.2	509.8	34.2%	13.2%	12.7%
2015/16	(1.4)	9.3	12.0	10.6	21.3	529.0	32.7%	6.1%	12.3%
2016/17	3.9	12.8	12.0	15.9	24.8	559.3	32.7%	8.7%	13.5%
2017/18	6.8	6.2	12.0	18.8	18.2	601.7	32.4%	9.6%	9.3%
2018/19*	4.4	2.7	12.0	16.4	14.7	622.6	32.4%	8.1%	7.3%
2019/20*	3.6	3.6	12.0	15.6	15.6	645.6	31.8%	7.6%	7.6%

Average Actual/Forecasted Earnings 2003-2020	$3.0
Average Weather Norm. Earnings 2003-2020	$3.2
Average ROE 2003-2020 - Actual/Forecasted NI	9.56%
Average ROE 2003-2020 - Weather Norm. NI	9.62%

Colder than average
Warmer than average

***Forecast based on CGM Approved Budget updated with 2019 Summer Interest Rates**

The average actual and forecasted earnings between 2003-2020 is $3M and the average actual and forecasted weather normalized earnings between 2003-2020 is $3.2M. The average calculated ROE based on actual and forecasted results between 2003-2020 is 9.56% and the average calculated ROE based on weather normalized earnings between 2003-2020 is 9.62%.

REFERENCE:

CAC/Centra I-7 i) & k)

QUESTION:

a) Please file the IFF scenarios referred to in i).
b) Please provide details on the different forecast scenario variations performed including interest rates, fixed returns and ROE not disclosed in k).
c) Please indicate whether any included a ROE of less than 8.3%.

RESPONSE:

a) The long-term debt figures provided in the response to CAC/CENTRA I-7i were inadvertently transposed between the 8.7% ROE scenario and the $3 million scenario. The revised table has been provided below:

Closing Long-Term Debt (Millions)		
	2023	2028
8.7% scenario	499.9	565.0
$3 million scenario	519.9	615.0
Difference	20.0	50.0

The closing long-term debt figures in the table above include the current portion of long-term debt of $9.9M in 2023 and $0 in 2028.

The financial statements for the 8.7% ROE scenario and the $3 million net income scenario have been provided below.

GAS OPERATIONS (CGM18)
PROJECTED OPERATING STATEMENT
CGM18 - Targeted Net Income assuming 8.7% ROE starting in 2018/19
(In Millions of Dollars)

For the year ended March 31	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
REVENUES										
Domestic Revenue										
Cost of Gas at Approved Rates	159	158	166	166	165	165	164	163	162	163
Non-Gas Costs *	152	150	150	151	151	151	151	152	152	151
Furnace Replacement Program Funding	(4)	(1)	-	-	-	-	-	-	-	-
Late Payment Charges and Broker Revenue	1	1	1	1	1	1	1	1	1	1
	308	308	316	317	317	316	316	315	315	315
additional revenue requirement***	3	4	8	10	14	18	22	26	30	35
	311	312	324	327	331	335	338	342	345	349
Weighted Average Cost of Gas Sold **	159	158	166	166	165	165	164	163	162	163
Gross Margin	152	154	158	161	166	170	174	178	183	187
Other	2	2	2	2	2	2	2	2	2	2
	154	156	160	163	168	172	176	181	185	189
EXPENSES										
Operating and Administrative	63	61	62	63	64	65	66	68	69	70
Finance Expense	22	23	25	26	27	28	29	30	31	32
Depreciation and Amortization	24	25	27	28	29	31	31	32	33	34
Capital and Other Taxes	17	17	18	18	19	19	20	20	21	21
Other Expenses	12	13	13	12	12	12	12	12	12	11
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
	150	152	157	159	162	167	170	173	177	180
Net Income before Net Movement in Regulatory Deferral	4	3	3	4	5	5	6	7	7	9
Net Movement in Regulatory Deferral **	3	3	3	3	3	3	2	3	3	2
Net Income	6	7	7	7	8	8	9	10	10	11

* The Non-Gas Costs reflect the proposed discontinuance of FRP funding and removal of associated costs from rates for the SGS class, effective Aug 1, 2019

** The adjusted gross margin reflects the cost of gas charged to customer through rates (WACOG). The PGVA has been reclassified to the gross margin from net movement for rate setting purposes.

***Additional Revenue Requirement**										
Percent Increase	1.14%	0.13%	1.29%	0.43%	1.52%	0.99%	1.17%	1.07%	1.11%	1.21%
Cumulative Percent Increase	1.14%	1.28%	2.58%	3.03%	4.59%	5.63%	6.86%	8.00%	9.20%	10.52%
Equity Ratio (PUB Approved Methodology)	32%	31%	31%	30%	30%	30%	31%	31%	31%	32%

GAS OPERATIONS (CGM18)
PROJECTED BALANCE SHEET
CGM18 - Targeted Net Income assuming 8.7% ROE starting in 2018/19
(In Millions of Dollars)

For the year ended March 31	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
ASSETS										
Plant in Service	622	658	698	737	776	814	854	894	935	977
Accumulated Depreciation	(65)	(79)	(95)	(112)	(130)	(148)	(168)	(187)	(208)	(229)
Net Plant in Service	557	579	603	626	646	666	686	707	727	747
Construction in Progress	6	9	6	4	4	4	4	4	4	4
Current and Other Assets	92	92	92	92	92	92	92	92	92	92
Goodwill and Intangible Assets	10	9	9	9	9	9	9	9	9	9
Total Assets before Regulatory Deferral	665	689	710	730	751	771	791	812	832	853
Regulatory Deferral Balance	106	109	113	116	118	121	123	126	128	130
	771	798	823	846	869	891	914	937	960	983
LIABILITIES AND EQUITY										
Long-Term Debt	390	430	470	460	490	520	495	545	545	565
Current and Other Liabilities	119	105	82	108	91	73	110	72	85	75
Deferred Revenue	47	49	49	50	52	55	57	58	59	60
Share Capital	121	121	121	121	121	121	121	121	121	121
Retained Earnings	82	89	95	102	110	119	127	137	147	158
Total Liabilities and Equity before Regulatory Deferral	759	794	818	842	864	887	910	933	957	979
Regulatory Deferral Balance	12	5	4	4	4	4	4	4	4	3
	771	798	823	846	869	891	914	937	960	983
Net Debt	437	465	500	517	532	547	561	575	587	598
Equity (PUB Approved Methodology)	32%	31%	31%	30%	30%	30%	31%	31%	31%	32%

GAS OPERATIONS (CGM18)
PROJECTED CASH FLOW STATEMENT
CGM18 - Targeted Net Income assuming 8.7% ROE starting in 2018/19
(In Millions of Dollars)

For the year ended March 31	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
OPERATING ACTIVITIES										
Net Income	6	7	7	7	8	8	9	10	10	11
Add Back:										
Depreciation and Amortization	24	25	27	28	29	31	31	32	33	34
Finance Expense	22	23	25	26	27	28	29	30	31	32
Net Movement Impacts on Depreciation and Finance Expense	10	10	11	10	10	9	10	10	10	9
Adjustments for Non-Cash Items	11	11	11	11	11	11	11	11	11	11
Adjustments for Changes in Non-Cash Working Capital Accounts	(9)	(9)	(19)	(2)	(2)	(2)	(1)	(1)	(0)	(0)
Interest Paid	(33)	(35)	(36)	(38)	(39)	(40)	(41)	(42)	(43)	(44)
Cash Provided by Operating Activities	31	32	24	42	44	46	47	49	51	53
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	40	40	40	10	40	30	10	50	10	20
Retirement of Long-Term Debt	-	(20)	-	-	(20)	(10)	-	(35)	-	(10)
Cash Provided by Financing Activities	40	20	40	10	20	20	10	15	10	10
INVESTING ACTIVITIES										
Additions to Property, Plant and Equipment	(42)	(47)	(45)	(46)	(47)	(48)	(49)	(50)	(51)	(52)
Additions to Intangible Assets	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Additions to Regulatory Deferral Balances	(14)	(15)	(16)	(15)	(14)	(14)	(15)	(14)	(15)	(13)
Contributions Received	3	3	3	3	3	2	2	3	3	3
Cash Used for Investing Activities	(54)	(60)	(59)	(58)	(59)	(61)	(62)	(62)	(64)	(63)
Net Increase (Decrease) in Cash	16	(7)	5	(7)	5	5	(5)	1	(2)	(0)
Cash at Beginning of Year	(44)	(28)	(35)	(30)	(37)	(32)	(27)	(32)	(30)	(32)
Cash at End of Year	(28)	(35)	(30)	(37)	(32)	(27)	(32)	(30)	(32)	(33)

GAS OPERATIONS (CGM18)
PROJECTED OPERATING STATEMENT
CGM18 - $3M Net Income starting in 2018/19
(In Millions of Dollars)

For the year ended March 31	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
REVENUES										
Domestic Revenue										
Cost of Gas at Approved Rates	159	158	166	166	165	165	164	163	162	163
Non-Gas Costs *	152	150	150	151	151	151	151	152	152	151
Furnace Replacement Program Funding	(4)	(1)	-	-	-	-	-	-	-	-
Late Payment Charges and Broker Revenue	1	1	1	1	1	1	1	1	1	1
	308	308	316	317	317	316	316	315	315	315
additional revenue requirement***	(0)	1	5	7	10	14	18	21	25	29
	307	309	321	324	327	330	334	336	340	344
Weighted Average Cost of Gas Sold **	159	158	166	166	165	165	164	163	162	163
Gross Margin	149	150	155	158	162	166	170	173	178	181
Other	2	2	2	2	2	2	2	2	2	2
	150	152	157	160	164	168	172	175	180	183
EXPENSES										
Operating and Administrative	63	61	62	63	64	65	66	68	69	70
Finance Expense	22	23	25	26	28	29	30	31	33	34
Depreciation and Amortization	24	25	27	28	29	31	31	32	33	34
Capital and Other Taxes	17	17	18	18	19	19	20	20	21	21
Other Expenses	12	13	13	12	12	12	12	12	12	11
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
	150	152	157	160	163	168	171	175	179	182
Net Income before Net Movement in Regulatory Deferral	0	(0)	(0)	(0)	0	0	1	0	0	1
Net Movement in Regulatory Deferral **	3	3	3	3	3	3	2	3	3	2
Net Income	3	3	3	3	3	3	3	3	3	3

* The Non-Gas Costs reflect the proposed discontinuance of FRP funding and removal of associated costs from rates for the SGS class, effective Aug 1, 2019

** The adjusted gross margin reflects the cost of gas charged to customer through rates (WACOG). The PGVA has been reclassified to the gross margin from net movement for rate setting purposes.

***Additional Revenue Requirement**										
Percent Increase	-0.10%	0.37%	1.33%	0.41%	1.32%	0.98%	1.17%	0.68%	1.41%	0.94%
Cumulative Percent Increase	-0.10%	0.28%	1.61%	2.02%	3.37%	4.37%	5.60%	6.31%	7.81%	8.83%
Equity Ratio (PUB Approved Methodology)	32%	31%	29%	28%	28%	28%	27%	27%	26%	26%

GAS OPERATIONS (CGM18)
PROJECTED BALANCE SHEET
CGM18 - $3M Net Income starting in 2018/19
(In Millions of Dollars)

For the year ended March 31	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
ASSETS										
Plant in Service	622	658	698	737	776	814	854	894	935	977
Accumulated Depreciation	(65)	(79)	(95)	(112)	(130)	(148)	(168)	(187)	(208)	(229)
Net Plant in Service	557	579	603	626	646	666	686	707	727	747
Construction in Progress	6	9	6	4	4	4	4	4	4	4
Current and Other Assets	92	92	92	92	92	92	92	92	92	92
Goodwill and Intangible Assets	10	9	9	9	9	9	9	9	9	9
Total Assets before Regulatory Deferral	665	689	710	730	751	771	791	812	832	853
Regulatory Deferral Balance	106	109	113	116	118	121	123	126	128	130
	771	798	823	846	869	891	914	937	960	983
LIABILITIES AND EQUITY										
Long-Term Debt	390	440	480	480	510	540	525	585	585	615
Current and Other Liabilities	122	102	83	103	91	78	110	70	89	77
Deferred Revenue	47	49	49	50	52	55	57	58	59	60
Share Capital	121	121	121	121	121	121	121	121	121	121
Retained Earnings	79	82	85	88	91	94	97	100	103	106
Total Liabilities and Equity before Regulatory Deferral	759	794	818	842	864	887	910	933	957	979
Regulatory Deferral Balance	12	5	4	4	4	4	4	4	4	3
	771	798	823	846	869	891	914	937	960	983
Net Debt	441	472	511	531	551	572	592	613	631	650
Equity (PUB Approved Methodology)	32%	31%	29%	28%	28%	28%	27%	27%	26%	26%

GAS OPERATIONS (CGM18)
PROJECTED CASH FLOW STATEMENT
CGM18 - $3M Net Income starting in 2018/19
(In Millions of Dollars)

For the year ended March 31	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
OPERATING ACTIVITIES										
Net Income	3	3	3	3	3	3	3	3	3	3
Add Back:										
Depreciation and Amortization	24	25	27	28	29	31	31	32	33	34
Finance Expense	22	23	25	26	28	29	30	31	33	34
Net Movement Impacts on Depreciation and Finance Expense	10	10	11	10	10	9	10	10	10	9
Adjustments for Non-Cash Items	11	11	11	11	11	11	11	11	11	11
Adjustments for Changes in Non-Cash Working Capital Accounts	(9)	(9)	(19)	(2)	(2)	(2)	(1)	(1)	0	(0)
Interest Paid	(33)	(35)	(37)	(38)	(39)	(41)	(42)	(44)	(45)	(46)
Cash Provided by Operating Activities	27	29	20	38	40	40	42	42	45	45
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	40	50	40	20	40	30	20	60	10	30
Retirement of Long-Term Debt	-	(20)	-	-	(20)	(10)	-	(35)	-	(10)
Cash Provided by Financing Activities	40	30	40	20	20	20	20	25	10	20
INVESTING ACTIVITIES										
Additions to Property, Plant and Equipment	(42)	(47)	(45)	(46)	(47)	(48)	(49)	(50)	(51)	(52)
Additions to Intangible Assets	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Additions to Regulatory Deferral Balances	(14)	(15)	(16)	(15)	(14)	(14)	(15)	(14)	(15)	(13)
Contributions Received	3	3	3	3	3	2	2	3	3	3
Cash Used for Investing Activities	(54)	(60)	(59)	(58)	(59)	(61)	(62)	(62)	(64)	(63)
Net Increase (Decrease) in Cash	13	(1)	1	(1)	0	(1)	(0)	4	(9)	2
Cash at Beginning of Year	(44)	(31)	(32)	(31)	(31)	(31)	(32)	(32)	(28)	(37)
Cash at End of Year	(31)	(32)	(31)	(31)	(31)	(32)	(32)	(28)	(37)	(35)

b) Financial scenarios using return on equities of 8.3%, 8.5%, and 8.7% were all performed as well as an assumed $3 million/year net income. These scenarios were also analyzed assuming an increase in the interest rates of 100 basis points. The projected annual rate increases in the various financial scenarios were derived so that net income plus corporate allocation plus the cost of service finance expense (including impacts to finance expense in net movement in regulatory deferrals) would equal the total return on rate base under the Rate Base/Rate of Return methodology for each of ROE % identified above.

c) The $3 million net income/year scenario was prepared which resulted in annual ROEs of less than 8.3%. See response to PUB/Centra II-1 for the annual implied ROE percentage for the $3 million net income/year scenario.

REFERENCE:

CAC/Centra I-10 j)

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide details on how 24-month amortization period was determined for the costs related to the 2019/20 GRA.

RESPONSE:

In the past, Centra's general rate applications have included two test years and as such the costs have traditionally been amortized over a 24 month period. While the current GRA is based on the 2019/20 Test Year, it also includes the 2018/19 forecast year, as well as the disposition of prior period deferral account balances back to the 2014/15 Gas Year. As such, it was determined that a 24 month amortization period continued to be appropriate.

REFERENCE:

CAC/Centra I-10 j)

QUESTION:

b) Please provide details on how other regulatory proceedings forecasted in 2019/20 such as the TCPL 2018-20 Tolls Application and the NGTL Rate Design and Services Review will be amortized.

RESPONSE:

Please see below for details on the amortization of expenditures occurring during the 2019/20 fiscal period. In addition, please see the updated table below from the response to CAC/CENTRA I-10 (f) and (g) that has corrections made for the following:

- TCPL 2018-2020 Tolls Application expenditures also include expenditures for the TCPL Post 2020 Tolls Application. The descriptor for this line item has been updated in the attached table.

Other Gas Regulatory Matters: These expenditures address a number of different regulatory issues and are amortized over a 12 month period in the fiscal year following when the expenditures were made.

TCPL 2018-2020 and Post 2020 Tolls Application: The regulatory proceeding costs related to the 2018-2020 TCPL Tolls Application are being amortized over a 36 month period. Expenditures for the Post 2020 Tolls Application are planned to be amortized over a 60 month period, but this period will depend on the outcome of the application.

NGTL Rate Design & Services Review: The regulatory proceeding costs for this application will be amortized over a 60 month period. It is not known when the pipeline could seek another change to its rate design, but 60 months is planned given that the current NGTL rate design has been in effect since 2010.

IFRS Compliant ASL Depreciation Study: The expenditures associated with the IFRS compliant ASL Depreciation study are planned to be amortized over a 60 month period to approximate the time period between depreciation studies.

2019/20 General Rate Application: The expenditures associated with the 2019/20 General Rate Application are planned to be amortized over a 24 month period.

2020/21 Cost of Gas Application: The expenditures associated with the 2020/21 Cost of Gas hearing are planned to be amortized over a 12 month period.

Centra Gas - Regulatory Deferrals

		Additions						Amortization*					
Regulatory Proceeding	Source of Costs	2014/15 Actual	2015/16 Actual	2016/17 Actual	2017/18 Actual	2018/19 Outlook	2019/20 Approved Budget	2014/15 Actual	2015/16 Actual	2016/17 Actual	2017/18 Actual	2018/19 Outlook	2019/20 Approved Budget
2013/14 General Rate Application	Centra							(55 459)	(18 486)				
	PUB and PUB Advisor							(216 316)	(72 105)				
	Intervenor							(137 462)	(45 821)				
2012 Gas Portfolio Review	Centra							(57 906)	(57 906)	(57 906)	(33 778)		
	PUB and PUB Advisor							(28 821)	(28 821)	(28 821)	(16 812)		
	Intervenor							(21 492)	(21 492)	(21 492)	(12 537)		
2010 Cost of Service Review	Centra							(13 371)	(13 371)	(13 371)	(13 371)	(5 571)	
Non-Primary Gas Rate Riders Effective November 1, 2014	Centra	14 286	204					(929)	(8 541)	(5 019)			
	PUB and PUB Advisor	252 429	21 306					(17 557)	(161 349)	(94 828)			
Application for Acquistion of the Swan Valley Gas Corporation	Centra	3 219						(3 219)					
	PUB and PUB Advisor	(5 662)						5 662					
	Intervenor	17 683						(17 683)					
TCPL Toll Application - Mainline Segment	Centra	658 220	278					(15 650)	(94 083)	(94 087)	(121 268)	(117 701)	(117 701)
2015/16 Cost of Gas	Centra		115 969	43					(17 137)	(62 200)	(36 675)		
	PUB and PUB Advisor		472 745	58 146					(78 421)	(284 640)	(167 830)		
	Intervenor		97 021						(14 332)	(52 018)	(30 671)		
Fixed Rate Primary Gas Service	Centra		3 980	(3 980)									
Mainline Storage Transportation Service	Centra		30 784	351 212							(101 866)	(98 870)	(98 870)
ANR Rate Case	Centra			63 276						(13 361)	(21 392)	(21 392)	(7 130)
Other Gas Regulatory Matters	PUB and PUB Advisor			155 860	227 892	240 200	240 200				(155 860)	(227 892)	(240 200)
TCPL 2018-20 and Post 2020 Tolls Application	Centra				45 521	298 769	178 000				(1 293)	(124 726)	(232 993)
Dawn Long Term Fixed Price Service	Centra				138 911						(9 935)	(28 140)	(28 140)
GLTL Tolls Application	Centra				17 170						(1 827)	(4 384)	(4 384)
NGTL Rate Design & Services Review	Centra				3 974	38 600	256 526						(58 000)
IFRS Compliant ASL Depreciation Study	Centra					47 833	34 167						
Audit of Safety & Loss Management System	PUB and PUB Advisor					100 000							
2019/20 General Rate Application	Centra					372 500	77 500						(150 000)
	PUB and PUB Advisor					472 500	277 500						(250 000)
	Intervenor					315 000	185 000						(166 667)
2020/21 Gas Rate Application	Centra						187 784						(28 926)
	PUB and PUB Advisor						584 100						(89 975)
	Intervenor						124 428						(19 167)
	Total	**$ 940 175**	**$ 742 286**	**$ 624 557**	**$ 433 466**	**$ 1 885 402**	**$ 2 145 205**	**$ (580 202)**	**$ (631 865)**	**$ (727 744)**	**$ (725 114)**	**$ (628 677)**	**$ (1 492 153)**

* Amortization of deferred costs is calculated on the total deferral balance. For the purposes of this response, amortization has been provided on a pro-rated basis by the source of the cost.

REFERENCE:

PUB/Centra I-61, I-69

PREAMBLE TO IR (IF ANY):

Centra characterizes much of the capital program spending as non-discretionary.

QUESTION:

Which of the Level 1 and Level 2 categories shown in the response to PUB/Centra I-61 does Centra consider non-discretionary?

RESPONSE:

As discussed in PUB/Centra I-69, Centra has no discretion with respect to investment requirements for new customer attachments and regulatory compliance, which are included in the following Level I and Level 2 categories shown in the response to PUB/Centra I-61:

- Capacity & Growth / Customer Connections
- Sustainment / Mandated Compliance

In addition, the timing of investment is a complex risk decision with significant potential operational and cost consequences. Centra considers the timing of investment execution as part of its annual capital planning process, based on the best information available at the time, and adjustments are made as new information becomes available. Only those investments associated with unacceptable risks to the operability or sustainability of the system are advanced to execution. Less critical potential investments are deferred and revisited in future planning cycles such that potential investments being advanced to execution in the current year may have been repeatedly deferred in previous planning cycles. During the year, adjustments to the plan may also occur if anticipated risk exposures do not come to fruition.

REFERENCE:

PUB/Centra I-67; PUB/Centra I-73

QUESTION:

a) Explain why some Capital Investment Justifications shown in PUB/Centra I-73 Attachment (e.g. pages 131, 171, 230) do not have Corporate Value Framework scores.
b) Provide a table of Corporate Value Framework scores ("value" and "value/$k") for the Capital Investment Justifications shown in PUB/Centra I-73 that have CVF scores.
c) The CVF value score for the Cathodic Protection Remote Monitoring (page 317) is 0.92/$k, which appears to be one of the lowest scores for those provided in PUB/Centra I-73. Is there a cut-off or threshold value where projects proceed or do not proceed? If so, what is the threshold?
d) With reference to the Corporate Value Framework in PUB/Centra I-67 Attachment, explain how the CVF scoring is developed using the example of the Capital Investment Justification for the PR 201/Red River Transmission Pressure Pipeline Replacements (Letellier Crossing) as shown on PUB/Centra I-73 Attachment page 271.

RESPONSE:

a) All projects that do not have a Corporate Value Framework ("CVF") score were approved prior to implementing the CVF evaluation tool within Centra.

b) Please see table below for projects that have a CVF score.

Project	**Net Value**	**Net Value/$k**
2017-04049 PR 201/Red River Transmission Pressure Pipeline Replacements	9,020	6.05
Remote Monitoring for Cathodic Protection	413	0.92
System Betterment: Capacity	132,520	7.74
System Betterment: Integrity	709,478	10.34
System Betterment: Measurement & Regulator Stations	368,061	8.47
Gas Station Upgrades	94,505	10.10
Cathodic Protection	191,475	37.09
Leak/Non Conformance Upgrades, Gas Modifications	68,644	3.96
Gas Meters	319,793	2.90

c) When applying the Corporate Value Framework, Centra has not established a threshold for the evaluation of proposed projects. Generally speaking, only investments with a positive net value contribution are considered for approval in the proposed forecast.

d) The Letellier Crossing project was proposed following geotechnical monitoring which has been in place since a bank failure and leak occurred in 2015. The results of the monitoring have shown that both pipeline crossings are still within an active slope failure zone and a large geotechnical bank failure or deep seated slope failure could damage both pipeline crossings. Considering the applicable risks of this pipeline it was determined that the main CVF value measures related to this investment were Gas Distribution Reliability Benefit, Safety Risk, Environmental Risk and Compliance Risk. The CVF tool is calibrated in order for the value measures to be comparable in evaluation processes. Standard corporate questionnaires related to each value measure were completed in the investment evaluation tool considering the appropriate likelihood and consequence related to each value measure. Prior to investment approval, a peer review process of the evaluation was undertaken for the investment including staff from the project design group, supervisory staff, capital portfolio support and finance to help ensure consistency and completeness of the evaluation. Following the peer review, a final review of the investment which includes the CVF evaluation was completed by the appropriate management as per the Capital Investment Approval Levels policy.

REFERENCE:

PUB/Centra I-67; Manitoba Hydro 2017/18 & 2018/19 GRA PUB MFR 107

PREAMBLE TO IR (IF ANY):

Centra states that: "The Corporate Value Framework helps identify the optimal set of investments that deliver the greatest value (or mitigates risk) to the organization, within funding, resource and timing constraints."

The Corporate Value Framework document provided in the response to PUB/Centra I-67(a) is the same CVF document provided in the Manitoba Hydro 2017/18 & 2018/19 GRA as PUB MFR 107.

QUESTION:

a) Is the capital planning process and application of the CVF completely separate between Manitoba Hydro and Centra? Does the fact that Manitoba Hydro and Centra share resources (for example, there are no Centra employees, there are common assets and facilities) mean that Centra's investments are affected by funding, resource, or timing constraints related to Manitoba Hydro's operations or investments?
b) If there is interdependency between the application of each utility's CVF, explain how this affects the level of investments that Centra is approved to make.

RESPONSE:

a) The capital planning process and application of the Corporate Value Framework ("CVF") is not separate between Manitoba Hydro and Centra. Manitoba Hydro and Centra share the same CVF and processes for planning and applying the CVF to their capital investments; however, there are dedicated resources that focus on the planning, design and execution of Centra capital investments. These dedicated resources, as well as the fact that funding requirements are determined autonomously of Manitoba Hydro's, and that timing constraints are based on the natural gas system and associated parameters, allow for Centra's investments to be planned and delivered independently and are therefore not affected by Manitoba Hydro's investments or constraints.

b) Both Manitoba Hydro and Centra use the same CVF to assess the value of capital investments across all areas of the corporation in support of allocating funds to projects and assets that optimize strategic value or mitigate risk. However, investments by Centra and Manitoba Hydro are not compared against and are independent of each other for funding. The level of investment that Centra is approved to make is based on an assessment that determines the appropriate amount necessary to balance operational priorities and optimize overall corporate value considering changes in business, financial and economic assumptions as well as operational risk factors. The capital target for Centra is based on the corporation's capital investment requirements, associated risks as well as current and future resource demands. The majority of Centra's capital investments are determined and driven by customer requirements and mandatory needs, and are not affected by funding, resource or timing constraints related to Manitoba Hydro's operations or investments.

REFERENCE:

PUB/Centra I-67; Manitoba Hydro 2017/18 & 2018/19 GRA PUB MFR 107

PREAMBLE TO IR (IF ANY):

Centra states that: “The Corporate Value Framework helps identify the optimal set of investments that deliver the greatest value (or mitigates risk) to the organization, within funding, resource and timing constraints.”

The Corporate Value Framework document provided in the response to PUB/Centra I-67(a) is the same CVF document provided in the Manitoba Hydro 2017/18 & 2018/19 GRA as PUB MFR 107.

QUESTION:

c) When does Centra expect to be able to use the CVF scoring to develop its Capital Expenditure Forecast?

RESPONSE:

Centra has begun to use the CVF scoring to develop its Capital Expenditure Forecast and will continue to do so for future years.

REFERENCE:

PUB/Centra I-71, Appendix 4.3 p. 60, 61 of 64; PUB/Centra I-72 Attachment p.25 of 52; PUB/Centra I-73 Attachment p.178 of 370

QUESTION:

a) Confirm whether the inability to serve a single additional customer indefinitely due to the capacity of the system being at maximum would generate the consequence factor “System Reliability – High”. Likewise, would an indefinite outage for a single customer also generate the “Customer Value – High” consequence? If not confirmed, explain how these scenario would score in the risk rating criteria shown in Table A-1 of Appendix 4.3 and the threshold of customers or types of customers that would elevate these consequences to “High”.

b) Explain why the inability to serve customers for an extended period of time (for example, the 2014 Otterburne outage) is given the same consequence score (“High”) as an event that resulted in severe injuries or fatalities.

RESPONSE:

a) Not confirmed. The inability to serve a single additional customer would not generate a rating factor of “System Reliability- High”. The inability to serve a single customer would be considered “System Reliability –Low”.

   The Planning process used by Centra does not individually review all of the approximate 3000 new natural gas service installations each year but rather provides an annual review of each individual distribution system to determine how system growth has affected remaining system capacity and the ability of that system to meet the requirements of the connected customers while providing capacity for additional growth. It should be noted that system modeling is performed for all larger commercial customers and all customers requiring a main extension to determine if they can be connected to the existing distribution system. Continued growth on an individual distribution system creates the risk that existing customers may not have sufficient gas at design winter conditions.

System Reliability is associated with projects to add capacity but provides both the ability to add new customers and the ability to continue to provide existing customers with safe and reliable service. A System Reliability-High would be associated with insufficient capacity at design conditions that could nominally affect 100 or more existing customers (residential, commercial or combined).

Notwithstanding that the actual occurrence of an indefinite outage of a single customer would be rated “Customer Value – High”, within the risk assessment methodology, the potential for an indefinite outage of a single customer would be rated “Customer Value-Low”.

b) As shown in Appendix 4.3, the 2018-2023 Natural Gas Asset Management Capital Investment Plan pages 60, 61 and 62 of 64, five consequences are identified. These include financial, system reliability, safety (employee and public), environmental, and customer value. Each of the consequences is individually evaluated and a low, medium or high rating is determined. The ratings are relative with the consequence. While two consequences may receive the same rating, it does not mean that the outcomes are comparable.

REFERENCE:

PUB/Centra I-73 Attachment p.63 of 370

PREAMBLE TO IR (IF ANY):

Centra states that the rupture of the TCPL Mainline near Otterburne that interrupted Centra's gas supply caused Centra to incur costs of $1.5 million.

QUESTION:

Confirm whether Centra sought and received compensation from TCPL for these costs. If not, explain why not.

RESPONSE:

By way of an all-inclusive settlement with TCPL, Centra received $1,180,000 in compensation.

REFERENCE:

PUB/Centra I-72 Attachment pp. 44-46 of 52, Appendix 4.3 pp. 10-11 of 64

QUESTION:

a) For each program or project item included in Centra's 2017 Long Term Development Plan but not included in Centra's 2018-2023 Asset Management Capital Investment Plan, explain the reasons why the programs or projects were not included in Centra's 2018-2023 plan.

b) Explain whether the programs or projects in (a) are still being considered for potential implementation within the next 10 years.

c) If the 2019-2024 Natural Gas Asset Management Capital Investment Plan is now available, please provide.

RESPONSE:

a) Project or programs items shown in the 2017 Long Term Development Plan but not shown in the 2018-2023 Asset Management Capital Investment Plan were completed or are not proposed for the 5 year period covered by the 2018-23 Plan.

b) Details on the potential implementation of projects shown in the 2017 Long Term Development Plan but not the 2018-23 Asset Management Capital Investment plan are provided in the table below

Projects Shown in the 2017 Long Term Development Plan but not the 2018-23 Asset Management Capital Investment Plan		
Project	**ISD**	**Comment**
Winnipeg CentrePort MP Upgrade – Phase 2	2025	Will be constructed to suit the development in this area.
St Pierre TP Upgrade (Phase 2)	2031	Will be constructedas needed to suit system capacity requirements.
Minell TP Upgrade	2023	A planning study is in progress which will better define the project timing.

Projects Shown in the 2017 Long Term Development Plan but not the 2018-23 Asset Management Capital Investment Plan		
Project	**ISD**	**Comment**
Brandon MP Upgrade	2027	Further development required. Remains a longer term consideration.
SCADA Upgrade – Software	2024, 2031	To be added as required, this is an ongoing maintenance item.
Obtain wider easements Brandon TP	2020	This work will proceed but the schedule is being reviewed.
Inline inspection Program Brandon GS-123 to GS-168	2018	The schedule of the in-line inspections has been revised. The Brandon NPS 10 line will be inspected in 2019 and the Brandon NPS 6 line in 2021. The referenced NPS 12 line from GS-123 to GS-168 will be inspected at a date to be determined.
Pipeline Replacement Program	2020-2036	There are no pipelines which have been identified that require replacement. Investigation of pipeline condition through in-line inspection and other condition survey activities, and the implementation of an asset management plan have the potential to define pipeline replacement requirements.
Brandon TP Main-Secure Gas Supply	2025-2026	This project is unlikely to proceed as originally identified. There are currently multiple transmission pipelines to the Brandon area. Development of a pipeline operating protocol that would permit access to the other pipelines if there is a service interruption on the pipeline supplying general customers in Brandon and the southwest communities is in progress. Some capital requirements may remain but not at the same magnitude ($27 million) indicated in the 2017 document.

c) The 2019-24 Natural Gas Asset Management Capital Investment Plan is not yet complete.

REFERENCE:

PUB/Centra I-72 Attachment pp. 44-46 of 52, Appendix 4.3 pp. 10-11 of 64

QUESTION:

d) Explain whether, how, and when Centra will inform the PUB of its capital plan for the 2020 construction season and whether Centra will seek approval from the PUB for these rate base additions in advance of construction.

RESPONSE:

d) As noted in IGU/CENTRA I-3a-c, Centra's rates are regulated using a hybrid model that applies both the rate base/rate of return and cost of service methodologies, in accordance with the PUB's finding in Orders 131/04 and 135/05 shown below:

> *The Board is aware that the current legislation allows the Board to review Centra's rates on a rate base, rate of return basis. However, the legislation may also permit other forms of regulation of the gas utility. The Board notes that Centra is of the view that for an income tax exempt wholly-owned subsidiary of a Crown Corporation, the appropriate methodology should be revenue requirement and cost of service, as is the case with MH. The Board encourages Centra to file its next GRA in a timely fashion and on the basis of both rate base rate of return and revenue requirement, cost of service with emphasis on the latter. This will enable to Board to reach its determination taking into account revenue requirement, cost of service, and comparing such approach with the current rate base, rate of return methodology.* ***(Order 131/04, page 84)***

> *Accordingly, the Board will direct that future General Rate Applications by Centra continue to be filed using Cost of Service to calculate revenue requirement and Rate Base Rate of Return to test that result, and continue broad oversight over Centra's operations. As well, the Board will, if legislative*

> *amendments are proposed in future prescribing Cost of Service, recommend that the Board's oversight of gas operations remain as is.* ***(Order 135/05, page 69)***

Since the issuance of Order 135/05, where the PUB found that the cost of service methodology was an appropriate model for Crown and municipal corporations, Centra has filed its general rate applications using the Cost of Service methodology approach to determine its revenue requirement. In accordance with Order 135/05, Centra also includes in its GRAs details with respect to the components of revenue requirement using the rate base/rate of return methodology; however, this is to enable the PUB to compare the results under each approach only.

Under the current hybrid model established by the PUB, Centra does not request approval of the PUB for specific forecasted additions to rate base in advance of construction. Rather, Centra provides the PUB with a forecast of its capital plan and forecasted expenditures which for 2019/20 in the current application, forms the basis of the 2019/20 rate base amounts included in Tab 6.

REFERENCE:

PUB/Centra I-65, PUB/Centra I-69, PUB/Centra I-70

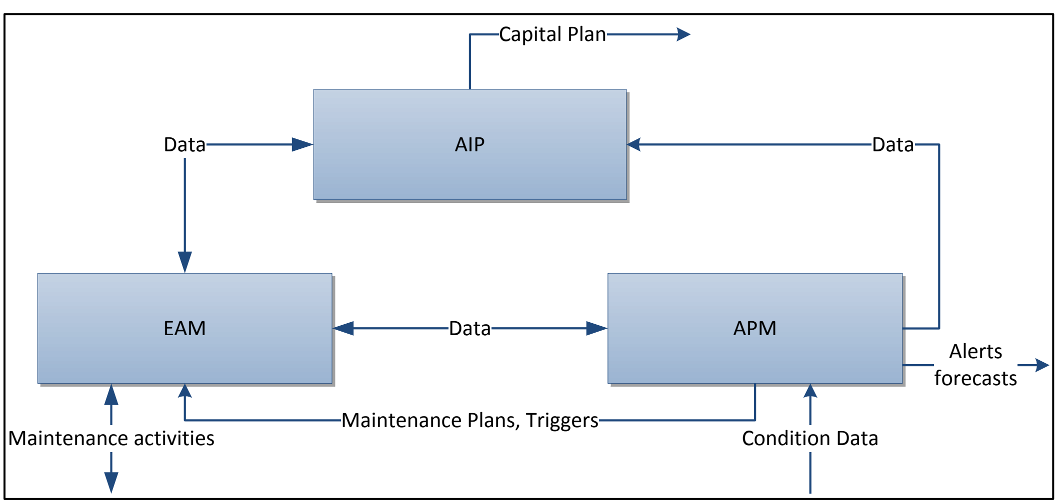
QUESTION:

Explain the relationship between the Asset Performance Management software initiative and Centra's (and Manitoba Hydro's) initiative to implement the Copperleaf C55 asset investment planning software. How do these software tools interface with each other, if at all?

RESPONSE:

Asset Performance Management software ("APM") is designed to support safe, reliable and efficient operation of equipment and infrastructure. Copperleaf C55 (Asset Investment Planning ("AIP") software) is designed to support both short and long term capital investment decisions. The two software programs often use the same data and similar analytical techniques, but for different purposes. The third related, but separate, asset management system is Enterprise Asset Management ("EAM") which provides enterprise-wide execution of maintenance programs.

The conceptual architecture of asset management systems and flow of data is depicted below.



REFERENCE:

CAC/Centra I-59, I 60b (ii); PUB/Centra I-73 pp.317-323 and 345-349 of 370; Appendix 4.3

PREAMBLE TO IR (IF ANY):

Centra proposes to upgrade equipment and control hardware in regulation stations to allow remote control through the SCADA system. In the justification for station automation and cathodic protection remote monitoring projects, Centra identifies operational efficiency, reduced labour hours, and increased productivity of personnel.

Centra appears to state that farm tap removals was the only program item in Appendix 4.3 where a cost benefit analysis was conducted.

QUESTION:

Confirm whether Centra compares the lifecycle costs (capital plus operation and maintenance) for remote monitoring and station automation projects with the costs of continued manual operation and attendant staffing costs. If confirmed, provide the comparisons of lifecycle costs with ongoing operating and maintenance staffing costs. If not confirmed, explain why business cases or cost-benefit analyses were not prepared for these types of projects or programs.

RESPONSE:

For station automation projects Centra did not compare the life cycle costs of remote monitoring to human resources. Centra’s pressure regulating stations are not continuously staffed. The key benefits of remote monitoring are improved station reliability, emergency response and marginal reductions in time spent on seasonal operating adjustments. The addition of station monitoring would not provide an annual positive financial benefit.

For cathodic protection remote monitoring projects Centra did compare the life cycle costs of remote monitoring to human resources. The main benefit of Centra’s cathodic protection remote monitoring project is reduced labour to collect checkpoint readings throughout the province. It is estimated that cathodic protection remote monitoring will result in a 60% labour hour reduction in gathering this critical data. The economic analysis indicated a break-even point at approximately 5 years after the installation.

REFERENCE:

PUB/Centra I-73 Attachment (pgs. 345-349), CAC/Centra I-60b, Appendix 4.3 p. 33 of 64

QUESTION:

Provide the cost-benefit analysis associated with the replacement of the three existing indirect-fired line heaters as GS-001, GS-003, and GS-020. Do these replacements increase or decrease the annual revenue requirement?

RESPONSE:

Although a formal cost-benefit analysis was not conducted, operation and maintenance costs were considered in the project Capital Investment Justifications.

Beyond the initial capital investment, the new vacuum boiler line heaters have reduced operation and maintenance costs. Compared to the existing indirect-fired bath line heater technology, the higher efficiency vacuum boilers will consume less fuel gas. The existing line heaters hold a large volume of a water/glycol mixture and require the use of a secondary containment enclosure which requires maintenance on a regular basis. The significantly reduced glycol volume used in the vacuum boilers is below the threshold at which a secondary containment is required, eliminating the need for containment maintenance. The reduced glycol volume also reduces the costs for periodic glycol replacement. The heaters are monitored and controlled by a programmable logic controller (“PLC”) resulting in fewer site calls from operations staff.

REFERENCE:

PUB/Centra I-88; PUB/Centra I-73 Attachment p.133 of 370

QUESTION:

Please further explain the cost increases experienced on the Compressed Natural Gas Trailer Filling Station project. If there were delays in the project such that the original February 2017 in-service date was not attainable, why did Centra continue with winter construction with its attendant higher costs in order to achieve a July 2017 in-service date (when criticality of gas supplies is generally at its lowest)?

RESPONSE:

Increased costs on the Compressed Natural Gas ("CNG") Trailer Filling Station project were the result of: delay in procurement and delivery of materials; additional civil work; winter construction and design changes. Additional costs for winter construction was approximately $140,000 or 3% of the total project cost. The delay caused by procurement and delivery of materials pushed the start date of construction for the CNG Trailer Filling Station to November 2016. Although winter construction is not ideal, the In Service Date shifted to July 2017, giving Manitoba Hydro sufficient time to commission the station, provide training for the operating personnel and go through one round of maintenance prior to the 2017 heating season. The CNG Trailer Filling Station was fully commissioned at the end of August 2017, and staff fully trained in September 2017. The original in service date, including commissioning and staff training, was February 1, 2017. While having CNG available during the coldest period of winter is advantageous, the original in service date was determined by the consultants planned schedule.

REFERENCE:

PUB/Centra I-100a-b, PUB/Centra I-101a-b

PREAMBLE TO IR (IF ANY):

The 2018/19 Q3 report includes an updated furnace replacement market assessment. The revised estimate of standard efficiency furnaces remaining in the LICO 125% market is approximately 6,700 as opposed to 4,600 previously filed in Tab 7, page 11. [PUB/Centra I-101a]

QUESTION:

a) Explain how the revised estimate of standard efficiency furnaces remaining in the LICO125 market affects the estimated Furnace Replacement Program costs over the next ten years. For example, is the estimated cost to complete the transformation of standard efficiency furnaces and boilers over the next 10 years still $14.9 million?

RESPONSE:

Figure 7.5 filed in Tab 7, page 10 outlines the forecasted number of standard efficiency furnaces being replaced through the program until they are expected to be depleted in 2025/26. This forecast was revised using the updated furnace replacement market assessment outlined in the 2018/19 Q3 report. Therefore, the estimated cost for furnace replacements over the next 10 years is still $14.9 million.

REFERENCE:

PUB/Centra I-100a-b, PUB/Centra I-101a-b

PREAMBLE TO IR (IF ANY):

The 2018/19 Q3 report includes an updated furnace replacement market assessment. The revised estimate of standard efficiency furnaces remaining in the LICO 125% market is approximately 6,700 as opposed to 4,600 previously filed in Tab 7, page 11. [PUB/Centra I-101a]

QUESTION:

b) What is the expected additional funding that will accrue to the FRP (incremental to the $545,000 in 2019/20 Approved Budget) as a result of the proposed rate changes occurring on November 1, 2019 instead of August 1?

RESPONSE:

The expected additional funding that will accrue to the Furnace Replacement Program (incremental to the $545,000 included in the 2019/20 Approved Budget) from August 1, 2019 to November 1, 2019 is approximately $393,000 for a total of $938,000.

REFERENCE:

PUB/Centra I-100a-b, PUB/Centra I-101a-b

PREAMBLE TO IR (IF ANY):

The 2018/19 Q3 report includes an updated furnace replacement market assessment. The revised estimate of standard efficiency furnaces remaining in the LICO 125% market is approximately 6,700 as opposed to 4,600 previously filed in Tab 7, page 11. [PUB/Centra I-101a]

QUESTION:

c) Refile the table included in PUB/Centra I-100a based on the revised estimate of standard efficiency furnaces remaining in the LICO125 market and the additional funding as indicated in (b).

RESPONSE:

Please refer to attachment PUB/CENTRA II-46c (attachment).

Furnace Replacement Fund ending March 31 (000's)	2008/9 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Actual	2014/15 Actual	2015/16 Actual	2016/17 Actual	2017/18 Actual	2018/19 Forecast	2019/20 Forecast	2020/21 Forecast	2021/22 Forecast	2022/23 Forecast	2023/24 Forecast	2024/25 Forecast	2025/26 Forecast	2026/27 Forecast	2027/28 Forecast
Opening Balance	$ 2,327	$ 5,972	$ 9,050	$ 11,644	$ 14,145	$ 16,071	$ 18,176	$ 19,272	$ 20,971	$ 22,922	$ 24,856	$ 27,151	$ 26,547	$ 7,564	$ 5,792	$ 4,134	$ 2,670	$ 1,363	$ 133	$ 99
Funding from SGS Class	$ 3,855	$ 3,800	$ 3,762	$ 3,838	$ 3,800	$ 3,800	$ 3,800	$ 3,800	$ 3,800	$ 3,800	$ 3,800	$ 938	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Disbursements	$ (264)	$ (815)	$ (1,312)	$ (1,627)	$ (2,167)	$ (2,012)	$ (3,191)	$ (2,394)	$ (2,170)	$ (2,298)	$ (2,137)	$ (2,395)	$ (2,192)	$ (2,002)	$ (1,830)	$ (1,591)	$ (1,383)	$ (1,260)	$ (38)	$ (40)
Interest	$ 54	$ 93	$ 144	$ 290	$ 287	$ 322	$ 336	$ 293	$ 320	$ 433	$ 632	$ 853	$ 909	$ 230	$ 171	$ 127	$ 77	$ 30	$ 4	$ 3
Proposed Disposition	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (17,700)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ending Balance	$ 5,972	$ 9,050	$ 11,644	$ 14,145	$ 16,071	$ 18,176	$ 19,272	$ 20,971	$ 22,922	$ 24,856	$ 27,151	$ 26,547	$ 7,564	$ 5,792	$ 4,134	$ 2,670	$ 1,363	$ 133	$ 99	$ 62
Number of Furnace Installations	280	508	445	662	630	605	796	673	547	561	510	459	413	372	335	284	242	217	0	0
Number of Boiler Installations	5	9	16	18	9	18	21	11	11	12	10	10	10	10	10	10	9	9	8	8
Cumulative Furnace Installations	280	788	1,233	1,895	2,525	3,130	3,926	4,599	5,146	5,707	6,217	6,676	7,089	7,461	7,796	8,080	8,322	8,539	8,539	8,539
Cumulative Boiler Installations	5	14	30	48	57	75	96	107	118	130	140	150	160	170	180	190	199	208	216	224

-

Denotes what has changed.

REFERENCE:

PUB/Centra I-108 CSI

QUESTION:

Please file the actual versus forecast EHDD for 2018/19 and the impact on net income for that year.

RESPONSE:

The Corporation is still in the process of finalizing the 2018/19 year-end results. Once the results have been finalized and made available for public distribution, the financial results for 2018/19 will be filed with the Public Utilities Board.

REFERENCE:

PUB/Centra I-109 Attachments 3 and 4; 2010/11 Cost of Gas PUB/Centra-16

QUESTION:

a) Provide the reasons ConocoPhillips scored [redacted] in the evaluations of the 2016-2018 or 2018-2020 contract proposals. Is ConocoPhillips recognized in the Western Canadian Sedimentary Basin as [redacted]? 1b

b) Explain what has changed to [redacted] scored during the evaluation of the 2009-2012 gas supply contract to the [redacted]. Does Centra's evaluation criteria [redacted]? 1b

RESPONSE:

a) and b):

[redacted] 1b

[redacted] 1b

[redacted] 1b

[redacted] 1b

REFERENCE:

PUB/Centra I-111, I-116; CAC/Centra I-93 Attachment 1

QUESTION:

Explain why Centra [redacted] Did Centra's [redacted]? 1a, 1c

RESPONSE:

There were a number of factors influencing the decision to [redacted] 1a, 1c

- [redacted]; 1c
- During the 2017/18 winter, Centra's experience was that [redacted]; 1d
- [redacted]; 1c
- The 1,000 GJ/day of Empress to MDA FT capacity that Centra took assignment of from a T-Service customer that migrated to Sales Service effective April 1, 2017 would expire effective March 31, 2019; and
- A new industrial load was expected to have an in-service date in 2019.[3]

Given these factors, Centra elected to [redacted] 1a, 1c

[1] CAC/Centra I-97 a).
[2] PUB/Centra I-111.
[3] The in-service date has since been updated to 2020.

REFERENCE:

PUB/Centra I-129; CAC/Centra I-109; TCPL/Centra I-2

QUESTION:

a) Provide a comparison of the minimum and maximum proportions of gas that Centra can source from Western Canada [redacted]

b) [redacted]

RESPONSE:

a) [redacted]

b) [redacted]

[redacted]

REFERENCE:

Tab 8 p. 8 of 52; CAC/Centra I-92; Centra's Acquisition of Assets of Swan Valley Gas Corporation

QUESTION:

a) File Tab 3 page 4 of 11 from Centra's November 4, 2013 filing to the PUB with respect to the Acquisition of Assets of Swan Valley Gas Corporation.

b) Confirm whether Centra has extended or intends to extend the Gas Management Agreement with SaskEnergy that was in place when the assets of Swan Valley Gas Corporation were sold to Centra and confirm whether any agreement extension contains or is expected to contain the same pricing terms.

RESPONSE:

a) Please see the attachment to this response.

b) Centra's initial five-year gas management agreement with SaskEnergy was extended by one year to October 31, 2019 under the agreement's evergreening provisions. SaskEnergy provided notice of its intention to not extend the current agreement beyond this date, and SaskEnergy and Centra are in the process of finalizing a new agreement that will take effect November 1, 2019.

[redacted] 1a

The Gas Management Agreement-in-principle reflects a five-year contract for the sourcing, acquisition, nomination and balancing of all gas commodity requirements for SVGC by SaskEnergy. These commodity supplies will be indexed to a published AECO market index price that will be determined monthly, plus an AECO to TEP (the intra-Saskatchewan TransGas Energy Pool) market basis differential to be determined annually. Added to the foregoing will be a gas management fee on all commodity supplies provided to SVGC by SaskEnergy to be fixed for the five-year term at a level equal to that currently being paid by SVGC to SaskEnergy under its existing gas management package agreement. In addition, SaskEnergy will hold contracts for firm upstream transportation capacity on both TransGas from TEP to MIPL and on MIPL from the TransGas/MIPL interconnect to the SVGC gate station of 523 GJ/day and pass the resulting costs directly through to Centra with no profit or markup. The Gas Management Agreement-in-principle specifies a five-year initial contract term, with evergreening annual renewal provisions each year thereafter. If either party does not intend to continue the agreement after the initial 5-year term, notice of those intentions must be provided a minimum of one-year in advance.

A purchased gas cost forecast for SVGC for the 2013/14 Gas Year, reflecting the terms of the Gas Management Agreement-in-principle described above, based on AECO futures market prices as at September 1, 2013, is provided in Attachment 3.3 to Tab 3.

An Emergency Services Agreement between Centra and SaskEnergy is also in the process of being finalized. The Emergency Services Agreement defines the terms related to Centra’s retention of SaskEnergy to provide certain emergency response services to over or under pressurization at the gate/regulation stations, as well as safety

REFERENCE:

CAC/Centra I-98c, Tab 8 p. 2 of 52

QUESTION:

Explain whether Centra anticipates executing NGL extraction agreements with Empress straddle plant operators for a portion (or entirety) of its incremental [redacted] AECO-to-Empress NGTL capacity. 1a

RESPONSE:

Yes, Centra anticipates executing NGL extraction agreements with Empress straddle plant operators in relation to its incremental NGTL capacity. [redacted] 1a, 1c

REFERENCE:

PUB/Centra I-122 c)

QUESTION:

The request in PUB/Centra I-122(c) used the phrase "with imputed transportation" which should have said "with Centra's cost to deliver the gas to Emerson such that it is on a comparable basis to Emerson-sourced gas". If those prices are shown in Centra's schedules, please indicate where. If not, please provide.

RESPONSE:

Michigan and Chicago futures prices relate to gas transactions at the MichCon City Gate and Chicago City Gates points, respectively. Centra does not have transportation capacity from these points but it does have firm transportation capacity from Emerson to its market. Emerson futures prices specifically relate to gas transacted at Emerson. Accordingly, futures prices at Emerson are the most appropriate to use for Supplemental Gas pricing on a forecast basis, in addition to the reasons discussed in PUB/Centra I-122 a).

Additionally, regardless of which futures prices are used for forecast purposes, actual Supplemental Gas prices and volumes inevitably differ from forecast whether purchased at [redacted], and Centra purchases the 1c most economic supply on the day when required. Any differences between forecast and actuals are accounted for in the Supplemental Gas PGVA and ultimately collected from or refunded to customers in rates.

REFERENCE:

PUB/Centra I-136b , PUB/Centra I-88, Appendix 6.1 pp. 18-18 of 27, Tab 10 Schedules, IGU/Centra I-8b

PREAMBLE TO IR (IF ANY):

The Winnipeg North West Phases 1 and 2 expansion projects are significant plant additions completed since the 2013/14 Centra GRA. As the incremental cost impact of these projects are combined with other revenue requirement items in Centra's 2019/20 Cost Allocation Study, the incremental customer class cost impacts of these projects are difficult to isolate.

QUESTION:

Based on the estimated incremental revenue requirement related to the Winnipeg North West Phases 1 and 2 expansion project as estimated in IGU/Centra I-8, provide schedules that show the cost responsibility of each class for these projects

RESPONSE:

Please see the attachment to this response.

Estimated Revenue Requirement related to the Winnipeg North West Project allocated by classes

		System Total	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Fixed Price Offering FRPGS	
2019/20 GRA	($)	148,519,256	102,632,670	32,455,799	6,824,301	8,233	2,057,841	2,246,833	157,798	769,561	[redacted]			21,155	
PUB-Centra II-54 (Revenue Requirement adjusted for estimated costs attributable to the Winnipeg North West project as per IGU-Centra I-8b ii)	($)	146,419,256	101,371,763	31,918,097	6,699,991	8,081	2,009,702	2,140,051	152,001	755,333	[redacted]			21,145	1e
Estimated Revenue Requirement by class related to the Winnipeg North West project	($)	2,100,000	1,260,907	537,702	124,310	152	48,139	106,783	5,797	14,228	[redacted]			11	
	(%)	*100.0%*	*60.0%*	*25.6%*	*5.9%*	*0.0%*	*2.3%*	*5.1%*	*0.3%*	*0.7%*				*0.0%*	

REFERENCE:

IGU/Centra I-27, Completeness Review Attachment 11 (pp. 15-17 of 25), Tab 10 p. 1, PUB/Centra I-1a Attachment 2 (p. 9 of 9)

PREAMBLE TO IR (IF ANY):

In Centra's response to Christensen Associates' recommendations with respect to the cost allocation model, Centra states:

Recommendation 30: With respect to heating value deferral, CA recommends that Centra should include only customers with monthly bills that are determined according to energy sales volumes in the disposition of differentials attributable to heating value Centra's Position and Rationale: Centra accepts CA's recommendation with respect to the allocation of the disposition of the heating value deferral. Centra currently assigns heating value residuals to all customer classes on the basis of each class' contribution to total annual throughput. [...] For most customer classes, gross margin is largely collected through volumetric rates. The Special Contract Class rate structure is predominantly fixed (with only unaccounted for gas collected volumetrically), and should not, therefore, participate in the disposition of the heating value deferral.

[Completeness Review Attachment 11, pages 15-16 of 25]

QUESTION:

a) Confirm whether the Special Contract class volumetric rates currently recover any non-gas costs.
b) Confirm whether the Special Contract class billed demand in any month is affected by the heating value of the gas.
c) If neither (a) or (b) are confirmed, is it correct that variations in the heating value of gas have no impact on the monthly margin billed to the Special Contract class?
d) If (b) is confirmed, explain whether the current approach of allocating the Special Contract class a share of the heating value deferral account based on volumes is

appropriate. If not appropriate, how should the Special Contract class bear responsibility for changes in gross margin related to heating value?

e) If (b) is confirmed, demonstrate how changes in the heating value affect the billed demand for the Special Contract class, the dollar impact of these changes, and compare these dollar impacts to the proposed recovery or refund of heating value margin deferral proposed for the Special Contract class.

RESPONSE:

a) The volumetric rates for the Special Contract class recover the cost of UFG as allocated by the fixed allocation percentage. It is noted that there is a very small amount of non-gas related cost (approximately $160) that is recovered in the volumetric charge as well.

b) Not confirmed. The Special Contract class is billed using a two-part fixed/volumetric rate design, which has a BMC that recovers 100% of the fixed costs allocated to the class. Capacity costs are recovered through the BMC and there is no separate demand charge billed in the rates for this class.

c), d) and e)

While Centra would agree that a variation in heating value would not have a measurable impact on the monthly margin recovered from the Special Contract class, it has maintained the past practice of allocating the Heating Value Deferral on a volumetric basis.

In the current application, Centra has continued to allocate the Heating Value Deferral on a volumetric basis as it has done in the past when the Heating Value Deferral Account was in a refund position. During those periods, the Heating Value of gas was lower than [redacted] $GJ/10^3m^3$ and all classes participated in receiving refunds of the 1d
resulting gross margin adjustment. The Special Contract class was allocated a proportionate share of the refunds owing from the deferral account and received approximately [redacted] in refunds from the deferral account over the period from 2d
2002 to 2016 as shown in the response to IGU/CENTRA II–4a.

Centra proposes to examine the application of the Heating Value Deferral account after the completion of this GRA, and would advise the PUB and interveners of any changes that may be proposed on a go-forward basis.

REFERENCE:

PUB/Centra I-143

PREAMBLE TO IR (IF ANY):

The request in PUB/Centra I-143(c) was to show the non-gas bill impacts proposed in the current application. These non-gas bill impacts will contain elements of the reversal of the August 1, 2017 rate reversion but also non-gas rate changes based on the updated cost allocation model results.

QUESTION:

a) Please provide a bill impact schedule that isolates the non-gas rate changes proposed in the current application. The requested bill impacts should remove the gas rate impacts but include the impacts from all the non-gas rate changes (both the reversal of the rate reversion and the updated cost allocation results). Endeavour to include in these impacts the change in the Primary Gas overhead rate.

b) Refile Figures 1 and 2 in the response to PUB/Centra I-147(d) based on the bill impacts calculated in (a) above. In addition, recalculate the Mainline-Firm bill impacts in Figure 1 based on consistent consumption and load factors (that is, use 2,833 and 75% for the first row and 28,328 and 40% for the second row, or another set of consistent factors).

RESPONSE:

a) Please see the attachment to this response that provides a bill impact that isolates the non-gas rate changes proposed in the current application. The Primary Gas overhead rate change (from currently approved to proposed in the current application) is included in this bill impact.

b) The figures below compare the bill impacts from the August 1, 2017 non-gas rate changes (including the Primary Gas Overhead rate change) with the isolated bill impacts of non-gas rate changes proposed in the current application (including the proposed Primary Gas Overhead rate change).

Figure 1: Annual Bill Impacts for Sales Service Customers comparing the isolated non-gas rate changes proposed in this current application to the non-gas rate changes in August 1, 2017 Primary Gas Application (both include the Primary Gas overhead rate change).

2019/20 Test Year			Annual Impacts Base Rates *non-gas rates changes only* *(Includes PG Overhead Rate change)* **2019/20 GRA**		Annual Impacts Base Rates *Aug 1, 2017 non-gas rates changes* *(Includes PG Overhead Rate change)* **Aug 1, 2017 PG Application**	
Customer Class	Consumption (10^3M^3)	Load Factor	$ Impact	% Change	$ Impact	% Change
SGS	1.0		($13)	-3.3%	($3)	-0.8%
	2.2		($29)	-4.3%	($8)	-1.0%
	11.3		($146)	-5.3%	($38)	-1.3%
LGS	11.3		$25	0.9%	($17)	-0.6%
	679.9		$1,484	1.2%	($1,033)	-0.8%
HVF*	685.0	75%	($1,614)	-1.5%	($1,057)	-0.9%
	849.8	25%	$1,108	0.7%	($2,372)	-1.3%
Mainline *	2,833	75%	($17,823)	-4.7%	$9,190	2.2%
	28,328	40%	$46,525	1.1%	($55,722)	-1.1%
Interruptible	850	25%	($3,839)	-2.9%	($2,939)	-2.0%
	14,164	75%	($80,087)	-4.7%	$1,706	0.1%

* Mainline and HVF class consumption level represent the min to max range from 2019/20 GRA and coresponding $ and % impact for that consumption from Aug 1, 2017 Primary Gas Application .

Figure 2: Annual Bill Impacts for T-Service Customers comparing the isolated non-gas rate changes proposed in this current application to the non-gas rate changes in August 1, 2017 Primary Gas Application (both include the Primary Gas overhead rate change).

2019/20 Test Year			Annual Impacts Base Rates *non-gas rates changes only* *(Includes PG Overhead Rate change)* **2019/20 GRA**		Annual Impacts Base Rates *Aug 1, 2017 non-gas rates changes* *(Includes PG Overhead Rate change)* **Aug 1, 2017 PG Application**	
Customer Class	Consumption (10^3M^3)	Load Factor	$ Impact	% Change	$ Impact	% Change
HVF (T-Service)	2,600	40%	$13,562	21.0%	($9,449)	-12.8%
	17,600	75%	$77,085	29.9%	($45,850)	-15.1%
Mainline (T-Service)	14,000	75%	$42,721	30.0%	($47,138)	-24.9%
	44,000	40%	$295,372	45.3%	($217,030)	-25.0%
Special Contract	[redacted]					
Power Stations						

2d

Centra Gas Manitoba Inc.
2019/20 General Rate Application
Bill Impact Schedule isolating the the non-gas rate changes proposed in the 2019/20 GRA

1					**FEB 1/19 APPROVED BASE RATES**				**NOV 1/19 PROPOSED BASE RATES**				**BASE IMPACTS**	
2									*Cost of Gas rate component*				*non-gas rate changes only*	
3									*unchanged from Feb 1/19 approved rates*				*(including Primary Gas Rate change)*	
4														
5		Load	Annual Use		Basic Chg	Demand	Commodity	Annual	Basic Chg	Demand	Commodity	Annual	$	%
6		Factor	10^3m^3	Mcf										
7														
8	Small General Service *		1.00	35	$168	$0	$227	$395	$168	$0	$214	$382	($13)	-3.3%
9			1.98	70	$168	$0	$450	$618	$168	$0	$424	$592	($25)	-4.1%
10	*(Typical Residential Customer)*		2.22	78	$168	$0	$504	$672	$168	$0	$475	$643	($29)	-4.3%
11			2.80	99	$168	$0	$637	$805	$168	$0	$601	$769	($36)	-4.5%
12			3.20	113	$168	$0	$727	$895	$168	$0	$686	$854	($41)	-4.6%
13			3.68	130	$168	$0	$837	$1,005	$168	$0	$789	$957	($47)	-4.7%
14			11.33	400	$168	$0	$2,575	$2,743	$168	$0	$2,429	$2,597	($146)	-5.3%
15														
16	Large General Service		11.33	400	$924	$0	$1,974	$2,898	$924	$0	$1,998	$2,922	$25	0.9%
17			59.49	2,100	$924	$0	$10,362	$11,286	$924	$0	$10,492	$11,416	$130	1.2%
18			679.87	24,000	$924	$0	$118,420	$119,344	$924	$0	$119,904	$120,828	$1,484	1.2%
19														
20	HVF (Sales Service)	25%	850	30,000	$13,420	$51,159	$96,626	$161,205	$12,097	$55,348	$94,868	$162,313	$1,108	0.7%
21		40%	850	30,001	$13,420	$31,976	$96,629	$142,024	$12,097	$34,593	$94,871	$141,562	($463)	-0.3%
22		40%	1,416	50,000	$13,420	$53,291	$161,043	$227,753	$12,097	$57,654	$158,113	$227,864	$111	0.0%
23		40%	2,833	100,000	$13,420	$106,581	$322,086	$442,087	$12,097	$115,308	$316,226	$443,631	$1,544	0.3%
24		40%	6,200	218,866	$13,420	$233,271	$704,936	$951,626	$12,097	$252,369	$692,112	$956,578	$4,952	0.5%
25		40%	12,600	444,792	$13,420	$474,066	$1,432,611	$1,920,097	$12,097	$512,879	$1,406,550	$1,931,526	$11,428	0.6%
26		75%	685	24,181	$13,420	$13,745	$77,884	$105,049	$12,097	$14,871	$76,467	$103,435	($1,614)	-1.5%
27		75%	850	30,000	$13,420	$17,053	$96,626	$127,098	$12,097	$18,449	$94,868	$125,414	($1,684)	-1.3%
28		75%	1,416	50,000	$13,420	$28,422	$161,043	$202,884	$12,097	$30,749	$158,113	$200,959	($1,925)	-0.9%
29		75%	2,833	100,000	$13,420	$56,843	$322,086	$392,349	$12,097	$61,497	$316,226	$389,821	($2,528)	-0.6%
30		75%	6,200	218,866	$13,420	$124,411	$704,936	$842,767	$12,097	$134,597	$692,112	$838,806	($3,961)	-0.5%
31		75%	12,600	444,792	$13,420	$252,835	$1,432,611	$1,698,866	$12,097	$273,535	$1,406,550	$1,692,182	($6,684)	-0.4%
32														
33	HVF (T-Service)	40%	2,600	91,783	$13,420	$32,128	$18,923	$64,470	$12,097	$39,204	$26,731	$78,033	$13,562	21.0%
34		40%	11,000	388,311	$13,420	$135,925	$80,057	$229,402	$12,097	$165,863	$113,095	$291,055	$61,653	26.9%
35		40%	17,600	621,297	$13,420	$217,481	$128,091	$358,991	$12,097	$265,381	$180,952	$458,429	$99,438	27.7%
36		75%	2,600	91,783	$13,420	$17,135	$18,923	$49,477	$12,097	$20,909	$26,731	$59,737	$10,260	20.7%
37		75%	11,000	388,311	$13,420	$72,494	$80,057	$165,970	$12,097	$88,460	$113,095	$213,652	$47,682	28.7%
38		75%	17,600	621,297	$13,420	$115,990	$128,091	$257,500	$12,097	$141,536	$180,952	$334,585	$77,085	29.9%
39														
40	Cooperative	35%	250	8,825	$3,289	$14,042	$23,150	$40,481	$3,169	$15,091	$21,835	$40,095	($386)	-1.0%
41		35%	350	12,355	$3,289	$19,659	$32,410	$55,358	$3,169	$21,127	$30,569	$54,865	($493)	-0.9%
42		35%	500	17,650	$3,289	$28,084	$46,300	$77,673	$3,169	$30,182	$43,670	$77,021	($653)	-0.8%
43														
44	MLC (Sales Service)	40%	2,833	100,000	$28,240	$163,725	$266,366	$458,331	$12,969	$182,435	$253,836	$449,240	($9,091)	-2.0%
45		40%	14,164	500,000	$28,240	$818,626	$1,331,830	$2,178,696	$12,969	$912,176	$1,269,178	$2,194,323	$15,627	0.7%
46		40%	28,328	1,000,000	$28,240	$1,637,252	$2,663,660	$4,329,152	$12,969	$1,824,351	$2,538,357	$4,375,677	$46,525	1.1%
47		75%	2,833	100,000	$28,240	$87,320	$266,366	$381,926	$12,969	$97,299	$253,836	$364,103	($17,823)	-4.7%
48		75%	14,164	500,000	$28,240	$436,601	$1,331,830	$1,796,671	$12,969	$486,494	$1,269,178	$1,768,641	($28,030)	-1.6%
49		75%	28,328	1,000,000	$28,240	$873,201	$2,663,660	$3,565,101	$12,969	$972,987	$2,538,357	$3,524,313	($40,788)	-1.1%
50		75%	41,000	1,447,339	$28,240	$1,263,818	$3,855,220	$5,147,279	$12,969	$1,408,243	$3,673,864	$5,095,076	($52,203)	-1.0%
51														
52	MLC (T- Service)	40%	14,000	494,213	$28,240	$181,393	$17,293	$226,926	$12,969	$268,925	$28,601	$310,495	$83,570	36.8%
53		40%	18,000	635,417	$28,240	$233,219	$22,234	$283,693	$12,969	$345,761	$36,773	$395,503	$111,810	39.4%
54		40%	44,000	1,553,242	$28,240	$570,091	$54,349	$652,680	$12,969	$845,193	$89,890	$948,052	$295,372	45.3%
55		75%	14,000	494,213	$28,240	$96,743	$17,293	$142,276	$12,969	$143,427	$28,601	$184,997	$42,721	30.0%
56		75%	18,000	635,417	$28,240	$124,384	$22,234	$174,857	$12,969	$184,406	$36,773	$234,148	$59,291	33.9%
57		75%	44,000	1,553,242	$28,240	$304,049	$54,349	$386,638	$12,969	$450,770	$89,890	$553,629	$166,991	43.2%
58														
59	Special Contract	[redacted]												2d
60														
61	Power Stations	[redacted]												
62														
63	Interruptible Sales	25%	850	30,000	$12,513	$24,602	$93,682	$130,796	$12,423	$26,177	$88,357	$126,957	($3,839)	-2.9%
64		40%	2,833	100,000	$12,513	$51,254	$312,273	$376,039	$12,423	$54,535	$294,523	$361,482	($14,557)	-3.9%
65		40%	14,164	500,000	$12,513	$256,268	$1,561,364	$1,830,144	$12,423	$272,677	$1,472,615	$1,757,716	($72,429)	-4.0%
66		75%	850	30,000	$12,513	$8,201	$93,682	$114,395	$12,423	$8,726	$88,357	$109,506	($4,889)	-4.3%
67		75%	2,833	100,000	$12,513	$27,335	$312,273	$352,121	$12,423	$29,086	$294,523	$336,032	($16,089)	-4.6%
68		75%	14,164	500,000	$12,513	$136,676	$1,561,364	$1,710,553	$12,423	$145,428	$1,472,615	$1,630,466	($80,087)	-4.7%

* The bill impact for SGS customers class reflecting the non-gas rate changes including the Primary Gas Overhead rate change
by coincident it is almost the same as the bill impact reflecting the base rates (updated March 22).

Centra Gas Manitoba Inc.
2019/20 General Rate Application
Bill Impact Schedule isolating the the non-gas rate changes proposed in the 2019/20 GRA

1					**FEB 1/19 APPROVED BASE RATES**				**NOV 1/19 PROPOSED BASE RATES**				**BASE IMPACTS**	
2									*Cost of Gas rate component*				*non-gas rate changes only*	
3									*unchanged from Feb 1/19 approved rates*				*(including Primary Gas Rate change)*	
4														
5		Load	Annual Use		Basic Chg	Demand	Commodity	Annual	Basic Chg	Demand	Commodity	Annual	$	%
6		Factor	10^3m^3	Mcf										
7														
8	Small General Service *		1.00	35	$168	$0	$227	$395	$168	$0	$214	$382	($13)	-3.3%
9			1.98	70	$168	$0	$450	$618	$168	$0	$424	$592	($25)	-4.1%
10	*(Typical Residential Customer)*		2.22	78	$168	$0	$504	$672	$168	$0	$475	$643	($29)	-4.3%
11			2.80	99	$168	$0	$637	$805	$168	$0	$601	$769	($36)	-4.5%
12			3.20	113	$168	$0	$727	$895	$168	$0	$686	$854	($41)	-4.6%
13			3.68	130	$168	$0	$837	$1,005	$168	$0	$789	$957	($47)	-4.7%
14			11.33	400	$168	$0	$2,575	$2,743	$168	$0	$2,429	$2,597	($146)	-5.3%
15														
16	Large General Service		11.33	400	$924	$0	$1,974	$2,898	$924	$0	$1,998	$2,922	$25	0.9%
17			59.49	2,100	$924	$0	$10,362	$11,286	$924	$0	$10,492	$11,416	$130	1.2%
18			679.87	24,000	$924	$0	$118,420	$119,344	$924	$0	$119,904	$120,828	$1,484	1.2%
19														
20	HVF (Sales Service)	25%	850	30,000	$13,420	$51,159	$96,626	$161,205	$12,097	$55,348	$94,868	$162,313	$1,108	0.7%
21		40%	850	30,001	$13,420	$31,976	$96,629	$142,024	$12,097	$34,593	$94,871	$141,562	($463)	-0.3%
22		40%	1,416	50,000	$13,420	$53,291	$161,043	$227,753	$12,097	$57,654	$158,113	$227,864	$111	0.0%
23		40%	2,833	100,000	$13,420	$106,581	$322,086	$442,087	$12,097	$115,308	$316,226	$443,631	$1,544	0.3%
24		40%	6,200	218,866	$13,420	$233,271	$704,936	$951,626	$12,097	$252,369	$692,112	$956,578	$4,952	0.5%
25		40%	12,600	444,792	$13,420	$474,066	$1,432,611	$1,920,097	$12,097	$512,879	$1,406,550	$1,931,526	$11,428	0.6%
26		75%	685	24,181	$13,420	$13,745	$77,884	$105,049	$12,097	$14,871	$76,467	$103,435	($1,614)	-1.5%
27		75%	850	30,000	$13,420	$17,053	$96,626	$127,098	$12,097	$18,449	$94,868	$125,414	($1,684)	-1.3%
28		75%	1,416	50,000	$13,420	$28,422	$161,043	$202,884	$12,097	$30,749	$158,113	$200,959	($1,925)	-0.9%
29		75%	2,833	100,000	$13,420	$56,843	$322,086	$392,349	$12,097	$61,497	$316,226	$389,821	($2,528)	-0.6%
30		75%	6,200	218,866	$13,420	$124,411	$704,936	$842,767	$12,097	$134,597	$692,112	$838,806	($3,961)	-0.5%
31		75%	12,600	444,792	$13,420	$252,835	$1,432,611	$1,698,866	$12,097	$273,535	$1,406,550	$1,692,182	($6,684)	-0.4%
32														
33	HVF (T-Service)	40%	2,600	91,783	$13,420	$32,128	$18,923	$64,470	$12,097	$39,204	$26,731	$78,033	$13,562	21.0%
34		40%	11,000	388,311	$13,420	$135,925	$80,057	$229,402	$12,097	$165,863	$113,095	$291,055	$61,653	26.9%
35		40%	17,600	621,297	$13,420	$217,481	$128,091	$358,991	$12,097	$265,381	$180,952	$458,429	$99,438	27.7%
36		75%	2,600	91,783	$13,420	$17,135	$18,923	$49,477	$12,097	$20,909	$26,731	$59,737	$10,260	20.7%
37		75%	11,000	388,311	$13,420	$72,494	$80,057	$165,970	$12,097	$88,460	$113,095	$213,652	$47,682	28.7%
38		75%	17,600	621,297	$13,420	$115,990	$128,091	$257,500	$12,097	$141,536	$180,952	$334,585	$77,085	29.9%
39														
40	Cooperative	35%	250	8,825	$3,289	$14,042	$23,150	$40,481	$3,169	$15,091	$21,835	$40,095	($386)	-1.0%
41		35%	350	12,355	$3,289	$19,659	$32,410	$55,358	$3,169	$21,127	$30,569	$54,865	($493)	-0.9%
42		35%	500	17,650	$3,289	$28,084	$46,300	$77,673	$3,169	$30,182	$43,670	$77,021	($653)	-0.8%
43														
44	MLC (Sales Service)	40%	2,833	100,000	$28,240	$163,725	$266,366	$458,331	$12,969	$182,435	$253,836	$449,240	($9,091)	-2.0%
45		40%	14,164	500,000	$28,240	$818,626	$1,331,830	$2,178,696	$12,969	$912,176	$1,269,178	$2,194,323	$15,627	0.7%
46		40%	28,328	1,000,000	$28,240	$1,637,252	$2,663,660	$4,329,152	$12,969	$1,824,351	$2,538,357	$4,375,677	$46,525	1.1%
47		75%	2,833	100,000	$28,240	$87,320	$266,366	$381,926	$12,969	$97,299	$253,836	$364,103	($17,823)	-4.7%
48		75%	14,164	500,000	$28,240	$436,601	$1,331,830	$1,796,671	$12,969	$486,494	$1,269,178	$1,768,641	($28,030)	-1.6%
49		75%	28,328	1,000,000	$28,240	$873,201	$2,663,660	$3,565,101	$12,969	$972,987	$2,538,357	$3,524,313	($40,788)	-1.1%
50		75%	41,000	1,447,339	$28,240	$1,263,818	$3,855,220	$5,147,279	$12,969	$1,408,243	$3,673,864	$5,095,076	($52,203)	-1.0%
51														
52	MLC (T- Service)	40%	14,000	494,213	$28,240	$181,393	$17,293	$226,926	$12,969	$268,925	$28,601	$310,495	$83,570	36.8%
53		40%	18,000	635,417	$28,240	$233,219	$22,234	$283,693	$12,969	$345,761	$36,773	$395,503	$111,810	39.4%
54		40%	44,000	1,553,242	$28,240	$570,091	$54,349	$652,680	$12,969	$845,193	$89,890	$948,052	$295,372	45.3%
55		75%	14,000	494,213	$28,240	$96,743	$17,293	$142,276	$12,969	$143,427	$28,601	$184,997	$42,721	30.0%
56		75%	18,000	635,417	$28,240	$124,384	$22,234	$174,857	$12,969	$184,406	$36,773	$234,148	$59,291	33.9%
57		75%	44,000	1,553,242	$28,240	$304,049	$54,349	$386,638	$12,969	$450,770	$89,890	$553,629	$166,991	43.2%
58														
59	Special Contract	[redacted]												
60														2d
61	Power Stations													
62														
63	Interruptible Sales	25%	850	30,000	$12,513	$24,602	$93,682	$130,796	$12,423	$26,177	$88,357	$126,957	($3,839)	-2.9%
64		40%	2,833	100,000	$12,513	$51,254	$312,273	$376,039	$12,423	$54,535	$294,523	$361,482	($14,557)	-3.9%
65		40%	14,164	500,000	$12,513	$256,268	$1,561,364	$1,830,144	$12,423	$272,677	$1,472,615	$1,757,716	($72,429)	-4.0%
66		75%	850	30,000	$12,513	$8,201	$93,682	$114,395	$12,423	$8,726	$88,357	$109,506	($4,889)	-4.3%
67		75%	2,833	100,000	$12,513	$27,335	$312,273	$352,121	$12,423	$29,086	$294,523	$336,032	($16,089)	-4.6%
68		75%	14,164	500,000	$12,513	$136,676	$1,561,364	$1,710,553	$12,423	$145,428	$1,472,615	$1,630,466	($80,087)	-4.7%

* The bill impact for SGS customers class reflecting the non-gas rate changes including the Primary Gas Overhead rate change
by coincident it is almost the same as the bill impact reflecting the base rates (updated March 22).

REFERENCE:

PUB/Centra I-145, I-147(e), PUB/Centra I-149(b) Attachment 2, IGU/Centra I-22(p), IGU/Centra I-26

QUESTION:

a) Why does Centra describe the balancing tolerance as "approximately 7%" and not provide a specific percentage? Provide the absolute daily imbalance tolerance and the cumulative imbalance tolerances. Explain the two exceptions noted in the footnote to PUB/Centra I-145(c).

b) Explain how the 150 GJ and 300 GJ absolute tolerances shown in PUB/Centra I-149b Attachment 2 were derived and whether these tolerances apply to all T-Service customers.

c) Are the absolute daily and cumulative balancing tolerances static or do they vary daily with the magnitude of the nomination? Are there contractual levels of nominations between Centra and T-Service customers such that the balancing tolerances are static?

d) Confirm whether Centra's proposal to implement a T-Service Balancing fee structure "at 50% of TCPL's", effectively implies that Centra will apply the same calculations for the TCPL daily and cumulative balancing fees shown in PUB/Centra I-145a-e Attachment 1, but apply 50% of the prevalent KPUC EDA Eastern Zone Mainline toll to any billed excess above the various tolerance Tiers (and base these Tier billed excess using the more generous daily and cumulative tolerances referenced in (a) above).

RESPONSE:

a) Absolute daily and cumulative tolerances would be assigned to T-Service customers on the basis of their average daily consumption[1] over the prior gas year where in general terms, the higher the average daily consumption the greater the tolerance afforded. The following chart illustrates the groupings of absolute daily and cumulative tolerances that would be assigned to T-Service customers based on ranges of customers' average daily consumption:

[1] By contrast, Centra measures balancing performance against average daily available (i.e., net nomination).

Average Daily Consumption (GJ/day)	Number of Customers	Absolute Daily Tolerance	Absolute Cumulative Tolerance
Less than 1,000	4	+/- 50 GJ	+/- 100 GJ
1,000 to less than 1,700	4	+/- 100 GJ	+/- 200 GJ
1,700 to less than 2,500	3	+/- 150 GJ	+/- 300 GJ
2,500 to less than 5,000	3	+/- 250 GJ	+/- 500 GJ
[redacted]	1	+/- 500 GJ	+/- 1,000 GJ

This approach helps to ensure relative consistency amongst the majority of T-Service customers, with all but 2 of fifteen customers having absolute daily tolerances that allow for imbalances between 6% and 8% of their average daily available. The two 2d
exceptions are [redacted] whose absolute daily tolerances allow for imbalances of [redacted], respectively. These exceptions are related to the magnitude of these customers' average daily consumption: [redacted] is by far the smallest T-Service customer at less than [redacted], while [redacted] is the largest T-Service customer at just over [redacted]. Accordingly, these customers' absolute daily tolerances fall 2d
outside the norm of approximately 7% for Centra's T-Service customers.

b) Please see the response to part a) above. The illustrative example in Attachment 2 to the response to PUB/CENTRA I-149b depicts a customer whose average daily consumption is between 1,700 GJ/day and 2,500 GJ/day. As such, its absolute daily tolerance is +/- 150 GJ and its absolute cumulative tolerance is +/- 300 GJ.

c) Absolute daily and cumulative tolerances would be assigned and set a year at a time, and re-assessed on an annual basis using actual historical consumption information from the most recently completed gas year.

There are no contractual levels of nominations between Centra and T-Service customers. As described in the response to PUB/CENTRA I-147a, Centra must reserve a buffer on a daily basis to contend with the uncertainty of T-Service nominations and both the direction and magnitude of their imbalances.

d) Confirmed.

REFERENCE:

PUB/Centra I-147, IGU/Centra I-1a-c

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Given the assumptions made in the responses to PUB/Centra I-147 (a) and (b), confirm the following difference in TCPL-to-Centra and Centra-to-T-Service customers balancing charges that could have resulted in gas years 2016/17 and 2017/18. If not confirmed, correct the table below as required.

Balancing Charges	Gas Year		Source
	2016/17	**2017/18**	
TCPL to Centra	$243,856	$273,504	PUB/Centra I-147a
Centra to T-Service Customers	$920,602	$760,191	PUB/Centra I-147b
Difference	**-$676,746**	**-$486,687**	

b) In the response to PUB/Centra I-147(d), Centra states that T-service customers are not part of a “pool” and thus Centra did not provide the balancing charges avoided due to T-service customers offsetting Centra’s Sales Service imbalances. However, does TCPL treat the Manitoba Delivery Area as a “pool” in that balancing fees are charged on the aggregate imbalance of Sales Service and T-service customers?

c) Centra states that it will charge balancing fees to T-service customers even if TCPL does not levy balancing charges against Centra. In this sense, is it correct that these charges do not represent cost recovery from Centra’s T-Service customers? Would this view also apply to TCPL, which levies balancing fees on Centra even if the Mainline is in balance or if Centra’s balance is contrary to the Mainline’s position? Is the Mainline a cost of service pipeline whose charges to customers (shippers) are based on the approved costs of the pipeline? What other charges does Centra levy on its customers that are approved by the PUB but are not directly cost-based or have an incentive nature (for example, unauthorized over-run charges to Interruptible customers)?

d) Confirm whether the following is correct for Centra’s current practice, or, if not confirmed, make corrections or clarifications: If a T-service customer drafts the

Mainline, Centra uses its supply, storage, and transportation assets to try to bring the Centra MDA into balance. It does this by nominating additional volumes on the Mainline (presumably with unutilized FT capacity) and also nominates additional commodity supplies from its Western Canadian gas supplier (currently ConocoPhillips). The fixed cost of the FT is already part of the fixed costs paid for by Sales Service customers, so there are no incremental variable costs for the additional pipeline nominations, but there are opportunity costs for foregone capacity management revenues. The costs of the additional commodity supplied by Centra will also fall to Sales Service customers.

In the reverse situation, if a T-service customer packs the Mainline, Centra will adjust its nominations down for Sales Service customers to try to bring the MDA into balance. Centra will then have additional unused FT capacity which it could release to possibly generate capacity management revenues. Centra will also nominate fewer commodity supplies from its Western Canadian supplier (ConocoPhillips), which will lower Centra's commodity costs for its Sales Service customers.

RESPONSE:

a) Confirmed.

b) Yes, Centra's delivery areas are treated as pools by TCPL. By electing T-Service however, T-Service customers are opting out of the pools managed by Centra. As described in the response to PUB/CENTRA I-145e, the central premise of T-Service is that customers electing it are choosing to manage their *individual* upstream natural gas portfolios, thereby opting out of Centra's upstream contracting and activities as represented by the pools that Centra manages within its delivery areas. T-Service customers avoid any cost responsibility for Centra's upstream portfolio thus, to be fair, they should not be entitled to selectively use Centra's portfolio to offset their imbalances without an appropriate balancing fee structure in place.

c) Similar to the National Energy Board ("NEB")-approved TCPL Mainline balancing fee structure, Centra is seeking approval from this Board to institute balancing fees that are not cost recovery-based because:

1) Centra has an obligation to the TCPL Mainline to ensure that its delivery areas are balanced, both to protect the integrity and reliability of the pipeline and to ensure that customers at the far downstream end of the system obtain their gas. This is not a casual requirement. It is thus <u>critical</u> that shippers do not routinely pack or draft outside of tolerance. Both the NEB and shippers on the TCPL Mainline support the concept of balancing fees in their current form because they are necessary to appropriately incent balancing behaviour. The fees are significant and are not cost-based because they must strongly deter and minimize account imbalances.

2) Centra incurs balancing fees regardless of:
   i. The TCPL Mainline's line-pack position. The pipeline overall may be balanced but Centra will incur fees if its delivery areas are out of balance in excess of tolerance and regardless of the reason for the imbalance (e.g., there is no exemption if Centra and/or its customers are contending with unplanned maintenance or an outage); and
   ii. Centra's position (pack or draft) relative to the pipeline's position. Similarly, there is no exemption from paying fees for an imbalance because Centra's position is contrary to (i.e., helping) the pipeline's position.

   Neither of these features of the NEB-approved TCPL Mainline balancing fee structure is cost-based, yet they exist for the reasons described in part 1) above. Fines or fees are routinely used to guide behaviour, e.g., speeding fines are not cost-based because they're effected to serve as a strong deterrent to behaviour that could harm others and result in extraordinary societal (i.e., system) costs.

3) Balancing fees are but a small portion of the costs that Centra incurs as a result of T-Service imbalances. Centra also incurs opportunity costs in the form of foregone Capacity Management revenue and further direct costs in the form of higher commodity costs associated with the delay of transactions from day-ahead to intra-day (i.e., a higher purchase price or a lower sales price, the later in the gas day the transaction takes place).

With respect to the other charges that are approved by the PUB that are not directly cost-based or have an incentive nature, please see the following table:

Charge	Comments
Unauthorized Overrun Delivery Charge and Unauthorized Overrun Gas Charge	Charged to customers that fail to curtail service upon notice from Centra and who otherwise are not supplied with Alternate Supply Service. This charge was established to provide a better incentive to interruptible customers during a period of curtailment.
Late Payment Charge	Late payment charges are assessed on accounts remaining unpaid after the due date. While revenues from late payment charges help to recover the cost of collection activities, the late payment charge is also assessed to provide incentive to customers to pay their bills on time.
Gas Meter Test Fee	The Meter Test Fee is applied when a customer requests that their meter be removed from service to be tested for accuracy by Measurement Canada. The fee is only applied in cases where the meter is found to be recording within acceptable tolerances. As noted in Tab 12 of Centra's Application, the proposed Meter Test Fee is set below the actual costs of both the electric and gas meter dispute costs to ensure that customers who believe there is a problem with their meter do not face a fee so high that it acts as a deterrent to having the test performed. At the same time, the fee needs to be high enough that customers don't request a test be performed every time they perceived their bill to be too high.
ABC (Agency Billing & Collection) Fee	Agency Billing and Collection ("ABC") Service is offered in conjunction with Western Transportation Service. ABC Service allows Centra to bill Customer's for Primary Gas on behalf of a Broker, using the Broker's Primary Gas price. The Customer makes a single payment to the Company. The Broker pays to Centra $0.25 per customer per month for ABC service. As noted in Centra's response to PUB/Centra I-155, this $0.25 nominal fee does not fully recover the overall cost of maintaining the ABC Service. Centra's actual incurred ABC costs over and above the amounts recovered directly from WTS Brokers via ABC fees are recovered from all gas customers in their rates in return for the benefits of being able to choose their Primary Gas supplier.

d) The inference in this question appears to be that the impacts of T-Service customers' routine imbalances (packs and drafts) may offset one another over time such that the result is neutral for Sales Service customers. To the contrary and as Centra described in its response to PUB/Centra 147 a), the actions taken by Centra to counteract T-Service imbalances and the need to maintain a buffer to contend with the uncertainty of their positions currently results in costs borne solely by Sales Service customers well in excess of the direct costs of the balancing fees charged by TCPL, both:

i. opportunity costs in the form of foregone Capacity Management revenue; and
ii. further direct costs (in addition to the balancing fees charged by TCPL) in the form of higher commodity costs associated with the delay of transactions from day-ahead to intra-day (i.e., a higher purchase price or a lower sales price, the later in the gas day the transaction takes place).

With regard to the specifics of Centra's current practice, if a T-Service customer drafts the Manitoba Delivery Area (MDA) for example, Centra may use its supply, storage and transportation assets to bring the delivery area into balance in any of the following ways depending on the circumstances at the time:

- If there is unutilized TCPL Mainline FT capacity from Empress, additional supply may be nominated by Centra;
- If there is unutilized storage withdrawal capability and associated transportation capacity on ANR and GLGT, additional supply may be nominated from storage;
- Supplemental Gas may be purchased to serve the delivery area; or
- If Centra has the operational capability to repay a loan in the coming days, this service may be taken from the TCPL Mainline (depending on availability).

If a T-Service customer packs the MDA, Centra may use its supply, storage and transportation assets to bring the delivery area into balance in any of the following ways, depending on the circumstances at the time:

- Reduce the Western Canadian supply nomination or sell excess supply;
- Reduce the supply nomination from Centra's storage inventory; or
- If Centra has the operational capability to utilize incremental gas in the coming days, Centra may execute a park with the TCPL Mainline (depending on availability).

Centra confirms that:

- There are no variable transportation costs associated with incremental supply nominations on the TCPL Mainline by Centra to bring the delivery area into balance if T-Service customers are drafting the system, other than compressor fuel paid to TCPL with gas in kind, the cost of which is recoverable from Sales Service customers;
- There are variable storage and transportation costs associated with storage nominations used to balance the MDA, which are also borne by Sales Service customers;
- Given that decisions about T-Service customers' positions cannot be made day-ahead, they result in Sales Service customers bearing the incremental costs (or reduced value) of supply nominated or sold on an intra-day basis;
- Additionally, uncertainty over whether T-Service customers will address packs or drafts (due to the absence of an appropriate balancing fee structure) results in delayed decisions on capacity management transactions, representing foregone capacity management revenue to the account of Sales Service customers, specifically the difference in revenue that could have been earned if Centra made its decisions earlier in the gas day rather than having to wait until the ID2 or ID3 nomination window. The value of this timing difference averaged $0.24/GJ over the 2016/17 and 2017/18 gas years; and
- The costs associated with purchases of Supplemental Gas to balance the MDA are borne by Sales Service customers, rather than the T-Service customer(s) that caused the imbalances.

REFERENCE:

PUB/Centra I-147b, PUB/Centra I-150c Attachment 1, IGU/Centra I-22h Attachment 1

PREAMBLE TO IR (IF ANY):

The table provided in PUB/Centra I-147b provides the pro-forma balancing fee outcomes that would have been experienced if Centra's proposed balancing fee structure had been in place since 2016/17 and T-Service customers made no attempt to improve their balancing performance.

QUESTION:

a) File a revised version of the table provided in PUB/Centra I-147b for the 2017/18 year only assuming Centra's proposed balancing fee structure had been in place and all T-Service customers had made a 10% improvement in the daily balancing performance. That is, their daily nominations were 10% more accurate than they actually were.
b) File a revised version of the table provided in PUB/Centra I-147b for the 2017/18 year only assuming Centra's proposed balancing fee structure had been in place and all T-Service customers had a 50% improvement in the daily balancing performance.

RESPONSE:

a) and b):

The actions Centra would have taken in response to T-Service imbalances, and the resulting delivery area imbalances and balancing fees assessed by TCPL would all have been different if T-Service customers' balancing performance was different historically. Centra's decisions are made in real time, at up to six different nomination windows for each gas day. Accordingly, Centra cannot model the historical impacts of improvements in T-Service customers' balancing performance without recreating a total of 1,976[1] decision points and all of the potential resultant outcomes, which is not feasible.

[1] (151 days of the winter season x 6 nomination windows) + (214 days of the summer season x 5 nomination windows) = 1,976

Directionally, a 10% improvement in T-Service customers' daily balancing performance would result in a greater than 10% reduction in their balancing fees and, similarly, a 50% improvement in T-Service customers' daily balancing performance would result in a greater than 50% reduction in their balancing fees. In both of these circumstances, T-Service customers' absolute daily and cumulative tolerances would remain the same, thus the amount of the imbalance on which balancing fees are assessed would diminish proportionally. Put another way, the closer T-Service customers get to operating within their absolute daily and cumulative tolerances, the greater the likelihood they will pay no balancing fees. Please see the response to IGU/Centra I-26 which illustrates a scenario in which a T-Service customer would pay no balancing fees despite its daily and cumulative imbalances.

REFERENCE:

PUB/Centra I-151(d), CAC/Centra I-32(d)

QUESTION:

Explain how many times Centra waived reconnection fees for low income customers in 2017/18.

RESPONSE:

Centra does not track which customers are low income and is therefore unable to provide how many times reconnection fees were waived for low income customers in 2017/18.

REFERENCE:

PUB/Centra I-162(g)

QUESTION:

Confirm whether Centra maintains any measures of performance related to timeliness of responding to service calls or line locate requests, appointments met within the designated time period, cost per service call, call centre performance, etc. If confirmed, provide these measures of performance for 2016/17 and 2017/18.

RESPONSE:

Centra has established internal guidelines to manage response time. The guidelines consider risk, customer service and financial accountability. Reports are generated and monitored to effectively manage performance.

Service calls or Customer Equipment Problem Program calls are measured in response time. Below are the response times for the Winnipeg region in hours per call.

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
2016/17	4.8	18.0	16.0	14.5	11.5	59.1	26.6	8.7	5.1	4.8	4.05	4.6
2017/18	7.5	15.4	11.4	13.1	22.9	43.8	37.7	9.91	4.9	4.13	4.2	4.9

Centra also provides notifications to customers acknowledging their line locate requests have been received the same day as the request was made. Centra manages those requests and tracks performance by monitoring days to complete a locate on a weekly basis. Below is the performance for the Winnipeg region for residential customers (in days):

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
2016/17	3.7	8	6	2.3	2	1.4	3.8	2.6	3.5	0.5	2.4	1.5
2017/18	6.1	6.4	6.2	2.8	2.6	3.1	3.1	2.1	1.1	1.8	1.3	1.5

Centra does not track appointments met but does utilize internal measures tracking the status of service orders such as “complete”, “CGI or can’t get in” and “INCM or incomplete" as outlined in the chart below.

Completed Customer Equipment Problem Program orders by Month													
2016/17	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	TOTAL
Compl	771	406	334	306	262	694	1626	1011	2022	1695	1140	1133	**11,400**
CGI	13	10	8	4	7	21	47	33	63	33	15	15	**269**
INCM	2	1	5	0	1	11	10	2	7	6	6	8	**59**
Total	**786**	**417**	**347**	**310**	**270**	**726**	**1683**	**1046**	**2092**	**1734**	**1161**	**1156**	**11,728**
2017/18	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	TOTAL
Compl	629	383	310	251	298	680	1122	1389	1842	1545	1153	956	**10,558**
CGI	15	7	8	9	11	21	53	45	44	28	22	18	**281**
INCM	2	6	4	3	0	2	5	3	8	2	2	5	**42**
Total	**646**	**396**	**322**	**263**	**309**	**703**	**1180**	**1437**	**1894**	**1575**	**1177**	**979**	**10,881**

The average cost per CEPP call in 2016/17 was $115 and in 2017/18 it was $119.

The Customer Contact Centre measures the timeliness of responses for telephone inquiries. The Average Speed of Answer (“ASA”) and Telephone Service Factor (“TSF”) are measured.

The ASA is the average amount of time in seconds that it takes for a call to be answered and the target in 2016/17 and 2017/18 was 30 seconds. The TSF is the percentage of calls answered within x seconds or less and the target in 2016/17 and 2017/18 was responding to 80% of the calls in 30 seconds or less. The following tables provide the ASA and TSF measures each month for 2016/17 and 2017/18.

Average Speed of Answer (seconds)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
2016/17	47	60	81	76	83	91	65	43	46	53	42	34
2017/18	40	40	37	45	52	88	91	55	65	77	95	120

Telephone Service Factor (%)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
2016/17	70%	63%	67%	57%	51%	45%	53%	67%	69%	63%	70%	74%
2017/18	72%	70%	73%	66%	59%	45%	48%	61%	57%	49%	45%	39%

REFERENCE:

PUB/Centra I-154; Unifor/Centra I-2, I 7

PREAMBLE TO IR (IF ANY):

With respect to the Customer Equipment Problem Program ("Burner Tip Service"), PUB/Centra I-154(b) requested that Centra: "Confirm whether Centra personnel will replace all the appliance parts identified in Order 49/95 at page 120." [emphasis added] Centra's response was that Centra does not stock all of the parts [in this list] but does not indicate whether Centra will replace them. The response to Unifor/Centra I-7(e) indicates that Centra does not replace all the appliance parts identified in Order 49/95. The attachment to PUB/Centra I-154(a) indicates: "When a Service Person encounters an equipment problem for which a specific brand and model of part is required, the customer is advised that Centra can order and obtain the part and return to install it that Centra will order the parts and return to install them."

QUESTION:

a) Confirm whether the course of action to "order and obtain the part and return to install it" applies to the parts identified in Order 49/95 (and Unifor/Centra I 7(d)) that are not in the current list of parts as shown in Unifor/Centra I 7(e).
b) Provide the number of service calls in each of 2015/16, 2016/17, and 2017/18 where Centra personnel have made two or more visits for the same service call, the second and subsequent visits being to install the proprietary parts that the customer requested Centra order and install.
c) In light of the challenges indicated by Centra with proprietary parts and complexity of appliances, explain why Centra has not sought PUB approval to vary Order 49/95 or the Terms and Conditions of service.
d) Provide the date or dates when Centra amended the parts list from the Order 49/95 list shown in Unifor/Centra I-7(d) to the current parts list shown in Unifor/Centra I-7(e).

RESPONSE:

a) Items on the current list of parts are universal and cover the vast majority of CEPP required repairs. Technological changes aimed at improving the efficiency and safety of natural gas appliances have resulted in parts being integrated into circuit boards which are not universal across all manufacturers. Other parts have become obsolete as new models with improved safety features have been introduced. The cost of maintaining an inventory of all these parts is prohibitive and has resulted in having to source the parts from manufacturers or distributors.

b) The following table provides a listing of the number of occurrences where a subsequent call was created to install parts after a CEPP call.

Fiscal year	Parts Replacement orders after CEPP order
2015/2016	86
2016/2017	92
2017/2018	104

c) The Terms and Conditions of Service for the Customer Equipment Problem Program ("CEPP") are set out under "Other Services" (Section IV. E) c)) of Centra's Schedule of Sales and Transportation Services and Rates, dated August 2, 2013.

As indicated in the response to PUB/Centra I-154a, there have been no changes to the Customer Equipment Problem Program ("CEPP") since Centra's Terms and Conditions of Services were last approved by the PUB at the 2013/14 GRA. As such, no approvals with respect to the Terms and Conditions of Service were sought as part of the current GRA.

Centra's interpretation of the PUB's findings with respect to the CEPP contained in Order 49/95, also outlined in PUB/CENTRA I-154a, was that the focus of the program should be on safety and advice to the consumer. As outlined on page 117 of Order 49/95, as part of this program, Centra is required to complete a diagnosis of the problem, make immediate safety repairs, provide operating advice and make referral to heating dealers for more significant and complex repairs. Centra was also required to respond to "no heat" calls in critically cold weather, complete some repairs and eliminate health risks associated with no heat. Centra continues to offer the CEPP to its customers in a manner that is fully consistent with the original intent of the program and is fully compliant with Order 49/95.

The PUB's findings on page 120 of Order 49/95 also identified a list of components on gas furnaces and hot water heaters that should be replaced under the CEPP. Since Order 49/95 was issued, Centra has made adjustments to the component list of parts that will be repaired or replaced under the CEPP (for reasons as outlined in Appendix 12.4). Centra understood the PUB's findings on page 120 of Order 49/95 related to the list of components was intended to provide guidance as to the service activities confined to the CEPP to meet the safety objectives of the program. As such, changes made by Centra to this list of components since Order 49/95 were not brought to the PUB for approval. Centra notes that while individual items have been removed from the list during this period, other individual items have been added, in keeping with the intent of Order 49/95.

d) Current procedure 4.003.02 Customer Equipment Service was effective January 15, 2018.

REFERENCE:

PUB/Centra I-157

QUESTION:

Identify for which franchise applications Centra has refunded customer contributions based on the results of 5-year true-up calculations of the feasibility test since the 2013/14 GRA and provide the amounts of the refunds.

RESPONSE:

Please see table below for franchise applications where Centra has refunded customer contributions.

Order Approving Franchise Application	Franchise Application	Refunded Contribution Amount
61/12	RM of Whitewater	$204,029
70/12	RM of South Norfolk/Grey	$89,795
70/12	RM of South Norfolk/Grey	$31,831
80/11	RM of Thompson/Roland	$5,885
89/11	RM of Portage la Prairie	$117,681
94/12	RM of Bifrost/Woodlands	$10,088
101/11	RM of Rockwood	$33,063

REFERENCE:

PUB/Centra I 157(ix), 2013/14 Centra GRA Appendix 5.8, Order 85/13

QUESTION:

Explain the reasons why the depreciation rate embedded in the feasibility test true-up report filed for the RM of Bifrost/Woodlands (Order 94/12) appears to be different than the ASL (with net salvage) depreciation rate of 2.61% based on Centra's weighted average depreciation rate for distribution plant (2010 Gannet Fleming Depreciation Study).

RESPONSE:

Centra used 2.88% depreciation rate in the true up, which was the depreciation rate in effect at the time the true up was completed. Please see PUB/CENTRA II-65a-c for a detailed response regarding deprecation rates.

REFERENCE:

PUB/Centra I-158a-e, 2013 Centra GRA Appendix 5.8, Order 85/13, Order 53/16, Appendix 13.2

QUESTION:

a) Explain the reasons why the depreciation rates embedded in the feasibility tests filed for parts a) through e) of PUB/Centra I-158 appear to be based on the ELG depreciation methodology as opposed to the ASL-based (inclusive of asset retirement costs) depreciation rates approved in Order 85/13 (from the 2010 Gannet Fleming Depreciation Study).
b) If applicable, identify the other feasibility tests, prepared by Centra since the 2013/14 Centra GRA, associated with main extensions greater than 500m that make use of depreciation rates that are different than those approved in Order 85/13.
c) Directionally, what impact would ASL-based depreciation rates instead of ELG-based rates have on the results of the main extension requests and customer contributions?

RESPONSE:

a) The depreciation rates used by Centra for feasibility test purposes are not based on the Equal Life Group ("ELG") methodology. The depreciation rates below are based upon the Average Service Life ("ASL") methodology, with the ASL rates between August 1st 2013 and February 1st 2016 calculated excluding salvage value and true-up adjustments.

   The following table summarizes the distribution depreciation and amortization rates used in the feasibility test from May 1st 2011 onwards:

Start Date	End Date	Distribution Depreciation Rate	Amortization Rate
May 1st 2011	July 31st 2013	2.88%	2.88%
August 1st 2013	October 31st 2013	2.61%	1.7%
November 1st 2013	January 31st 2016	2.04%	2.04%
February 1st 2016	Not applicable - still in use	2.61%	2.61%

The following discussion details the historical changes in methodologies for depreciation and amortization rates for feasibility test purposes since May 1, 2011.

Effective May 1, 2011 Centra updated the feasibility test depreciation and amortization rates based on the ASL with Salvage rates from the 2005 Depreciation Study, which was approved by the PUB in Order 99/07[1]:

Depreciation/Amortization Rate = Annual Depreciation Expense * Average Gross Plant ((2010 + 2011)/2)

On August 1 2013, after the 2013/14 Centra GRA, the depreciation rate for feasibility test purposes was changed to 2.61% and the amortization rate was changed to 1.7%. The depreciation rate was updated to reflect the ASL with Salvage rates from the 2010 Depreciation Study, which were approved by the PUB in Order 85/13. The amortization rate was updated to reflect a change in Centra's approach to amortization of contributions for financial reporting purposes.

As indicated in Centra's response to PUB/CENTRA I-82 from its 2013/14 GRA, "following the 2010 Depreciation Study, Centra reviewed the approach to the amortization of

[1] Prior to this change, the depreciation rate used for feasibility test purposes was based on the rates from the 2005 Depreciation Study, as approved in Order 99/07, and the 2008/09 forecast average gross plant for the years ending 2008 & 2009.

Contributions in Aid of Construction. Centra determined that it was inappropriate to use plant depreciation rates to amortize contributions, as the plant depreciation rates include factors that are not applicable to contributions. As contributions use the amortization method of accounting and not physical in nature, plant asset assumptions with respect to retirement (IOWA curves), net salvage, and the inclusion of true-up amount designed to allocate any accumulated depreciation variance on the plant asset accounts do not pertain to the contribution amounts."

For financial reporting and feasibility test purposes, the amortization rate methodology for customer contributions was changed so that amortization rates were calculated based upon contribution amounts instead of gross plant. The calculation methodology was as follows:

$$\text{Annual Amortization Expense} = \frac{\text{Net Book Value of Contributions}}{\text{Probable Remaining Life of Associated Plant Assets}}$$

$$\text{Amortization Rate} = \frac{\text{Annual Amortization Expense}}{\text{Gross Contribution Amount (Depreciable Base)}}$$

During 2013, Centra realized that using different depreciation and contribution amortization rates caused larger contributions than normally expected. The lower contribution amortization rate meant contribution amounts were amortized more slowly than depreciation expense, which resulted in larger contributions in aid of construction. During the investigation, it was determined that the two rates need to be the same for purposes of Centra's financial feasibility test.

During the review of relationship between amortization rates and depreciation rates, the depreciation rate methodology for feasibility test purposes was changed to use the 2010 ASL based Depreciation Study rates excluding both the provision for net salvage and the depreciation variance true-up. The rationale behind the change was that salvage costs are incurred beyond the thirty year time frame of the feasibility test and depreciation variance true-ups result from historical accounting differences, which should not influence the determination of feasibility for new customer connections. As a result, on November 1st, 2013 the depreciation and amortization rates for feasibility test purposes were both changed to 2.04%.

Effective February 1, 2016, based upon Order 53/16, the depreciation rate and the amortization rates for feasibility test purposes were changed to 2.61%, reflecting on the 2010 ASL with salvage depreciation study rates originally approved by the PUB in Order 85/13, and remain in effect today:

Depreciation/Amortization Rate = Annual Depreciation Expense (including salvage value and true-up) * Average Gross Plant ((2013 + 2014)/2)

b) The following is a list of all MERs included in the 500m report and the associated depreciation rate:

MER Number	Depreciation Rate
2013-00052	2.88
2013-00080	2.88
2013-00085	2.88
2013-00086	2.88
2013-00096	2.88
2013-00098	2.88
2013-00100	2.88
2013-00128	2.88
2013-00143	2.88
2013-00700	2.88
2013-00702	2.88
2013-00712	2.88
2013-00716	2.88
2013-00719	2.88
2013-00722	2.88
2013-00023	2.88
2013-00039	2.88
2013-00040	2.88
2013-00069	2.88
2013-00102	2.88

MER Number	Depreciation Rate
2013-00127	2.88
2013-00156	2.88
2013-00005	2.88
2013-00006	2.88
2013-00012	2.88
2013-00017	2.88
2013-00029	2.88
2013-00041	2.88
2013-00042	2.88
2013-00043	2.88
2013-00049	2.88
2013-00054	2.88
2013-00056	2.88
2013-00058	2.88
2013-00062	2.88
2013-00063	2.88
2013-00066	2.88
2013-00070	2.88
2013-00071	2.88
2013-00072	2.88
2013-00094	2.88
2013-00104	2.88
2013-00107	2.88
2013-00108	2.88
2013-00111	2.88
2013-00112	2.88
2013-00113	2.88
2013-00119	2.88
2013-00120	2.88
2013-00148	2.88
2013-00153	2.88
2013-00159	2.88
2013-00162	2.88
2014-00001*	1.96
2014-00002	2.88

MER Number	Depreciation Rate
2014-00004	2.61
2014-00009	2.04
2014-00025	2.04
2014-00029	2.04
2014-00042	2.04
2014-00043	2.04
2014-00061	2.04
2014-00073	2.04
2014-00074	2.04
2014-00086	2.04
2014-00088	2.04
2014-00092	2.04
2014-00107	2.04
2014-00109	2.04
2014-00110	2.04
2014-00112	2.04
2014-00139	2.04
2014-00153	2.04
2014-00016	2.04
2014-00020	2.04
2014-00030	2.04
2014-00033	2.88
2014-00044	2.04
2014-00066	2.04
2014-00114	2.04
2014-00141	2.04
2014-00152	2.04
2014-00003	2.04
2014-00007	2.61
2014-00015	2.61
2014-00021	2.61
2014-00034	2.04
2014-00041	2.04
2014-00045	2.04
2014-00046	2.04

MER Number	Depreciation Rate
2014-00047	2.04
2014-00048	2.04
2014-00052	2.04
2014-00053	2.04
2014-00054	2.04
2014-00057	2.04
2014-00060	2.04
2014-00063	2.04
2014-00069	2.04
2014-00076	2.04
2014-00089	2.04
2014-00094	2.04
2014-00095	2.04
2014-00126	2.04
2014-00132	2.04
2014-00163	2.04
2014-00166	2.04
2014-00170	2.04
2014-00174	2.04
2014-00182	2.04
2015-00005	2.04
2015-00008	2.04
2015-00042	2.04
2015-00056	2.04
2015-00077	2.04
2015-00120	2.04
2015-00709	2.04
2015-00714	2.04
2015-00802	2.04
2015-00803	2.04
2015-00807	2.04
2015-00813	2.04
2015-00816	2.04
2015-00818	2.04
2015-00822	2.04

MER Number	Depreciation Rate
2015-00823	2.04
2015-00827	2.04
2015-00837	2.04
2015-00841	2.04
2015-00843	2.04
2015-00844	2.04
2015-00846	2.04
2015-00019	2.04
2015-00024	2.04
2015-00038	2.04
2015-00068	2.04
2015-00091	2.04
2015-00830	2.04
2015-00848	2.04
2015-00009	2.04
2015-00012	2.04
2015-00015	2.04
2015-00017	2.04
2015-00021	2.04
2015-00033	2.04
2015-00051	2.04
2015-00057	2.04
2015-00058	2.04
2015-00059	2.04
2015-00065	2.04
2015-00069	2.04
2015-00070	2.04
2015-00083	2.04
2015-00085	2.04
2015-00092	2.04
2015-00103	2.04
2015-00104	2.04
2015-00122	2.04
2015-00127	2.04
2015-00833	2.04

MER Number	Depreciation Rate
2015-00836	2.04
2016-00014	2.04
2016-00015	2.04
2016-00056	2.61
2016-00066	2.61
2016-00073	2.61
2016-00706	2.04
2016-00808	2.04
2016-00812	2.04
2016-00819	2.04
2016-00822	2.04
2016-00826	2.04
2016-00827	2.04
2016-00838	2.04
2016-00839	2.04
2016-00847	2.04
2016-00848	2.04
2016-00850	2.61
2016-00853	2.61
2016-00058	2.61
2016-00062	2.61
2016-00069	2.61
2016-00837	2.04
2016-00845	2.04
2016-00002	2.04
2016-00017	2.04
2016-00039	2.04
2016-00048	2.61
2016-00049	2.04
2016-00053	2.61
2016-00063	2.04
2016-00067	2.61
2016-00071	2.61
2016-00075	2.61
2016-00077	2.61

MER Number	Depreciation Rate
2016-00086	2.61
2016-00089	2.61
2016-00092	2.61
2016-00093	2.61
2016-00101	2.61
2016-00105	2.61
2016-00833	2.04
2017-00021	2.61
2017-00025	2.61
2017-00043	2.61
2017-00056	2.61
2017-00080	2.61
2017-00082	2.61
2017-00085	2.61
2017-00717	2.61
2017-00805	2.61
2017-00813	2.61
2017-00828	2.61
2017-00832	2.61
2017-00833	2.04
2017-00839	2.61
2017-00846	2.61
2017-00023	2.61
2017-00033	2.61
2017-00041	2.61
2017-00069	2.61
2017-00086	2.61
2017-00001	2.61
2017-00015	2.61
2017-00016	2.61
2017-00027	2.61
2017-00028	2.61
2017-00029	2.61
2017-00030	2.61
2017-00036	2.61

MER Number	Depreciation Rate
2017-00040	2.61
2017-00044	2.61
2017-00054	2.61
2017-00060	2.61
2017-00064	2.61
2017-00071	2.61
2017-00073	2.61
2017-00094	2.61
2017-00097	2.61
2017-00100	2.61
2017-00104	2.61

*2014-00001 had a 1.96% depreciation rate because the main extension included steel transmission pipe

c) The depreciation rates used by Centra for feasibility test purposes are not based on the Equal Life Group ("ELG") methodology; the difference in rates is tied to the inclusion or exclusion of salvage values and variance true-ups.

REFERENCE:

PUB/Centra I-160a-b

QUESTION:

Explain whether Centra will continue the activities related to its 2014 marketing plan for residential customers in the former franchise area of the Swan Valley Gas Corporation beyond fiscal year 2018/19.

RESPONSE:

Centra does not currently have plans to target additional marketing activities to the Swan Valley area.

Centra continues to maintain and update heating education information through print and online channels to customers so they better understand their heating costs. Manitoba Hydro's website offers a dedicated Home Heating section that includes a heating cost comparison tool which details the costs of heating with natural gas compared to other heating sources. The Corporation also continues to maintain heating education billboards in various rural locations of the Province including one near the community of Swan River.