REFERENCE:

CAC/Centra I-1 (a)

PREAMBLE TO IR (IF ANY):

Centra states in the response to CAC/Centra I-1 (a) that "…while Centra is not specifically required to receive explicit PUB "approval" of items f) and g) per the legislation, it is requesting endorsement of these items in order to obtain the audit evidence required by Centra's external auditors to validate the annual regulatory deferral and amortization amounts that are recorded in its financial statements."

QUESTION:

a) Please explain why Centra is not requesting PUB approval with respect to items f) and g) given that they relate to "regulatory" deferral accounts and associated amortization periods, all of which are factors in the PUB setting non-gas rates.

RESPONSE:

As stated in CAC/CENTRA I-1a and Appendix 3.4 of the Application, Centra requests the endorsement of the PUB to validate the annual regulatory deferral accounts and amortization periods recorded in the financial statements and provide evidence to its external auditors.

Use of the term "endorsement" was intended to maintain consistency with the approach taken by Manitoba Hydro in the 2017/18 Electric General Rate Application.

Centra agrees that the annual regulatory deferral accounts and amortization periods are relevant factors in the setting of just and reasonable rates. Use of the term "endorsement" over "approval" has no impact upon the jurisdiction of the PUB as set out in *The Public Utilities Board Act*.

REFERENCE:

CAC/Centra I-1 (a)

PREAMBLE TO IR (IF ANY):

Centra states in the response to CAC/Centra I-1 (a) that "…while Centra is not specifically required to receive explicit PUB "approval" of items f) and g) per the legislation, it is requesting endorsement of these items in order to obtain the audit evidence required by Centra's external auditors to validate the annual regulatory deferral and amortization amounts that are recorded in its financial statements."

QUESTION:

b) Please explain if PUB approval of regulatory deferral accounts and the related amortization periods is required to obtain sufficient audit evidence for Centra's external auditors.

RESPONSE:

Interim standard *IFRS 14 Regulatory Deferral Accounts* requires rate regulated entities to use regulatory deferral accounts to record timing differences between the recognition of income or expense amounts for rate setting purposes (as determined by the rate regulator) and the recognition of those same amounts for financial reporting purposes (as determined by the accounting standards). IFRS 14 defines a rate regulator as:

> *"An authorized body that is empowered by statute or regulation to establish the rate or a range of rates that bind an entity."*

IFRS 14 further defines a regulatory deferral account as:

> "*The balance of any expense (or income) account that would not be recognized as an asset or a liability in accordance with other Standards, but that qualifies for deferral*

> *because it is included, or is expected to be included, by the* ***rate regulator*** *in establishing the rate(s) that can be charged to customers."*

Notably, there are no words in the IFRS14 standard that state the "approval" of the regulator is required to recognize regulatory deferral accounts. IFRS 14 recognizes that the role of the regulator is to approve the timing of when revenues and expenses may be recognized for determining customer rates; not to approve how such amounts are to be recognized for financial reporting purposes. This point is consistent with the words of the PUB in their letter dated April 4, 2016 to Centra regarding the *March 10, 2016 Request for Accounting Clarification* where the PUB states on page 2 of the letter,

> "*At the outset, the Board clarifies 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."*

Given that the PUB does not prescribe the use of regulatory deferral accounts or accounting methods for financial reporting purposes,, Centra's auditors do not require such approval as audit evidence. Instead, Centra's auditors seek evidence from the PUB as to the timing of when income and expenses are to be recognized for rate setting purposes so as to confirm if timing differences exist between recognition for rate setting and financial reporting purposes. The endorsement of the PUB with respect to Centra's proposed regulatory deferral accounts and their respective amortization periods provides the auditors with evidence as to when such amounts are to be recognized for rate setting purposes. Centra's auditors can then assess if Centra has appropriately applied the requirements of IFRS 14 for financial reporting purposes.

REFERENCE:

CAC/Centra I-2 (f) Attachment 1; CAC/Centra I-2 (g), CAC/Centra I-2 (h); CAC/Centra I-2 (i)

QUESTION:

a) Please explain if the direct reporting relationship of the Gas Supply Department Manager to the Director of Marketing & Sales (as outlined on Page 2 of Attachment 1 to CAC/Centra I-2 (f)) is on an interim basis pending the appointment of a Vice-President of Marketing & Customer Service or is expected to remain in place after the appointment of the new Vice-President.

RESPONSE:

The Gas Supply Department currently reports to the Director of Customer Care. On an interim basis, pending the appointment of a Vice-President of Marketing & Customer Service, the Customer Care Division is reporting to the Director of Marketing & Sales. There are no planned organizational changes at this time. However, it should be noted that the Corporation's future organizational structure may or may not change depending upon the outcome of the Corporation's long term strategic plan currently under development.

REFERENCE:

CAC/Centra I-2 (f) Attachment 1; CAC/Centra I-2 (g), CAC/Centra I-2 (h); CAC/Centra I-2 (i)

PREAMBLE TO IR (IF ANY):

QUESTION:

b) The response to CAC/Centra I-2 (g) indicates that "During the VDP, Manitoba Hydro Executives responsible for the gas management structure reviewed and aligned the organizational structure as part of an overall effort to streamline operations and management." Please elaborate on the specifics of how the gas management structure was aligned and streamlined and what were the changes that resulted from this review.

RESPONSE:

The most fundamental change that occurred in this process was the consolidation of all gas operational and customer service functions under a single Vice President ("VP"), the VP of Marketing & Customer Service. This change meant that a single member of the Manitoba Hydro Executive Committee carried full accountability for gas operations. Now, all five Directors reporting to the VP of Marketing & Customer Service carry some level of responsibility for gas operations. This compared to eight Directors reporting to two Vice Presidents under the previous structure. Specifically:

- the responsibilities of the previous Director of Business Support Services were divided between the Director of Engineering & Construction, the Director of Customer Service Operations - Rural and the Director of Customer Service Operations - Winnipeg;
- The vacant Director of Gas Supply position was eliminated. Reporting within Gas Supply was consolidated under the Manager of Gas Supply who now reports to the Director of Customer Care; and
- The responsibilities of the Director of Industrial & Commercial Solutions and the Director of Consumer Marketing & Sales were consolidated under the Director of Marketing & Sales.

REFERENCE:

CAC/Centra I-2 (f) Attachment 1; CAC/Centra I-2 (g), CAC/Centra I-2 (h); CAC/Centra I-2 (i)

QUESTION:

c) The response to CAC/Centra I-2 (h) indicates under Other Areas of Concern that "The implementation of an asset management system over the next two to three years will better define investment decisions and may result in additional requirements for gas capital beyond current levels…The implementation of an advanced meter infrastructure ("AMI") program may also influence investment levels". Please explain (i) if asset management is considered a risk by Centra, then why has it not considered expediting the implementation of the asset management system earlier than two to three years (ii) why it is Centra's view that improved asset management will lead to higher future capital requirements versus improved prioritization and pacing of future gas capital requirements and (iii) would AMI investment necessarily increase future capital requirements versus displacing other programs/projects based on a revised prioritization.

RESPONSE:

c)

i. As indicated in the response to CAC/CENTRA I-2h, Asset Management is considered an "Area of Concern" and not a high priority risk. The development of the asset management plan will require time from the appropriate subject matter experts familiar with the details in developing and implementing asset management best practices as they relate to the natural gas system.

ii. The implementation of an asset management plan and how it may or may not determine the requirement for additional capital is an unknown. Centra has identified this as a potential area of concern and is taking this opportunity to communicate this concern to the PUB. The resultant plan may provide improved prioritization and pacing of the future gas capital requirements.

iii. The estimated magnitude of an AMI investment relative to current capital project spending is likely to increase future capital requirements. In the absence of a Corporate Value Framework score for an AMI project to permit the comparison and prioritization against other proposed projects, it is not possible to provide a more definite response at this time.

REFERENCE:

CAC/Centra I-2 (f) Attachment 1; CAC/Centra I-2 (g), CAC/Centra I-2 (h); CAC/Centra I-2 (i)

PREAMBLE TO IR (IF ANY):

QUESTION:

d) CAC/Centra I-2 (i) requested a CGM18 sensitivity analysis related to potential variance in Gas O&A, Business Operations Capital (BOC) and DSM. Centra's response to this portion of the information request was not responsive to the question despite the fact that the response to CAC/Centra I-2 (h) outlines the risk of variability in gas capital spending in the future. Please provide CGM18 scenarios (including changes to proposed/indicative rate increases and financial ratio calculations) assuming (i) $5 million additional Gas BOC and (ii) $5 million less Gas BOC, for each of the 10 years of CGM18.

RESPONSE:

CGM18 financial scenarios and projected ratios assuming (i) $5 million additional Gas BOC and (ii) $5 million less Gas BOC each year starting in 2019/20 have been provided below.

(i) $5 million additional spending per year in BOC

GAS OPERATIONS (CGM18)
PROJECTED OPERATING STATEMENT
CGM18 - BOC Spending increased by $5M per year
(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	13	17	21	24	28	32	35
	308	308	323	330	334	337	340	343	347	350
Weighted Average Cost of Gas Sold **	159	158	166	166	165	165	164	163	162	163
Gross Margin	149	150	157	164	169	173	176	180	184	187
Other	2	2	2	2	2	2	2	2	2	2
	151	151	158	166	171	174	178	182	186	189
EXPENSES										
Operating and Administrative	63	61	62	63	64	65	66	68	69	70
Finance Expense	22	23	26	27	28	29	31	31	33	34
Depreciation and Amortization	24	26	27	28	30	31	32	33	34	36
Capital and Other Taxes	17	17	18	19	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	158	161	164	169	173	176	181	184
Net Income before Net Movement in Regulatory Deferral	1	(1)	1	6	6	6	6	6	5	5
Net Movement in Regulatory Deferral **	3	3	3	3	3	3	2	3	3	2
Net Income	3	2	4	9	9	9	8	9	8	8

* 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%	2.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
Cumulative Percent Increase	0.00%	0.00%	2.25%	4.30%	5.34%	6.39%	7.46%	8.53%	9.62%	10.71%
Equity Ratio (PUB Approved Methodology)	32%	30%	29%	28%	29%	29%	29%	29%	29%	29%

GAS OPERATIONS (CGM18)
PROJECTED BALANCE SHEET
CGM18 - BOC Spending increased by $5M per year
(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	663	708	752	796	839	884	929	975	1 022
Accumulated Depreciation	(65)	(79)	(95)	(112)	(131)	(150)	(170)	(191)	(213)	(236)
Net Plant in Service	557	584	613	640	665	689	713	738	762	786
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	694	720	745	769	794	818	843	867	891
Regulatory Deferral Balance	106	109	113	116	118	121	123	126	128	130
	771	803	832	860	887	914	941	968	995	1 021
LIABILITIES AND EQUITY										
Long-Term Debt	390	450	490	490	520	550	525	585	595	615
Current and Other Liabilities	122	98	82	101	87	73	115	72	80	78
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	81	85	94	103	111	120	128	136	144
Total Liabilities and Equity before Regulatory Deferral	759	799	828	856	883	910	937	965	991	1 018
Regulatory Deferral Balance	12	5	4	4	4	4	4	4	4	3
	771	803	832	860	887	914	941	968	995	1 021
Net Debt	441	478	520	539	558	577	596	615	633	650
Equity (PUB Approved Methodology)	32%	30%	29%	28%	29%	29%	29%	29%	29%	29%

GAS OPERATIONS (CGM18)
PROJECTED CASH FLOW STATEMENT
CGM18 - BOC Spending increased by $5M per year
(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	2	4	9	9	9	8	9	8	8
Add Back:										
Depreciation and Amortization	24	26	27	28	30	31	32	33	34	36
Finance Expense	22	23	26	27	28	29	31	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)	(39)	(40)	(41)	(43)	(44)	(45)	(46)
Cash Provided by Operating Activities	27	28	22	44	46	47	48	49	51	51
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	40	60	40	20	40	30	10	60	20	20
Retirement of Long-Term Debt	-	(20)	-	-	(20)	(10)	-	(35)	-	(10)
Cash Provided by Financing Activities	40	40	40	20	20	20	10	25	20	10
INVESTING ACTIVITIES										
Additions to Property, Plant and Equipment	(42)	(52)	(50)	(51)	(52)	(53)	(54)	(55)	(56)	(57)
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)	(65)	(64)	(63)	(64)	(66)	(67)	(67)	(68)	(68)
Net Increase (Decrease) in Cash	13	3	(2)	0	2	1	(9)	6	2	(7)
Cash at Beginning of Year	(44)	(31)	(28)	(30)	(30)	(28)	(27)	(36)	(30)	(28)
Cash at End of Year	(31)	(28)	(30)	(30)	(28)	(27)	(36)	(30)	(28)	(35)

GAS OPERATIONS (CGM18)
PROJECTED FINANCIAL RATIOS
CGM18 - BOC Spending increased by $5M per year

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	429.903	469.903	499.903	519.903	539.903	554.903	572.403	594.903	609.952
Average Due to Parent	37.384	29.185	28.760	29.716	28.765	27.590	31.716	33.073	28.786	31.307
Average Debt	**427.287**	**459.088**	**498.663**	**529.619**	**548.668**	**567.493**	**586.619**	**605.476**	**623.689**	**641.259**
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	79.984	83.101	89.476	98.288	107.055	115.452	123.980	132.389	140.112
Average Equity	**198.474**	**201.233**	**204.351**	**210.726**	**219.538**	**228.305**	**236.702**	**245.230**	**253.639**	**261.362**
Average Debt	427.287	459.088	498.663	529.619	548.668	567.493	586.619	605.476	623.689	641.259
Average Equity	198.474	201.233	204.351	210.726	219.538	228.305	236.702	245.230	253.639	261.362
Average Debt and Equity	625.761	660.322	703.013	740.346	768.206	795.797	823.321	850.706	877.327	902.621
PUB Approved Equity Ratio	**31.72%**	**30.48%**	**29.07%**	**28.46%**	**28.58%**	**28.69%**	**28.75%**	**28.83%**	**28.91%**	**28.96%**

GAS OPERATIONS (CGM18)
PROJECTED FINANCIAL RATIOS
CGM18 - BOC Spending increased by $5M per year

For the year ended March 31	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
INTEREST COVERAGE										
Net Income	3.267	2.251	3.983	8.768	8.856	8.676	8.118	8.938	7.879	7.567
Finance Expense	20.502	22.230	24.271	25.811	26.966	28.493	29.852	30.827	32.650	33.702
Capitalized Interest	0.171	0.286	0.299	0.180	0.083	0.084	0.084	0.085	0.086	0.086
	23.941	24.766	28.554	34.759	35.905	37.253	38.054	39.850	40.615	41.356
Finance Expense	20.502	22.230	24.271	25.811	26.966	28.493	29.852	30.827	32.650	33.702
Capitalized Interest	0.171	0.286	0.299	0.180	0.083	0.084	0.084	0.085	0.086	0.086
	20.674	22.516	24.570	25.991	27.049	28.577	29.936	30.911	32.736	33.788
Interest Coverage	**1.16**	**1.10**	**1.16**	**1.34**	**1.33**	**1.30**	**1.27**	**1.29**	**1.24**	**1.22**
Add: Depreciation and Amortization *	34.899	36.736	38.752	39.191	40.948	41.648	42.983	43.312	44.653	45.225
Total EBITDA	58.840	61.503	67.305	73.950	76.853	78.901	81.037	83.161	85.268	86.580
EBITDA Interest Coverage	**2.85**	**2.73**	**2.74**	**2.85**	**2.84**	**2.76**	**2.71**	**2.69**	**2.60**	**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	27.795	21.517	43.791	45.881	46.609	47.747	48.787	50.675	51.007
Capitalized Interest*	0.171	0.286	0.299	0.180	0.083	0.084	0.084	0.085	0.086	0.086
	27.560	28.081	21.816	43.972	45.964	46.692	47.831	48.872	50.761	51.094
Net Capital Construction Expenditures	35.404	45.075	43.382	43.991	44.800	45.596	46.408	47.236	48.081	48.943
Capital Coverage	**0.78**	**0.62**	**0.50**	**1.00**	**1.03**	**1.02**	**1.03**	**1.03**	**1.06**	**1.04**

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

(ii) $5 million per year less spending on BOC

GAS OPERATIONS (CGM18)
PROJECTED OPERATING STATEMENT
CGM18 - BOC Spending decreased by $5M per year
(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	10	14	17	21	24	28
	308	308	323	325	327	330	333	336	339	343
Weighted Average Cost of Gas Sold **	159	158	166	166	165	165	164	163	162	163
Gross Margin	149	150	157	159	162	166	169	173	177	180
Other	2	2	2	2	2	2	2	2	2	2
	151	151	158	161	164	167	171	175	179	182
EXPENSES										
Operating and Administrative	63	61	62	63	64	65	66	68	69	70
Finance Expense	22	23	25	26	27	28	29	29	31	31
Depreciation and Amortization	24	25	26	28	29	30	30	31	32	33
Capital and Other Taxes	17	17	18	18	19	19	20	20	20	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	166	169	172	176	178
Net Income before Net Movement in Regulatory Deferral	1	(1)	2	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	2	5	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%	0.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
Cumulative Percent Increase	0.00%	0.00%	2.25%	2.25%	3.27%	4.31%	5.35%	6.40%	7.47%	8.54%
Equity Ratio (PUB Approved Methodology)	32%	31%	30%	29%	29%	29%	29%	29%	29%	29%

GAS OPERATIONS (CGM18)
PROJECTED BALANCE SHEET
CGM18 - BOC Spending decreased by $5M per year
(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	653	688	722	756	789	824	859	895	932
Accumulated Depreciation	(65)	(79)	(94)	(111)	(128)	(147)	(165)	(184)	(203)	(223)
Net Plant in Service	557	574	593	611	627	643	659	675	692	709
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	684	700	716	732	748	764	780	797	814
Regulatory Deferral Balance	106	109	113	116	118	121	123	126	128	130
	771	793	813	832	850	868	887	906	925	944
LIABILITIES AND EQUITY										
Long-Term Debt	390	440	470	460	490	510	485	535	545	565
Current and Other Liabilities	122	98	82	105	87	78	114	77	79	71
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	81	86	91	96	101	105	112	117	123
Total Liabilities and Equity before Regulatory Deferral	759	789	808	827	846	864	883	902	922	941
Regulatory Deferral Balance	12	5	4	4	4	4	4	4	4	3
	771	793	813	832	850	868	887	906	925	944
Net Debt	441	467	499	513	527	542	556	569	582	593
Equity (PUB Approved Methodology)	32%	31%	30%	29%	29%	29%	29%	29%	29%	29%

GAS OPERATIONS (CGM18)
PROJECTED CASH FLOW STATEMENT
CGM18 - BOC Spending decreased by $5M per year
(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	2	5	5	5	5	5	6	6	6
Add Back:										
Depreciation and Amortization	24	25	26	28	29	30	30	31	32	33
Finance Expense	22	23	25	26	27	28	29	29	31	31
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)	(38)	(40)	(41)	(42)	(43)	(43)
Cash Provided by Operating Activities	27	28	22	39	41	41	43	44	46	47
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	40	50	30	10	40	20	10	50	20	20
Retirement of Long-Term Debt	-	(20)	-	-	(20)	(10)	-	(35)	-	(10)
Cash Provided by Financing Activities	40	30	30	10	20	10	10	15	20	10
INVESTING ACTIVITIES										
Additions to Property, Plant and Equipment	(42)	(42)	(40)	(41)	(42)	(43)	(44)	(45)	(46)	(47)
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)	(55)	(54)	(53)	(54)	(56)	(57)	(58)	(59)	(58)
Net Increase (Decrease) in Cash	13	3	(2)	(4)	6	(5)	(4)	1	8	(2)
Cash at Beginning of Year	(44)	(31)	(28)	(29)	(33)	(27)	(32)	(36)	(34)	(27)
Cash at End of Year	(31)	(28)	(29)	(33)	(27)	(32)	(36)	(34)	(27)	(28)

GAS OPERATIONS (CGM18)
PROJECTED FINANCIAL RATIOS
CGM18 - BOC Spending decreased by $5M per year

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	454.903	474.903	489.903	504.903	514.903	527.403	544.903	559.952
Average Due to Parent	37.384	29.160	28.404	31.309	30.335	29.556	33.876	35.194	30.631	27.634
Average Debt	**427.287**	**454.063**	**483.307**	**506.212**	**520.238**	**534.459**	**548.779**	**562.597**	**575.534**	**587.586**
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	80.051	83.752	88.803	93.599	98.237	103.048	108.559	114.525	120.387
Average Equity	**198.474**	**201.301**	**205.002**	**210.053**	**214.849**	**219.487**	**224.297**	**229.808**	**235.775**	**241.636**
Average Debt	427.287	454.063	483.307	506.212	520.238	534.459	548.779	562.597	575.534	587.586
Average Equity	198.474	201.301	205.002	210.053	214.849	219.487	224.297	229.808	235.775	241.636
Average Debt and Equity	625.761	655.364	688.309	716.265	735.087	753.947	773.076	792.405	811.309	829.222
PUB Approved Equity Ratio	**31.72%**	**30.72%**	**29.78%**	**29.33%**	**29.23%**	**29.11%**	**29.01%**	**29.00%**	**29.06%**	**29.14%**

GAS OPERATIONS (CGM18)
PROJECTED FINANCIAL RATIOS
CGM18 - BOC Spending decreased by $5M per year

For the year ended March 31

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
INTEREST COVERAGE										
Net Income	3.267	2.385	5.017	5.085	4.507	4.769	4.851	6.171	5.763	5.960
Finance Expense	20.502	22.230	23.758	24.796	25.621	27.027	28.063	28.853	30.338	31.188
Capitalized Interest	0.171	0.189	0.203	0.084	(0.014)	(0.013)	(0.012)	(0.012)	(0.011)	(0.010)
	23.941	24.804	28.977	29.965	30.114	31.783	32.902	35.012	36.090	37.138
Finance Expense	20.502	22.230	23.758	24.796	25.621	27.027	28.063	28.853	30.338	31.188
Capitalized Interest	0.171	0.189	0.203	0.084	(0.014)	(0.013)	(0.012)	(0.012)	(0.011)	(0.010)
	20.674	22.419	23.960	24.880	25.607	27.014	28.050	28.841	30.328	31.178
Interest Coverage	**1.16**	**1.11**	**1.21**	**1.20**	**1.18**	**1.18**	**1.17**	**1.21**	**1.19**	**1.19**
Add: Depreciation and Amortization *	34.899	36.652	38.329	38.431	39.850	40.211	41.208	41.199	42.203	42.436
Total EBITDA	58.840	61.456	67.306	68.396	69.964	71.994	74.110	76.211	78.293	79.575
EBITDA Interest Coverage	**2.85**	**2.74**	**2.81**	**2.75**	**2.73**	**2.67**	**2.64**	**2.64**	**2.58**	**2.55**

* Includes amortization of deferred income tax

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
CAPITAL COVERAGE										
Internally Generated Funds	27.389	27.942	22.224	39.381	40.529	41.361	42.802	44.003	46.204	46.708
Capitalized Interest*	0.171	0.189	0.203	0.084	(0.014)	(0.013)	(0.012)	(0.012)	(0.011)	(0.010)
	27.560	28.131	22.427	39.464	40.515	41.348	42.789	43.991	46.193	46.698
Net Capital Construction Expenditures	35.404	35.075	33.382	33.991	34.800	35.596	36.408	37.236	38.081	38.943
Capital Coverage	**0.78**	**0.80**	**0.67**	**1.16**	**1.16**	**1.16**	**1.18**	**1.18**	**1.21**	**1.20**

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

REFERENCE:

CAC/Centra I-3 (b); CAC/Centra I-4 (b)

PREAMBLE TO IR (IF ANY):

In information request CAC/Centra I-3 (b), CAC requested a copy of the Centra compliance filing flowing from Order 79/17. Centra indicated in the response to that information request that a compliance filing was not required following Order 79/17 and did not provide any information related to its application for rates effective August 1, 2017. Centra states it is seeking final approval of Order 79/17 as per its Letter of Application and Appendix 13.1. Order 79/17 approved changes to all (or nearly all) rates pursuant to the PUB's direction to roll-back rates flowing from Order 85/13, in addition to the change in the quarterly Primary Gas Rate.

As Centra's Application that led to Order 79/19 was filed on an interim ex-parte basis, intervenors do not have access to the filed materials and schedules. While no formal cost allocation study was prepared, there were materials and analysis prepared in order to generate the roll-back of rates underpinning August 1, 2017 rates. CAC is seeking to obtain copies of all materials prepared and filed with the PUB as part of that ex-parte process leading to August 1, 2017 rates, for which Centra is now seeking final approval.

*****

In information request CAC/Centra I-4(b), CAC requested Centra to provide a quantitative analysis to support the assertion that there is no general revenue increase requested for 2019/20. In the response to that information request, Centra stated "Please refer to the Supplement to Centra's 2019/20 General Rate Application, page 7, Figure 2 which demonstrates there is no additional revenue requirement requested for 2019/20. The non-gas costs of $149.6 million are shown net of the removal of the Furnace Replacement Program. As such, there is no request for a general revenue increase." Figure 2, page 7 of the Supplement shows total non-gas costs of $149.2 million (total expenses of $149.1 million less net movement of $1.1 million less other revenue of $1.7 million plus net income of $2.9 million) in the Approved Budget column for 2019/20. Figure

2 also shows a gross margin of $149.2 million which is assumed to be Centra's representation of revenues at existing non-gas rates. If revenue at existing non-gas rates are equal to non-gas costs of $149.2 million, then this would support that there is no non-gas revenue increase requested in the application (ie., there is no non-gas revenue deficiency or sufficiency).

However, in Figure 6 – Cost of Service vs. Cost Allocation, page 11 of the Supplement under the Updated Cost of Service column the total non-gas costs are $148.5 million (net of the cost of gas and excluding the Furnace Replacement Program) and under the Updated Cost Allocation column, the total non-gas costs included in the Cost Allocation Study are $148.5 million (net of the cost of gas and excluding the Furnace Replacement Program). In the response to IGU/Centra I-15, Attachment 1 under the total column, Centra indicates that the revenues at existing non-gas rates are $152.5 million and that the non-gas cost of service is $148.5 million, which results in a non-gas revenue sufficiency of $4.0 million. The revenues at existing non-gas rates of $152.5 million are calculated on updated Schedule 10.1.6.

QUESTION:

a) Please provide Centra's submission filed with the PUB as part of Centra's August 1, 2017 Rate Application. This should include all materials prepared and filed with the PUB including the rate rollback materials, and any correspondence and scenario analysis provided to the PUB in conjunction with Centra's August 1, 2017 rate application.
b) With respect to the response to CAC/Centra I-4 (b), Figures 2 and 6 of the Supplement and the response to IGU/Centra 15, please provide the following based on the updated application for 2019/20 rates:
    i. a detailed reconciliation/supporting narrative by cost component between the requested non-gas revenue requirement in Figure 2 of $149.2 million and in Figure 6 of $148.5 million
    ii. a detailed reconciliation/supporting narrative by revenue component between the existing revenues at non-gas rates in Figure 2 of $149.2 million, Figure 6 of $148.5 million and IGU/Centra I-15 of $152.5 million; and

iii. a calculation/confirmation of the non-gas revenue requirement, revenues at existing non-gas rates and non-gas sufficiency/deficiency that reflects Centra's application before the PUB.

RESPONSE:

a) Please see the attachment for Centra's submission filed with the PUB related to Centra's August 1, 2017 Primary Gas rate application.

b)

i. The following table provides a reconciliation by cost component of the $149.1 million of Non-Gas Cost with respect to Figure 2 of the Supplement, with the $148.5 Million of Non-Gas Costs included in the Cost Allocation Study as per Figure 6 of the Supplement:

Reconciliation of Non-Gas Revenue Requirement vs. Non-Gas Cost Allocation 2019/20 Approved Budget *(in thousands of dollars)*	Supplement Figure 2			Adjustments for Cost Allocation Study Purposes					Supplement Figure 6
	Non-Gas Amounts Identified in Preamble	Other Domestic Revenue Items	Non-Gas Costs Revenue Requirment	Reclassify Net Movement	Reclassify Late Payment Charges and Broker Revenue	Reclassify Customer Contributions	Reclassify Other Expenses	Remove FRP Funding	Cost Allocation
Other Income	(1 730)		(1 730)		(636)	1 130	46		(1 190)
Operating & Administrative	61 250		61 250	(700)					60 550
Finance Expense	22 554		22 554	(951)					21 603
Depreciation & Amortization	25 474		25 474	8 006		(1 130)			32 350
Capital & Other Taxes	17 119		17 119	3 193					20 312
Other Expenses	10 674		10 674	(10 628)			(46)		-
Corporate Allocation	12 000		12 000						12 000
Net Movement	(1 080)		(1 080)	1 080					-
Net Income	2 894		2 894						2 894
Furnace Replacement Program Funding		545	545					(545)	-
Late Payment Charges & Broker Revenue		(636)	(636)		636				-
Total	149 155	(91)	149 064	-	-	-	-	(545)	148 519

With respect to the $149.2 million referenced by CAC, Centra notes that following additional items need to be included to determine the $149.1 million Non-Gas Costs Revenue Requirement:

- Furnace Replacement Program (FRP) funding - reflects the budgeted amount to be collected from customers to fund the furnace replacement program prior to August 1, 2019, the date at which the 2019/20 Approved Budget anticipated implementation of new rates which would no longer include FRP funding.

- Late Payment Charges and Broker Revenue reflect a separate source of Domestic Revenue which reduces the amount to be recovered through Non-Gas rates. Prior to the adoption of IFRS, these amounts were included in Other Income.

  For Cost Allocation Study Purposes, Centra has adjusted the IFRS based presentation of Cost of Service to provide a Rate Setting view which is consistent with the presentation used previously under CGAAP in past Cost Allocation Studies. The following items have been reclassified:
- Net Movement has been reclassified to the relevant cost components for rate setting purposes. Please refer to Appendix 6.12 (Update) – Figure 3 (Page 4) for a breakdown of the specific amounts included in this reclassification.
- Late Payment Charges and Broker Revenue has been included with Other Income
- Amortization of Customer Contributions has been included with Depreciation and Amortization Expense
- Other Expenses in the amount of $46K have been included with Other Income, as this amount was reclassified from Other Income for financial reporting purposes on IFRS transition.

In addition, for Cost Allocation Study purposes, the FRP funding amount has been removed, as Centra's Application proposes to discontinue funding this program.

ii. The following table provides a comparison of Non-Gas Revenue at Existing Rates as reported in the Figure 2 of the Supplement and in the response to IGU/Centra I-15:

Non-Gas Revenue at Existing Rates 2019/20 *(in thousands of dollars)*	**Supplement Figure 2 Approved Budget**	**IGU/Centra I-15 ***
Non-Gas Revenue at Existing Rates	149 064	152 525
Less Embedded FRP Funding	(545)	(3 800)
Rounding difference		(206)
Non-Gas Revenue at Existing Rates Excluding FRP Funding	148 519	148 519

* per Schedule 10.1.6 Update, line 35

The difference in the amount of Non-Gas Revenue at Existing Rates presented in the above table is due primarily to the inclusion of different amounts of FRP funding. The response to IGU/Centra I-15 includes a full year of FRP funding, as this funding is included in the existing rates, while the approved budget shown in the Supplement includes four months of FRP funding, as Centra's 2019/20 Approved Budget reflects an assumption that the FRP funding will be discontinued effective August 1, 2019. The Non-Gas costs of $148.5 million as per Figure 6 of the Supplement reflect the discontinuation of all FRP funding.

The remaining $0.2 million difference between the Non-Gas Revenue amounts presented in the above table is due to a difference in the method used to calculate Non-Gas Revenues for the Approved Budget, which rounds the Gas vs Non-Gas rate components to 1 decimal place, as compared to the 2019/20 Cost Allocation Study, which uses unrounded Gas vs Non-Gas rate components.

iii. Based on the approved forecast, a non-gas revenue requirement of $149.1 million is sufficient to generate a net income of $2.9 million for 2019/20, assuming discontinuation of FRP funding effective August 1, 2019, as reflected in Figure 2 of the Supplement.

As discussed in part b) ii) above, the total revenue sufficiency of $4.0 million shown in the response to IGU/CENTRA I-15 reflects the inclusion of FRP funding in the current rates ($3.8 million), which Centra is proposing to discontinue, and $0.2 million of rounding differences.

Manitoba Hydro
360 Portage Avenue (22) • Winnipeg Manitoba Canada • R3C 0G8
Telephone / N° de téléphone: (204) 360-3257 • Fax / N° de télécopieur: (204) 360-6147 • baczarnecki@hydro.mb.ca

July 14, 2017

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

ATTENTION: Mr. D. Christle, Board Secretary and Executive Director

Dear Mr. Christle:

RE: CENTRA GAS MANITOBA INC.
INTERIM PRIMARY GAS RATES EFFECTIVE AUGUST 1, 2017

Enclosed are nine (9) copies of Centra Gas Manitoba Inc.'s ("Centra") Application to the Public Utilities Board of Manitoba ("PUB") for Primary Gas sales rates to be effective August 1, 2017. The Application is filed on an interim ex-parte basis in accordance with the Rate Setting Methodology ("RSM") and process approved by the PUB in Orders 55/00, 99/01, 143/03, and 69/04, and with Section 45 of *The Public Utilities Board Act*.

In this Application, Centra is requesting approval of a Primary Gas rate which is a decrease relative to the previous billed rate and reflects the following:

1. The July 4, 2017 12-month futures price for Western Canadian supplies for the period August 1, 2017 to July 31, 2018 (weighted for the cost of gas in storage); and,
2. The disposition of the forecast balance in the Primary Gas Purchased Gas Variance Account ("PGVA") accumulated to July 31, 2017 over a 12-month period beginning August 1, 2017.

In accordance with Directive 5 of Order 108/15, the attached August 1, 2017 Rate Schedules also reflect the reversion of non-gas rates to levels approved as final in Order 85/13. The reversion impacts all rates with the exception of the Basic Monthly Charge for the Small General Service and Large General Service customer classes which are unchanged and reflects an increase to the non-gas overhead component embedded in the Primary Gas rate, from $0.00087/m^3 to $0.00164/m^3.

The resulting Primary Gas billed rate is $0.0921/m^3, which reflects an embedded cost of Primary Gas of $2.569/GJ for Western Canadian Supplies. The current approved Primary Gas billed rate is $0.1017/m^3, which reflects an embedded cost of Primary Gas of $2.845/GJ for Western Canadian supplies.

The combined bill impact of the August 1, 2017 Primary Gas rate adjustment and reversion of rates pursuant to Order 108/15 results in a decrease for the typical residential customer of approximately

4.0% or $29 per year. The annualized bill impact for larger volume customers ranges from decreases of 3.8% to decreases of 31.4% depending on customer class and consumption levels. It is noted that the Special Contract class and Power Station class would experience annualized bill increases of approximately 14.4% and 81.8% respectively, assuming the rate reversion.

Centra has also attached the following alternate rate schedules and bill impacts as requested by PUB Counsel on July 10, 2017:

- August 1, 2017 Rate schedules and bill impacts that reflect the Primary Gas rate change and the reversion to non-gas components in the rates of all customer classes with the exception of Special Contract and Power Station classes (Attachment 3), and;
- August 1, 2017 Rate Schedules and bill Impacts reflecting a Primary Gas rate change only and no rollback of non-gas rates (Attachment 4). This scenario reflects a Primary Gas billed rate of $0.0914/m^3 and results in a decrease of approximately 3.0% or $22 per year in the annual bill for a typical residential customer.

Centra respectfully requests the PUB issue an Order on the above matter by July 27, 2017 in order to implement the proposed rate changes for August 1, 2017.

Centra certifies, to the best of its knowledge and belief, that the information provided in this submission is accurate and correct. Copies of this Application have also been provided to the PUB advisors. If you require clarification of the details in this Application, please do not hesitate to call the writer at (204) 360-3257 or Greg Barnlund at (204) 360-5243.

Yours truly,

MANITOBA HYDRO LAW DIVISION
Per:

Brent A. Czarnecki
Barrister & Solicitor
Att.

cc: Mr. B. Peters, Fillmore Riley
Mr. R. Cathcart, Cathcart Advisors Inc.
Mr. B. Ryall, Ryall Engineering

CENTRA GAS MANITOBA INC.

APPLICATION FOR INTERIM PRIMARY GAS RATES

EFFECTIVE AUGUST 1, 2017

1.0 Application

Centra Gas Manitoba Inc. ("Centra") is applying to the Public Utilities Board of Manitoba ("PUB") for an Order pursuant to Section 45 of *The Public Utilities Board Act* and pursuant to PUB Orders 55/00, 99/01, 143/03, and 69/04 to approve Primary Gas sales rates on an interim ex-parte basis to be effective for all natural gas consumed on and after August 1, 2017 and to remain in effect until further Order of the PUB. This Application reflects a 12-month futures price strip taken on July 4, 2017.

The requested Primary Gas billed rate for August 1, 2017 is a decrease relative to the previous billed rate and reflects the following:

1. The July 4, 2017 12-month futures price for Western Canadian supplies for the period August 1, 2017 to July 31, 2018 (weighted for the cost of gas in storage); and
2. The disposition of the forecast balance in the Primary Gas Purchased Gas Variance Account ("PGVA") accumulated to July 31, 2017 over a 12-month period beginning August 1, 2017.

In accordance with Directive 5 of Order 108/15, the attached August 1, 2017 Rate Schedules also reflect the reversion of non-gas rates to levels approved on an interim basis in Order 66/11 and subsequently approved as final in Order 85/13. The reversion impacts all rates with the exception of the Basic Monthly Charge for the Small General Service and Large General Service customer classes which are unchanged and reflects an increase to the non-gas overhead component embedded in the Primary Gas rate, from $0.00087/m^3 to $0.00164/m^3.

The resulting Primary Gas billed rate is $0.0921/m^3, which reflects an embedded cost of Primary Gas of $2.569/GJ for Western Canadian Supplies. The current approved Primary Gas billed rate is $0.1017/m^3, which reflects an embedded cost of Primary Gas of $2.845/GJ for Western Canadian supplies.

The combined bill impact of the August 1, 2017 Primary Gas rate adjustment and the reversion of non-gas rates pursuant to Order 108/15 results in a decrease for the typical residential customer of approximately 4.0% or $29 per year. The annualized bill impact for larger volume customers ranges from decreases of 3.8% to decreases of 31.4% depending on customer class and consumption levels. It is noted that the Special Contract class and Power Station class will experience annualized bill increases of approximately 14.4% and 81.8% respectively, assuming the rate reversion.

Centra has also attached the following alternate rate schedules and bill impacts as requested by PUB Counsel on July 10, 2017:

- August 1, 2017 rate schedules and bill impacts that reflect the Primary Gas rate change and the reversion of non-gas components in the rates of all customer classes with the exception of Special Contract and Power Station classes (Attachment 3), and;
- August 1, 2017 rate schedules and bill Impacts reflecting a Primary Gas rate change only and no reversion of non-gas rates (Attachment 4). This scenario reflects a Primary Gas billed rate of $0.0914/m3 and results in a decrease of approximately 3.0% or $22 per year in the annual bill for a typical residential customer.

The resulting Primary Gas billed rate is $0.0921/$m^3$, which reflects an embedded cost of Primary Gas of $2.569/GJ for Western Canadian Supplies. The current approved Primary Gas billed rate is $0.1017/$m^3$, which reflects an embedded cost of Primary Gas of $2.845/GJ for Western Canadian supplies.

2.0 <u>Current Gas Market Pricing: Futures Price Strip</u>

AECO futures prices have decreased relative to the cost of Primary Gas embedded in current rates. The result is that the 12-month average price for Alberta supply as of July 4, 2017 is [redacted]GJ in comparison to [redacted]GJ as of April 3, 2017. The actual average 1a cost of Primary Gas in storage equates to [redacted]GJ as at October 31, 2016. After weighting for Primary Gas in storage, Centra's 12-month forecast average unit cost for Primary Gas supplies equates to $2.569/GJ. This compares with the currently approved weighted Primary Gas average unit cost of $2.845/GJ. 1a

The calculations are based on futures market prices as of July 4, 2017 for the 12-month period from August 1, 2017 to July 31, 2018.

3.0 <u>Calculation of Primary Gas Rate</u>

3.1 Primary Gas Base Rate

In accordance with the standard Rate Setting Methodology, Centra has calculated a Primary Gas base rate to be implemented on August 1, 2017. These calculations appear in Schedule 1.1.0.

Schedule 1.1.1 shows the detail of the month by month Alberta futures prices for AECO deliveries, and also indicates Centra's resulting forecast monthly Western Canadian supply prices at Empress. In accordance with the terms of Centra's Western Canadian gas supply contract that became effective November 1, 2016, the forward average cost of Western Canadian supply (i.e., Primary Gas) direct to the load (lines 3 to 9) for the period of August 1, 2017 through July 31, 2018 reflects the following pricing structure information:

- AECO futures market prices (line 1);
- Centra's forecast Western Canadian Supply Price at Empress per Gigajoule, which [redacted] (line 3); and, 1a
- Centra's forecast total of Western Canadian supply costs direct to the load at Empress, which includes the weighting for Western Canadian [redacted] (lines 5 to 7). 1a

The Primary Gas weighted average cost of \$2.569/GJ (Line 4 of Schedule 1.1.0) reflects a storage component priced at [redacted] GJ, which is the actual average cost of Primary Gas 1a in storage as at October 31, 2016 (i.e., at the conclusion of the 2016 summer injection season). Schedule 1.1.2 provides details of the average storage cost determination. Column 1 shows gas storage balances at the end of the 2015/16 winter withdrawal season. [redacted] Columns 2 and 1d 3 show injections and withdrawals for the April 2016 to October 2016 period. Column 4 shows the actual balance at October 31, 2016 with storage full at 16,500,000 GJs.

The Primary Gas cost to be embedded in rates is \$2.569/GJ. The corresponding amount converted to a volumetric price is \$97.10 per 10^3m^3, which appears on line 14 of Schedule 1.1.0. The Primary Gas base rate also reflects the Primary Gas non-gas overhead component of \$1.64 per 10^3m^3 (approved in Order 128/09) and \$1.40 per

10^3m^3 to reflect TCPL compressor fuel costs from Alberta to Manitoba. The details of the calculation of the TCPL compressor fuel costs (on a unit of Western Canadian gas supply) are shown on lines 12 to 20 of Schedule 1.1.1. The resulting Primary Gas base rate is \$100.14 per 10^3m^3 (\$0.1001 per m^3), shown on line 17 of Schedule 1.1.0.

3.2 Primary Gas Rate Riders

Schedule 1.1.3 provides the detail of the total forecasted Primary Gas PGVA balance to July 31, 2017. The estimated balance in the Primary Gas PGVA at July 31, 2017 is approximately [redacted] owing to customers. The Primary Gas rate rider required to refund the balance owing to customers equates to \$0.008 per m^3, which in combination with the Primary Gas base rate, results in a Primary Gas billed rate of \$0.0921/m^3.

4.0 Customer Impacts

The annualized bill impacts are summarized on Schedule 1.2.0. Impacts are shown by customer class for a range of consumption levels. The bill impacts are calculated relative to the existing May 1, 2017 billed rates which were approved in Order 44/17.

Columns 4 through 7 of Schedule 1.2.0 provide the annualized bill impacts by class as a result of the Primary Gas rate change only (including the reversion of the Primary Gas overhead rate). The annualized bill decrease for a typical residential customer as a result of the Primary Gas rate change, based on an annual consumption of 2,243 m^3, is 2.8% or \$20 per year. The annualized bill impacts of the requested Primary Gas rate change, by customer class, are summarized as follows:

Customer Class	Annualized Bill Impact
SGS	(2.2%) – (3.4%)
LGS	(3.3%) – (4.6%)
High Volume Firm (Sales Service)	(4.3%) – (5.9%)
Mainline (Sales Service)	(5.0%) – (6.2%)
Interruptible	(5.0%) – (6.3%)

Columns 8 through 11 of Schedule 1.2.0 provide the combined annualized bill impacts by class as a result of the Primary Gas rate change and the reversion of non-gas rates pursuant to Order 108/15. The annualized bill impact for a typical residential customer is a decrease of 4.0% or $29 per year. The combined annualized bill impacts, by customer class, are summarized below:

Customer Class	Annualized Bill Impact
SGS	(3.1%) - (5.0%)
LGS	(4.1%) – (5.7%)
High Volume Firm (Sales Service)	(5.9%) – (6.5%)
High Volume Firm (Transportation Service)	(12.8%) – (15.1%)
Mainline (Sales Service)	(3.8%) – (6.8%)
Mainline (Transportation Service)	(20.9%) – (31.4%)
Interruptible	(6.6%) – (7.8%)
Special Contract	14.4%
Power Stations	81.8%

In accordance with the PUB's minimum filing requirements and Order 143/03, Centra has also included Schedule 2.0.0, the April 3, 2017 Forward Average Cost of Western Canadian Supply.

5.0 <u>Interim Rate Request</u>

Centra is requesting interim ex-parte approval of the Primary Gas rate as per the attached rate schedules, which also reflect the directed reversion of non-gas rates pursuant to Order 108/15. Centra respectfully requests the PUB issue an Order on the above matter by July 27, 2017 in order to implement the proposed rate change for August 1, 2017.

CENTRA GAS MANITOBA INC.
Interim Primary Gas Rates Effective August 1, 2017
Calculation of Weighted Average Primary Gas Cost

Schedule 1.1.0

Primary costs based on 100% of cost change

(based on forward market strip as at July 4, 2017 close)

			Average Cost $/GJ	Test Year Volumes GJ's	Weighting
1	Updated 12-Month Forward Primary Gas Cost				
2	Primary Gas direct to load		[redacted] 1a	[redacted] 1d	[redacted] 1d
3	Primary Gas in storage supply to load		1a	1d	1d
4	Primary Gas Weighted Average Cost	$/GJ	$2.569		100%
5					
6	Primary Gas Base Rate				
7	Weighted Primary Gas Cost				
8	Existing Rate		$2.845		
9	With Current Strip		$2.569		
10	Change		($0.276)		
11	100% of change		($0.276)		
12	**Primary Gas Cost**	$/GJ	**$2.569**		
13					
14	Updated Weighted Cost Component (line 12 * 37.80)		$97.10		
15	TCPL Compressor Fuel		$1.40		
16	Gas Overhead Component		$1.64		
17	**Primary Gas Base Rate**	$/$10^3m^3$	**$100.14**		
18					
19	**Calculation of Primary Gas PGVA Rate Rider - August 1, 2017 to July 31, 2018**				
20	Primary Gas PGVA Balance at July 31, 2017 (estimated)		[redacted] 1e		
21	Annual Sales Supplied by Primary Gas	10^3m^3	1d		
22	**Primary Gas PGVA Rate Rider**	$/$10^3m^3$	**($8.00)**		
23					
24	**Primary Gas Billed Rate**	$/$10^3m^3$	**$92.14**		

CENTRA GAS MANITOBA INC. Schedule 1.1.1

Interim Primary Gas Rates Effective August 1, 2017

Forward Average Cost of Western Canadian Supply (Primary Gas direct to load)

(based on forward market strip as at July 4, 2017 close)

			Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18		
1	AECO Price - $/GJ		$2.2386	$2.1974	$2.2612	$2.3971	$2.5735	$2.6535	$2.6552	$2.5951	$2.2327	$2.2174	$2.2479	$2.2692		
2																
3	Western Cdn. Supply Price at Empress - $/GJ	($Cdn)	[redacted]													1a + 2b
4																
5	Monthly Weightings Based on Forecast 2016/17 Gas Year Volumes															
6	Primary Gas direct to load - GJ's		[redacted]												[redacted]	1d
7	Cost															1a + 1e
8																
9	12-Month Average Cost															1a
10																
11																

12 **TCPL Compressor Fuel Costs**

		Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Totals	
13															
15															
16	Fuel Volume - GJ's	[redacted]												[redacted]	1d
17	Cost														1a + 1e
18															
19												Compressor Fuel Cost per unit of Western Supply - $/GJ =		$0.037	
20												Compressor Fuel Cost per unit of Western Supply - $/10^{3}m^3 =		$1.40	

CENTRA GAS MANITOBA INC.
Interim Primary Gas Rates Effective August 1, 2017
Average Cost of Gas in Storage

Schedule 1.1.2

		(1)	(2)	(3)	(4)	
		Balance at March 31, 2016	Injections April to October	Withdrawals April to October	Actual Balance at October 31, 2016	
1	**Volumes - GJ's**					
2	Primary Gas	[redacted]	[redacted]	[redacted]	[redacted]	1d
3	Supplemental Gas	[redacted]	[redacted]	[redacted]	[redacted]	1d
4						
5	Total	[redacted]	[redacted]	[redacted]	16,500,000	1d
6						
7						
8	**Dollars**					
9	Primary Gas	[redacted]	[redacted]	[redacted]	[redacted]	1a
10	Supplemental Gas	[redacted]	[redacted]	[redacted]	[redacted]	1a
11	Variable Transport & Fuel	[redacted]	[redacted]	[redacted]	[redacted]	1a
12						
13	Total	[redacted]	[redacted]	[redacted]	[redacted]	1a
14						
15						
16	**Average Cost - $ per GJ**					
17	Primary Gas	[redacted]	[redacted]	[redacted]	[redacted]	1a
18	Supplemental Gas	[redacted]	[redacted]	[redacted]	[redacted]	1a
19	Variable Transport & Fuel	[redacted]	[redacted]	[redacted]	[redacted]	1a

CENTRA GAS MANITOBA INC. — **Schedule 1.1.3**
Interim Primary Gas Rates Effective August 1, 2017
Primary Gas PGVA
(based on forward market strip as at July 4, 2017 close)

			(1) April Actual	(2) May Actual	(3) June Outlook	(4) July Outlook	
	Primary Gas PGVA						
1	Inflows						
2	Primary Gas Direct to Load			[redacted]			1a
3	Primary Gas from Storage						1a
4	TCPL Fuel to MDA & SSDA						1a
5	Exchanges With Counterparties (excluding stg. Withd.)						1a
6	TCPL Line Pack/Draft Nomination & T-Service Imbalances						1a
7	Primary Gas Delivered Service						1a
8	Miscellaneous Primary			$0	$0	$0	
9	**Total Inflows**			[redacted]			1a
10	Less: UFG Component			($98,760)	($92,193)	($67,854)	
11	Less: FRPGS Average Cost			($7,824)	($1,832)	($1,099)	
12	**Inflow After UFG Transfer**			[redacted]			1a
13							
14	WACOG Outflows	-		[redacted]			1e
15	Primary Gas Rate Rider Amortizations	+					1e
16	**Total Outflows**						1e
17							
18	Carrying Costs			($13,469)	($13,898)	($13,517)	
19							
20	**Net Balance**		[redacted]				1e

CENTRA GAS MANITOBA INC.
Interim Primary Gas Rates Effective August 1, 2017
Impact of Proposed Primary Gas Rate Change on Annualized Billings

Schedule 1.2.0

Primary costs based on 100% of cost change

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	
	(based on forward market strip as at July 4, 2017 close)												
					1-May-17	1-Aug-17							
1	**Primary Gas Billed Rates**												
2	Primary Gas Embedded Rate			$/GJ	$2.845	$2.569							
3													
4	Primary Gas Base Rate			$/10³m³	$110.07	$100.14							
5	Primary Gas PGVA Rate Rider			$/10³m³	($8.40)	($8.00)							
6	Primary Gas Billed Rate			$/10³m³	$101.67	$92.14							
7	**Primary Gas Billed Rate - in $/m³**			$/m³	$0.1017	$0.0921							
8													
9		Load	Annual		Primary Gas Rate Change				Primary Gas Rate Change and Rate Reversion Combined				
10		Factor	Consumption										
11		%	m³		1-May-17	1-Aug-17			1-May-17	1-Aug-17			
12					Annual Bill	Annual Bill	% Change	$ Change	Annual Bill	Annual Bill	% Change	$ Change	
13	SGS		1,000		$417	$408	-2.2%	($9)	$417	$404	-3.1%	($13)	
14			1,983		$662	$645	-2.7%	($18)	$662	$636	-3.9%	($26)	
15	*(Typical Residential Customer)*		2,243		$727	$707	-2.8%	($20)	$727	$698	-4.0%	($29)	
16			2,804		$867	$842	-2.9%	($25)	$867	$830	-4.2%	($37)	
17			3,201		$966	$937	-3.0%	($29)	$966	$924	-4.3%	($42)	
18			3,683		$1,086	$1,053	-3.1%	($33)	$1,086	$1,038	-4.4%	($48)	
19			11,331		$2,993	$2,891	-3.4%	($102)	$2,993	$2,844	-5.0%	($148)	
20													
21	LGS		11,331		$3,127	$3,025	-3.3%	($102)	$3,127	$3,000	-4.1%	($127)	
22			59,488		$12,489	$11,953	-4.3%	($535)	$12,489	$11,821	-5.3%	($667)	
23			679,868		$133,090	$126,972	-4.6%	($6,119)	$133,090	$125,463	-5.7%	($7,628)	
24													
25	HVF (Sales Service)	25%	850,000		$179,470	$171,820	-4.3%	($7,650)	$179,470	$168,853	-5.9%	($10,617)	
26		40%	850,000		$159,517	$151,867	-4.8%	($7,650)	$159,517	$149,664	-6.2%	($9,853)	
27		40%	1,416,392		$256,043	$243,296	-5.0%	($12,748)	$256,043	$240,450	-6.1%	($15,593)	
28		40%	2,832,784		$497,429	$471,934	-5.1%	($25,495)	$497,429	$467,480	-6.0%	($29,949)	
29		40%	6,200,000		$1,071,281	$1,015,481	-5.2%	($55,800)	$1,071,281	$1,007,203	-6.0%	($64,078)	
30		40%	12,600,000		$2,161,990	$2,048,590	-5.2%	($113,400)	$2,161,990	$2,033,044	-6.0%	($128,946)	
31		75%	685,000		$118,891	$112,726	-5.2%	($6,165)	$118,891	$111,190	-6.5%	($7,701)	
32		75%	849,835		$143,973	$136,324	-5.3%	($7,649)	$143,973	$134,716	-6.4%	($9,256)	
33		75%	1,416,392		$230,183	$217,436	-5.5%	($12,748)	$230,183	$215,581	-6.3%	($14,603)	
34		75%	2,832,784		$445,710	$420,215	-5.7%	($25,495)	$445,710	$417,742	-6.3%	($27,968)	
35		75%	6,200,000		$958,085	$902,285	-5.8%	($55,800)	$958,085	$898,344	-6.2%	($59,741)	
36		75%	12,600,000		$1,931,946	$1,818,546	-5.9%	($113,400)	$1,931,946	$1,811,814	-6.2%	($120,132)	
37													
38	HVF (T-Service)	40%	2,600,000		$73,919	$73,919	0.0%	$0	$73,919	$64,470	-12.8%	($9,449)	
39		40%	11,000,000		$265,382	$265,382	0.0%	$0	$265,382	$229,402	-13.6%	($35,980)	
40		40%	17,600,000		$415,816	$415,816	0.0%	$0	$415,816	$358,991	-13.7%	($56,825)	
41		75%	2,600,000		$57,305	$57,305	0.0%	$0	$57,305	$49,477	-13.7%	($7,828)	
42		75%	11,000,000		$195,090	$195,090	0.0%	$0	$195,090	$165,970	-14.9%	($29,120)	
43		75%	17,600,000		$303,350	$303,350	0.0%	$0	$303,350	$257,500	-15.1%	($45,850)	
44													
45	Mainline Firm	40%	2,500,000		$447,281	$424,781	-5.0%	($22,500)	$447,281	$430,216	-3.8%	($17,065)	
46		40%	11,000,000		$1,917,152	$1,818,152	-5.2%	($99,000)	$1,917,152	$1,796,934	-6.3%	($120,217)	
47		75%	2,500,000		$377,367	$354,867	-6.0%	($22,500)	$377,367	$362,787	-3.9%	($14,580)	
48		75%	11,000,000		$1,609,532	$1,510,532	-6.2%	($99,000)	$1,609,532	$1,500,245	-6.8%	($109,286)	
49													
46	MLF (T-Service)	40%	14,000,000		$286,930	$286,930	0.0%	$0	$286,930	$226,926	-20.9%	($60,004)	
47		40%	18,000,000		$364,634	$364,634	0.0%	$0	$364,634	$283,693	-22.2%	($80,941)	
48		40%	44,000,000		$869,711	$869,711	0.0%	$0	$869,711	$652,680	-25.0%	($217,030)	
49		75%	14,000,000		$189,413	$189,413	0.0%	$0	$189,413	$142,276	-24.9%	($47,138)	
50		75%	18,000,000		$239,255	$239,255	0.0%	$0	$239,255	$174,857	-26.9%	($64,398)	
47		75%	44,000,000		$563,230	$563,230	0.0%	$0	$563,230	$386,638	-31.4%	($176,592)	
48													
49	Interruptible (Sales Service)	25%	849,835		$146,949	$139,641	-5.0%	($7,309)	$146,949	$136,107	-7.4%	($10,843)	
50		40%	2,832,784		$422,730	$398,368	-5.8%	($24,362)	$422,730	$393,741	-6.9%	($28,989)	
51		40%	14,163,920		$2,053,436	$1,931,626	-5.9%	($121,810)	$2,053,436	$1,918,653	-6.6%	($134,782)	
48		75%	849,835		$129,895	$122,586	-5.6%	($7,309)	$129,895	$119,706	-7.8%	($10,189)	
49		75%	2,832,784		$397,859	$373,497	-6.1%	($24,362)	$397,859	$369,823	-7.0%	($28,036)	
50		75%	14,163,920		$1,929,080	$1,807,270	-6.3%	($121,810)	$1,929,080	$1,799,062	-6.7%	($130,018)	
51													
52	Special Contract	[redacted]											2d
53													
54	Power Stations												2d
55													2d
56													
57													

53 Notes:
54 Firm Billing percentages: 94% Primary Gas, 6% Supplemental Gas
55 Interruptible Billing percentages 90% Primary Gas, 10% Supplemental Gas

CENTRA GAS MANITOBA INC.

Schedule 2.0.0

Interim Primary Gas Rates Effective May 1, 2017

Forward Average Cost of Western Canadian Supply (Primary Gas direct to load)

(based on forward market strip as at April 3, 2017 close)

Line			May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18		
1	AECO Price - $/GJ		$2.5414	$2.5050	$2.5359	$2.5913	$2.6044	$2.6783	$2.7861	$2.9621	$3.0407	$3.0335	$2.9303	$2.3132		
2																
3	Western Cdn. Supply Price at Empress - $/GJ	($Cdn)	[redacted]													1a + 2b
4																
5	Monthly Weightings Based on Forecast 2016/17 Gas Year Volumes		[redacted]												[redacted]	
6	Primary Gas direct to load - GJ's															1d
7	Cost															1a + 1c
8																
9	12-Month Average Cost															1d
10																
11																

12 TCPL Compressor Fuel Costs

Line		May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Totals	
13															
14															
15															
16	Fuel Volume - GJ's	[redacted]												[redacted]	1d
17	Cost														1a + 1c
18															
19	Compressor Fuel Cost per unit of Western Supply - $/GJ =													$0.042	
20	Compressor Fuel Cost per unit of Western Supply - $/$10^3m^3$ =													$1.60	

CENTRA GAS MANITOBA INC.
FIRM SALES AND DELIVERY SERVICES
RATES SCHEDULES (BASE RATES ONLY - NO RIDERS)

Territory: Entire natural gas service area of Company, including all zones

Availability:

SGC:	For gas supplied through one domestic-sized meter.
LGC:	For gas delivered through one meter at annual volumes less than 680,000 m³
HVF:	For gas delivered through one meter at annual volumes greater than 680,000 m³
CO-OP:	For gas delivered to natural gas distribution cooperatives
MLC:	For gas delivered through one meter to customers served from the Transmission system
Special Contract:	For gas delivered under the terms of a Special Contract with the Company
Power Station:	For gas delivered under the terms of a Special Contract with the Company

Rates:

		Distribution to Customers			
	Transportation to Centra	**Sales Service**	**T-Service**	**Primary Gas Supply**	**Supplemental Gas Supply[1]**
Basic Monthly Charge: ($/month)					
Small General Class (SGC)	N/A	$14.00	N/A	N/A	N/A
Large General Class (LGC)	N/A	$77.00	$77.00	N/A	N/A
High Volume Firm (HVF)	N/A	$1,118.31	$1,118.31	N/A	N/A
Cooperative (CO-OP)	N/A	$274.06	$274.06	N/A	N/A
Main Line Class (MLC)	N/A	$2,353.33	$2,353.33	N/A	N/A
Special Contract	N/A	N/A	$135,362.20	N/A	N/A
Power Station	N/A	N/A	$11,565.60	N/A	N/A
Monthly Demand Charge ($/m³/month)					
High Volume Firm Class (HVF)	$0.3074	$0.1503	$0.1503	N/A	N/A
Cooperative (CO-OP)	$0.4681	$0.1298	$0.1298	N/A	N/A
Main Line Class (MLC)	$0.5456	$0.1576	$0.1576	N/A	N/A
Special Contract	N/A	N/A	N/A	N/A	N/A
Power Station	N/A	N/A	$0.0283	N/A	N/A
Commodity Volumetric Charge: ($/m³)					
Small General Class (SGC)	$0.0538	$0.0866	N/A	$0.1001	$0.1559
Large General Class (LGC)	$0.0516	$0.0357	N/A	$0.1001	$0.1559
High Volume Firm (HVF)	$0.0196	$0.0073	$0.0073	$0.1001	$0.1559
Cooperative (CO-OP)	$0.0057	$0.0001	$0.0001	$0.1001	$0.1559
Main Line Class (MLC)	$0.0060	$0.0012	$0.0012	$0.1001	$0.1559
Special Contract	N/A	N/A	$0.0001	N/A	N/A
Power Station	N/A	N/A	$0.0084	N/A	N/A

[1] Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

Minimum Monthly Bill: Equal to the Basic Monthly Charge as described above, plus Demand Charge as appropriate.

Effective: Rates to be charged for all billings based on gas consumed on and after Aug 1, 2017.

Approved by Board Order: **Supersedes Board Order: 44/17**
Effective from: Aug 1, 2017 **Supersedes: May 1, 2017 Rates**
Date Implemented: Aug 1, 2017

CENTRA GAS MANITOBA INC.
INTERRUPTIBLE SALES AND DELIVERY SERVICES
RATE SCHEDULES (BASE RATES ONLY - NO RIDERS)

Territory: Entire natural gas service area of Company, including all zones.

Availability: For any Consumer at one location whose annual natural gas requirements equal or exceed 680,000m^3 and who contracts for such service for a minimum of one year, or who received Interruptible Service continuously since December 31, 1996. Service under this rate shall be limited to the extent that the Company considers it has available natural gas supplies and/or capacity to provide delivery service.

Rates:

	Transportation to Centra	Distribution to Customers: Sales Service	Distribution to Customers: T-Service	Primary Gas Supply	Supplemental Gas Supply[1]
Basic Monthly Charge: ($/month)					
Interruptible Service	N/A	$1,042.72	$1,042.72	N/A	N/A
Mainline Interruptible (with firm delivery)	N/A	$2,353.33	$2,353.33	N/A	N/A
Monthly Demand Charge ($/m3/month)					
Interruptible Service	$0.1429	$0.0772	$0.0772	N/A	N/A
Mainline Interruptible (with firm delivery)	$0.2199	$0.1576	$0.1576	N/A	N/A
Commodity Volumetric Charge: ($/m3)					
Interruptible Service	$0.0115	$0.0066	$0.0066	$0.1001	$0.1560
Mainline Interruptible (with firm delivery)	$0.0061	$0.0012	$0.0012	$0.1001	$0.1560
Alternate Supply Service:			Negotiated		
Gas Supply (Interruptible Sales and Mainline Interruptible)			Cost of Gas		
Delivery - Interruptible Class			$0.0092		
Delivery - Mainline Interruptible Class			$0.0064		

[1] Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

Minimum Monthly Bill: Equal to the Basic Monthly Charge as described above, plus Demand Charge as appropriate.

Effective: Rates to be charged for all billings based on gas consumed on and after Aug 1, 2017.

CENTRA GAS MANITOBA INC.
FIRM SALES AND DELIVERY SERVICES
RATE SCHEDULES (BASE RATES PLUS RIDERS)

Territory: Entire natural gas service area of Company, including all zones.

Availability:

SGC:	For gas supplied through one domestic-sized meter.
LGC:	For gas delivered through one meter at annual volumes less than 680,000 m^3.
HVF:	For gas delivered through one meter at annual volumes greater than 680,000 m^3.
Co-op:	For gas delivered to natural gas distribution cooperatives.
MLC:	For gas delivered through one meter to consumers served from the Transmission system.
Special Contract:	For gas delivered under the terms of a Special Contract with the Company.
Power Station:	For gas delivered under the terms of a Special Contract with the Company.

Rates:		**Distribution to Customers**			
	Transportation to Centra	**Sales Service**	**T-Service**	**Primary Gas Supply**	**Supplemental Gas Supply[1]**
Basic Monthly Charge: ($/month)					
Small General Class (SGC)	N/A	$14.00	N/A	N/A	N/A
Large General Class (LGC)	N/A	$77.00	$77.00	N/A	N/A
High Volume Firm Class (HVF)	N/A	$1,118.31	$1,118.31	N/A	N/A
Cooperative (Co-op)	N/A	$274.06	$274.06	N/A	N/A
Main Line Class (MLC)	N/A	$2,353.33	$2,353.33	N/A	N/A
Special Contract	N/A	N/A	$135,362.20	N/A	N/A
Power Station	N/A	N/A	$11,565.60	N/A	N/A
Monthly Demand Charge ($/$m^3$/month)					
High Volume Firm Class (HVF)	$0.3074	$0.1503	$0.1503	N/A	N/A
Cooperative (Co-op)	$0.4681	$0.1298	$0.1298	N/A	N/A
Main Line Class (MLC) (Firm)	$0.5456	$0.1576	$0.1576	N/A	N/A
Special Contract	N/A	N/A	N/A	N/A	N/A
Power Station	N/A	N/A	$0.0283	N/A	N/A
Commodity Volumetric Charge: ($/$m^3$)					
Small General Class (SGC)	$0.0538	$0.0866	N/A	$0.0921	$0.1559
Large General Class (LGC)	$0.0516	$0.0357	N/A	$0.0921	$0.1559
High Volume Firm Class (HVF)	$0.0196	$0.0073	$0.0073	$0.0921	$0.1559
Cooperative (Co-op)	$0.0057	$0.0001	$0.0001	$0.0921	$0.1559
Main Line Class (MLC) (Firm)	$0.0060	$0.0012	$0.0012	$0.0921	$0.1559
Special Contract	N/A	N/A	$0.0001	N/A	N/A
Power Station	N/A	N/A	$0.0084	N/A	N/A

¹ Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

Minimum Monthly Bill: Equal to the Basic Monthly Charge as described above, plus Demand Charge as appropriate.

Effective: Rates to be charged for all billings based on gas consumed on and after Aug 1, 2017.

CENTRA GAS MANITOBA INC. **ATTACHMENT 1**
Appendix A - Schedule of Sales and Transportation Services and Rates **Aug 1, 2017**
Proposed Rates Effective Aug 1, 2017 (reversion of Non-Gas Rates reflecting PUB Order 108/15) **Page 4 of 4**

CENTRA GAS MANITOBA INC.
INTERRUPTIBLE SALES AND DELIVERY SERVICES
RATE SCHEDULES (BASE RATES PLUS RIDERS)

Territory: Entire natural gas service area of Company, including all zones.

Availability: For any Consumer at one location whose annual natural gas requirements equal or exceed 680,000m^3 and who contracts for such service for a minimum of one year, or who received Interruptible Service continuously since December 31, 1996. Service under this rate shall be limited to the extent that the Company considers it has available natural gas supplies and/or capacity to provide delivery service.

Rates:	Transportation to Centra	Distribution to Customers: Sales Service	Distribution to Customers: T-Service	Primary Gas Supply	Supplemental Gas Supply[1]
Basic Monthly Charge: ($/month)					
Interruptible Service	N/A	$1,042.72	$1,042.72	N/A	N/A
Mainline Interruptible (with firm delivery)	N/A	$2,353.33	$2,353.33	N/A	N/A
Monthly Demand Charge ($/m^3/month)					
Interruptible Service	$0.1429	$0.0772	$0.0772	N/A	N/A
Mainline Interruptible (with firm delivery)	$0.2199	$0.1576	$0.1576	N/A	N/A
Commodity Volumetric Charge: ($/m^3)					
Interruptible Service	$0.0115	$0.0066	$0.0066	$0.0921	$0.1560
Mainline Interruptible (with firm delivery)	$0.0061	$0.0012	$0.0012	$0.0921	$0.1560
Alternate Supply Service:			Negotiated		
Gas Supply (Interruptible Sales and Mainline Interruptible)			Cost of Gas		
Delivery Service - Interruptible Class			$0.0092		
Delivery Service - Mainline Interruptible Class			$0.0064		

[1] Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

Minimum Monthly Bill: Equal to Basic Monthly Charge as described above, plus Demand charges as appropriate.

Effective: Rates to be charged for all billings based on gas consumed on and after Aug 1, 2017.

Approved by Board Order: **Supersedes Board Order: 44/17**
Effective from: Aug 1, 2017 **Supersedes: May 1, 2017 Rates**
Date Implemented: Aug 1, 2017

CENTRA GAS MANITOBA INC.
FIRM SALES AND DELIVERY SERVICES
RATES SCHEDULES (BASE RATES ONLY - NO RIDERS)

Territory:	Entire natural gas service area of Company, including all zones
Availability:	
SGC:	For gas supplied through one domestic-sized meter.
LGC:	For gas delivered through one meter at annual volumes less than 680,000 m³
HVF:	For gas delivered through one meter at annual volumes greater than 680,000 m³
CO-OP:	For gas delivered to natural gas distribution cooperatives
MLC:	For gas delivered through one meter to customers served from the Transmission system
Special Contract:	For gas delivered under the terms of a Special Contract with the Company
Power Station:	For gas delivered under the terms of a Special Contract with the Company

Rates:		**Distribution to Customers**			
	Transportation to Centra	**Sales Service**	**T-Service**	**Primary Gas Supply**	**Supplemental Gas Supply[1]**
Basic Monthly Charge: ($/month)					
Small General Class (SGC)	N/A	$14.00	N/A	N/A	N/A
Large General Class (LGC)	N/A	$77.00	$77.00	N/A	N/A
High Volume Firm (HVF)	N/A	$1,221.42	$1,221.42	N/A	N/A
Cooperative (CO-OP)	N/A	$318.21	$318.21	N/A	N/A
Main Line Class (MLC)	N/A	$1,247.13	$1,247.13	N/A	N/A
Special Contract	N/A	N/A	$117,914.17	N/A	N/A
Power Station	N/A	N/A	$8,026.07	N/A	N/A
Monthly Demand Charge ($/m^3/month)					
High Volume Firm Class (HVF)	$0.3094	$0.1666	$0.1666	N/A	N/A
Cooperative (CO-OP)	$0.4709	$0.1310	$0.1310	N/A	N/A
Main Line Class (MLC)	$0.5475	$0.1816	$0.1816	N/A	N/A
Special Contract	N/A	N/A	N/A	N/A	N/A
Power Station	N/A	N/A	$0.0048	N/A	N/A
Commodity Volumetric Charge: ($/m^3)					
Small General Class (SGC)	$0.0502	$0.0943	N/A	$0.1101	$0.1563
Large General Class (LGC)	$0.0480	$0.0416	N/A	$0.1101	$0.1563
High Volume Firm (HVF)	$0.0174	$0.0091	$0.0091	$0.1101	$0.1563
Cooperative (CO-OP)	$0.0034	$0.0001	$0.0001	$0.1101	$0.1563
Main Line Class (MLC)	$0.0037	$0.0045	$0.0045	$0.1101	$0.1563
Special Contract	N/A	N/A	$0.0001	N/A	N/A
Power Station	N/A	N/A	$0.0083	N/A	N/A

[1] Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

Minimum Monthly Bill:	Equal to the Basic Monthly Charge as described above, plus Demand Charge as appropriate.
Effective:	Rates to be charged for all billings based on gas consumed on and after May 1, 2017.

CENTRA GAS MANITOBA INC.
INTERRUPTIBLE SALES AND DELIVERY SERVICES
RATE SCHEDULES (BASE RATES ONLY - NO RIDERS)

Territory: Entire natural gas service area of Company, including all zones.

Availability: For any Consumer at one location whose annual natural gas requirements equal or exceed 680,000m^3 and who contracts for such service for a minimum of one year, or who received Interruptible Service continuously since December 31, 1996. Service under this rate shall be limited to the extent that the Company considers it has available natural gas supplies and/or capacity to provide delivery service.

Rates:

		Distribution to Customers			
	Transportation to Centra	**Sales Service**	**T-Service**	**Primary Gas Supply**	**Supplemental Gas Supply[1]**
Basic Monthly Charge: ($/month)					
Interruptible Service	N/A	$1,254.45	$1,254.45	N/A	N/A
Mainline Interruptible (with firm delivery)	N/A	$1,247.13	$1,247.13	N/A	N/A
Monthly Demand Charge ($/m3/month)					
Interruptible Service	$0.1438	$0.0851	$0.0851	N/A	N/A
Mainline Interruptible (with firm delivery)	$0.2213	$0.1816	$0.1816	N/A	N/A
Commodity Volumetric Charge: ($/m3)					
Interruptible Service	$0.0093	$0.0089	$0.0089	$0.1101	$0.1560
Mainline Interruptible (with firm delivery)	$0.0038	$0.0045	$0.0045	$0.1101	$0.1560
Alternate Supply Service:					
Gas Supply (Interruptible Sales and Mainline Interruptible)			Negotiated Cost of Gas		
Delivery - Interruptible Class			$0.0117		
Delivery - Mainline Interruptible Class			$0.0105		

[1] Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

Minimum Monthly Bill: Equal to the Basic Monthly Charge as described above, plus Demand Charge as appropriate.

Effective: Rates to be charged for all billings based on gas consumed on and after May 1, 2017.

CENTRA GAS MANITOBA INC.
FIRM SALES AND DELIVERY SERVICES
RATE SCHEDULES (BASE RATES PLUS RIDERS)

Territory:	Entire natural gas service area of Company, including all zones.
Availability:	
SGC:	For gas supplied through one domestic-sized meter.
LGC:	For gas delivered through one meter at annual volumes less than 680,000 m^3.
HVF:	For gas delivered through one meter at annual volumes greater than 680,000 m^3.
Co-op:	For gas delivered to natural gas distribution cooperatives.
MLC:	For gas delivered through one meter to consumers served from the Transmission system.
Special Contract:	For gas delivered under the terms of a Special Contract with the Company.
Power Station:	For gas delivered under the terms of a Special Contract with the Company.

Rates:	Transportation to Centra	Distribution to Customers: Sales Service	Distribution to Customers: T-Service	Primary Gas Supply	Supplemental Gas Supply[1]
Basic Monthly Charge: ($/month)					
Small General Class (SGC)	N/A	$14.00	N/A	N/A	N/A
Large General Class (LGC)	N/A	$77.00	$77.00	N/A	N/A
High Volume Firm Class (HVF)	N/A	$1,221.42	$1,221.42	N/A	N/A
Cooperative (Co-op)	N/A	$318.21	$318.21	N/A	N/A
Main Line Class (MLC)	N/A	$1,247.13	$1,247.13	N/A	N/A
Special Contract	N/A	N/A	$117,914.17	N/A	N/A
Power Station	N/A	N/A	$8,026.07	N/A	N/A
Monthly Demand Charge ($/m³/month)					
High Volume Firm Class (HVF)	$0.3094	$0.1666	$0.1666	N/A	N/A
Cooperative (Co-op)	$0.4709	$0.1310	$0.1310	N/A	N/A
Main Line Class (MLC) (Firm)	$0.5475	$0.1816	$0.1816	N/A	N/A
Special Contract	N/A	N/A	N/A	N/A	N/A
Power Station	N/A	N/A	$0.0048	N/A	N/A
Commodity Volumetric Charge: ($/m³)					
Small General Class (SGC)	$0.0502	$0.0943	N/A	$0.1017	$0.1563
Large General Class (LGC)	$0.0480	$0.0416	N/A	$0.1017	$0.1563
High Volume Firm Class (HVF)	$0.0174	$0.0091	$0.0091	$0.1017	$0.1563
Cooperative (Co-op)	$0.0034	$0.0001	$0.0001	$0.1017	$0.1563
Main Line Class (MLC) (Firm)	$0.0037	$0.0045	$0.0045	$0.1017	$0.1563
Special Contract	N/A	N/A	$0.0001	N/A	N/A
Power Station	N/A	N/A	$0.0083	N/A	N/A

¹ Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

Minimum Monthly Bill:	Equal to the Basic Monthly Charge as described above, plus Demand Charge as appropriate.
Effective:	Rates to be charged for all billings based on gas consumed on and after May 1, 2017.

CENTRA GAS MANITOBA INC.
INTERRUPTIBLE SALES AND DELIVERY SERVICES
RATE SCHEDULES (BASE RATES PLUS RIDERS)

Territory: Entire natural gas service area of Company, including all zones.

Availability: For any Consumer at one location whose annual natural gas requirements equal or exceed 680,000m^3 and who contracts for such service for a minimum of one year, or who received Interruptible Service continuously since December 31, 1996. Service under this rate shall be limited to the extent that the Company considers it has available natural gas supplies and/or capacity to provide delivery service.

Rates:	Transportation to Centra	Distribution to Customers: Sales Service	Distribution to Customers: T-Service	Primary Gas Supply	Supplemental Gas Supply[1]
Basic Monthly Charge: ($/month)					
Interruptible Service	N/A	$1,254.45	$1,254.45	N/A	N/A
Mainline Interruptible (with firm delivery)	N/A	$1,247.13	$1,247.13	N/A	N/A
Monthly Demand Charge ($/m³/month)					
Interruptible Service	$0.1438	$0.0851	$0.0851	N/A	N/A
Mainline Interruptible (with firm delivery)	$0.2213	$0.1816	$0.1816	N/A	N/A
Commodity Volumetric Charge: ($/m³)					
Interruptible Service	$0.0093	$0.0089	$0.0089	$0.1017	$0.1560
Mainline Interruptible (with firm delivery)	$0.0038	$0.0045	$0.0045	$0.1017	$0.1560
Alternate Supply Service:			Negotiated		
Gas Supply (Interruptible Sales and Mainline Interruptible)			Cost of Gas		
Delivery Service - Interruptible Class			$0.0117		
Delivery Service - Mainline Interruptible Class			$0.0105		

[1] Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

Minimum Monthly Bill: Equal to Basic Monthly Charge as described above, plus Demand charges as appropriate.

Effective: Rates to be charged for all billings based on gas consumed on and after May 1, 2017.

CENTRA GAS MANITOBA INC.
FIRM SALES AND DELIVERY SERVICES
RATES SCHEDULES (BASE RATES ONLY - NO RIDERS)

Territory: Entire natural gas service area of Company, including all zones

Availability:

SGC:	For gas supplied through one domestic-sized meter.
LGC:	For gas delivered through one meter at annual volumes less than 680,000 m³
HVF:	For gas delivered through one meter at annual volumes greater than 680,000 m³
CO-OP:	For gas delivered to natural gas distribution cooperatives
MLC:	For gas delivered through one meter to customers served from the Transmission system
Special Contract:	For gas delivered under the terms of a Special Contract with the Company
Power Station:	For gas delivered under the terms of a Special Contract with the Company

Rates:

		Distribution to Customers			
	Transportation to Centra	**Sales Service**	**T-Service**	**Primary Gas Supply**	**Supplemental Gas Supply**[1]
Basic Monthly Charge: ($/month)					
Small General Class (SGC)	N/A	$14.00	N/A	N/A	N/A
Large General Class (LGC)	N/A	$77.00	$77.00	N/A	N/A
High Volume Firm (HVF)	N/A	$1,118.31	$1,118.31	N/A	N/A
Cooperative (CO-OP)	N/A	$274.06	$274.06	N/A	N/A
Main Line Class (MLC)	N/A	$2,353.33	$2,353.33	N/A	N/A
Special Contract	N/A	N/A	$117,914.17	N/A	N/A
Power Station	N/A	N/A	$8,026.07	N/A	N/A
Monthly Demand Charge ($/m³/month)					
High Volume Firm Class (HVF)	$0.3074	$0.1503	$0.1503	N/A	N/A
Cooperative (CO-OP)	$0.4681	$0.1298	$0.1298	N/A	N/A
Main Line Class (MLC)	$0.5456	$0.1576	$0.1576	N/A	N/A
Special Contract	N/A	N/A	N/A	N/A	N/A
Power Station	N/A	N/A	$0.0048	N/A	N/A
Commodity Volumetric Charge: ($/m³)					
Small General Class (SGC)	$0.0538	$0.0866	N/A	$0.1001	$0.1559
Large General Class (LGC)	$0.0516	$0.0357	N/A	$0.1001	$0.1559
High Volume Firm (HVF)	$0.0196	$0.0073	$0.0073	$0.1001	$0.1559
Cooperative (CO-OP)	$0.0057	$0.0001	$0.0001	$0.1001	$0.1559
Main Line Class (MLC)	$0.0060	$0.0012	$0.0012	$0.1001	$0.1559
Special Contract	N/A	N/A	$0.0001	N/A	N/A
Power Station	N/A	N/A	$0.0083	N/A	N/A

[1] Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

Minimum Monthly Bill: Equal to the Basic Monthly Charge as described above, plus Demand Charge as appropriate.

Effective: Rates to be charged for all billings based on gas consumed on and after Aug 1, 2017.

CENTRA GAS MANITOBA INC.
INTERRUPTIBLE SALES AND DELIVERY SERVICES
RATE SCHEDULES (BASE RATES ONLY - NO RIDERS)

Territory: Entire natural gas service area of Company, including all zones.

Availability: For any Consumer at one location whose annual natural gas requirements equal or exceed 680,000m^3 and who contracts for such service for a minimum of one year, or who received Interruptible Service continuously since December 31, 1996. Service under this rate shall be limited to the extent that the Company considers it has available natural gas supplies and/or capacity to provide delivery service.

Rates:

	Transportation to Centra	Distribution to Customers: Sales Service	Distribution to Customers: T-Service	Primary Gas Supply	Supplemental Gas Supply[1]
Basic Monthly Charge: ($/month)					
Interruptible Service	N/A	$1,042.72	$1,042.72	N/A	N/A
Mainline Interruptible (with firm delivery)	N/A	$2,353.33	$2,353.33	N/A	N/A
Monthly Demand Charge ($/m3/month)					
Interruptible Service	$0.1429	$0.0772	$0.0772	N/A	N/A
Mainline Interruptible (with firm delivery)	$0.2199	$0.1576	$0.1576	N/A	N/A
Commodity Volumetric Charge: ($/m3)					
Interruptible Service	$0.0115	$0.0066	$0.0066	$0.1001	$0.1560
Mainline Interruptible (with firm delivery)	$0.0061	$0.0012	$0.0012	$0.1001	$0.1560
Alternate Supply Service:			Negotiated		
Gas Supply (Interruptible Sales and Mainline Interruptible)			Cost of Gas		
Delivery - Interruptible Class			$0.0092		
Delivery - Mainline Interruptible Class			$0.0064		

[1] Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

Minimum Monthly Bill: Equal to the Basic Monthly Charge as described above, plus Demand Charge as appropriate.

Effective: Rates to be charged for all billings based on gas consumed on and after Aug 1, 2017.

CENTRA GAS MANITOBA INC.
FIRM SALES AND DELIVERY SERVICES
RATE SCHEDULES (BASE RATES PLUS RIDERS)

Territory: Entire natural gas service area of Company, including all zones.

Availability:

SGC:	For gas supplied through one domestic-sized meter.
LGC:	For gas delivered through one meter at annual volumes less than 680,000 m^3.
HVF:	For gas delivered through one meter at annual volumes greater than 680,000 m^3.
Co-op:	For gas delivered to natural gas distribution cooperatives.
MLC:	For gas delivered through one meter to consumers served from the Transmission system.
Special Contract:	For gas delivered under the terms of a Special Contract with the Company.
Power Station:	For gas delivered under the terms of a Special Contract with the Company.

Rates:

		Distribution to Customers			
	Transportation to Centra	**Sales Service**	**T-Service**	**Primary Gas Supply**	**Supplemental Gas Supply**[1]
Basic Monthly Charge: ($/month)					
Small General Class (SGC)	N/A	$14.00	N/A	N/A	N/A
Large General Class (LGC)	N/A	$77.00	$77.00	N/A	N/A
High Volume Firm Class (HVF)	N/A	$1,118.31	$1,118.31	N/A	N/A
Cooperative (Co-op)	N/A	$274.06	$274.06	N/A	N/A
Main Line Class (MLC)	N/A	$2,353.33	$2,353.33	N/A	N/A
Special Contract	N/A	N/A	$117,914.17	N/A	N/A
Power Station	N/A	N/A	$8,026.07	N/A	N/A
Monthly Demand Charge ($/$m^3$/month)					
High Volume Firm Class (HVF)	$0.3074	$0.1503	$0.1503	N/A	N/A
Cooperative (Co-op)	$0.4681	$0.1298	$0.1298	N/A	N/A
Main Line Class (MLC) (Firm)	$0.5456	$0.1576	$0.1576	N/A	N/A
Special Contract	N/A	N/A	N/A	N/A	N/A
Power Station	N/A	N/A	$0.0048	N/A	N/A
Commodity Volumetric Charge: ($/$m^3$)					
Small General Class (SGC)	$0.0538	$0.0866	N/A	$0.0921	$0.1559
Large General Class (LGC)	$0.0516	$0.0357	N/A	$0.0921	$0.1559
High Volume Firm Class (HVF)	$0.0196	$0.0073	$0.0073	$0.0921	$0.1559
Cooperative (Co-op)	$0.0057	$0.0001	$0.0001	$0.0921	$0.1559
Main Line Class (MLC) (Firm)	$0.0060	$0.0012	$0.0012	$0.0921	$0.1559
Special Contract	N/A	N/A	$0.0001	N/A	N/A
Power Station	N/A	N/A	$0.0083	N/A	N/A

[1] Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

Minimum Monthly Bill: Equal to the Basic Monthly Charge as described above, plus Demand Charge as appropriate.

Effective: Rates to be charged for all billings based on gas consumed on and after Aug 1, 2017.

Approved by Board Order: **Supersedes Board Order: 44/17**
Effective from: Aug 1, 2017 **Supersedes: May 1, 2017 Rates**
Date Implemented: Aug 1, 2017

CENTRA GAS MANITOBA INC.
INTERRUPTIBLE SALES AND DELIVERY SERVICES
RATE SCHEDULES (BASE RATES PLUS RIDERS)

Territory: Entire natural gas service area of Company, including all zones.

Availability: For any Consumer at one location whose annual natural gas requirements equal or exceed 680,000m^3 and who contracts for such service for a minimum of one year, or who received Interruptible Service continuously since December 31, 1996. Service under this rate shall be limited to the extent that the Company considers it has available natural gas supplies and/or capacity to provide delivery service.

Rates:

	Transportation to Centra	Distribution to Customers: Sales Service	Distribution to Customers: T-Service	Primary Gas Supply	Supplemental Gas Supply[1]
Basic Monthly Charge: ($/month)					
Interruptible Service	N/A	$1,042.72	$1,042.72	N/A	N/A
Mainline Interruptible (with firm delivery)	N/A	$2,353.33	$2,353.33	N/A	N/A
Monthly Demand Charge ($/m^3/month)					
Interruptible Service	$0.1429	$0.0772	$0.0772	N/A	N/A
Mainline Interruptible (with firm delivery)	$0.2199	$0.1576	$0.1576	N/A	N/A
Commodity Volumetric Charge: ($/m^3)					
Interruptible Service	$0.0115	$0.0066	$0.0066	$0.0921	$0.1560
Mainline Interruptible (with firm delivery)	$0.0061	$0.0012	$0.0012	$0.0921	$0.1560

Alternate Supply Service:	Negotiated
Gas Supply (Interruptible Sales and Mainline Interruptible)	Cost of Gas
Delivery Service - Interruptible Class	$0.0092
Delivery Service - Mainline Interruptible Class	$0.0064

[1] Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

Minimum Monthly Bill: Equal to Basic Monthly Charge as described above, plus Demand charges as appropriate.

Effective: Rates to be charged for all billings based on gas consumed on and after Aug 1, 2017.

CENTRA GAS MANITOBA INC.
Interim Primary Gas Rates Effective August 1, 2017
Impact of Proposed Primary Gas Rate Change on Annualized Billings

Attachment 3

Primary costs based on 100% of cost change

(based on forward market strip as at July 4, 2017 close)

Line		(1) Load Factor %	(2) Annual Consumption m³	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	
					1-May-17	1-Aug-17							
1	**Primary Gas Billed Rates**												
2	Primary Gas Embedded Rate			$/GJ	$2 845	$2 569							
3													
4	Primary Gas Base Rate			$/10³m³	$110 07	$100 14							
5	Primary Gas PGVA Rate Rider			$/10³m³	($8 40)	($8 00)							
6	Primary Gas Billed Rate			$/10³m³	$101 67	$92 14							
7	**Primary Gas Billed Rate - In $/m³**			$/m³	$0.1017	$0.0921							
8													
9					Primary Gas Rate Change				Primary Gas Rate Change and Rate Reversion Combined				
11					1-May-17	1-Aug-17			1-May-17	1-Aug-17			
12					Annual Bill	Annual Bill	% Change	$ Change	Annual Bill	Annual Bill	% Change	$ Change	
13	SGS		1,000		$417	$408	-2.2%	($9)	$417	$404	-3 1%	($13)	
14			1,983		$662	$645	-2.7%	($18)	$662	$636	-3 9%	($26)	
15	*(Typical Residential Customer)*		2,243		$727	$707	-2.8%	($20)	$727	$698	-4.0%	($29)	
16			2,804		$867	$842	-2.9%	($25)	$867	$830	-4 2%	($37)	
17			3,201		$966	$937	-3.0%	($29)	$966	$924	-4 3%	($42)	
18			3,683		$1,086	$1,053	-3.1%	($33)	$1,086	$1,038	-4.4%	($48)	
19			11,331		$2,993	$2,891	-3.4%	($102)	$2,993	$2,844	-5 0%	($148)	
20													
21	LGS		11,331		$3,127	$3,025	-3.3%	($102)	$3,127	$3,000	-4 1%	($127)	
22			59,488		$12,489	$11,953	-4 3%	($535)	$12,489	$11,821	-5 3%	($667)	
23			679,868		$133 090	$126 972	-4 6%	($6 119)	$133 090	$125,463	-5 7%	($7,628)	
24													
25	HVF (Sales Service)	25%	850,000		$179,470	$171,820	-4 3%	($7 650)	$179 470	$168,853	-5 9%	($10,617)	
26		40%	850,000		$159,517	$151,867	-4 8%	($7 650)	$159 517	$149,664	-6 2%	($9,853)	
27		40%	1 416,392		$256 043	$243,296	-5 0%	($12,748)	$256 043	$240,450	-6.1%	($15,593)	
28		40%	2,832 784		$497 429	$471 934	-5 1%	($25 495)	$497 429	$467 480	-6.0%	($29,949)	
29		40%	6,200,000		$1,071,281	$1,015,481	-5 2%	($55 800)	$1,071,281	$1,007,203	-6.0%	($64,078)	
30		40%	12 600,000		$2,161,990	$2,048,590	-5 2%	($113,400)	$2,161,990	$2,033,044	-6.0%	($128 946)	
31		75%	685,000		$118,891	$112,726	-5 2%	($6,165)	$118,891	$111,190	-6.5%	($7,701)	
32		75%	849,835		$143,973	$136,324	-5.3%	($7,649)	$143,973	$134,716	-6.4%	($9,256)	
33		75%	1,416,392		$230,183	$217,436	-5 5%	($12,748)	$230,183	$215,581	-6.3%	($14,603)	
34		75%	2,832,784		$445,710	$420,215	-5 7%	($25,495)	$445,710	$417,742	-6 3%	($27,968)	
35		75%	6,200 000		$958,085	$902,285	-5 8%	($55 800)	$958,085	$898,344	-6.2%	($59 741)	
36		75%	12,600,000		$1 931,946	$1,818,546	-5 9%	($113,400)	$1,931,946	$1,811,814	-6.2%	($120 132)	
37													
38	HVF (T-Service)	40%	2,600,000		$73,919	$73,919	0 0%	$0	$73,919	$64,470	-12 8%	($9,449)	
39		40%	11,000,000		$265,382	$265,382	0.0%	$0	$265,382	$229,402	-13.6%	($35,980)	
40		40%	17,600,000		$415,816	$415,816	0 0%	$0	$415,816	$358,991	-13.7%	($56,825)	
41		75%	2,600,000		$57,305	$57 305	0 0%	$0	$57 305	$49,477	-13.7%	($7,828)	
42		75%	11,000,000		$195,090	$195 090	0.0%	$0	$195,090	$165,970	-14.9%	($29,120)	
43		75%	17,600,000		$303,350	$303 350	0.0%	$0	$303,350	$257,500	-15.1%	($45,850)	
44													
45	Mainline Firm	40%	2,500,000		$447,281	$424 781	-5.0%	($22,500)	$447 281	$430,216	-3.8%	($17,065)	
46		40%	11,000,000		$1,917,152	$1,818 152	-5.2%	($99,000)	$1 917 152	$1,796,934	-6.3%	($120,217)	
47		75%	2,500,000		$377,367	$354 867	-6.0%	($22,500)	$377 367	$362,787	-3.9%	($14,580)	
48		75%	11,000,000		$1,609,532	$1,510 532	-6.2%	($99 000)	$1,609 532	$1,500,245	-6.8%	($109,286)	
49													
46	MLF (T-Service)	40%	14,000,000		$286,930	$286 930	0.0%	$0	$286,930	$226,926	-20.9%	($60,004)	
47		40%	18,000,000		$364,634	$364,634	0.0%	$0	$364 634	$283,693	-22.2%	($80,941)	
48		40%	44,000,000		$869,711	$869 711	0.0%	$0	$869,711	$652,680	-25.0%	($217,030)	
49		75%	14,000,000		$189,413	$189 413	0.0%	$0	$189,413	$142,276	-24.9%	($47,138)	
50		75%	18,000,000		$239,255	$239,255	0.0%	$0	$239,255	$174,857	-26.9%	($64,398)	
47		75%	44,000,000		$563,230	$563,230	0.0%	$0	$563,230	$386,638	-31 4%	($176,592)	
48													
49	Interruptible (Sales Service)	25%	849,835		$146,949	$139,641	-5.0%	($7 309)	$146,949	$136,107	-7 4%	($10,843)	
50		40%	2,832,784		$422,730	$398,368	-5.8%	($24 362)	$422 730	$393,741	-6 9%	($28,989)	
51		40%	14,163,920		$2,053,436	$1 931 626	-5.9%	($121 810)	$2,053 436	$1,918,653	-6.6%	($134,782)	
48		75%	849,835		$129,895	$122,586	-5 6%	($7 309)	$129 895	$119,706	-7 8%	($10,189)	
49		75%	2,832,784		$397,859	$373,497	-6 1%	($24 362)	$397 859	$369,823	-7 0%	($28,036)	
50		75%	14,163,920		$1,929,080	$1,807,270	-6 3%	($121,810)	$1,929,080	$1,799,062	-6 7%	($130,018)	
51													
52	Special Contract	81%	[redacted]		[redacted]	[redacted]	0 0%	$0	[redacted]	[redacted]	0 0%	[redacted]	2d
53													
54	Power Stations	5%	[redacted]		[redacted]	[redacted]	0 0%	$0	[redacted]	[redacted]	0 0%	[redacted]	2d
55		6%	[redacted]		[redacted]	[redacted]	0 0%	$0	[redacted]	[redacted]	0.0%	[redacted]	2d
56													
57													

53 Notes:
54 Firm Billing percentages: 94% Primary Gas, 6% Supplemental Gas
55 Interruptible Billing percentages: 90% Primary Gas, 10% Supplemental Gas

CENTRA GAS MANITOBA INC.
FIRM SALES AND DELIVERY SERVICES
RATES SCHEDULES (BASE RATES ONLY - NO RIDERS)

Territory:	Entire natural gas service area of Company, including all zones
Availability:	
SGC:	For gas supplied through one domestic-sized meter.
LGC:	For gas delivered through one meter at annual volumes less than 680,000 m^3
HVF:	For gas delivered through one meter at annual volumes greater than 680,000 m^3
CO-OP:	For gas delivered to natural gas distribution cooperatives
MLC:	For gas delivered through one meter to customers served from the Transmission system
Special Contract:	For gas delivered under the terms of a Special Contract with the Company
Power Station:	For gas delivered under the terms of a Special Contract with the Company

Rates:	Transportation to Centra	Distribution to Customers: Sales Service	Distribution to Customers: T-Service	Primary Gas Supply	Supplemental Gas Supply[1]
Basic Monthly Charge: ($/month)					
Small General Class (SGC)	N/A	$14.00	N/A	N/A	N/A
Large General Class (LGC)	N/A	$77.00	$77.00	N/A	N/A
High Volume Firm (HVF)	N/A	$1,221.42	$1,221.42	N/A	N/A
Cooperative (CO-OP)	N/A	$318.21	$318.21	N/A	N/A
Main Line Class (MLC)	N/A	$1,247.13	$1,247.13	N/A	N/A
Special Contract	N/A	N/A	$117,914.17	N/A	N/A
Power Station	N/A	N/A	$8,026.07	N/A	N/A
Monthly Demand Charge ($/m³/month)					
High Volume Firm Class (HVF)	$0.3094	$0.1666	$0.1666	N/A	N/A
Cooperative (CO-OP)	$0.4709	$0.1310	$0.1310	N/A	N/A
Main Line Class (MLC)	$0.5475	$0.1816	$0.1816	N/A	N/A
Special Contract	N/A	N/A	N/A	N/A	N/A
Power Station	N/A	N/A	$0.0048	N/A	N/A
Commodity Volumetric Charge: ($/m³)					
Small General Class (SGC)	$0.0502	$0.0943	N/A	$0.0994	$0.1563
Large General Class (LGC)	$0.0480	$0.0416	N/A	$0.0994	$0.1563
High Volume Firm (HVF)	$0.0174	$0.0091	$0.0091	$0.0994	$0.1563
Cooperative (CO-OP)	$0.0034	$0.0001	$0.0001	$0.0994	$0.1563
Main Line Class (MLC)	$0.0037	$0.0045	$0.0045	$0.0994	$0.1563
Special Contract	N/A	N/A	$0.0001	N/A	N/A
Power Station	N/A	N/A	$0.0083	N/A	N/A

[1] Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

Minimum Monthly Bill: Equal to the Basic Monthly Charge as described above, plus Demand Charge as appropriate.

Effective: Rates to be charged for all billings based on gas consumed on and after Aug 1, 2017.

CENTRA GAS MANITOBA INC.
INTERRUPTIBLE SALES AND DELIVERY SERVICES
RATE SCHEDULES (BASE RATES ONLY - NO RIDERS)

Territory: Entire natural gas service area of Company, including all zones.

Availability: For any Consumer at one location whose annual natural gas requirements equal or exceed 680,000m^3 and who contracts for such service for a minimum of one year, or who received Interruptible Service continuously since December 31, 1996. Service under this rate shall be limited to the extent that the Company considers it has available natural gas supplies and/or capacity to provide delivery service.

Rates:

	Transportation to Centra	Distribution to Customers: Sales Service	Distribution to Customers: T-Service	Primary Gas Supply	Supplemental Gas Supply[1]
Basic Monthly Charge: ($/month)					
Interruptible Service	N/A	$1,254.45	$1,254.45	N/A	N/A
Mainline Interruptible (with firm delivery)	N/A	$1,247.13	$1,247.13	N/A	N/A
Monthly Demand Charge ($/m3/month)					
Interruptible Service	$0.1438	$0.0851	$0.0851	N/A	N/A
Mainline Interruptible (with firm delivery)	$0.2213	$0.1816	$0.1816	N/A	N/A
Commodity Volumetric Charge: ($/m3)					
Interruptible Service	$0.0093	$0.0089	$0.0089	$0.0994	$0.1560
Mainline Interruptible (with firm delivery)	$0.0038	$0.0045	$0.0045	$0.0994	$0.1560
Alternate Supply Service:			Negotiated		
Gas Supply (Interruptible Sales and Mainline Interruptible)			Cost of Gas		
Delivery - Interruptible Class			$0.0117		
Delivery - Mainline Interruptible Class			$0.0105		

[1] Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

Minimum Monthly Bill: Equal to the Basic Monthly Charge as described above, plus Demand Charge as appropriate.

Effective: Rates to be charged for all billings based on gas consumed on and after Aug 1, 2017.

CENTRA GAS MANITOBA INC.
FIRM SALES AND DELIVERY SERVICES
RATE SCHEDULES (BASE RATES PLUS RIDERS)

Territory:	Entire natural gas service area of Company, including all zones.
Availability:	
SGC:	For gas supplied through one domestic-sized meter.
LGC:	For gas delivered through one meter at annual volumes less than 680,000 m^3.
HVF:	For gas delivered through one meter at annual volumes greater than 680,000 m^3.
Co-op:	For gas delivered to natural gas distribution cooperatives.
MLC:	For gas delivered through one meter to consumers served from the Transmission system.
Special Contract:	For gas delivered under the terms of a Special Contract with the Company.
Power Station:	For gas delivered under the terms of a Special Contract with the Company.

Rates:

	Transportation to Centra	Distribution to Customers: Sales Service	Distribution to Customers: T-Service	Primary Gas Supply	Supplemental Gas Supply[1]
Basic Monthly Charge: ($/month)					
Small General Class (SGC)	N/A	$14.00	N/A	N/A	N/A
Large General Class (LGC)	N/A	$77.00	$77.00	N/A	N/A
High Volume Firm Class (HVF)	N/A	$1,221.42	$1,221.42	N/A	N/A
Cooperative (Co-op)	N/A	$318.21	$318.21	N/A	N/A
Main Line Class (MLC)	N/A	$1,247.13	$1,247.13	N/A	N/A
Special Contract	N/A	N/A	$117,914.17	N/A	N/A
Power Station	N/A	N/A	$8,026.07	N/A	N/A
Monthly Demand Charge ($/m³/month)					
High Volume Firm Class (HVF)	$0.3094	$0.1666	$0.1666	N/A	N/A
Cooperative (Co-op)	$0.4709	$0.1310	$0.1310	N/A	N/A
Main Line Class (MLC) (Firm)	$0.5475	$0.1816	$0.1816	N/A	N/A
Special Contract	N/A	N/A	N/A	N/A	N/A
Power Station	N/A	N/A	$0.0048	N/A	N/A
Commodity Volumetric Charge: ($/m³)					
Small General Class (SGC)	$0.0502	$0.0943	N/A	$0.0914	$0.1563
Large General Class (LGC)	$0.0480	$0.0416	N/A	$0.0914	$0.1563
High Volume Firm Class (HVF)	$0.0174	$0.0091	$0.0091	$0.0914	$0.1563
Cooperative (Co-op)	$0.0034	$0.0001	$0.0001	$0.0914	$0.1563
Main Line Class (MLC) (Firm)	$0.0037	$0.0045	$0.0045	$0.0914	$0.1563
Special Contract	N/A	N/A	$0.0001	N/A	N/A
Power Station	N/A	N/A	$0.0083	N/A	N/A

[1] Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

Minimum Monthly Bill:	Equal to the Basic Monthly Charge as described above, plus Demand Charge as appropriate.
Effective:	Rates to be charged for all billings based on gas consumed on and after Aug 1, 2017.

CENTRA GAS MANITOBA INC.
INTERRUPTIBLE SALES AND DELIVERY SERVICES
RATE SCHEDULES (BASE RATES PLUS RIDERS)

1 ***Territory:*** Entire natural gas service area of Company, including all zones.

2

3 ***Availability:*** For any Consumer at one location whose annual natural gas requirements equal or exceed 680,000m^3 and who contracts for such service for a minimum of one year, or who received Interruptible Service continuously since December 31, 1996. Service under this rate shall be limited to the extent that the Company considers it has available natural gas supplies and/or capacity to provide delivery service.

4

5 ***Rates:***

Line		Transportation to Centra	Distribution to Customers: Sales Service	Distribution to Customers: T-Service	Primary Gas Supply	Supplemental Gas Supply[1]
7						
8	***Basic Monthly Charge: ($/month)***					
9	Interruptible Service	N/A	$1,254.45	$1,254.45	N/A	N/A
10	Mainline Interruptible (with firm delivery)	N/A	$1,247.13	$1,247.13	N/A	N/A
11						
12	***Monthly Demand Charge ($/m^3/month)***					
13	Interruptible Service	$0.1438	$0.0851	$0.0851	N/A	N/A
14	Mainline Interruptible (with firm delivery)	$0.2213	$0.1816	$0.1816	N/A	N/A
15						
16	***Commodity Volumetric Charge: ($/m^3)***					
17	Interruptible Service	$0.0093	$0.0089	$0.0089	$0.0914	$0.1560
19	Mainline Interruptible (with firm delivery)	$0.0038	$0.0045	$0.0045	$0.0914	$0.1560
20						
21	***Alternate Supply Service:***					
22	Gas Supply (Interruptible Sales and Mainline Interruptible)			Negotiated Cost of Gas		
23	Delivery Service - Interruptible Class			$0.0117		
24	Delivery Service - Mainline Interruptible Class			$0.0105		
25						

26 [1] Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

27

28 ***Minimum Monthly Bill:*** Equal to Basic Monthly Charge as described above, plus Demand charges as appropriate.

29

30 ***Effective:*** Rates to be charged for all billings based on gas consumed on and after Aug 1, 2017.

CENTRA GAS MANITOBA INC. **Attachment 4**

Interim Primary Gas Rates Effective August 1, 2017

Calculation of Weighted Average Primary Gas Cost

Primary costs based on 100% of cost change

(based on forward market strip as at July 4, 2017 close)

			Average Cost $/GJ		Test Year Volumes GJ's		Weighting	
1	Updated 12-Month Forward Primary Gas Cost							
2	Primary Gas direct to load		[redacted]	1a	[redacted]	1d	[redacted]	1d
3	Primary Gas in storage supply to load		[redacted]	1a	[redacted]	1d	[redacted]	1d
4	Primary Gas Weighted Average Cost	$/GJ	$2.569				100%	
5								
6	Primary Gas Base Rate							
7	Weighted Primary Gas Cost							
8	Existing Rate		$2.845					
9	With Current Strip		$2.569					
10	Change		($0.276)					
11	100% of change		($0.276)					
12	**Primary Gas Cost**	$/GJ	**$2.569**					
13								
14	Updated Weighted Cost Component (line 12 * 37.80)		$97.10					
15	TCPL Compressor Fuel		$1.40					
16	Gas Overhead Component		$0.87					
17	**Primary Gas Base Rate**	$/$10^3m^3$	**$99.37**					
18								
19	**Calculation of Primary Gas PGVA Rate Rider - August 1, 2017 to July 31, 2018**							
20	Primary Gas PGVA Balance at July 31, 2017 (estimated)		[redacted]	1e				
21	Annual Sales Supplied by Primary Gas	10^3m^3	[redacted]	1d				
22	**Primary Gas PGVA Rate Rider**	$/$10^3m^3$	**($8.00)**					
23								
24	**Primary Gas Billed Rate**	$/$10^3m^3$	**$91.37**					

CENTRA GAS MANITOBA INC.
Interim Primary Gas Rates Effective August 1, 2017
Impact of Proposed Primary Gas Rate Change on Annualized Billings

Attachment 4

Primary costs based on 100% of cost change

		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	(based on forward market strip as at July 4, 2017 close)							
					1-May-17	1-Aug-17		
1	**Primary Gas Billed Rates**							
2	Primary Gas Embedded Rate			\$/GJ	\$2.845	\$2.569		
3								
4	Primary Gas Base Rate			$\$/10^3m^3$	\$110.07	\$99.37		
5	Primary Gas PGVA Rate Rider			$\$/10^3m^4$	(\$8.40)	(\$8.00)		
6	Primary Gas Billed Rate			$\$/10^3m^3$	\$101.67	\$91.37		
7	**Primary Gas Billed Rate - in $\$/m^3$**			$\$/m^3$	\$0.1017	\$0.0914		
8								
9		Load	Annual			Primary Gas Rate Change		
10		Factor	Consumption					
11		%	m^3		1-May-17	1-Aug-17		
12					Annual Bill	Annual Bill	% Change	\$ Change
13	SGS		1,000		\$417	\$408	-2.3%	(\$10)
14			1,983		\$662	\$643	-2.9%	(\$19)
15	*(Typical Residential Customer)*		2,243		\$727	\$705	-3.0%	(\$22)
16			2,804		\$867	\$840	-3.1%	(\$27)
17			3,201		\$966	\$935	-3.2%	(\$31)
18			3,683		\$1,086	\$1,050	-3.3%	(\$36)
19			11,331		\$2,993	\$2,883	-3.7%	(\$110)
20								
21	LGS		11,331		\$3,127	\$3,017	-3.5%	(\$110)
22			59,488		\$12,489	\$11,912	-4.6%	(\$577)
23			679,868		\$133,090	\$126,496	-5.0%	(\$6,595)
24								
25	HVF	25%	850,000		\$179,470	\$171,225	-4.6%	(\$8,245)
26		40%	850,000		\$159,517	\$151,272	-5.2%	(\$8,245)
27		40%	1,416,392		\$256,043	\$242,304	-5.4%	(\$13,739)
28		40%	2,832,784		\$497,429	\$469,951	-5.5%	(\$27,478)
29		40%	6,200,000		\$1,071,281	\$1,011,141	-5.6%	(\$60,140)
30		40%	12,600,000		\$2,161,990	\$2,039,770	-5.7%	(\$122,220)
31		75%	685,000		\$118,891	\$112,246	-5.6%	(\$6,645)
32		75%	849,835		\$143,973	\$135,729	-5.7%	(\$8,243)
33		75%	1,416,392		\$230,183	\$216,444	-6.0%	(\$13,739)
34		75%	2,832,784		\$445,710	\$418,232	-6.2%	(\$27,478)
35		75%	6,200,000		\$958,085	\$897,945	-6.3%	(\$60,140)
36		75%	12,600,000		\$1,931,946	\$1,809,726	-6.3%	(\$122,220)
37								
38	Mainline Firm	40%	2,500,000		\$447,281	\$423,031	-5.4%	(\$24,250)
39		40%	11,000,000		\$1,917,152	\$1,810,452	-5.6%	(\$106,700)
40		75%	2,500,000		\$377,367	\$353,117	-6.4%	(\$24,250)
41		75%	11,000,000		\$1,609,532	\$1,502,832	-6.6%	(\$106,700)
38								
39	Interruptible Service	25%	849,835		\$146,949	\$139,046	-5.4%	(\$7,903)
40		40%	2,832,784		\$422,730	\$396,385	-6.2%	(\$26,345)
41		40%	14,163,920		\$2,053,436	\$1,921,711	-6.4%	(\$131,724)
42		75%	849,835		\$129,895	\$121,992	-6.1%	(\$7,903)
43		75%	2,832,784		\$397,859	\$371,514	-6.6%	(\$26,345)
44		75%	14,163,920		\$1,929,080	\$1,797,356	-6.8%	(\$131,724)

45 Notes:
46 Firm Billing percentages: 94% Primary Gas, 6% Supplemental Gas
47 Interruptible Billing percentages: 90% Primary Gas, 10% Supplemental Gas

REFERENCE:

CAC/Centra I-4(a); CAC/Centra I-4 (e) Attachment

PREAMBLE TO IR (IF ANY):

QUESTION:

a) In the chart in the response to CAC/Centra I-4 (a), Centra indicates that the O&A forecast was completed in March 2018 for the November 30, 2018 original application and in February 2019 for the March 22, 2019 updated application. Based on a review of Appendix 5.9 – Figure 5.5 and Appendix 5.13 – Figure 5.9, there appears to be no change in the O&A forecast for 2018/19 and 2019/20 as a result of the March 22, 2019 update. Please confirm that there were no changes to the O&A targets or detailed O&A information between the original and updated application. If not confirmed, please provide a schedule outlining the changes to O&A with a narrative as to the reasons for the changes.
b) In the chart in the response to CAC/Centra I-4 (a), Centra indicates that the O&A forecast was completed in March 2018 for the November 30, 2018 original application and in February 2019 for the March 22, 2019 updated application. A review of CGM16 which was filed as Section 21.0 in Appendix 3.1 of the Manitoba Hydro 2017/18 & 2018/10 GRA, indicates that the Gas O&A forecasts for 2018/19 and 2019/20 rounded to the nearest $millions were $60 million and $61 million, respectively. Please (i) provide a copy of CGM16 on the record of this proceeding and include the financial ratio calculations similar to those provided for CGM18 (ii) provide CGM16 in a format similar to PUB/Centra II-139 from the 2013/14 GRA (iii) provide a schedule and narrative that supports the reasons for the increase in the 2018/19 Gas O&A forecast from $60 million in CGM16 to $63 million in CGM18 and (iv) confirm that there were no changes to the 2019/20 Gas O&A forecast between CGM16 and CGM18. If not confirmed, please provide a schedule outlining the changes to O&A with a narrative as to the reasons for the changes.
c) Please provide the response to PUB/Centra I-6 (d) (CGM12 with IFRS deferral to 2015/16, grandfathering of regulatory accounting, $3 million net income) from the

2013/14 GRA, which is provided in the Attachment to CAC/Centra I-4 (e) of this proceeding, in a format similar to PUB/Centra II-139 from the 2013/14 GRA.

RESPONSE:

a) Confirmed. There were no changes made to the O&A targets or detailed O&A information between the November 2018 and March 2019 filings.

b)

i. Below please find the CGM16 statements and the financial ratio calculations similar to those provided for CGM18.

GAS OPERATIONS (CGM16)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
REVENUES											
Domestic Revenue											
Cost of Gas	199	212	236	228	228	228	227	226	226	225	224
Non-Gas Costs	146	150	150	151	151	152	152	152	152	152	153
Furnace Replacement Program Funding	(4)	(4)	(4)	-	-	-	-	-	-	-	-
Late Payment Charges and Broker Revenue	1	1	1	1	1	1	1	1	1	1	1
	342	360	383	380	380	381	380	380	379	378	378
additional revenue requirement*	-	-	-	-	3	4	8	13	17	18	23
	342	360	383	380	384	385	389	393	396	396	401
Weighted Average Cost of Gas Sold	192	228	228	228	228	228	227	226	226	225	224
Gross Margin	150	131	155	152	155	157	161	166	171	171	177
Other	2	2	2	2	2	2	2	2	2	2	2
	152	133	157	153	157	158	163	168	172	173	179
EXPENSES											
Operating and Administrative	68	67	60	61	62	63	64	65	66	68	69
Finance Expense	19	20	21	22	23	24	25	26	26	27	28
Depreciation and Amortization	22	23	24	25	26	27	28	29	30	31	33
Capital and Other Taxes	16	16	17	17	18	18	18	19	19	19	20
Other Expenses	11	16	13	13	14	12	12	12	12	12	12
Corporate Allocation	12	12	12	12	12	12	12	12	12	12	12
	147	154	147	151	154	155	158	162	165	169	173
Net Income before Net Movement in Regulatory Deferral	4	(21)	9	3	3	3	5	6	7	4	6
Net Movement in Regulatory Deferral	(5)	20	(6)	1	0	(1)	(2)	(3)	(4)	(3)	(3)
Net Income	(0)	(1)	3	4	4	2	3	3	3	2	3
***Additional Revenue Requirement**											
Percent Increase	0.00%	-1.00%	0.00%	0.00%	1.00%	0.00%	1.50%	1.25%	1.00%	0.00%	1.75%
Cumulative Percent Increase	0.00%	-1.00%	-1.00%	-1.00%	-0.01%	-0.01%	1.49%	2.76%	3.79%	3.79%	5.60%
Equity Ratio (PUB Approved Methodology)	32%	31%	30%	30%	30%	30%	29%	29%	29%	29%	29%

GAS OPERATIONS (CGM16)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
ASSETS											
Plant in Service	559	592	626	656	688	721	757	791	830	869	908
Accumulated Depreciation	(40)	(56)	(72)	(89)	(107)	(125)	(144)	(164)	(185)	(207)	(229)
Net Plant in Service	518	536	554	567	581	596	612	626	645	662	679
Construction in Progress	5	4	4	4	4	4	4	4	4	4	4
Current and Other Assets	76	76	76	76	76	76	76	76	76	76	76
Goodwill and Intangible Assets	8	8	7	7	6	6	6	6	6	6	6
Total Assets before Regulatory Deferral	608	624	641	653	667	682	699	713	731	748	765
Regulatory Deferral Balance	100	112	106	106	106	104	101	97	93	91	88
	708	737	747	759	773	786	800	810	824	839	853
LIABILITIES AND EQUITY											
Long-Term Debt	370	400	390	420	430	420	450	460	435	485	495
Current and Other Liabilities	91	97	113	92	92	112	91	89	124	87	87
Deferred Revenue	44	45	47	48	48	50	52	53	53	54	54
Share Capital	121	121	121	121	121	121	121	121	121	121	121
Retained Earnings	64	64	67	70	74	76	79	82	85	87	90
Total Liabilities and Equity before Regulatory Deferral	691	727	738	751	766	779	794	804	819	834	848
Regulatory Deferral Balance	17	9	9	8	7	7	6	5	5	5	5
	708	737	747	759	773	786	800	810	824	839	853
Net Debt	400	434	439	450	462	475	487	496	506	518	528
Equity (PUB Approved Methodology)	32%	31%	30%	30%	30%	30%	29%	29%	29%	29%	29%

GAS OPERATIONS (CGM16)
PROJECTED DIRECT CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
OPERATING ACTIVITIES											
Cash Receipts from Customers	374	394	418	411	415	416	420	425	428	428	434
Cash Paid to Suppliers and Employees	(310)	(361)	(352)	(353)	(355)	(356)	(357)	(358)	(359)	(360)	(362)
Interest Paid	(19)	(20)	(21)	(22)	(22)	(23)	(24)	(25)	(26)	(26)	(28)
Cash Provided by Operating Activities	46	14	45	36	38	37	39	41	43	42	45
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	30	30	10	30	10	10	40	10	10	50	10
Retirement of Long-Term Debt	-	-	-	(20)	-	-	(20)	(10)	-	(35)	-
Other	-	-	-	-	-	-	-	-	-	-	-
Cash Provided by Financing Activities	30	30	10	10	10	10	20	-	10	15	10
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(63)	(46)	(47)	(44)	(46)	(47)	(49)	(47)	(53)	(53)	(53)
Other	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(2)	(1)	(1)	(1)
Cash Used for Investing Activities	(65)	(48)	(50)	(47)	(49)	(50)	(52)	(50)	(54)	(54)	(54)
Net Increase (Decrease) in Cash	10	(5)	5	(1)	(2)	(3)	8	(8)	(0)	3	0
Cash at Beginning of Year	(40)	(30)	(34)	(29)	(30)	(32)	(35)	(27)	(36)	(36)	(33)
Cash at End of Year	(30)	(34)	(29)	(30)	(32)	(35)	(27)	(36)	(36)	(33)	(33)

GAS OPERATIONS (CGM16)
PROJECTED FINANCIAL RATIOS

For the year ended March 31	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
PUB APPROVED DEBT TO EQUITY RATIO											
Average Long-Term Debt	355.000	385.000	405.000	415.000	425.000	435.000	450.000	460.000	465.000	477.500	490.000
Average Due to Parent	34.702	31.936	31.840	29.883	31.223	33.487	31.179	31.469	35.749	34.606	33.235
Average Debt	**389.702**	**416.936**	**436.840**	**444.883**	**456.223**	**468.487**	**481.179**	**491.469**	**500.749**	**512.106**	**523.235**
Average Share Capital	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250
Average Retained Earnings	64.709	64.035	65.155	68.547	72.265	75.120	77.640	80.553	83.518	85.944	88.414
Average Equity	**185.959**	**185.285**	**186.405**	**189.797**	**193.514**	**196.370**	**198.890**	**201.802**	**204.768**	**207.194**	**209.664**
Average Debt	389.702	416.936	436.840	444.883	456.223	468.487	481.179	491.469	500.749	512.106	523.235
Average Equity	185.959	185.285	186.405	189.797	193.514	196.370	198.890	201.802	204.768	207.194	209.664
Average Debt and Equity	575.661	602.220	623.245	634.679	649.737	664.857	680.069	693.272	705.517	719.300	732.899
PUB Approved Equity Ratio	**32%**	**31%**	**30%**	**30%**	**30%**	**30%**	**29%**	**29%**	**29%**	**29%**	**29%**

GAS OPERATIONS (CGM16)
PROJECTED FINANCIAL RATIOS

For the year ended March 31	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
INTEREST COVERAGE											
Net Income	(0.486)	(0.862)	3.103	3.680	3.755	1.956	3.084	2.741	3.190	1.662	3.278
Finance Expense	17.474	18.255	19.550	20.631	21.713	22.770	24.001	25.003	25.620	26.334	27.787
Capitalized Interest	0.765	0.292	0.177	0.140	0.156	0.170	0.192	0.171	0.226	0.220	0.223
	17.753	17.686	22.829	24.451	25.625	24.896	27.277	27.915	29.036	28.216	31.288
Finance Expense	17.474	18.255	19.550	20.631	21.713	22.770	24.001	25.003	25.620	26.334	27.787
Capitalized Interest	0.765	0.292	0.177	0.140	0.156	0.170	0.192	0.171	0.226	0.220	0.223
	18.239	18.547	19.727	20.771	21.870	22.940	24.193	25.174	25.846	26.554	28.010
Interest Coverage	**0.97**	**0.95**	**1.16**	**1.18**	**1.17**	**1.09**	**1.13**	**1.11**	**1.12**	**1.06**	**1.12**
Add: Depreciation and Amortization	28.695	30.724	34.521	35.904	37.703	38.915	40.115	42.349	43.956	44.115	45.142
Total EBITDA	46.448	48.409	57.350	60.355	63.328	63.811	67.392	70.264	72.992	72.331	76.430
EBITDA Interest Coverage	**2.55**	**2.61**	**2.91**	**2.91**	**2.90**	**2.78**	**2.79**	**2.79**	**2.82**	**2.72**	**2.73**
CAPITAL COVERAGE											
Internally Generated Funds	45.809	13.599	44.897	35.581	37.518	36.819	39.095	41.428	43.452	41.640	44.528
Net Capital Construction Expenditures	60.568	41.386	44.050	40.029	41.826	43.604	45.585	44.074	49.524	49.538	49.955
Capital Coverage	**0.76**	**0.33**	**1.02**	**0.89**	**0.90**	**0.84**	**0.86**	**0.94**	**0.88**	**0.84**	**0.89**

ii. The schedule below reflects CGM16 restated in a format similar to PUB/CENTRA II-139 from the 2013/14 GRA.

CGM16
(In Millions of Dollars)
For the year ended March 31

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
REVENUES											
Domestic Revenue											
Cost of Gas	199	212	236	228	228	228	227	226	226	225	224
Non-Gas Costs	146	150	150	151	151	152	152	152	152	152	153
Furnace Replacement Program Funding	(4)	(4)	(4)	-	-	-	-	-	-	-	-
Late Payment Charges and Broker Revenue	1	1	1	1	1	1	1	1	1	1	1
	342	360	383	380	380	381	380	380	379	378	378
Weighted Average Cost of Gas Sold	192	228	228	228	228	228	227	226	226	225	224
Gross Margin	150	131	155	152	152	153	153	153	153	153	154
Other	2	2	2	2	2	2	2	2	2	2	2
	152	133	157	153	154	155	155	155	155	155	156
EXPENSES											
Operating and Administrative	68	67	60	61	62	63	64	65	66	68	69
Finance Expense	19	20	21	22	23	24	25	26	26	27	28
Depreciation and Amortization	22	23	24	25	26	27	28	29	30	31	33
Capital and Other Taxes	16	16	17	17	18	18	18	19	19	19	20
Other Expenses	11	16	13	13	14	12	12	12	12	12	12
Corporate Allocation	12	12	12	12	12	12	12	12	12	12	12
	147	154	147	151	154	155	158	162	165	169	173
Net Income before Net Movement in Regulatory Deferral	4	(21)	9	3	0	(0)	(3)	(7)	(10)	(14)	(18)
Net Movement in Regulatory Deferral	(5)	20	(6)	1	0	(1)	(2)	(3)	(4)	(3)	(3)
Net Income (loss) before proposed rate increases*	**(0)**	**(1)**	**3**	**4**	**1**	**(2)**	**(6)**	**(11)**	**(16)**	**(19)**	**(24)**
additional revenue requirement**	-	-	-	-	3	4	8	13	17	18	23
Net Income (loss) after proposed rate increases	**(0)**	**(1)**	**3**	**4**	**4**	**2**	**3**	**3**	**3**	**2**	**3**
Retained Earnings before proposed rate increases	64	64	67	70	71	69	63	52	36	17	(7)
Retained Earnings after proposed rate increases	64	64	67	70	74	76	79	82	85	87	90
Financial Ratios - with rate increase											
Equity Ratio (PUB Approved Methodology)	32%	31%	30%	30%	30%	30%	29%	29%	29%	29%	29%
EBITDA Interest Coverage	2.55	2.61	2.91	2.91	2.90	2.78	2.79	2.79	2.82	2.72	2.73
Capital Coverage	0.76	0.33	1.02	0.89	0.90	0.84	0.86	0.94	0.88	0.84	0.89
Financial Ratios - without rate increase											
Equity Ratio (PUB Approved Methodology)	32%	31%	30%	30%	30%	29%	28%	26%	23%	21%	17%
EBITDA Interest Coverage	2.55	2.61	2.91	2.91	2.76	2.60	2.40	2.19	2.02	1.86	1.67
Capital Coverage	0.76	0.33	1.02	0.89	0.82	0.76	0.66	0.62	0.49	0.42	0.35

*In a "no rate increase" scenario, finance expense also increases due to additional borrowing requirements. Thus, the difference between Retained Earnings assuming no rate increase and Retained Earning including rate increases is not simply the Proposed rate increases, but includes additional finance expense.

**Additional Revenue Requirement	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Percent Increase	0.00%	-1.00%	0.00%	0.00%	1.00%	0.00%	1.50%	1.25%	1.00%	0.00%	1.75%
Cumulative Percent Increase	0.00%	-1.00%	-1.00%	-1.00%	-0.01%	-0.01%	1.49%	2.76%	3.79%	3.79%	5.60%

iii. The O&A forecast provided in CGM18 assumed that the $3 million in costs associated with meter compliance would continue to be expensed in 2018/19 with capitalization of these costs starting in 2019/20. CGM16 assumed that the meter compliance costs would be capitalized starting in 2018/19 and therefore the 2018/19 O&A forecast in CGM16 is $3 million lower than that of CGM18.

iv. Confirmed.

c) The schedule below reflects PUB/Centra I-6 d) (CGM12 with IFRS deferral to 2015/16, grandfathering of regulatory accounting, $3 million net income) restated in a format similar to PUB/Centra II-139 from the 2013/14 GRA.

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

PUB-CENTRA-I-16 d

(In Millions of Dollars)
For the year ended March 31

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
REVENUES											
Domestic Revenue											
at approved rates	319	312	356	351	349	348	349	349	350	350	351
Cost of Gas Sold	176	168	212	203	202	201	201	201	201	201	201
Gross Margin	143	144	144	148	147	148	148	148	149	149	150
Other	2	2	2	2	2	2	2	2	2	2	2
	145	146	146	149	149	149	150	150	151	151	152
EXPENSES											
Operating and Administrative	67	69	71	70	71	73	74	76	77	79	81
Finance Expense	18	17	19	20	22	23	23	24	25	26	26
Depreciation and Amortization	28	30	31	30	31	32	32	33	32	33	32
Capital and Other Taxes	18	19	19	19	19	20	20	20	20	20	21
Corporate Allocation	12	12	12	12	12	12	12	12	12	12	12
	143	147	152	151	155	159	161	165	166	170	172
Net Income (loss) before proposed rate increases*	**2**	**(1)**	**(6)**	**(2)**	**(7)**	**(11)**	**(14)**	**(18)**	**(21)**	**(25)**	**(28)**
additional revenue requirement**	0	4	9	4	9	13	15	17	19	21	23
Net Income (loss) after proposed rate increases	**2**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**
Retained Earnings before proposed rate increases	36	35	29	27	20	9	(5)	(24)	(44)	(69)	(98)
Retained Earnings after proposed rate increases	36	39	42	46	49	52	55	58	61	64	67
Financial Ratios - with rate increase											
Equity Ratio (PUB Approved Methodology)	19%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
EBIT Interest Coverage	1.09	1.17	1.16	1.15	1.14	1.13	1.13	1.12	1.12	1.12	1.11
Capital Coverage	1.23	0.00	1.08	0.63	0.62	0.80	0.81	0.83	0.80	0.80	0.76
Financial Ratios - without rate increase											
Equity Ratio (PUB Approved Methodology)	19%	19%	17%	16%	14%	11%	8%	4%	0%	0%	0%
EBIT Interest Coverage	1.09	0.95	0.67	0.90	0.70	0.54	0.46	0.35	0.31	0.22	0.19
Capital Coverage	1.23	(0.10)	0.84	0.52	0.40	0.41	0.33	0.24	0.15	0.03	(0.07)

*In a "no rate increase" scenario, finance expense also increases due to additional borrowing requirements. Thus, the difference between Retained Earnings assuming no rate increase and Retained Earning including rate increases is not simply the Proposed rate increases, but includes additional finance expense.

****Additional Revenue Requirement**

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Percent Increase	0.00%	1.19%	1.48%	-1.49%	1.50%	1.03%	0.47%	0.82%	0.25%	0.82%	0.28%
Cumulative Percent Increase	0.00%	1.19%	2.69%	1.16%	2.68%	3.74%	4.24%	5.09%	5.35%	6.22%	6.51%

REFERENCE:

CAC/Centra I-5(c);

PREAMBLE TO IR (IF ANY):

CAC/Centra I-5 (c) requested Centra to explain why the excess FRP funding could not be used in this regulatory proceeding to reduce the revenue requirement/rates of the residential customers that have contributed to the FRP balance in order to reduce the potential intergenerational inequity for those customers that have contributed to the excess funding.

Centra's response was a reference to the response to PUB/Centra I-120 (a)(b) which provides rate rider calculations for 1, 2 and 5-year dispositions of the $17 million of excess funding. Centra's response was not responsive to the CAC question with respect to dealing with the excess FRP funds in this proceeding versus waiting to a future regulatory proceeding to commence the disposition.

QUESTION:

Please explain Centra's position on the merits of waiting until a future gas regulatory proceeding, the timing of which is uncertain, to begin to deal with the disposition of the $17 million excess funding versus commencing the disposition flowing from the current regulatory proceeding.

RESPONSE:

As noted in the response to PUB/CENTRA I-102a, Centra's original intention was to seek stakeholder input on alternatives for disposing of the excess funding related to the Furnace Replacement Program. Centra notes, however, that on June 10, 2019 the Province of Manitoba released a consultation draft of a proposed regulation for The Efficiency Manitoba Act which would see the balance of the FRP Account transferred to Efficiency Manitoba "to be used to offset the cost of the natural gas demand-side management initiatives set out in an approved efficiency plan."

REFERENCE:

CAC/Centra I-6 (e); CAC/Centra I-6 (f);

PREAMBLE TO IR (IF ANY):

CAC requested the following information in CAC/Centra I-6 (e) and (f):
(e) Please provide 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.

(f) Please provide 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.

In the response to CAC/Centra I-6 (e) and (f), Centra stated that "…Centra is unsure of how these costs could be retroactively adjusted through retained earnings on Centra's financial statements in order to re-state net income and retained earnings as this would require a "one-sided" journal entry. Centra is therefore unable to provide the financial scenario requested."

QUESTION:

a) In order to provide Centra with the assumptions related to the "two-sided" journal entry for purposes of the financial scenario and to recognize Centra's concerns over financial scenarios that target a 30% Equity ratio every year (CAC/Centra I-8 (a)), CAC is modifying part (e) of the original information request and requesting that Centra respond to the following information request in second round of information requests as follows:

Please provide 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 to Centra's balance sheet (retained earnings) effective April 1, 2019 and adjusting the non-gas revenue requirement and required rate change for 2019/20 and the indicative rate increases for 2020/21 to 2027/28. CAC is requesting Centra to assume for the purposes of this financial scenario (for rate-setting purposes), that the journal entry for CGM18 as at April 1, 2019 would be to Debit: Property, Plant & Equipment $21.3 million; Credit: Accumulated Depreciation $5.9 million; and Credit: Retained Earnings $15.3 million.

b) Please provide alternate versions of Figure 3.3 and Figure 3.4 of Tab 3, Section 3.3 of the Application assuming that the form of the journal entry as provided in part (a) 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.

RESPONSE:

a) and b)

Please refer to the response to PUB/CENTRA-II-7c), parts (i) and (ii).

REFERENCE:

CAC/Centra I-7 (a); CAC/Centra I-7 e)

QUESTION:

a) In the response to CAC/Centra I-7 (a), Centra states that "…the PUB has also determined in past Orders that a 30% equity target is appropriate for Centra." Please confirm that the PUB has never set Centra's non-gas rates explicitly to achieve a 30% Equity ratio. If not confirmed, please provide the citations from previous PUB Orders where the PUB has set Centra's non-gas rates explicitly to achieve a 30% Equity ratio.

RESPONSE:

Not confirmed. While the PUB may not have set Centra's non-gas rates explicitly to achieve a 30% equity ratio in the past, the PUB has been explicit on a number of occasions in establishing a debt to equity target of 70:30 when determining Centra's overall level of net income to be derived through rates:

- Order 108/15, page 34:
    - *"The Board notes Centra's improved financial strength since the last General Rate Application, with a debt to equity ratio of 65:35 as of March 31, 2015. In past Orders, the level of net income was established at $3 million based on, in part, Centra's capital strength being above the Board-established debt to equity target of 70:30."*

- Order 85/13, page 27
  - *"The Board has previously stated that it considers a free-standing debt-to-equity ratio of 70:30 sufficient in light of the fact that Centra can avail itself of the Provincial Debt Guarantee, for which Centra pays 1% of its total debt to the Province, which amounts to approximately $3 million per year Centra's debt-to-equity ratio is stronger than the target ratio of 75:25 for Manitoba Hydro. Centra's current capital structure has improved from its target to 67:33."*

- Order 99/07, page 109:
  - *"As to the debt: equity ratio to be selected as the target on the standalone basis, the Board accepts Mr. Matwichuk's advice and finds that given Centra's borrowings are guaranteed by the Province, with the fee for the guarantee allowed in costs for rate setting, a 70:30 ratio is adequate, rather than the 60:40 model that would be acceptable if there were no provincial guarantee.*

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

REFERENCE:

CAC/Centra I-7 (a); CAC/Centra I-7 e)

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Please confirm that in Table 1 (Updated) in the response to CAC/Centra I-7 (e), the table should total to $315.0 million for 5 years and $628 million for 10 years versus the $355.0 million and $722.9 million, respectively.

RESPONSE:

The following response was provided by Mr. Drazen:

The Total line in Table 1 (Updated) includes the funds needed for debt repayment, but the line showing those amounts was inadvertently omitted. In addition, the Furnace Replacement Program disposition was shown as $23.7 million in error in CAC/CENTRA I-7e and has been updated to $17 million. With the debt repayment line shown, Table 1 is:

Table 1

Centra Capital Requirements ($Millions)

	5 Years	10 Years
Property, plant & equipment	$228	$479
Intangible assets & other	63	123
Furnace replacement plan disposition	17	17
Repay maturing debt	40	95
Total	$348	$715*

*differences due to rounding.

REFERENCE:

CAC/Centra I-7 (a); CAC/Centra I-7 e)

PREAMBLE TO IR (IF ANY):

QUESTION:

c) Please reconcile Mr. Drazen's calculation of Centra's financing requirements of approximately $70 million per year in the response to CAC/Centra I-7 (e) with Centra's projected Cash Flow Statement from CGM18, Appendix 3.1, Page 3 – that shows total Cash Used for Investing Activities of $602 million over the 10-year timeframe or approximately $60 million per year.

RESPONSE:

c) As indicated on pg. 5 of 17 in Table 1 in Appendix 3.5, Mr. Drazen includes Centra's capital requirements as well as the furnace replacement disposition and Centra's repayment of maturing debt in his calculation of Centra's total capital requirements. On average, the $70 million annual figure can be calculated as follows:

Centra Capital Requirements ($ millions) - CGM18

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	10 year Average
Additions to Property, Plant and Equipment	42	47	45	46	47	48	49	50	51	52	48
Additions to Intangible Assets	1	0	0	0	0	0	0	0	0	0	0
Additions to Regulatory Deferral Balances	14	15	16	15	14	14	15	14	15	13	15
Contributions Received	(3)	(3)	(3)	(3)	(3)	(2)	(2)	(3)	(3)	(3)	(3)
Furnace Replacement Program Disposition	-	-	17	-	-	-	-	-	-	-	2
Retirement of Long-Term Debt	-	20	-	-	20	10	-	35	-	10	9
	54	80	76	58	79	71	62	97	64	73	71

REFERENCE:

CAC/Centra I-8 (a)

PREAMBLE TO IR (IF ANY):

QUESTION:

a) In the response to CAC/Centra I-8 (a), Centra states that "CGM18 contains relatively smooth indicative rate increases over a 10-year period to remain at approximately the 30% equity ratio target level…" Please confirm that CGM18 is the first Centra IFF under MH ownership in which the company and its Board of Directors has used a 30% Equity ratio as the guideline to project future indicative rate increases. If this is not confirmed, please provide the prior Centra IFF's and associated Equity ratio calculations where a Centra Board approved IFF has based future indicative rate increases using 30% Equity ratio as a guideline.
b) If the response to part (a) is confirmed by Centra, then please provide a detailed explanation of the factors that have led Centra to adopt this change in policy.

RESPONSE:

a) and b)

CGM18 has used the 30% equity ratio as a guideline in determining the projected indicative rate increase over the forecast period. This was not a change in policy but rather meant to be illustrative. As discussed in Section 3.4 of Centra's Application, the $3 million net income level and the 70:30 debt-to-equity ratio deemed appropriate by the PUB are mutually exclusive over the 2020/21 – 2027/28 forecast period, in that restricting net income to $3 million annually results in a steady decline in the equity ratio to 26% capitalization by 2027/28.

REFERENCE:

CAC/Centra I-9 (a) (f) (g) (h); PUB/Centra I-45; PUB/Centra I-47 (b)

QUESTION:

a) In the charts in the response to CAC/Centra I-9 (a), Centra indicates that it projects the total of short-term debt and floating-rate debt to be approximately 15% as at March 31, 2019 and March 31, 2020, which is at the lower end of the Centra policy to maintain an aggregate of floating-rate debt and short-term debt within 15% to 25% of the total debt portfolio. Please explain Centra's policy considerations with respect to managing the aggregate of floating-rate debt and short-term debt at the lower end (15%) of the policy range versus in the middle (20%) or higher end (25%) of the policy range.
b) With respect to the quarterly debt structure information provided in the response to CAC/Centra I-9 (g) & (h), please explain/elaborate on the basis of how Centra manages the aggregate of floating-rate debt and short-term debt in terms of year-end, quarterly or moving averages or some other metric.
c) In order to understand the risk/rewards of pursuing a more aggressive debt portfolio, please provide the information contained in the response to PUB/Centra I-45 for the 10 year period of CGM18 targeting an aggregate of short-term debt and floating-rate debt at year-end of (i) 20% and (ii) 25%. Please assume that floating-rate debt is increased in the two scenarios to produce 20% and 25% in aggregate and add any narrative that Centra believes is necessary on the risks of being in the middle to higher end of the policy range.
d) In the charts in the response to CAC/Centra I-9 (a), Centra indicates that it projects the total of short-term debt, floating-rate debt and new borrowings within 12 months to be approximately 26% as at March 31, 2019 and 25% at March 31, 2020, which is 9% to 10% lower than the policy guideline to maintain an aggregate of floating-rate debt, short-term debt and new borrowings within 12 months to a maximum of 35% of the total debt portfolio. Please explain Centra's policy considerations with respect to managing the aggregate of floating-rate debt, short-term debt and new borrowings within 12 months at about 10% lower than the maximum policy of 35%.
e) In the response to CAC/Centra I-9 (f), Centra projects that the Weighted Average Term to Maturity (WATM) of Centra debt portfolio is expected to decline from 19.5 years at

March 31, 2013 to 14.6 years at March 31, 2020 and that the percentage of debt maturing in over 20 years has declined from 61.0% at March 31, 2013 to 13.1% as at March 31, 2020. Please explain if Centra has any plans on increasing the WATM of the Centra debt portfolio/increasing the portion of the debt portfolio maturing in over 20 years or allocating some of the Manitoba Hydro ultra-long debt issues to Centra to be more consistent with the projected WATM of Manitoba Hydro's debt portfolio of 17.0 years as at March 31, 2020. If not, please explain why.

RESPONSE:

a), b) and d)

Manitoba Hydro's interest rate risk policy on its existing debt portfolio which applies equally to Centra, is to limit the aggregate of:

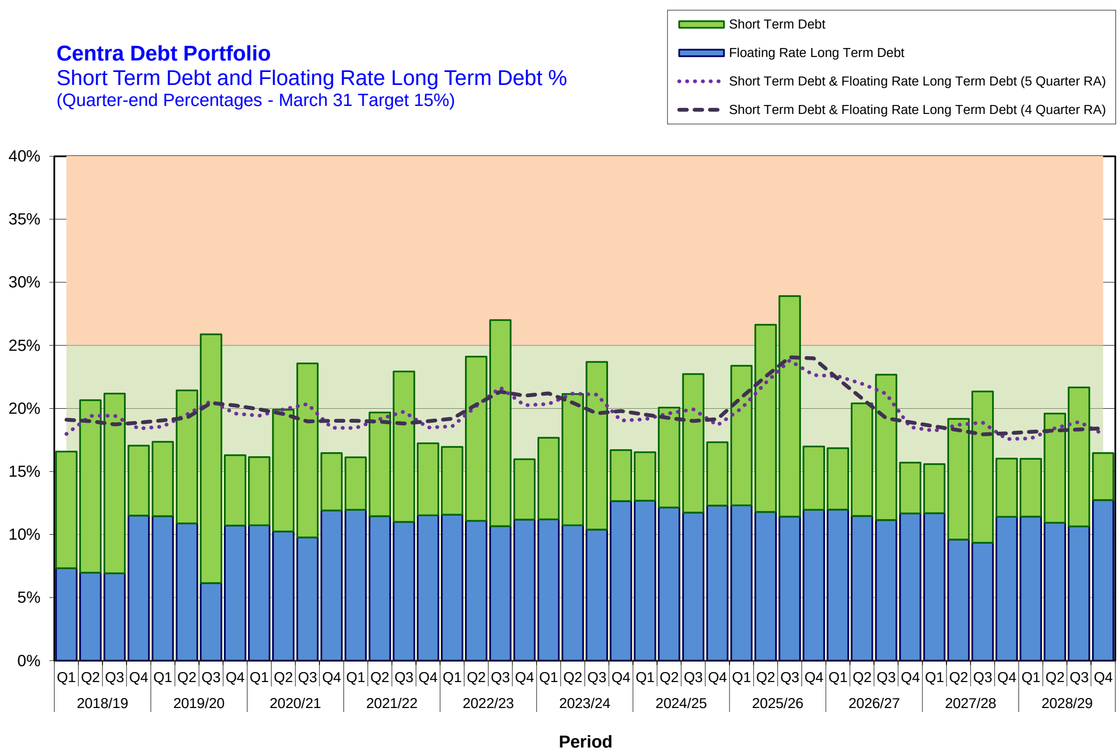
i. floating rate debt,
ii. short term debt, and
iii. fixed rate long term debt to be refinanced within the subsequent 12 month period;

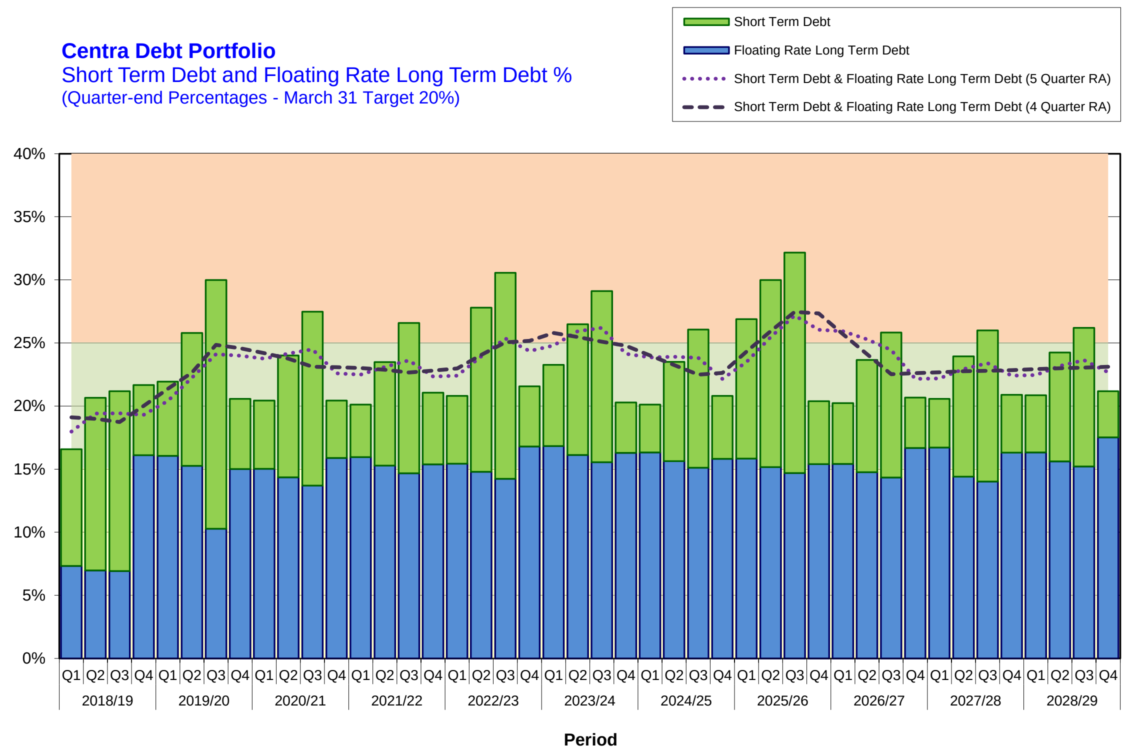
to a maximum of 35% of the total debt portfolio.

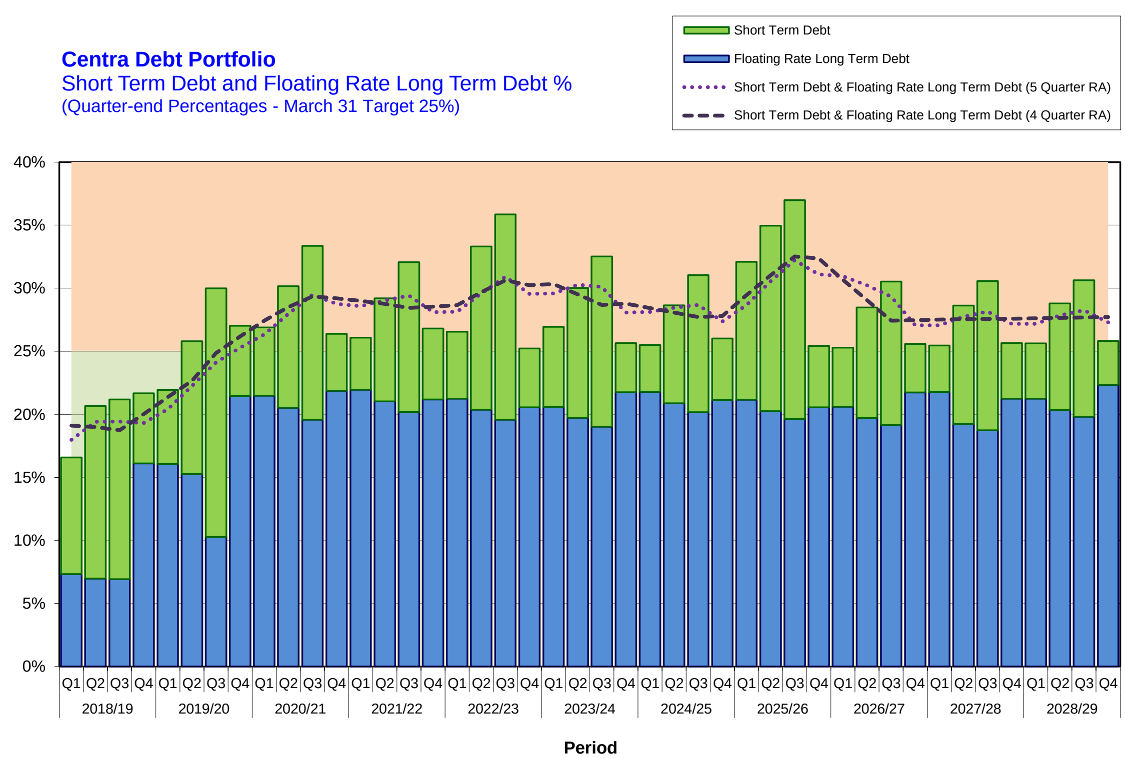
Manitoba Hydro's interest rate risk guidelines, which also apply equally to Centra, for its existing debt portfolio include maintaining an aggregate of floating rate debt and short term debt within 15 – 25% of the total debt portfolio, and having the fixed rate long term debt to be refinanced within a 12 month period being less than 15% of the total debt portfolio.

The charts in response to CAC/CENTRA I-9 indicate the total of short term debt and floating rate debt is projected to be at the lower end of this guideline range as at March 31, 2019 and March 31, 2020. However, as mentioned in PUB/CENTRA I-47b, Centra has seasonal temporary borrowing requirements arising primarily from its gas inventory and thus its short term debt balance will vary with the lowest balance for the year generally seen at the end of the fiscal year, March 31st.

As seen in the following charts, by targeting to be towards the low end of the range of 15% at March 31 of the fiscal year, Centra's total short term debt and floating rate long term debt will maintain rolling averages close to the middle of the range of 20% thus maintaining a moderate level of risk within the target band. However, if Centra were to target the 20% level at yearend, the rolling averages would be closer to the top of the range at 25%. Should Centra target the top of the range at 25% for yearend, the rolling averages would consistently exceed the top of the guideline range of 25% and some forecast quarters would exceed the interest rate risk policy limit of 35%. With rolling averages close to 30% in this scenario, there is very little room to allow for refinancing of maturing debt and still remain within the policy limit.




Centra Debt Portfolio
Short Term Debt and Floating Rate Long Term Debt %
(Quarter-end Percentages - March 31 Target 20%)
Short Term Debt
Floating Rate Long Term Debt
Short Term Debt & Floating Rate Long Term Debt (5 Quarter RA)
Short Term Debt & Floating Rate Long Term Debt (4 Quarter RA)
40%
35%
30%
25%
20%
15%
10%
5%
0%
Q1 Q2 Q3 Q4
2018/19
2019/20
2020/21
2021/22
2022/23
2023/24
2024/25
2025/26
2026/27
2027/28
2028/29
Period


Centra Debt Portfolio
Short Term Debt and Floating Rate Long Term Debt %
(Quarter-end Percentages - March 31 Target 25%)
Short Term Debt
Floating Rate Long Term Debt
Short Term Debt & Floating Rate Long Term Debt (5 Quarter RA)
Short Term Debt & Floating Rate Long Term Debt (4 Quarter RA)
40%
35%
30%
25%
20%
15%
10%
5%
0%
Q1 Q2 Q3 Q4
2018/19
2019/20
2020/21
2021/22
2022/23
2023/24
2024/25
2025/26
2026/27
2027/28
2028/29
Period

In CAC/CENTRA I-9b Centra also indicates that it projects the total of short term debt, floating rate debt, new borrowings within 12 months to be approximately 26% as at March 31, 2019 and 25% as at March 31, 2020. The seasonal variability normally increases the short term debt in the debt portfolio between 5-10% over the seasonal low at March 31. By keeping the prospective interest rate risk profile no higher than around 25% at March 31, this helps to mitigate the risk that the 35% policy limit will be exceeded throughout the year.

c) The following is the information provided in PUB/CENTRA I-45 for the 10 year period of CGM18 (with Winter 2018 interest rates), targeting an aggregate of short term debt and floating rate long term debt at March 31 of 20% and 25%.

CENTRA GAS MANITOBA INC.
Finance Expense - CGM18 Scenario with Winter 2018 Rates & 20% Target Short Term & Floating Rate Debt
($000'S)

	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
Interest on Long Term Debt/Advances	14,765	16,036	17,602	19,029	19,130	20,244	21,464	21,148	23,122	23,690
Provincial Guarantee Fee on Long Term Debt	3,699	4,099	4,399	4,799	4,899	5,099	5,299	5,399	5,549	5,749
Amortization of Debt Discounts	-	-	-	-	-	-	-	-	-	-
Interest on Short Term Debt	829	1,146	1,095	921	1,321	1,256	984	1,816	1,167	1,184
Provincial Guarantee Fee on Short Term Debt	373	241	259	228	295	255	220	284	291	239
Interest on Common Assets	1,505	1,220	1,000	1,050	1,104	1,160	1,211	1,263	1,317	1,371
Interest on Inventory	123	125	128	130	133	136	138	141	144	146
Interest Capitalized	(171)	(237)	(251)	(132)	(35)	(35)	(36)	(37)	(37)	(38)
Carrying Costs on Furnace Replacement Program	645	862	909	231	172	124	75	29	5	4
Other	-	-	-	-	-	-	-	-	-	-
Total Finance Expense	21,768	23,492	25,141	26,256	27,019	28,239	29,355	30,043	31,558	32,345
Year over year $ change		1,724	1,649	1,115	763	1,220	1,116	688	1,515	787
Year over year % change		7.9%	7.0%	4.4%	2.9%	4.5%	4.0%	2.3%	5.0%	2.5%

CENTRA GAS MANITOBA INC.
Finance Expense - CGM18 Scenario with Winter 2018 Rates & 25% Target Short Term & Floating Rate Debt
($000'S)

	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
Interest on Long Term Debt/Advances	14,765	16,036	17,479	18,861	18,977	20,202	21,341	21,025	22,999	23,567
Provincial Guarantee Fee on Long Term Debt	3,699	4,099	4,399	4,799	4,899	5,099	5,299	5,399	5,549	5,749
Amortization of Debt Discounts	-	-	-	-	-	-	-	-	-	-
Interest on Short Term Debt	829	1,146	1,094	917	1,313	1,244	970	1,798	1,145	1,158
Provincial Guarantee Fee on Short Term Debt	373	241	259	227	292	250	215	277	283	229
Interest on Common Assets	1,505	1,220	1,000	1,050	1,104	1,160	1,211	1,263	1,317	1,371
Interest on Inventory	123	125	128	130	133	136	138	141	144	146
Interest Capitalized	(171)	(237)	(251)	(132)	(35)	(35)	(36)	(37)	(37)	(38)
Carrying Costs on Furnace Replacement Program	645	862	909	231	172	124	75	29	5	4
Other	-	-	-	-	-	-	-	-	-	-
Total Finance Expense	21,768	23,492	25,017	26,083	26,855	28,180	29,213	29,895	31,405	32,186
Year over year $ change		1,724	1,525	1,066	772	1,325	1,033	682	1,510	781
Year over year % change		7.9%	6.5%	4.3%	3.0%	4.9%	3.7%	2.3%	5.1%	2.5%

In the two scenarios where the aggregate of short term debt and floating rate long term debt targets 20% and 25% at March 31, there are modest savings to finance expense (providing all forecast assumptions hold true) versus CGM18 (with Winter 2018 interest rates) which targets 15% at March 31. However, as indicated in the response to parts a), b) and d), in both scenarios, Centra would be incurring additional interest rate risk with the rolling average totals of short term debt and floating rate long term debt near or above the maximum of the interest rate risk guideline of 25%. To illustrate both the reward and the risk portions of the risk/reward trade-off, the following table shows the finance expense savings of the two scenarios measured against the additional risk if interest rates increase to 0.50% higher than forecast. As shown in the table, even with only a 0.50% increase in variable interest rates, borrowing costs escalate in these scenarios, such that there is a net negative impact to net income versus CGM18.

CENTRA GAS MANITOBA INC.
Finance Expense - CGM18 Scenarios with Winter 2018 Rates
Risk/ Reward of Increasing STD & Floating Rate LTD Balance if Interest Rates are 0.5% Higher than Forecast
($000'S)

	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
Total Finance Expense March 31 Target 15%	21,768	23,544	25,155	26,301	27,055	28,314	29,350	30,038	31,552	32,421
Total Finance Expense March 31 Target 20%	21,768	23,492	25,141	26,256	27,019	28,239	29,355	30,043	31,558	32,345
Total Finance Expense March 31 Target 25%	21,768	23,492	25,017	26,083	26,855	28,180	29,213	29,895	31,405	32,186
Finance Expense Savings with March 31 Target @ 20% vs 15%	-	52	14	45	36	75	(5)	(5)	(6)	76
Finance Expense Savings with March 31 Target @ 25% vs 15%	-	52	138	218	200	134	137	143	147	235
Average STD & Floating Rate LTD Balance March 31 Target @ 15%	80,338	93,841	93,748	99,515	113,833	110,257	110,067	141,710	114,663	112,089
Average STD & Floating Rate LTD Balance March 31 Target @ 20%	85,338	113,816	113,688	119,426	136,203	138,073	129,848	161,496	139,954	141,845
Average STD & Floating Rate LTD Balance March 31 Target @ 25%	85,338	121,316	143,626	149,214	163,322	160,078	159,253	190,755	166,062	170,796
Finance Expense Cost of Interest Rates 0.5% Higher than Forecast with March 31 Target @ 20% vs 15%	(25)	(100)	(100)	(100)	(112)	(139)	(99)	(99)	(126)	(149)
Finance Expense Cost of Interest Rates 0.5% Higher than Forecast with March 31 Target @ 25% vs 15%	(25)	(137)	(249)	(248)	(247)	(249)	(246)	(245)	(257)	(294)
Net Finance Expense Impact with March 31 Target @ 20% if Interest Rates 0.5% Higher than Forecast	(25)	(48)	(86)	(55)	(76)	(64)	(104)	(104)	(132)	(73)
Net Finance Expense Impact with March 31 Target @ 25% if Interest Rates 0.5% Higher than Forecast	(25)	(85)	(111)	(30)	(47)	(115)	(109)	(102)	(110)	(59)

e) Centra is currently compliant with Manitoba Hydro's interest rate risk policy and guidelines and will endeavor to maintain this compliance. For its most recent long term debt issues, Centra has required floating rate debt (which tends to be shorter-dated, thus the recent reduction to the WATM of the debt portfolio) to maintain compliance with the guidelines. The smaller size of Centra's long term debt portfolio in addition to the infrequency with which Centra issues long term debt compared to Manitoba Hydro will impact the ability to align Centra's WATM to Manitoba Hydro's. For forecasting purposes, the financial planning model has a simplifying assumption of a 20 year term to maturity for new long term debt issued. It is unlikely that the $50 million of long term debt which is forecast to be issued in fiscal 2020 will be issued for exactly that term. In practice, Centra will look at all possibilities available in the market around the time of issuance, including ultra-long debt, to firstly, maintain compliance with the policy and guidelines and secondly to more closely align its WATM to Manitoba Hydro's.

REFERENCE:

CAC/Centra I-10 (b); CAC/Centra I-10 (f) (g) (h) (i)

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Centra indicates in the response to CAC/Centra I-10 (b) that the last update to the probably remaining lives for plant assets was determined as part of the 2014 Depreciation study. Please explain Centra's plans for the next gas depreciation study, including (i) when the study is expected to be completed (ii) the fiscal year that the resulting changes would be implemented and (ii) if Centra plans to undertake an ASL IFRS compliant depreciation study, continue with an ELG depreciation study or develop both.

RESPONSE:

a)

i. Centra is currently in the process of conducting a depreciation study which is anticipated to be completed by February, 2020. The study will update depreciation rates for both the IFRS compliant Equal Life Group ("ELG") method and the previous CGAAP compliant Average Service Life ("ASL") method.

ii. Should changes in depreciation rates be required, Centra would seek approval of the new depreciation rates from Centra's Board of Directors. Assuming approval was received prior to the completion of Centra's 2019/20 fiscal period, the resulting ELG depreciation rate changes would be implemented for preparing the 2019/20 financial statements; as required by IFRS. However, for calculating net income for rate setting purposes, Centra will continue to apply the last PUB approved CGAAP ASL depreciation rates through the Net Movement in Regulatory Deferral Account. The financial impact of ELG based depreciation expense will continue to be deferred with no amortization of the deferral in the Net Movement in Regulatory Deferral Account. Centra would seek approval of the updated CGAAP ASL depreciation rates as part of its next General Rate Application.

iii. In response to directives #8 and #9 from Order 43/13, Manitoba Hydro is currently in the process of conducting an IFRS compliant ASL based depreciation study which will include a study of Centra’s plant asset components.

REFERENCE:

CAC/Centra I-10 (b); CAC/Centra I-10 (f) (g) (h) (i)

PREAMBLE TO IR (IF ANY):

QUESTION:

b) With respect to the responses to CAC/Centra I-10 (f), (g) and (h), please provide a breakdown of Centra's $1.170 million of internal costs of the 2019/20 GRA between the categories listed in the response to CAC/Centra I-10 (h) (labour, consulting, printing, public notices and meals) and provide a breakdown of those internal Centra costs that make up the $450,000 of Centra's costs projected to be deferred and amortized as outlined in the response to CAC/Centra I-10 (f).

RESPONSE:

Please see the following table for the breakdown of the $1.170 million identified as Centra's costs budgeted for the 2019/20 General Rate Application (CAC/CENTRA I-10h), which includes both operating and deferred costs. In addition to PUB Advisor and Intervener costs, Centra defers and amortizes costs associated with external consulting services engaged by Centra for its Regulatory applications, as well as overtime labour and other expenses associated with the proceeding, such as the costs to publish public notices for its applications.

2019/20 General Rate Application Budget
(Centra Operating & Deferred Costs)

($000s)		
Labour	$	820
Consulting	$	161
Other Costs	$	189
Total	$	1,170

Please see the following table for a breakdown of the $450 thousand identified as Centra's costs budgeted for the 2019/20 General Rate Application in CAC/CENTRA I-10f, which includes deferred costs only:

2019/20 General Rate Application Budget
(Centra Deferred Costs)

($000s)		
Consulting	$	161
OT Labour	$	100
Other Costs	$	189
Total	$	450

Other costs include costs associated with publishing public notices, supplies, printing, courier services, and meals. Centra did not separately budget for each of these items, but has considered the total of these types of costs historically incurred for its regulatory applications in formulating the budget of Other Costs for 2019/20.

REFERENCE:

CAC/Centra I-10 (b); CAC/Centra I-10 (f) (g) (h) (i)

PREAMBLE TO IR (IF ANY):

QUESTION:

c) With respect to the response to CAC/Centra I- 10 (i), please explain why Centra views the hours and hourly rates of its external consultants used in the GRA process to be confidential information.

RESPONSE:

Throughout this proceeding, Centra has redacted party/contract specific details in accordance with its Redaction Criteria. The hourly rate of Centra's external consultants is commercially sensitive information to them. By making the hourly rates available publicly or to the parties authorized to receive commercially sensitive information, Centra would prejudice its consultants' competitive position. As a specific example, many of the PUB advisors and Intervener expert witnesses provide similar or the same services and are in competition with Centra's consultants.

REFERENCE:

CAC/Centra I-11 (c); CAC/Centra I-11 (i);

QUESTION:

a) With respect to the response to CAC/Centra I-11 (c), please confirm that the addition of $31.059 million of regulatory deferral accounts into rate base will increase the overall return on rate base for 2019/10 by approximately $1.839 million ($31.059 * 5.92%) and increase the return on equity for 2019/20 by approximately $0.820 million ($31.059 * 31.8%* 8.30%). If not confirmed, please provide Centra's alternate calculations.
b) With respect to the response to CAC/Centra I-11 (i), please confirm that the inclusion of approximately $53.727 million (simple average of $54.458 million opening and $52.996 million ending balance for 2019/20) of DSM costs in rate base results in an overall return on rate base for 2019/10 of approximately $3.181 million ($53.727 * 5.92%) and a return on equity for 2019/20 of approximately $1.418 million ($53.727 * 31.8% * 8.30%). If not confirmed, please provide Centra's alternate calculations.

RESPONSE:

a) Confirmed. The $31.059 million in regulatory deferrals included in rate base increases the overall return on rate base for 2019/20 of approximately $1.839 million and increases the return on equity by approximately $0.820 million.

   As outlined in Centra's response to CAC/Centra I-11a) and d), removing these regulatory deferrals from rate base would require an increase to revenue requirement to reflect these as period costs.

b) Centra includes the 13-month average of DSM expenditures in rate base which for 2019/20 is $53.560 million as provided on line 42 of Schedule 6.7.8 (Update) filed on March 22, 2019 with the Supplement to Centra's Application. The inclusion of the $53.560 million in DSM spending results in an overall return on rate base for 2019/20 of approximately $3.17 million ($53.560 million * 5.92%) and a return on equity of approximately $1.41 million ($53.560 million * 8.3% * 31.8%).

As outlined in the response to CAC/Centra I-11 a), the PUB has previously approved the inclusion of DSM in working capital.

REFERENCE:

CAC/Centra I-12 (a); CAC/Centra I-12 (c); CAC/Centra I -12 (d) & (e); CAC/Centra I -12 (h); CAC/Centra I-12 (i); CAC/Centra I -12 (j) & (k); PUB/Centra I-38; PUB/Centra I-26 (b)

PREAMBLE TO IR (IF ANY):

QUESTION:

a) CAC/Centra I-2 (a) requested a comparison of the approved 2013/14 O&A expense with the 2017/18 actual O&A expense and Other expenses and explanations for the key business drivers of the decrease. Centra's response to CAC/Centra I-12 (a) was a reference to an analysis in Figure 5 of the response to PUB/Centra I-7 which contains a one paragraph high-level directional variance analysis but no detailed information and is not responsive to the question. Please provide a detailed quantitative analysis and associated explanations of the decreases in O&A between 2013/14 approved and 2017/18 actual O&A expense as requested.

b) CAC/Centra I-2 (c) requested an analysis of a number of specified cost drivers between 2017/18 actual O&A expense and 2018/19 and 2019/20 projected O&A expense. Centra declined to provide a response to this question due to the nature of the integrated cost allocation methodology that is used to allocate O&A costs to Centra from Manitoba Hydro and its inability to precisely isolate the impact of escalation as a specified cost driver. Please provide a quantitative analysis and associated explanations of the changes in O&A between 2017/18 actual and 2018/19 and 2019/20 projected O&A costs using the specified cost drivers of the original question and a high-level provision/assumption for escalation in labor and non-labor costs in 2018/19 and 2019/20.

c) In the responses to CAC/Centra I-12 (d) & (e), Centra indicated that allocation of the labor savings from the VDP and the sourcing savings from the Supply Chain Initiative is assumed to be 4%, "which is representative of the relative size of the electric and gas utility." In the response to PUB/Centra I-28 (a), Centra indicates that the split of total O&A between gas and electric operations has been/is projected to be approximately 11%/89% between 2015/16 and 2019/20. In the response to PUB/Centra I-28 (b), Centra indicates that (i) the Total Assets cost driver of 4% gas/96% electric is "a general driver that represents the relative size of the electric and gas utility." and (ii) the Activity Charges cost driver of 8% gas/92% electric is "a general driver that represents the relative amount of activity charges by staff to each of the utilities." In the response to PUB/Centra I-20 (d), Centra indicates that the corporate activity cost driver "…represents the relative amount of labour activity in each of the utilities." In the response to PUB/Centra I-25, Centra indicates that "staff approved under the VDP worked in all functions of the business…" Please explain given the broad nature of the VDP and Supply Chain Initiative savings, why have they been assumed to be allocated to gas operations O&A based on the relative size of the gas utility (4%) versus either (i) the relative amount of labour/activity charges (8%) to gas operations or (ii) the relative split of total O&A costs (11%) to gas operations.

d) Further to the response to CAC/Centra I-12 (h), please provide the escalation assumption in % and $ for Centra O&A for the 2018/19 and 2019/20 fiscal years.
e) With respect to the response to CAC/Centra I-12 (i), please explain if any of the Internal regulatory costs are associated with the 2019/20 GRA proceeding. If so, please provide the amount assumed to be related to the 2019/20 GRA proceeding.
f) With respect to the responses to CAC/Centra I-12 (j) & (k) and PUB/Centra I-38, please provide (i) a breakdown of the 2018/19 and 2019/20 contingency forecasts of $1.887 million and $1.059 million, respectively and (ii) a narrative description of the nature of each component of the contingency amount, which was requested in the first round information requests CAC/Centra I-12 (j) & (k), but not provided by Centra.
g) With respect to the response to PUB/Centra I-26 (b), please indicate if Centra has included a productivity factor in the development of its O&A targets for 2018/19 and 2019/20. If so, please provide the % and $ productivity projected for 2018/19 and 2019/20.

RESPONSE:

a) The following table provides a comparison of the 2013/14 PUB Approved forecast to the actual performance of 2017/18 by program.

CENTRA GAS PROGRAM COSTS
OPERATING & ADMINISTRATIVE EXPENSE
($000's)

	CGAAP 2013/14 Approved	IFRS 2017/18 Actual	Change Inc/(Dec)	Notes
Customer Service & Corporate Relations				
Back/middle office services	$ 279	$ 277	$ (2)	
Billing & collections	8 891	7 880	(1 011)	1
Customer & public relations	6 588	4 070	(2 517)	2
Customer information systems (Banner)	936	556	(379)	3
Customer inspections	7 349	7 488	138	
Customer safety services	1 846	1 394	(452)	4
Dispatch	2 290	2 061	(228)	
Energy supply, planning & support	1 990	2 517	527	5
Environment	412	261	(151)	
Meter reading	2 045	1 832	(213)	
Rate and regulatory affairs	1 665	846	(819)	6
	34 290	**29 183**	**(5 107)**	
Operations and Maintenance				
Communication systems	161	124	(37)	
Distribution maintenance	6 114	6 161	47	
Load forecast	184	89	(95)	
Metering	5 267	4 357	(910)	7
Plant failures & emergencies	92	271	179	
Quality assessment	464	427	(37)	
Station maintenance	4 950	5 120	170	
System performance & reliability	1 721	2 716	995	8
	18 953	**19 266**	**313**	
Organizational Support*	**18 501**	**16 757**	**(1 744)**	9
Total Program Costs	**71 744**	**65 206**	**(6 538)**	
Adjustments:				
Depreciation & taxes	(3 063)	(2 139)	924	10
Other	119	46	(73)	
	(2 944)	**(2 093)**	**851**	
Total Operating & Administrative	**$ 68 800**	**$ 63 113**	**$ (5 687)**	

*Individual programs within Organizatonal Support were created effective 2015/16 and are not available for 2012/13 through 2014/15.

Explanations have been provided below for programs with significant variances.

1. The decrease in the billing & collections program is primarily attributable to lower bad debt expense due to better collection efforts, as well as fewer hours worked as a result of staffing reductions and a lower number of uncollectible accounts.
2. The decrease in the customer & public relations program is attributable to less time spent on customer inquiries due to efficiencies gained in consolidation of district service centres, as well as a decrease in advertising, donations and consulting services for Power Smart programs.
3. The decrease in the customer information systems program is due to lower system maintenance activities than anticipated, as well as a focus on several IT capital projects such as the MyBill Business Integration project.
4. The decrease in the customer safety services program is due to a decrease in odour related calls as well as a reduction in advertising costs.
5. The increase in the energy supply, planning & support program is due to increased labour costs as a result of a change in the ratio of supervisory and technical staff required to support the program.
6. The decrease in the rates and regulatory affairs program is primarily related to the deferral of a General Rate Application for Centra as well as additional reductions related to vacancies.
7. The decrease in the metering program is related to a reduction in the work required under Measurement Canada requirements.
8. The increase in the system performance & reliability program is primarily related to higher labour requirements for work functions such as cathodic protection, external corrosion assessments, depth of cover investigations, close interval surveys and pipeline river crossing inspections.
9. The decrease in the organizational support program is primarily due to a reduction in staff due to the VDP, as well as reduction in senior management.
10. The decrease in depreciation & taxes is based on increases in the depreciation on common assets and payroll taxes that are imbedded in labour.

b) Centra did not decline to provide a response to CAC/CENTRA I-12. Rather, and as stated in the response to that first round information request, Centra is unable to provide the requested analysis as the method under which Centra's costs are allocated does not allow the analysis to be performed in a manner that would produce a meaningful result.

c) Please see the response to PUB/CENTRA II-11a and b.

d) Centra held the 2018/19 target constant with 2017/18 actual performance given the uncertainty associated with the impacts of the VDP. The escalation for 2019/20, after removing the impact of the proposal to capitalize meter sampling, testing and exchange, was an increase of approximately $0.9M or 1.5%.

e) The majority of the internal costs in CAC/CENTRA I-12i for 2018/19 and 2019/20 are related to the current General Rate Application. Please see Centra's response to CAC/CENTRA II-131b.

f) The contingency forecast for 2018/19 was for funds held to assist management in the restructuring process. Specific initiatives were not identified for these funds; as such there are no detailed cost components available. The contingency forecast for 2019/20 represents the difference between the target and the detailed budgets; a reserve for cost increases and program changes that have not yet been incorporated into detailed plans.

g) Centra did not explicitly incorporate a productivity factor in establishing the O&A targets for 2018/19 and 2019/20. However, as per the table below which compares the long term forecast under CGM15 to the current projected O&A forecast under CGM18, Centra's decision to implement an accelerated cost reduction program will result in an overall reduction in O&A costs of approximately $90 million over the 10 year period from 2018/19 through 2027/28. In addition, actual costs have been at or below those projected in CGM15 for the 3 year period from 2015/16 through 2017/18.

CENTRA GAS MANITOBA INC.
O&A FORECAST AND ACTUALS
(in millions)

	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	
CGM15	67	68	69	69	70	71	71	73	74	76	77	79	80	
Actuals	67	65	63											
(Decrease) from CGM15	**(0)**	**(2)**	**(5)**											
				2018/19	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**10 Year**
CGM15				69	70	71	71	73	74	76	77	79	80	739
CGM18				63	61	62	63	64	65	66	68	69	70	651
(Decrease) from CGM15				**(6)**	**(9)**	**(9)**	**(9)**	**(9)**	**(9)**	**(9)**	**(10)**	**(10)**	**(10)**	**(88)**

REFERENCE:

CAC/Centra I-13 €

PREAMBLE TO IR (IF ANY):

In CAC/Centra I-13 (e), CAC requested the following information:

(e) If the response to part (b) is no, please explain why Centra's properties are being assessed at a lower value and indicate (i) when the next province-wide reassessment of property taxes is excepted to occur in Manitoba, (ii) which Centra fiscal year(s) will be impacted by this reassessment and (iii) the expected increase or decrease in property taxes.

In the response to CAC/Centra I-13 (e), Centra indicated that Province-wide property tax reassessments occur in Manitoba every two years and the next reassessment is in 2020.

There appears to be confusion associated with the reference to the "next re-assessment". CAC's intent was to obtain information from Centra with respect to its assumptions with respect to the 2018 property tax re-assessment which will impact the 2018/19 and 2019/20 test years. In the prior re-assessments in 2012 and 2016, Centra had forecast increases in property taxes but there were actual decreases in property taxes given that the value of Centra's property did not increase to the same extent as all other property in Manitoba. For the purposes of this regulatory proceeding, CAC is wanting to understand the assumptions in the 2018/19 and 2019/20 test years with respect to the 2018 property tax re-assessment and if the same potential exists for the forecast of property taxes to be over-stated as had occurred in the last two provincial re-assessments.

QUESTION:

a) Please provide Centra's assumptions with respect to the 2018 property tax reassessment in terms of (i) percentage increase in property taxes and (ii) the dollar increase in property taxes for the both the 2018/19 and 2019/20 fiscal years.
b) Please explain if the impacts of the 2018 re-assessment were known to Centra when CGM18 and the underling property tax forecasts were prepared and have been factored

into the 2018/19 and 2019/20 property tax forecasts or if these forecasts were based on assumptions made by Centra.

RESPONSE:

a) The November 30, 2018 Application included a 3% increase in property taxes due to expected mill rate increases and routine gas property additions. This was based on a forecast prepared prior to the 2018 property tax re-assessment. No significant plant expansion projects were planned and the impacts of assessed values of farmland in comparison to Centra's properties were unknown so a nil impact was assumed on assessed property values.

The March 22, 2019 Supplement included an outlook for 2018/19 which reflected updated information as a significant portion of the annual property tax bills had been received. A 3% increase was included for those properties where the actual tax bill had not yet been received. The overall 5% increase for 2018/19 when compared to 2017/18 actual taxes is as a result of some properties, primarily within the City of Winnipeg, being significantly higher than the 3%. The increases within the City of Winnipeg were primarily a result of routine additions to the gas distribution system. The 2019/20 approved budget is based on a 3% increase when compared to the 2018/19 current outlook.

The following table provides municipal taxes and shows both the dollar and percentage increases.

	2017/18 Actual	**2018/19 Current Outlook**	**2019/20 Approved Budget**
Municipal Taxes	11 955	12 550	12 900
dollar increase		595	350
percentage increase		5.0%	2.8%

b) CGM18, which was the basis of the November 30, 2018 Application, was prepared before the results of the 2018 re-assessments were known. The forecast for CGM18 was based on a 3% increase.

As noted above, the current outlook was based on information from actual bills received, combined with a 3% increase for those properties where Centra had not received the bill. The approved budget is a 3% increase over the current outlook.

Centra does not base property tax forecasts solely on re-assessments as tax bills depend on how different types of properties change in value in comparison to one another. The results of a past re-assessment period are factored into the forecast by using actual data as a starting point when creating the forecast.

REFERENCE:

Response to CAC/Centra I – 17

PREAMBLE TO IR (IF ANY):

In the response to CAC/Centra I-17 (a) and (b), Centra stated:

"Centra did not prepare a Cost Allocation Study to support the August 1, 2017 non-gas rate reversion; as such schedules 10.1.0 – 10.1.6 cannot be filed. August 1, 2017 rates **were prepared by combining** the non-gas rates approved in Order 66/11 with gas cost rates approved in Order 108/15" and

"In the current 2019/20 GRA Centra **has chosen the last approved 2013/14 Cost Allocation Study** as the most appropriate comparison due to there being no single Cost Allocation Study that supports the currently approved base rates."

On this basis Centra did not provide the financial scenario requested.

CAC is not asking Centra to prepare a Cost Allocation Study for August 1, 2017 rates. Further, since the unbundling of rates in 1999, there has not been a single Cost Allocation Study to support current approved base rates as rate changes - both Non-Primary and Primary Gas - routinely occur outside a GRA.

QUESTION:

a) In order to understand the reasonability of the bill impacts in Schedules 11.1.0, CAC is modifying the original request and is seeking Centra prepare indicative Schedules 10.1.0, 10.1.1 and 10.1.2 based on rates currently approved. This can be prepared by combining:
   i. non-gas costs allocated to each class as part of the 2009/10 & 2010/11 GRA (and underpin the August 1, 2017 rate rollback for each class other than Special Contract and Power Stations)

ii. non-gas costs allocated to the Special Contract and Power Stations flowing from the 2013/14 GRA; and

iii. currently approved non-primary gas costs by class flowing from the 2015/16 Cost of Gas Application.

The billing determinant data in Schedule 10.1.1, can be similarly combined 1) upstream billing determinants underpinning the 2015/16 Cost of Gas Application 2) downstream billing determinants underpinning the 2009/10 & 2010/11 GRA for all classes except Special Contract and Power Stations and 3) downstream billing determinants flowing from the 2013/14 GRA for the Special Contract and Power Stations Classes.

b) Please provide Schedule 10.1.2 that calculates the variance (both $ and %) between the results of the 2019/20 Cost Allocation Study and Schedule 10.1.2 in part a).
c) Please provide Figures 7 and 8 of the March 22, 2019 Update (page 12) that adds a column to reflect currently approved in rates by class. This data can be found in the schedules in part a) of the information request.
d) Please provide Figure 10 of the March 22, 2019 Update (page 15) that adds a column to reflect currently non-primary gas costs approved in rates (the 2015/16 Cost of Gas Application) by class.

RESPONSE:

Centra notes that given the various periods being compared and the variables being manipulated, caution must be exercised in drawing conclusions from this analysis.

a) For this response Centra is not considering the Co-op class and considers non-gas costs only for the Primary Gas and FRPGS overhead rates.

   Centra notes that Order 128/09 only allowed Centra to raise the BMC for the SGS and LGS classes and freeze the non-gas portion of transportation and distribution rates for the SGS and LGS customers based on the 2008/09 approved Cost Allocation study. To demonstrate, the calculation of the currently approved SGS transportation and distribution rates is shown below:

SGS Transportation & Distribution Rates		$Costs	Billing Units	Rate	
	Upstream Demand ($)				
2008/09 TY	Gas Costs	19,016,913	695,187	$0.0274	
2008/09 TY	Non-gas Costs	762,443	695,187	$0.0011	
	Total	19,779,356			
	Upstream Commodity ($)				
2008/09 TY	Gas Costs	2,417,741	695,187	$0.0035	
2008/09 TY	Non-gas Costs	4,180,884	695,187	$0.0060	
	Total	6,598,624			
2008/09 TY	Approved 2008/09 SGS Transportation Rate	26,377,980		$0.0379	
	Remove 2008/09 Demand Gas Costs			-$0.0274	
	Remove 2008/09 Commodity Gas Costs	[redacted]	[redacted]	-$0.0035	
2015/16 TY	Add 2015/16 Demand Gas Costs	[redacted]	[redacted]	$0.0448	1d,1e
2015/16 TY	Add 2015/16 Commodity Gas Costs	[redacted]	[redacted]	$0.0020	
	Currently Approved SGS Transportation Rate			**$0.0539**	
		$Costs	**Billing Units**	**Rate**	
	Downstream Total ($)				
2008/09 TY	Total Gas Costs	2,306,375			
2008/09 TY	Total Non-gas Costs	98,761,891			
2008/09 TY	Total Downstream Costs	101,068,268			
2008/09 TY	Less BMC Revenue	-39,515,502	3,039,654	$13.00	
2008/09 TY	2008/09 Approved SGS Distribution Rate	61,552,766	695,187	$0.0885	
2008/09 TY	Remove 2008/09 Gas Costs	-2,306,375	695,187	-$0.0033	
		[redacted]	[redacted]		
2015/16 TY	Add 2015/16 Demand Gas Costs	[redacted]	[redacted]	$0.0001	1d,1e
2015/16 TY	Add 2015/16 Commodity Gas Costs	[redacted]	[redacted]	$0.0013	
	Currently Approved SGS Distribution Rate			**$0.0866**	

As a result, currently approved rates are based on multiple sources:

- 2008/09 Test Year for the non-gas portion of SGS and LGS rates,
- 2010/11 Test Year for the non-gas portion of HVF, Co-op, Mainline and Interruptible class rates,
- 2013/14 Test Year for the non-gas portion of Special Contract and Power Station classes,
- 2015/16 Test Year for the non-Primary Gas portion of all rate classes.

The schedules in Attachment 1 to this response reflect the multiple sources of rates; the aggregate totals of non-gas costs that are not relevant to the calculation are not included.

b) Please see the schedules in Attachment 2 to this response.

c) Please see the following tables for Figures 7 and 8 from the Supplement to Centra's Application filed on March 22, 2019, which have been updated to include costs from currently approved rates:

Figure 7 Cost of Service Allocation by Customer Class ($000s)	Current Rates	2019/20 TY Nov 30, 2018 GRA	2019/20 TY March 22, 2019 Update	Increase/ (Decrease)	
SGS	135,420	135,565	134,975	(590)	
LGS	50,103	56,859	57,157	297	
High Volume Firm	11,544	13,882	13,752	(130)	
Co-op	N/A	20	20	(0)	
Mainline	1,812	2,225	2,282	58	
Special Contract	[redacted]				
Power Stations					
Interruptible	3,106	1,728	1,651	(77)	1e
Primary Gas	[redacted]				
Supplemental Firm					
Supplemental Interruptible					
Fixed Rate Primary Gas	N/A	78	66	(12)	
Total Cost of Service	N/A	326,305	325,785	(520)	

Figure 8 Comparison of Non-Gas Costs by Customer Class ($000s)	Current Rates	2019/20 TY Nov 30, 2018 GRA	2019/20 TY March 22, 2019 Update	Increase/ (Decrease)	
SGS	103,705	103,098	102,633	(465)	
LGS	26,676	32,357	32,456	99	
High Volume Firm	4,854	6,919	6,824	(95)	
Co-op	N/A	8	8	(0)	
Mainline	1,505	2,000	2,058	58	
Special Contract	1,385	2,282	2,247	(35)	
Power Stations	256	167	158	(9)	
Interruptible	2,146	810	770	(41)	
Primary Gas	[redacted]				
Supplemental Firm					1e
Supplemental Interruptible					
Fixed Rate Primary Gas	454	32	21	(10)	
Total Cost of Service		149,040	148,519	(521)	

d) Please see the following table for Figure 10 from the Supplement to Centra's Application filed on March 22, 2019, updated to include costs from currently approved rates:

Figure 10 Non Primary Gas Costs by Customer Class ($000s)	Current Rates	2019/20 TY Nov 30, 2018 GRA	2019/20 TY March 22, 2019 Update	Increase/ (Decrease)	
SGS	31,715	32,468	32,343	(125)	
LGS	23,427	24,502	24,701	198	
High Volume Firm	6,690	6,963	6,927	(35)	
Co-op	N/A	12	12	(0)	
Mainline	307	225	224	(1)	
Special Contract	[redacted]	[redacted]	[redacted]	[redacted]	2d
Power Stations	[redacted]	[redacted]	[redacted]	[redacted]	
Interruptible	959	918	881	(36)	
Supplemental Firm	[redacted]	[redacted]	[redacted]	[redacted]	
Supplemental Interruptible	[redacted]	[redacted]	[redacted]	[redacted]	1a
Total Non-Primary Gas Costs	[redacted]	[redacted]	[redacted]	[redacted]	1e

Centra Gas Manitoba Inc.
2019/20 General Rate Application
Response to CAC-II-135 a)
Schedule 10.1.0 supporting currently approved rates

30-May-19

#		SGS				LGS				
2		Demand	Energy	Customer	Total	Demand	Energy	Customer	Total	
3	Cost of Gas	29,579,396	2,135,405	0	31,714,801	21,850,921	1,576,465	0	23,427,386	
4	Other Income	-0	-0	-2,084,110	-2,084,110	-0	-0	-25,776	-25,776	
5	Operating & Maintenance Expenses	5,033,959	76,671	39,564,332	44,674,963	3,448,271	52,731	5,298,240	8,799,242	
6	Depreciation & Amortization	3,322,727	3,861,963	14,058,156	21,242,846	1,964,036	4,771	2,557,410	4,526,217	
7	Capital & Other Taxes	3,911,141	675,729	11,014,428	15,601,298	2,678,759	471,334	1,846,369	4,996,462	
8	Finance Expense	2,869,862	2,058,285	9,543,537	14,471,684	1,964,569	1,435,555	1,596,329	4,996,453	
9	Corporate Allocation	1,554,509	1,114,905	5,169,417	7,838,831	1,064,142	777,592	864,679	2,706,413	
10	Net Income	388,627	278,726	1,292,354	1,959,708	266,035	194,398	216,170	676,603	
11	Total Cost of Service	46,660,221	10,201,684	78,558,116	135,420,021	33,236,733	4,512,847	12,353,421	50,103,000	
12										
13		HVF				Cooperative				
14		Demand	Energy	Customer	Total	Demand	Energy	Customer	Total	
15	Cost of Gas	6,224,901	465,470	0	6,690,371	N/A	N/A	N/A	N/A	
16	Other Income	0	0	-1,902	-1,902	N/A	N/A	N/A	N/A	
17	Operating & Maintenance Expenses	962,546	14,184	829,621	1,806,352	N/A	N/A	N/A	N/A	
18	Depreciation & Amortization	478,097	1,279	217,064	696,440	N/A	N/A	N/A	N/A	
19	Capital & Other Taxes	745,466	105,600	108,831	959,896	N/A	N/A	N/A	N/A	
20	Finance Expense	442,176	268,724	84,569	795,469	N/A	N/A	N/A	N/A	
21	Corporate Allocation	277,734	168,788	53,119	499,640	N/A	N/A	N/A	N/A	
22	Net Income	54,459	33,096	10,416	97,971	N/A	N/A	N/A	N/A	
23	Total Cost of Service	9,185,378	1,057,142	1,301,718	11,544,238	N/A	N/A	N/A	N/A	
24										
25		Main Line				Special Contract				
26		Demand	Energy	Customer	Total	Demand	Energy	Customer	Total	
27	Cost of Gas	144,494	162,381	0	306,875	[redacted]				1d
28	Other Income	0	0	-331	-331	-5,131	-1	-112	-5,244	
29	Operating & Maintenance Expenses	460,185	3,330	100,583	564,099	592,612	120	10,881	603,614	
30	Depreciation & Amortization	175,434	245	68,680	244,359	14,310	-15	12,374	26,669	
31	Capital & Other Taxes	261,720	26,606	17,385	305,711	366,014	27	7,715	373,756	
32	Finance Expense	133,272	67,713	22,613	223,598	199,300	64	5,587	204,951	
33	Corporate Allocation	83,709	42,531	14,204	140,444	141,139	45	3,956	145,141	
34	Net Income	16,414	8,340	2,785	27,539	35,285	11	989	36,285	
35	Total Cost of Service	1,275,229	311,145	225,919	1,812,293	[redacted]				1e
36										
37		Power Station				Interruptible				
38		Demand	Energy	Customer	Total	Demand	Energy	Customer	Total	
39	Cost of Gas	[redacted]				683,677	275,550	0	959,227	1d
40	Other Income	-746	-2	-270	-1,017	0	0	-841	-841	
41	Operating & Maintenance Expenses	86,114	236	21,765	108,116	359,549	11,200	377,398	748,146	
42	Depreciation & Amortization	-94,253	-29	67,841	-26,441	176,400	981	82,562	259,943	
43	Capital & Other Taxes	35,691	53	43,508	79,252	280,130	82,978	53,165	416,273	
44	Finance Expense	19,024	125	31,710	50,860	165,512	211,157	36,144	412,813	
45	Corporate Allocation	13,473	89	22,457	36,018	103,959	132,629	22,702	259,291	
46	Net Income	3,368	22	5,614	9,004	20,385	26,006	4,452	50,843	
47	Total Cost of Service	[redacted]				1,789,612	740,500	575,581	3,105,694	1e
48										
49		Primary Gas				Supplemental Gas - Firm				
50		Demand	Energy	Customer	Total	Demand	Energy	Customer	Total	
51	Cost of Gas	[redacted]				[redacted]				1a
52	Other Income									
53	Operating & Maintenance Expenses									
54	Depreciation & Amortization									
55	Capital & Other Taxes									1e
56	Finance Expense									
57	Corporate Allocation									
58	Net Income									
59	Total Cost of Service									1e
60										
61		Supplemental Gas - Interruptible				Fixed Price Offering				
62		Demand	Energy	Customer	Total	Demand	Energy	Customer	Total	
63	Cost of Gas	[redacted]								1a
64	Other Income						0		0	
65	Operating & Maintenance Expenses						293,421		293,421	
66	Depreciation & Amortization						136,402		136,402	
67	Capital & Other Taxes						7,549		7,549	1e
68	Finance Expense						9,566		9,566	
69	Corporate Allocation						6,008		6,008	
70	Net Income						1,178		1,178	
71	Total Cost of Service					0	454,124	0	454,124	1e

Centra Gas Manitoba Inc.
2019/20 General Rate Application
Response to CAC-II-135 a)
Schedule 10.1.1 supporting currently approved rates

30-May-19

		SGS	LGS	HVF	ML	SC	PS	INT	PG	FSP	ISP	FPO	
1	REVENUE REQUIREMENTS	[redacted]											
2	Upstream Demand ($)												
3	Upstream Commodity ($)												
4	Upstream Customer ($)												1e
5	Upstream Total ($)												
6													
7	Downstream Demand ($)												
8	Downstream Commodity ($)												
9	Downstream Customer ($)												
10	Downstream Total ($)												
11													
12	Total (incl. gas costs)												
13													
14													
15	MONTHLY BILLING DETERMINANTS	[redacted]											
16	Upstream Demand (10^3m^3-day)												
17	Upstream Commodity (10^3m^3)												
18	Upstream Customer (customers)												1d
19													
20	Downstream Demand (10^3m^3-day)	[redacted]											
21	Downstream Commodity (10^3m^3)												
22	Downstream Customer (customers)												
23													
24	PERCENT IN DEMAND CHARGE	0%	0%	65%	100%	100%	100%	65%					
25													
26	RESULTING UNIT CHARGES												
27	Upstream Demand ($/$10^3m^3$-day)	0.000	0.000	306.123	617.107	0.000	0.000	147.031					
28	Upstream Commodity ($/$10^3m^3$)	54.255	51.335	18.441	37.527	0.000	0.000	17.484	1.630	614.177	35.082	27.104	
29	Upstream Customer ($/customer)	0.000	0.000	0.000	0.000	0.000	0.000	0.000					
30													
31	Downstream Demand ($/$10^3m^3$-day)	0.000	0.000	150.538	157.485	88.317	4.739	76.968					
32	Downstream Commodity ($/$10^3m^3$)	30.356	23.779	7.640	1.160	0.143	7.798	4.500					
33	Downstream Customer ($/customer)	25.844	132.468	1,118.314	2,353.327	3,449.187	8,026.073	1,042.720					

Centra Gas Manitoba Inc.
2019/20 General Rate Application
Response to CAC-II-135 a)
Schedule 10.1.2 supporting currently approved rates

30-May-19

		SGS	LGS	HVF	ML	SC	GS	INT	PG	FSP	ISP	FPO	
1	REVENUE REQUIREMENTS												
2	Upstream Demand ($)												
3	Gas Costs	29,504,013	21,795,139	6,205,492	135,805	0	0	681,359					
4	Non-gas Costs	762,443	522,085	101,289	20,950	0	0	34,144					
5	Total	30,266,455	22,317,224	6,306,782	156,755	0	0	715,503	0	0	0	0	
6													
7	Upstream Commodity ($)												
8	Gas Costs	1,311,530	986,451	276,666	5,759	0	0	67,436	[redacted]				
9	Non-gas Costs	4,180,884	2,915,298	590,018	147,392	0	0	463,128	[redacted]			454,124	1a,1e
10	Total	5,492,414	3,901,749	866,684	153,151	0	0	530,564	[redacted]			454,124	
11													
12	Upstream Customer ($)												
13	Gas Costs	0	0	0	0	0	0	0	0	0	0	0	
14	Non-gas Costs	0	0	0	0	0	0	0	0	0	0	0	
15	Total	0	0	0	0	0	0	0	0	0	0	0	
16													
17	Upstream Total ($)												
18	Total Gas Costs	30,815,543	22,781,590	6,482,158	141,565	0	0	748,795	[redacted]			0	
19	Total Non-gas Costs	4,943,326	3,437,383	691,307	168,342	0	0	497,272	[redacted]			454,124	1e
20	Total Upstream Costs	35,758,869	26,218,973	7,173,465	309,906	0	0	1,246,067	[redacted]			454,124	
21													
22	Downstream Demand ($)												
23	Gas Costs	75,384	55,782	19,409	8,688	[redacted]		2,318					
24	Non-gas Costs	16,318,382	10,863,727	2,859,188	1,109,785	1 343 529	62 672	1,071,791					2d,1e
25	Total	16,393,766	10,919,509	2,878,597	1,118,474	[redacted]		1,074,109	0	0	0	0	
26													
27	Downstream Commodity ($)												
28	Gas Costs	823,874	590,014	188,804	156,622	[redacted]		208,114					
29	Non-gas Costs	3,885,395	21,083	1,654	1,372	252	494	1,823					2d,1e
30	Total	4,709,270	611,097	190,458	157,994	[redacted]		209,937	0	0	0	0	
31													
32	Downstream Customer ($)												
33	Gas Costs	0	0	0	0	[redacted]		0					
34	Non-gas Costs	78,558,116	12,353,421	1,301,718	225,919	41 390	192 626	575,581					2d,1e
35	Total	78,558,116	12,353,421	1,301,718	225,919	[redacted]		575,581	0	0	0	0	
36													
37	Downstream Total ($)												
38	Total Gas Costs	899,258	645,796	208,213	165,310	[redacted]		210,432	0	0	0	0	
39	Total Non-gas Costs	98,761,894	23,238,231	4,162,560	1,337,077	1,385,171	255,792	1,649,195	0	0	0	0	2d,1e
40	Total Downstream Costs	99,661,152	23,884,027	4,370,773	1,502,387	[redacted]		1,859,627	0	0	0	0	
41													
42	Grand Total Gas Costs	31,714,801	23,427,386	6,690,371	306,875	[redacted]		959,227	[redacted]			0	
43	Grand Total Non-gas Costs	103,705,220	26,675,614	4,853,867	1,505,418	1,385,171	255,792	2,146,467	[redacted]			454,124	2d,1e
44	Grand Total	135,420,021	50,103,000	11,544,238	1,812,293	[redacted]		3,105,694	[redacted]			454,124	

Centra Gas Manitoba Inc.
2019/20 General Rate Application
Response to CAC-II-135 b)
Schedule 10.1.2 INC/(DEC) from costs embedded in Approved Rates

30-May-19

		SGS	LGS	HVF	ML	SC	GS	INT	PG	FSP	ISP	FPO	
1	REVENUE REQUIREMENTS												
2	Upstream Demand ($)												
3	Gas Costs	1,252,374	1,720,461	359,398	-34,718	0	0	7,214	0	0	0	0	
4	Non-gas Costs	386,188	356,131	143,884	-17,174	0	0	-8,428	0	0	0	0	
5	Total	1,638,562	2,076,592	503,282	-51,892	0	0	-1,215	0	0	0	0	
6													
7	Upstream Commodity ($)								[redacted]	[redacted]	[redacted]		
8	Gas Costs	-370,250	-267,308	-62,545	-1,762	0	0	-20,137	[redacted]	[redacted]	[redacted]		
9	Non-gas Costs	-3,097,910	-2,059,251	-289,536	-140,804	0	0	-391,287	[redacted]	[redacted]	[redacted]	-453,585	le
10	Total	-3,468,160	-2,326,559	-352,081	-142,566	0	0	-411,424	[redacted]	[redacted]	[redacted]	-453,585	
11													
12	Upstream Customer ($)												
13	Gas Costs	0	0	0	0	0	0	0	0	0	0	0	
14	Non-gas Costs	0	0	0	0	0	0	0	0	0	0	0	
15	Total	0	0	0	0	0	0	0	0	0	0	0	
16													
17	Upstream Total ($)								[redacted]	[redacted]	[redacted]		
18	Total Gas Costs	882,124	1,453,153	296,854	-36,480	0	0	-12,923	[redacted]	[redacted]	[redacted]	0	
19	Total Non-gas Costs	-2,711,722	-1,703,120	-145,652	-157,979	0	0	-399,716	[redacted]	[redacted]	[redacted]	-453,585	le
20	Total Upstream Costs	-1,829,598	-249,967	151,201	-194,458	0	0	-412,639	[redacted]	[redacted]	[redacted]	-453,585	
21													
22	Downstream Demand ($)												
23	Gas Costs	2,170	3,599	-1,174	2,458	[redacted]	[redacted]	-442	0	0	0	0	
24	Non-gas Costs	3,438,459	3,903,339	1,668,288	684,594	869,469	-62,613	-648,809	0	0	0	0	le
25	Total	3,440,629	3,906,938	1,667,114	687,052	[redacted]	[redacted]	-649,250	0	0	0	0	
26													
27	Downstream Commodity ($)												
28	Gas Costs	-256,290	-183,541	-58,733	-48,722	[redacted]	[redacted]	-64,740		0	0		
29	Non-gas Costs	4,002,653	5,147,082	406,736	135,007	-92	-181	-1,271	0	0	0	0	le
30	Total	3,746,363	4,963,541	348,003	86,285	[redacted]	[redacted]	-66,011	0	0	0	0	
31													
32	Downstream Customer ($)												
33	Gas Costs	0	0	0	0	[redacted]	[redacted]	0	0	0	0	0	
34	Non-gas Costs	-5,801,941	-1,567,116	41,062	-109,199	-7,715	-35,200	-327,111	0	0	0	20,616	le
35	Total	-5,801,941	-1,567,116	41,062	-109,199	[redacted]	[redacted]	-327,111	0	0	0	20,616	
36													
37	Downstream Total ($)												
38	Total Gas Costs	-254,120	-179,943	-59,908	-46,264	[redacted]	[redacted]	-65,182		0	0	0	
39	Total Non-gas Costs	1,639,172	7,483,305	2,116,087	710,402	861,662	-97,994	-977,190	0	0	0	20,616	le
40	Total Downstream Costs	1,385,051	7,303,362	2,056,179	664,138	[redacted]	[redacted]	-1,042,372	0	0	0	20,616	
41													
42	Grand Total Gas Costs	628,003	1,273,210	236,946	-82,743	[redacted]	[redacted]	-78,105	[redacted]	[redacted]	[redacted]	0	
43	Grand Total Non-gas Costs	-1,072,550	5,780,185	1,970,434	552,423	861,662	-97,994	-1,376,906	[redacted]	[redacted]	[redacted]	-432,969	le
44	Grand Total	-444,547	7,053,395	2,207,380	469,680	[redacted]	[redacted]	-1,455,011	[redacted]	[redacted]	[redacted]	-432,969	

Centra Gas Manitoba Inc.
2019/20 General Rate Application
Response to CAC-II-135 b)
Schedule 10.1.2 INC/(DEC)% from costs embedded in Approved Rates

30-May-19

		SGS	LGS	HVF	ML	SC	GS	INT	PG	FSP	ISP	FPO	
1	REVENUE REQUIREMENTS												
2	Upstream Demand ($)												
3	Gas Costs	4.2%	7.9%	5.8%	-25.6%	0.0%	0.0%	1.1%	0.0%	0.0%	0.0%	0.0%	
4	Non-gas Costs	50.7%	68.2%	142.1%	-82.0%	0.0%	0.0%	-24.7%	0.0%	0.0%	0.0%	0.0%	
5	Total	5.4%	9.3%	8.0%	-33.1%	0.0%	0.0%	-0.2%	0.0%	0.0%	0.0%	0.0%	
6													
7	Upstream Commodity ($)												
8	Gas Costs	-28.2%	-27.1%	-22.6%	-30.6%	0.0%	0.0%	-29.9%	[redacted]	[redacted]	[redacted]	0.0%	
9	Non-gas Costs	-74.1%	-70.6%	-49.1%	-95.5%	0.0%	0.0%	-84.5%	[redacted]	[redacted]	[redacted]	-99.9%	1e
10	Total	-63.1%	-59.6%	-40.6%	-93.1%	0.0%	0.0%	-77.5%	[redacted]	[redacted]	[redacted]	-99.9%	
11													
12	Upstream Customer ($)												
13	Gas Costs	0	0	0	0	0	0	0	0	0	0	0	
14	Non-gas Costs	0	0	0	0	0	0	0	0	0	0	0	
15	Total	0	0	0	0	0	0	0	0	0	0	0	
16													
17	Upstream Total ($)												
18	Total Gas Costs	2.9%	6.4%	4.6%	-25.8%	0.0%	0.0%	-1.7%	[redacted]	[redacted]	[redacted]	0.0%	
19	Total Non-gas Costs	-54.9%	-49.5%	-21.1%	-93.8%	0.0%	0.0%	-80.4%	[redacted]	[redacted]	[redacted]	-99.9%	1e
20	Total Upstream Costs	-5.1%	-1.0%	2.1%	-62.7%	0.0%	0.0%	-33.1%	[redacted]	[redacted]	[redacted]	-99.9%	
21													
22	Downstream Demand ($)												
23	Gas Costs	2.9%	6.5%	-6.1%	28.3%	-2.4%	[redacted]	[redacted]	0.0%	0.0%	0.0%	0.0%	
24	Non-gas Costs	21.1%	35.9%	58.3%	61.7%	64.7%	-99.9%	-60.5%	0.0%	0.0%	0.0%	0.0%	1e
25	Total	21.0%	35.8%	57.9%	61.4%	63.2%	[redacted]	[redacted]	0.0%	0.0%	0.0%	0.0%	
26													
27	Downstream Commodity ($)												
28	Gas Costs	-31.1%	-31.1%	-31.1%	-31.1%	-31.1%	[redacted]	[redacted]	0.0%	0.0%	0.0%	0.0%	
29	Non-gas Costs	103.0%	24412.9%	24596.1%	9841.6%	-36.7%	-36.7%	-69.7%	0.0%	0.0%	0.0%	0.0%	1e
30	Total	79.6%	812.2%	182.7%	54.6%	-31.1%	[redacted]	[redacted]	0.0%	0.0%	0.0%	0.0%	
31													
32	Downstream Customer ($)												
33	Gas Costs	0.0%	0.0%	0.0%	0.0%	0.0%	[redacted]	[redacted]	0.0%	0.0%	0.0%	0.0%	
34	Non-gas Costs	-7.4%	-12.7%	3.2%	-48.3%	-18.6%	-18.3%	-56.8%	0.0%	0.0%	0.0%	0.0%	1e
35	Total	-7.4%	-12.7%	3.2%	-48.3%	-18.6%	[redacted]	[redacted]	0.0%	0.0%	0.0%	0.0%	
36													
37	Downstream Total ($)												
38	Total Gas Costs	-28.3%	-27.9%	-28.8%	-28.0%	-21.5%	[redacted]	[redacted]	0.0%	0.0%	0.0%	0.0%	
39	Total Non-gas Costs	1.7%	32.2%	50.8%	53.1%	62.2%	-38.3%	-59.3%	0.0%	0.0%	0.0%	0.0%	1e
40	Total Downstream Costs	1.4%	30.6%	47.0%	44.2%	57.1%	[redacted]	[redacted]	0.0%	0.0%	0.0%	0.0%	
41													
42	Grand Total Gas Costs	2.0%	5.4%	3.5%	-27.0%	-21.5%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0.0%	
43	Grand Total Non-gas Costs	-1.0%	21.7%	40.6%	36.7%	62.2%			[redacted]	[redacted]	[redacted]	-95.3%	1e
44	Grand Total	-0.3%	14.1%	19.1%	25.9%	57.1%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-95.3%	

REFERENCE:

Response to CAC/Centra I – 20

PREAMBLE TO IR (IF ANY):

In response to CAC/Centra I-20, Centra states that natural gas DSM programs are intended to reduce customer greenhouse gas emissions and to lower consumption (and resulting bills) for participants. In response to part c) Centra provided a sensitivity analysis allocating DSM costs to all classes that appears to have been functionalized to transmission and classified based on energy.

QUESTION:

a) Please explain and describe whether Centra assumes an average in terms of class participation costs, consistent with MH's electric operations COS treatment prior to Order 164/16. If not, why not? What are the advantages and disadvantages to a one-year approach versus one that averages the costs by class over some time period?
b) Please provide a sensitivity analysis similar to that provided in CAC/Centra 20 (c) that allocates DSM costs to all classes. In this analysis assume that DSM costs are functionalized as transmission, classified as demand and allocated based on peak and average. Please provide the results with any necessary supporting assumptions and quantify the differences by class against the current cost allocation methodology.
c) Please provide the percentage of total DSM costs (both capitalized and annualized) that are low-income related.

RESPONSE:

a) Centra assumes an average in terms of participation costs. The methodology to determine the average is different than the methodology that was used with Manitoba Hydro's electric operations COS treatment prior to Order 164/16. The previous electric COS treatment determined a ten year average of expenditures for each rate class using eight years of actual expenditures and two years of forecast expenditures. Centra determines the average using a fifteen year forecast of program expenditures by rate class from its DSM plan. A one-year approach would be susceptible to any anomalies in rate class participation in the single year used in the analysis; an average over a longer period of time provides a better representation of the typical breakdown by rate class.

b) Please see the attachment to this response.

c) The low-income related DSM expenditures represent the following percentages of the total DSM costs (as per Schedule 6.5.8 Update):
  - 18.2 % of the total DSM Amortization of $9.946 million
  - 25.2% of the total DSM Investments of $52.996 million

Centra Gas Manitoba Inc.
2019/20 General Rate Application

Comparison of the cost allocation treatment of DSM costs in the 2019/20 GRA to DSM allocation based on Peak and Average:

1						**Allocation to classes**								
2		**Function**	**Classify**	**Allocation Method**	**Total Amount ($)**	**SGS**	**LGS**	**HVF**	**CO-OP**	**MLF**	**SC**	**PS**	**INT**	
3	2019/20 GRA	Transmission	Energy	based on the forecasted	9,945,608	5,768,452	3,779,331	298,368	0	99,456	0	0	0	
4				participation in DSM										
5														
6	CAC-Centra II-136 b)	Transmission	Demand	allocated based on the	9,945,608	[redacted]								
7				Peak and Average (PAVG-T)										1e
8	Change in costs/class					[redacted]								
9	compared to 2019/20 GRA													

REFERENCE:

Response to CAC/Centra I- 21

PREAMBLE TO IR (IF ANY):

In the response to CAC/Centra I-21, Centra states that "the portion of SCADA replacement cost that was included in Distribution Plant (Computer Equipment Hardware) for accounting purposes was functionalized partly to the Distribution function and partly to the Onsite Function".

Centra also states that "the portion of SCADA replacement cost that was capitalized to Intangible Plant…..was functionalized to the Transmission, Distribution and Onsite functions".

QUESTION:

b) Please explain how the split between Distribution and Onsite functions was determined related to SCADA replacement costs included in Distribution Plant (for accounting purposes).
c) Please explain the cost allocation rationale that customer numbers drive, in part, the cost associated with SCADA.
d) Please explain with rationale for Centra's cost allocation treatment of SCADA as described in the preamble and CAC/Centra I-21, with the Corporation's statement (Application Tab 6 Appendix 6.1, Page 16) that "the gas SCADA system provides remote monitoring of the operation of the natural gas transmission system".
e) Please discuss and provide the rationale for how SCADA costs are functionalized, classified, and allocated in the MH electric COS.
f) Please discuss and provide the cost allocation rationale for functionalizing a portion of SCADA costs to transmission, distribution and onsite.
g) Please provide a sensitivity analysis based on the 2019/20 Cost Allocation Study (update) that functionalizes all SCADA-related costs as transmission and classifies based on demand. Please provide a table that compares the cost allocation results for each customer class of this scenario to the 2019/20 Cost Allocation Study

(updated).

Please file schedules 10.1.0, 10.1.1, 10.1.2, 10.1.3, 11.1.0 (pages 1 and 2) that reflect the requested sensitivity analysis.

RESPONSE:

Response to parts b), c), d) and f)

The Gas SCADA costs included in Centra's Intangible Plant – Computer System Development SCADA and Distribution Plant – Computer System Hardware plant asset accounts are comprised of computer hardware and software which allow employees to remotely monitor the natural gas system. These accounts do not contain the equipment used to take the various measurements which are reported through the SCADA system, which are captured in the relevant plant accounts for the classes of equipment being monitored. As such, the SCADA computer hardware and software assets are, primarily, a tool used by employees to facilitate and prioritize the day to day activities required to operate the natural gas system.

According to the Canadian Gas Association Uniform Classification of Accounts for Gas Companies, tools and work equipment should be classified as general plant, and prior to the acquisition of Centra by Manitoba Hydro, Centra's original Gas SCADA system was included in General Plant. With the acquisition of Centra by Manitoba Hydro, a decision was made that all new general plant assets (administrative buildings, office & computer equipment, tools, vehicles, computer systems, etc), would be acquired and managed by Manitoba Hydro on behalf of the consolidated entity. By integrating the acquisition and use of general plant assets, synergies could be achieved which would reduce overall corporate costs for the benefit both electric and gas operations. As such, Manitoba Hydro pools office facilities & equipment, vehicles, tools and computer systems, and allocates the combined costs between electric and gas operations through the integrated cost accounting methodology ("ICAM").

At the time of the Gas SCADA Replacement Project, Centra's previous SCADA related computer hardware and software had all become fully depreciated and had been retired from the respective accounts within general plant. Centra's prior SCADA computer development assets were retired in 2010/11 and the last of Centra's pre-existing computer hardware assets were retired in 2005/06.

When the Gas SCADA system was replaced, Manitoba Hydro decided Centra should have ownership of the assets as the resultant computer system would be of use only for the gas line of business. However, since Centra was no longer acquiring general plant assets, new Gas SCADA plant asset accounts were established within the Intangible Assets group for the SCADA computer system development assets and within the Distribution group for the SCADA computer equipment.

All of the assets in the Distribution Computer Equipment Hardware plant account are for equipment related to the gas SCADA system. However, it should be noted that the specific hardware assets capitalized in 2011/12, 2012/13 and 2013/14 as part of the Gas SCADA Replacement Project have all become fully amortized and were retired from rate base prior to April 1, 2019.

For the 2019/20 Cost Allocation Study, 87% of the rate base investment in the Distribution Computer Equipment Hardware account stems from the Natural Gas Medium Pressure Monitoring System Replacement Project.

For Cost Allocation Study purposes, the new SCADA computer system development plant account is treated as a cost which supports the natural gas system as a whole, consistent with the treatment of other intangible assets, whereby the investment is functionalized to transmission, distribution and onsite, and classified within each function in proportion to the allocation of total plant investment. The SCADA computer hardware plant account is treated as a cost which supports the distribution aspects of the system and is functionalized to distribution and onsite, and then classified within these functions in proportion to the allocation of total distribution plant investment. Although the cost allocation approach applied to the SCADA Computer Hardware plant account differs from the approach taken for the related software, in Centra's view, this difference in approach is reasonable, given that 87% of the costs included in the hardware account pertain to equipment used in monitoring the medium pressure portions of the natural gas system.

e) Manitoba Hydro's electric EMS/SCADA system includes hardware, software and associated equipment that provide real time monitoring and control of the electrical system. The costs and investment are functionalized between Generation, Transmission, Subtransmission and Distribution on a 16/52/4/29% basis. The proportion is based on the relative number of remote terminal units installed in stations and the function of those stations. Since remote terminal units are the interface that actually allow the utility to remotely view and control the overall power system, their quantity and location provides a reasonable basis of functionalizing total EMS/SCADA costs. The functionalized costs are classified between Energy and Demand and allocated consistent with the other costs within each function.

g) Please see the table below which provides the schedules reflecting the requested scenario. As discussed in parts a) – d) and f) of the response, the Gas SCADA system is used for distribution monitoring and large customer metering in addition to transmission monitoring, and it is Centra's view that it would not be appropriate to functionalize this investment 100% to Transmission.

The below table compares the costs allocation results for each customer class of the requested scenario to the 2019/20 Cost Allocation Study (updated).

	Total Revenue Requirement	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 (March 22 update)	325,784,091	134,975,474	57,156,395	13,751,619	19,972	2,281,973	[redacted]		1,650,683	[redacted]			66,034
CAC/Centra II-137 g)	325,784,091	134,705,945	57,226,362	13,792,028	20,062	2,320,843			1,654,649				66,034
Difference		-269,529	69,966	40,410	89	38,870			3,966				0

2d,1e

Centra Gas Manitoba Inc.
2019/20 General Rates Application
Summary of Allocated Costs by Customer Class
2019/20 Test Year

Schedule 10.1.0

Cost of Service Elements

SGS	Demand	Energy	Customer	Total
Cost of Gas	30,833,940	1,508,864	0	32,342,804
Other Income	-68,359	-452	-971,167	-1,039,978
Operating & Maintenance Expenses	7,480,011	49,422	36,957,610	44,487,044
Depreciation & Amortization	4,303,750	5,772,166	11,073,218	21,149,134
Capital & Other Taxes	3,750,873	481,214	9,315,004	13,547,091
Finance Expense	3,328,678	1,579,608	9,427,634	14,335,920
Corporate Allocation	1,848,986	877,427	5,236,784	7,963,197
Net Income	445,978	211,637	1,263,119	1,920,733
Total Cost of Service	51,923,857	10,479,887	72,302,201	134,705,945

LGS	Demand	Energy	Customer	Total
Cost of Gas	23,574,981	1,125,616	0	24,700,597
Other Income	-52,295	-345	-42,139	-94,778
Operating & Maintenance Expenses	5,722,216	37,698	4,337,539	10,097,453
Depreciation & Amortization	2,947,763	3,782,173	2,288,658	9,018,594
Capital & Other Taxes	2,869,198	336,850	1,476,830	4,682,878
Finance Expense	2,545,051	1,105,586	1,570,948	5,221,585
Corporate Allocation	1,413,704	614,122	872,617	2,900,442
Net Income	340,987	148,127	210,476	699,590
Total Cost of Service	39,361,605	7,149,828	10,714,928	57,226,362

HVF	Demand	Energy	Customer	Total
Cost of Gas	6,583,125	344,193	0	6,927,317
Other Income	-16,483	-103	-9,095	-25,681
Operating & Maintenance Expenses	1,803,632	11,245	960,145	2,775,022
Depreciation & Amortization	843,209	299,213	173,070	1,315,492
Capital & Other Taxes	875,758	60,941	81,119	1,017,818
Finance Expense	775,552	199,814	79,449	1,054,816
Corporate Allocation	430,797	110,991	44,132	585,920
Net Income	103,909	26,771	10,645	141,325
Total Cost of Service	11,399,499	1,053,064	1,339,465	13,792,028

Cooperative	Demand	Energy	Customer	Total
Cost of Gas	11,535	205	0	11,740
Other Income	-20	0	-20	-40
Operating & Maintenance Expenses	2,146	10	2,117	4,273
Depreciation & Amortization	775	1	418	1,194
Capital & Other Taxes	771	62	262	1,096
Finance Expense	636	204	224	1,065
Corporate Allocation	354	113	125	592
Net Income	85	27	30	143
Total Cost of Service	16,282	624	3,156	20,062

Main Line	Demand	Energy	Customer	Total
Cost of Gas	112,234	111,897	0	224,131
Other Income	-7,608	-4	-768	-8,380
Operating & Maintenance Expenses	832,509	444	80,931	913,884
Depreciation & Amortization	315,358	99,452	15,561	430,372
Capital & Other Taxes	293,154	6,578	7,741	307,473
Finance Expense	239,093	21,602	7,653	268,349
Corporate Allocation	132,810	11,999	4,251	149,060
Net Income	32,034	2,894	1,025	35,953
Total Cost of Service	1,949,584	254,864	116,395	2,320,843

Special Contract	Demand	Energy	Customer	Total	
Cost of Gas	[redacted]				1a
Other Income	-7,072	-1	-86	-7,159	
Operating & Maintenance Expenses	773,792	92	8,563	782,447	
Depreciation & Amortization	297,374	-8	7,804	305,171	
Capital & Other Taxes	533,048	13	6,675	539,736	
Finance Expense	432,685	37	6,134	438,857	
Corporate Allocation	240,344	21	3,407	243,773	
Net Income	57,971	5	822	58,798	
Total Cost of Service	[redacted]				1e

Power Station	Demand	Energy	Customer	Total
Cost of Gas	[redacted]			
Other Income	-564	-2	-194	-760
Operating & Maintenance Expenses	61,728	181	17,129	79,038
Depreciation & Amortization	-95,879	-15	42,048	-53,846
Capital & Other Taxes	16,522	25	37,610	54,157
Finance Expense	12,859	73	34,803	47,735
Corporate Allocation	7,143	41	19,332	26,516
Net Income	1,723	10	4,663	6,396
Total Cost of Service	[redacted]			

Interruptible	Demand	Energy	Customer	Total	
Cost of Gas	690,449	190,673	0	881,122	1d
Other Income	-1,578	-25	-1,629	-3,233	
Operating & Maintenance Expenses	172,679	2,739	171,800	347,217	
Depreciation & Amortization	65,551	166	33,654	99,371	
Capital & Other Taxes	86,913	10,639	16,416	113,968	
Finance Expense	76,823	34,848	16,301	127,973	
Corporate Allocation	42,673	19,357	9,055	71,085	
Net Income	10,293	4,669	2,184	17,146	
Total Cost of Service	1,143,803	263,065	247,781	1,654,649	1e

Primary Gas	Demand	Energy	Customer	Total
Cost of Gas	[redacted]			
Other Income				
Operating & Maintenance Expenses				
Depreciation & Amortization				
Capital & Other Taxes				
Finance Expense				
Corporate Allocation				
Net Income				
Total Cost of Service				

Supplemental Gas - Firm	Demand	Energy	Customer	Total	
Cost of Gas	[redacted]				1a
Other Income					
Operating & Maintenance Expenses					
Depreciation & Amortization					1e
Capital & Other Taxes					
Finance Expense					
Corporate Allocation					
Net Income					
Total Cost of Service					1e

Supplemental Gas - Interruptible	Demand	Energy	Customer	Total
Cost of Gas	[redacted]			
Other Income				
Operating & Maintenance Expenses				
Depreciation & Amortization				
Capital & Other Taxes				
Finance Expense				
Corporate Allocation				
Net Income				
Total Cost of Service				

Fixed Price Offering	Demand	Energy	Customer	Total	
Cost of Gas	0	44,879	0	44,879	1a
Other Income	0	-4	-171	-175	
Operating & Maintenance Expenses	0	419	18,750	19,168	
Depreciation & Amortization	0	33	1,486	1,520	1e
Capital & Other Taxes	0	19	304	323	
Finance Expense	0	43	146	189	
Corporate Allocation	0	24	81	105	
Net Income	0	6	20	25	
Total Cost of Service	0	45,418	20,616	66,034	1e

Unassigned	Demand	Energy	Customer	Total
Cost of Gas	0	0	0	0
Other Income	0	0	0	0
Operating & Maintenance Expenses	0	0	0	0
Depreciation & Amortization	0	0	0	0
Capital & Other Taxes	0	0	0	0
Finance Expense	0	0	0	0
Corporate Allocation	0	0	0	0
Net Income	0	0	0	0
Total Cost of Service	0	0	0	0

Total	Demand	Energy	Customer	Total
Cost of Gas	61,836,486	115,428,348	0	177,264,835
Other Income	-153,978	-10,480	-1,025,270	-1,189,728
Operating & Maintenance Expenses	16,848,713	1,146,704	42,554,583	60,550,000
Depreciation & Amortization	8,677,902	10,035,983	13,635,917	32,349,802
Capital & Other Taxes	8,426,237	943,305	10,941,962	20,311,504
Finance Expense	7,411,378	3,048,590	11,143,294	21,603,263
Corporate Allocation	4,116,811	1,693,405	6,189,784	12,000,000
Net Income	992,980	408,451	1,492,984	2,894,415
Total Cost of Service	108,156,528	132,694,308	84,933,255	325,784,091

Centra Gas Manitoba Inc.
2019/20 General Rates Application
Unit Cost Component Summary
2019/20 Test Year

CAC/CENTRA II-137 g)
Schedule 10.1.1

		ROR	System Total	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Fixed Price Offering FRPGS	
1	REVENUE REQUIREMENTS		[redacted]													
2	Upstream Demand ($)															
3	Upstream Commodity ($)															
4	Upstream Customer ($)															
5	Upstream Total ($)															
6																1e
7	Downstream Demand ($)															
8	Downstream Commodity ($)															
9	Downstream Customer ($)															
10	Downstream Total ($)															
11																
12	Total (incl. gas costs)															
13																
14																
15	MONTHLY BILLING DETERMINANTS		[redacted]													
16	Upstream Demand (10^3m^3-day)															
17	Upstream Commodity (10^3m^3)															
18	Upstream Customer (customers)															
19																1d
20	Downstream Demand (10^3m^3-day)															
21	Downstream Commodity (10^3m^3)															
22	Downstream Customer (customers)															
23																
24	PERCENT IN DEMAND CHARGE			0.0%	0.0%	65.0%	100.0%	100.0%	100.0%	100.0%	65.0%	100.0%	100.0%	100.0%	100.0%	
25																
26	RESULTING UNIT CHARGES															
27	Upstream Demand ($/$10^3m^3$-day)		454.726	0.000	0.000	295.043	470.592	422.296	0.000	0.000	149.285	0.000	0.000	0.000	0.000	
28	Upstream Commodity ($/$10^3m^3$)		80.314	49.715	48.053	15.160	2.310	2.509	0.000	0.000	8.050	76.908	134.897	134.294	80.883	
29	Upstream Customer ($/customer)		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
30																
31	Downstream Demand ($/$10^3m^3$-day)		251.580	0.000	0.000	185.201	171.391	238.857	143.773	0.434	89.768	0.000	0.000	0.000	0.000	
32	Downstream Commodity ($/$10^3m^3$)		7.252	41.722	38.011	10.083	0.000	1.518	0.096	18.305	6.417	0.000	0.000	0.000	0.000	
33	Downstream Customer ($/customer)		24.595	21.571	107.449	1,005.604	263.011	1,077.732	2,776.612	6,474.681	1,032.422	0.000	0.000	0.000	0.000	

Centra Gas Manitoba Inc.
2019/20 General Rates Application
Comparison of Gas Costs vs. Non-Gas Costs
2019/20 Test Year

CAC/CENTRA II-137 g)
Schedule 10.1.2

	Gas Costs vs. Non-Gas Costs	ROR	System Total	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Fixed Price Offering FRPGS	
1	REVENUE REQUIREMENTS															
2	Upstream Demand ($)	Upstream Demand ($)														
3	Gas Costs	Gas Costs	61,638,042	30,756,386	23,515,600	6,564,891	11,505	101,088	0	0	688,573	0	0	0	0	
4	Non-gas Costs	Non-gas Costs	2,301,940	1,148,631	878,216	245,173	430	3,775	0	0	25,716	0	0	0	0	
5	Total	Total	63,939,983	31,905,017	24,393,815	6,810,064	11,935	104,863	0	0	714,288	0	0	0	0	
6			0	0	0	0	0	0	0	0	0	0	0	0	0	
7	Upstream Commodity ($)	Upstream Commodity ($)														
8	Gas Costs	Gas Costs	113,950,265	941,280	719,143	214,121	205	3,997	0	0	47,299	[redacted]			44,879	
9	Non-gas Costs	Non-gas Costs	3,663,952	1,082,974	856,047	300,482	419	6,588	0	0	71,841	[redacted]			539	1a,1e
10	Total	Total	117,614,218	2,024,254	1,575,190	514,603	624	10,585	0	0	119,139	[redacted]			45,418	
11			0	0	0	0	0	0	0	0	0	0	0	0	0	
12	Upstream Customer ($)	Upstream Customer ($)														
13	Gas Costs	Gas Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	
14	Non-gas Costs	Non-gas Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	
15	Total	Total	0	0	0	0	0	0	0	0	0	0	0	0	0	
16																
17	Upstream Total ($)	Upstream Total ($)														
18	Total Gas Costs	Total Gas Costs	175,588,308	31,697,666	24,234,743	6,779,012	11,711	105,085	0	0	735,872	[redacted]			44,879	
19	Total Non-gas Costs	Total Non-gas Costs	5,965,892	2,231,605	1,734,263	545,655	848	10,363	0	0	97,556	[redacted]			539	1e
20	Total Upstream Costs	Total Upstream Costs	181,554,200	33,929,271	25,969,006	7,324,666	12,559	115,448	0	0	833,428	[redacted]			45,418	
21			0	0	0	0	0	0	0	0	0	0	0	0	0	
22	Downstream Demand ($)	Downstream Demand ($)														
23	Gas Costs	Gas Costs	198,444	77,554	59,381	18,234	29	11,146	[redacted]		1,876	0	0	0	0	
24	Non-gas Costs	Non-gas Costs	44,018,102	19,941,286	14,908,409	4,571,202	4,318	1,833,575	2,328,144	3,531	427,638	0	0	0	0	2d,1e
25	Total	Total	44,216,546	20,018,840	14,967,789	4,589,436	4,347	1,844,721	[redacted]		429,514	0	0	0	0	
26																
27	Downstream Commodity ($)	Downstream Commodity ($)														
28	Gas Costs	Gas Costs	1,478,083	567,584	406,473	130,071	0	107,900	[redacted]		143,374	0	0	0	0	
29	Non-gas Costs	Non-gas Costs	13,602,007	7,888,049	5,168,165	408,390	0	136,378	159	313	552	0	0	0	0	2d,1e
30	Total	Total	15,080,090	8,455,633	5,574,638	538,461	0	244,279	[redacted]		143,926	0	0	0	0	
31																
32	Downstream Customer ($)	Downstream Customer ($)														
33	Gas Costs	Gas Costs	0	0	0	0	0	0	[redacted]		0	0	0	0	0	
34	Non-gas Costs	Non-gas Costs	84,933,255	72,302,201	10,714,928	1,339,465	3,156	116,395	33,319	155,392	247,781	0	0	0	20,616	2d,1e
35	Total	Total	84,933,255	72,302,201	10,714,928	1,339,465	3,156	116,395	[redacted]		247,781	0	0	0	20,616	
36																
37	Downstream Total ($)	Downstream Total ($)														
38	Total Gas Costs	Total Gas Costs	1,676,527	645,137	465,854	148,306	29	119,046	[redacted]		145,250	0	0	0	0	
39	Total Non-gas Costs	Total Non-gas Costs	142,553,363	100,131,536	30,791,502	6,319,056	7,474	2,086,348	2,361,622	159,236	675,971	0	0	0	20,616	
40	Total Downstream Costs	Total Downstream Costs	144,229,890	100,776,674	31,257,356	6,467,362	7,503	2,205,395	[redacted]		821,222	0	0	0	20,616	2d,1e
41																
42	Grand Total Gas Costs	Grand Total Gas Costs	177,264,835	32,342,804	24,700,597	6,927,317	11,740	224,131	[redacted]		881,122	[redacted]			44,879	
43	Grand Total Non-gas Costs	Grand Total Non-gas Costs	148,519,256	102,363,141	32,525,765	6,864,711	8,322	2,096,711	2,361,622	159,236	773,527	[redacted]			21,155	2d,1e
44	Grand Total	Grand Total	325,784,091	134,705,945	57,226,362	13,792,028	20,062	2,320,843	[redacted]		1,654,649	[redacted]			66,034	
45																
46																

47 Calculation of the Primary Gas Overhead Rate: [redacted] line 9, PG column)
48 10^3m^3 (Schedule 10.1.1, line 17, PG column)
49 0.91 10^3m^3

Calculation of the Fixed Rate Primary Gas PCR 21,155 (lines 9 & 34, FPO column)
562 (10^3m^3 (Schedule 10.1.1, line 17, FPO column)
37.67 per 10^3m^3

1e

Centra Gas Manitoba Inc.
2019/20 General Rate Application
Total Functionalization By Customer Class
2019/20 Test Year

CAC/CENTRA II-137 g)
Schedule 10.1.3

		System Total	Residential SGS-R	Small Commercial SGS-C	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Fixed Price Offering FPO	
1	PRODUCTION																
2	Demand	0	[redacted]														
3	Energy	113,369,822	[redacted]														1a
4	Customer	0	[redacted]														
5	Total	113,369,822	[redacted]														
6			[redacted]														
7	PIPELINE		[redacted]														
8	Demand	44,875,222	[redacted]														
9	Energy	0	[redacted]														1a
10	Customer	0	[redacted]														
11	Total	44,875,222	[redacted]														
12			[redacted]														
13	STORAGE		[redacted]														
14	Demand	19,064,760	[redacted]														
15	Energy	4,244,395	[redacted]														1a
16	Customer	0	[redacted]														
17	Total	23,309,156	[redacted]														
18			[redacted]														
19	TRANSMISSION		[redacted]														
20	Demand	17,887,449	[redacted]														
21	Energy	15,080,090	[redacted]														1a
22	Customer	0	[redacted]														
23	Total	32,967,539	[redacted]														
24			[redacted]														
25	DISTRIBUTION																
26	Demand	26,329,097	10,642,558	2,034,641	12,677,199	9,694,670	2,945,706	1,918	722,526	[redacted]		287,077	[redacted]			0	
27	Energy	0	0	0	0	0	0	0		[redacted]			[redacted]			0	
28	Customer	10,936,727	9,921,359	694,524	10,615,883	315,838	4,219	2	20	[redacted]		760	[redacted]			0	2d,1e
29	Total	37,265,823	20,563,918	2,729,165	23,293,083	10,010,509	2,949,925	1,920	722,546	[redacted]		287,837	[redacted]			0	
30										[redacted]			[redacted]				
31	ONSITE									[redacted]			[redacted]				
32	Demand	0	0	0	0	0	0	0		[redacted]			[redacted]			0	
33	Energy	0	0	0	0	0	0	0		[redacted]			[redacted]			0	
34	Customer	73,996,528	55,338,590	6,347,728	61,686,318	10,399,090	1,335,246	3,154	116,375	[redacted]		247,021	[redacted]			20,616	2d,1e
35	Total	73,996,528	55,338,590	6,347,728	61,686,318	10,399,090	1,335,246	3,154	116,375	[redacted]		247,021	[redacted]			20,616	
36										[redacted]			[redacted]				
37	TOTAL SERVICE									[redacted]			[redacted]				
38	Demand	108,156,528	43,544,185	8,379,671	51,923,857	39,361,605	11,399,499	16,282	1,949,584	[redacted]		1,143,803	[redacted]			0	
39	Energy	132,694,308	8,027,388	2,452,499	10,479,887	7,149,828	1,053,064	624	254,864	[redacted]		263,065	[redacted]			45,418	2d,1e
40	Customer	84,933,255	65,259,950	7,042,252	72,302,201	10,714,928	1,339,465	3,156	116,395	[redacted]		247,781	[redacted]			20,616	
41	Total	325,784,091	116,831,523	17,874,422	134,705,945	57,226,362	13,792,028	20,062	2,320,843	[redacted]		1,654,649	[redacted]			66,034	

Centra Gas Manitoba Inc.
2019/20 General Rates Application
Bill Impact Comparison
2019/20 Test Year

BILLED VS. BILLED

				FEB 1/19 APPROVED BILLED RATES				NOV 1/19 PROPOSED BILLED RATES				BILL IMPACTS	
	Load Factor	Annual Use 10^3m^3	Mcf	Basic Chg	Demand	Commodity	Annual	Basic Chg	Demand	Commodity	Annual	$	%
Small General Service		1.00	35	$168	$0	$236	$404	$168	$0	$218	$386	($18)	-4.4%
		1.98	70	$168	$0	$468	$636	$168	$0	$433	$601	($35)	-5.5%
(Typical Residential Customer)		**2.22**	78	$168	$0	$523	$691	$168	$0	$484	$652	($39)	-5.7%
		2.80	99	$168	$0	$662	$830	$168	$0	$612	$780	($49)	-6.0%
		3.20	113	$168	$0	$755	$923	$168	$0	$699	$867	($56)	-6.1%
		3.68	130	$168	$0	$869	$1,037	$168	$0	$804	$972	($65)	-6.3%
		11.33	400	$168	$0	$2,673	$2,841	$168	$0	$2,473	$2,641	($200)	-7.0%
Large General Service		11.33	400	$924	$0	$2,072	$2,996	$924	$0	$2,070	$2,994	($2)	-0.1%
		59.49	2,100	$924	$0	$10,879	$11,803	$924	$0	$10,870	$11,794	($10)	-0.1%
		679.87	24,000	$924	$0	$124,335	$125,259	$924	$0	$124,224	$125,148	($111)	-0.1%
HVF (Sales Service)	25%	850	30,000	$13,420	$51,159	$103,976	$168,555	$12,067	$77,596	$78,883	$168,546	($9)	0.0%
	40%	850	30,000	$13,420	$31,974	$103,976	$149,370	$12,067	$48,497	$78,883	$139,447	($9,923)	-6.6%
	40%	1,416	50,000	$13,420	$53,291	$173,293	$240,004	$12,067	$80,829	$131,471	$224,367	($15,636)	-6.5%
	40%	2,833	100,000	$13,420	$106,581	$346,586	$466,588	$12,067	$161,658	$262,942	$436,668	($29,920)	-6.4%
	40%	6,200	218,866	$13,420	$233,271	$758,560	$1,005,250	$12,067	$353,814	$575,492	$941,373	($63,877)	-6.4%
	40%	12,600	444,792	$13,420	$474,066	$1,541,589	$2,029,075	$12,067	$719,041	$1,169,547	$1,900,656	($128,418)	-6.3%
	75%	685	24,181	$13,420	$13,745	$83,809	$110,974	$12,067	$20,848	$63,583	$96,498	($14,476)	-13.0%
	75%	850	30,000	$13,420	$17,053	$103,976	$134,449	$12,067	$25,865	$78,883	$116,815	($17,633)	-13.1%
	75%	1,416	50,000	$13,420	$28,422	$173,293	$215,135	$12,067	$43,109	$131,471	$186,647	($28,487)	-13.2%
	75%	2,833	100,000	$13,420	$56,843	$346,586	$416,850	$12,067	$86,218	$262,942	$361,227	($55,622)	-13.3%
	75%	6,200	218,866	$13,420	$124,411	$758,560	$896,390	$12,067	$188,701	$575,492	$776,260	($120,131)	-13.4%
	75%	12,600	444,792	$13,420	$252,835	$1,541,589	$1,807,844	$12,067	$383,489	$1,169,547	$1,565,103	($242,740)	-13.4%
HVF (T-Service)	40%	2,600	91,783	$13,420	$32,128	$18,923	$64,470	$12,067	$39,759	$26,025	$77,851	$13,381	20.8%
	40%	11,000	388,311	$13,420	$135,925	$80,057	$229,402	$12,067	$168,212	$110,105	$290,384	$60,982	26.6%
	40%	17,600	621,297	$13,420	$217,481	$128,091	$358,991	$12,067	$269,139	$176,168	$457,374	$98,382	27.4%
	75%	2,600	91,783	$13,420	$17,135	$18,923	$49,477	$12,067	$21,205	$26,025	$59,297	$9,820	19.8%
	75%	11,000	388,311	$13,420	$72,494	$80,057	$165,970	$12,067	$89,713	$110,105	$211,885	$45,915	27.7%
	75%	17,600	621,297	$13,420	$115,990	$128,091	$257,500	$12,067	$143,541	$176,168	$331,776	$74,275	28.8%
Cooperative	35%	250	8,825	$3,289	$14,042	$25,312	$42,643	$3,156	$15,076	$24,100	$42,332	($311)	-0.7%
	35%	350	12,355	$3,289	$19,659	$35,437	$58,385	$3,156	$21,107	$33,740	$58,003	($382)	-0.7%
	35%	500	17,650	$3,289	$28,084	$50,625	$81,998	$3,156	$30,153	$48,200	$81,509	($489)	-0.6%
MLC (Sales Service)	40%	2,833	100,000	$28,240	$163,725	$290,867	$482,832	$12,933	$98,072	$276,715	$387,719	($95,112)	-19.7%
	40%	14,164	500,000	$28,240	$818,626	$1,454,334	$2,301,200	$12,933	$490,360	$1,383,573	$1,886,866	($414,333)	-18.0%
	40%	28,328	1,000,000	$28,240	$1,637,252	$2,908,668	$4,574,160	$12,933	$980,721	$2,767,147	$3,760,800	($813,360)	-17.8%
	75%	2,833	100,000	$28,240	$87,320	$290,867	$406,427	$12,933	$52,305	$276,715	$341,953	($64,474)	-15.9%
	75%	14,164	500,000	$28,240	$436,601	$1,454,334	$1,919,174	$12,933	$261,525	$1,383,573	$1,658,032	($261,143)	-13.6%
	75%	28,328	1,000,000	$28,240	$873,201	$2,908,668	$3,810,109	$12,933	$523,051	$2,767,147	$3,303,130	($506,978)	-13.3%
	75%	41,000	1,447,339	$28,240	$1,263,818	$4,209,829	$5,501,888	$12,933	$757,032	$4,005,001	$4,774,966	($726,922)	-13.2%
MLC (T- Service)	40%	14,000	494,213	$28,240	$181,393	$17,293	$226,926	$12,933	$275,361	$9,891	$298,184	$71,259	31.4%
	40%	18,000	635,417	$28,240	$233,219	$22,234	$283,693	$12,933	$354,035	$12,717	$379,685	$95,992	33.8%
	40%	44,000	1,553,242	$28,240	$570,091	$54,349	$652,680	$12,933	$865,419	$31,086	$909,438	$256,757	39.3%
	75%	14,000	494,213	$28,240	$96,743	$17,293	$142,276	$12,933	$146,859	$9,891	$169,683	$27,407	19.3%
	75%	18,000	635,417	$28,240	$124,384	$22,234	$174,857	$12,933	$188,819	$12,717	$214,468	$39,611	22.7%
	75%	44,000	1,553,242	$28,240	$304,049	$54,349	$386,638	$12,933	$461,557	$31,086	$505,576	$118,938	30.8%
Special Contract	[redacted]												
Power Stations													
Interruptible Sales	25%	850	30,000	$12,513	$24,602	$100,479	$137,593	$12,389	$40,395	$79,761	$132,545	($5,048)	-3.7%
	40%	2,833	100,000	$12,513	$51,254	$334,929	$398,696	$12,389	$84,157	$265,870	$362,416	($36,280)	-9.1%
	40%	14,164	500,000	$12,513	$256,268	$1,674,647	$1,943,427	$12,389	$420,784	$1,329,349	$1,762,522	($180,906)	-9.3%
	75%	850	30,000	$12,513	$8,201	$100,479	$121,192	$12,389	$13,465	$79,761	$105,615	($15,577)	-12.9%
	75%	2,833	100,000	$12,513	$27,335	$334,929	$374,777	$12,389	$44,884	$265,870	$323,142	($51,635)	-13.8%
	75%	14,164	500,000	$12,513	$136,676	$1,674,647	$1,823,836	$12,389	$224,418	$1,329,349	$1,566,156	($257,680)	-14.1%

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Centra Gas Manitoba Inc.
2019/20 General Rates Application
Bill Impact Comparison
2019/20 Test Year

CAC/CENTRA II-137 g)
Schedule 11.1.0
Page 2 of 2

1	**BASE VS. BASE**													
2														
3					**FEB 1/19 APPROVED BASE RATES**				**NOV 1/19 PROPOSED BASE RATES**				**BASE IMPACTS**	
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)	-3.4%
9			1.98	70	$168	$0	$450	$618	$168	$0	$424	$592	($26)	-4.3%
10	*(Typical Residential Customer)*		2.22	78	$168	$0	$504	$672	$168	$0	$474	$642	($30)	-4.4%
11			2.80	99	$168	$0	$637	$805	$168	$0	$600	$768	($37)	-4.6%
12			3.20	113	$168	$0	$727	$895	$168	$0	$685	$853	($43)	-4.8%
13			3.68	130	$168	$0	$837	$1,005	$168	$0	$788	$956	($49)	-4.9%
14			11.33	400	$168	$0	$2,575	$2,743	$168	$0	$2,424	$2,592	($151)	-5.5%
15														
16	Large General Service		11.33	400	$924	$0	$1,974	$2,898	$924	$0	$2,006	$2,930	$32	1.1%
17			59.49	2,100	$924	$0	$10,362	$11,286	$924	$0	$10,529	$11,453	$168	1.5%
18			679.87	24,000	$924	$0	$118,420	$119,344	$924	$0	$120,337	$121,261	$1,917	1.6%
19														
20	HVF (Sales Service)	25%	850	30,000	$13,420	$51,159	$96,626	$161,205	$12,067	$53,667	$93,992	$159,726	($1,479)	-0.9%
21		40%	850	30,001	$13,420	$31,976	$96,629	$142,024	$12,067	$33,543	$93,995	$139,605	($2,419)	-1.7%
22		40%	1,416	50,000	$13,420	$53,291	$161,043	$227,753	$12,067	$55,903	$156,653	$224,623	($3,130)	-1.4%
23		40%	2,833	100,000	$13,420	$106,581	$322,086	$442,087	$12,067	$111,806	$313,306	$437,179	($4,908)	-1.1%
24		40%	6,200	218,866	$13,420	$233,271	$704,936	$951,626	$12,067	$244,705	$685,720	$942,492	($9,134)	-1.0%
25		40%	12,600	444,792	$13,420	$474,066	$1,432,611	$1,920,097	$12,067	$497,303	$1,393,560	$1,902,930	($17,167)	-0.9%
26		75%	685	24,181	$13,420	$13,745	$77,884	$105,049	$12,067	$14,419	$75,761	$102,247	($2,802)	-2.7%
27		75%	850	30,000	$13,420	$17,053	$96,626	$127,098	$12,067	$17,889	$93,992	$123,948	($3,151)	-2.5%
28		75%	1,416	50,000	$13,420	$28,422	$161,043	$202,884	$12,067	$29,815	$156,653	$198,535	($4,349)	-2.1%
29		75%	2,833	100,000	$13,420	$56,843	$322,086	$392,349	$12,067	$59,630	$313,306	$385,003	($7,346)	-1.9%
30		75%	6,200	218,866	$13,420	$124,411	$704,936	$842,767	$12,067	$130,509	$685,720	$828,296	($14,470)	-1.7%
31		75%	12,600	444,792	$13,420	$252,835	$1,432,611	$1,698,866	$12,067	$265,228	$1,393,560	$1,670,855	($28,011)	-1.6%
32														
33	HVF (T-Service)	40%	2,600	91,783	$13,420	$32,128	$18,923	$64,470	$12,067	$39,577	$26,260	$77,904	$13,434	20.8%
34		40%	11,000	388,311	$13,420	$135,925	$80,057	$229,402	$12,067	$167,441	$111,100	$290,608	$61,206	26.7%
35		40%	17,600	621,297	$13,420	$217,481	$128,091	$358,991	$12,067	$267,906	$177,760	$457,733	$98,742	27.5%
36		75%	2,600	91,783	$13,420	$17,135	$18,923	$49,477	$12,067	$21,108	$26,260	$59,435	$9,958	20.1%
37		75%	11,000	388,311	$13,420	$72,494	$80,057	$165,970	$12,067	$89,302	$111,100	$212,469	$46,499	28.0%
38		75%	17,600	621,297	$13,420	$115,990	$128,091	$257,500	$12,067	$142,883	$177,760	$332,710	$75,210	29.2%
39														
40	Cooperative	35%	250	8,825	$3,289	$14,042	$23,150	$40,481	$3,156	$15,076	$21,925	$40,157	($324)	-0.8%
41		35%	350	12,355	$3,289	$19,659	$32,410	$55,358	$3,156	$21,107	$30,695	$54,958	($400)	-0.7%
42		35%	500	17,650	$3,289	$28,084	$46,300	$77,673	$3,156	$30,153	$43,850	$77,159	($515)	-0.7%
43														
44	MLC (Sales Service)	40%	2,833	100,000	$28,240	$163,725	$266,366	$458,331	$12,933	$153,948	$252,968	$419,849	($38,483)	-8.4%
45		40%	14,164	500,000	$28,240	$818,626	$1,331,830	$2,178,696	$12,933	$769,741	$1,264,838	$2,047,512	($131,184)	-6.0%
46		40%	28,328	1,000,000	$28,240	$1,637,252	$2,663,660	$4,329,152	$12,933	$1,539,482	$2,529,676	$4,082,091	($247,061)	-5.7%
47		75%	2,833	100,000	$28,240	$87,320	$266,366	$381,926	$12,933	$82,106	$252,968	$348,006	($33,920)	-8.9%
48		75%	14,164	500,000	$28,240	$436,601	$1,331,830	$1,796,671	$12,933	$410,529	$1,264,838	$1,688,299	($108,371)	-6.0%
49		75%	28,328	1,000,000	$28,240	$873,201	$2,663,660	$3,565,101	$12,933	$821,057	$2,529,676	$3,363,666	($201,435)	-5.7%
50		75%	41,000	1,447,339	$28,240	$1,263,818	$3,855,220	$5,147,279	$12,933	$1,188,348	$3,661,300	$4,862,581	($284,698)	-5.5%
51														
52	MLC (T- Service)	40%	14,000	494,213	$28,240	$181,393	$17,293	$226,926	$12,933	$274,899	$21,000	$308,831	$81,906	36.1%
53		40%	18,000	635,417	$28,240	$233,219	$22,234	$283,693	$12,933	$353,441	$27,000	$393,374	$109,681	38.7%
54		40%	44,000	1,553,242	$28,240	$570,091	$54,349	$652,680	$12,933	$863,967	$66,000	$942,900	$290,220	44.5%
55		75%	14,000	494,213	$28,240	$96,743	$17,293	$142,276	$12,933	$146,613	$21,000	$180,545	$38,270	26.9%
56		75%	18,000	635,417	$28,240	$124,384	$22,234	$174,857	$12,933	$188,502	$27,000	$228,435	$53,577	30.6%
57		75%	44,000	1,553,242	$28,240	$304,049	$54,349	$386,638	$12,933	$460,782	$66,000	$539,715	$153,078	39.6%
58		[redacted]												
59	Special Contract													
60														
61	Power Stations													
62														
63	Interruptible Sales	25%	850	30,000	$12,513	$24,602	$93,682	$130,796	$12,389	$26,722	$87,873	$126,984	($3,813)	-2.9%
64		40%	2,833	100,000	$12,513	$51,254	$312,273	$376,039	$12,389	$55,670	$292,910	$360,969	($15,070)	-4.0%
65		40%	14,164	500,000	$12,513	$256,268	$1,561,364	$1,830,144	$12,389	$278,350	$1,464,549	$1,755,288	($74,856)	-4.1%
66		75%	850	30,000	$12,513	$8,201	$93,682	$114,395	$12,389	$8,907	$87,873	$109,169	($5,226)	-4.6%
67		75%	2,833	100,000	$12,513	$27,335	$312,273	$352,121	$12,389	$29,691	$292,910	$334,990	($17,131)	-4.9%
68		75%	14,164	500,000	$12,513	$136,676	$1,561,364	$1,710,553	$12,389	$148,453	$1,464,549	$1,625,392	($85,161)	-5.0%

2d

REFERENCE:

Response to CAC/Centra I - 26

PREAMBLE TO IR (IF ANY):

In response to CAC/Centra 26 (b) (Page 2), Centra states "the increased investment in transmission plant has shifted the costs of programs such as Distribution Maintenance from the Onsite Function to the Transmission function"

QUESTION:

Please explain what is meant by Centra's statement in the preamble. How does the increase in Transmission investment cause program costs (such as Distribution Maintenance) to no longer be functionalized as Onsite driven by the number of customers on Centra's system?

RESPONSE:

To clarify the response in CAC/CENTRA I-26b (Page 2), the response should state "the increased investment in transmission plant has **partially** shifted costs of programs …". Distribution Maintenance program costs have not shifted entirely from Onsite to Transmission function. The Distribution Maintenance program has consistently in past GRAs been functionalized to Transmission, Distribution and Onsite functions using the MAINS/SERVICES functionalization factor. The following table shows the calculation of the MAINS/SERVICES functionalization factor from the past three GRAs, and demonstrates the partial shift of Distribution Maintenance program costs from the Onsite function to the Transmission function, driven by increased transmission mains investment in the 2019/20 GRA.

	Test Year	Description	Total	Transmission	Distribution	OnSite
1	2019/20	Mains		155,008,042	231,880,662	
2	2019/20	Services				284,239,631
3	2019/20	Total	671,128,336	155,008,042	231,880,662	284,239,631
4	2019/20	Total %		23.1%	34.6%	42.4%
5						
6	2013/14	Mains		96,265,407	182,038,564	
7	2013/14	Services				225,205,587
8	2013/14	Total	503,509,559	96,265,407	182,038,564	225,205,587
9	2013/14	Total %		19.1%	36.2%	44.7%
10						
11	2010/11	Mains		92,081,965	162,291,074	
12	2010/11	Services				207,117,471
13	2010/11	Total	461,490,511	92,081,965	162,291,074	207,117,471
14	2010/11	Total %		20.0%	35.2%	44.9%

REFERENCE:

Response to CAC/Centra I - 29

QUESTION:

Please provide a sensitivity analysis using the 2019/20 Cost Allocation Study (Updated March 22, 2019) that assumes the 2013/14 demand and volume Power Station load of [redacted] and monthly consumption of [redacted] (Schedule 11.1.1 July 31, 2013 2d, 1e filed as Attachment 1 to CAC/Centra 3a). All other inputs are to remain unchanged.

Please also provide a table that compares the cost allocation results for each customer class of the scenario to the 2019/20 Cost Allocation Study (updated). Please also file schedules 10.1.0, 10.1.1, and 11.1.0 (pages 1 and 2) that reflect the scenario.

RESPONSE:

The following table compares allocation results for the scenario proposed compared to 2019/20 proposed allocation results:

	Total	SGS	LGS	HVF	CO-OP	ML	SC	GS	INT	PG	FSP	ISP	FPO
2019/20 TY Proposed	325,784,091	134,975,474	57,156,395	13,751,619	19,972	2,281,973	[redacted]		1,650,683	[redacted]			66,034
2019/20 TY PS Load Changes	325,784,091	134,959,204	57,144,177	13,748,494	19,967	2,280,477			1,650,683				66,034
Inc/(Dec)	0	-16,270	-12,218	-3,125	-6	-1,496	-3,822	36,937	0	0	0	0	0

2d, 1e

Schedules 10.1.0, 10.1.1 and 11.1.0 that reflect the 2013/14 Power Station demand and volumes are attached to this response.

Schedule 10.1.0

Centra Gas Manitoba Inc.
2019/20 General Rates Application
Summary of Allocated Costs by Customer Class
2019/20 Test Year with PS Load Changes

Cost of Service Elements

SGS	Demand	Energy	Customer	Total
Cost of Gas	30,833,747	1,508,864	0	32,342,612
Other Income	-68,314	-452	-971,167	-1,039,932
Operating & Maintenance Expenses	7,475,067	49,422	36,957,610	44,482,099
Depreciation & Amortization	4,148,309	5,772,166	11,448,390	21,368,866
Capital & Other Taxes	3,729,789	481,214	9,358,475	13,569,478
Finance Expense	3,317,373	1,579,608	9,448,546	14,345,527
Corporate Allocation	1,842,707	877,427	5,248,400	7,968,534
Net Income	444,463	211,637	1,265,921	1,922,020
Total Cost of Service	51,723,142	10,479,887	72,756,175	134,959,204

LGS	Demand	Energy	Customer	Total
Cost of Gas	23,574,836	1,125,616	0	24,700,452
Other Income	-52,261	-345	-42,140	-94,745
Operating & Maintenance Expenses	5,718,503	37,698	4,337,539	10,093,740
Depreciation & Amortization	2,828,693	3,782,173	2,347,647	8,958,514
Capital & Other Taxes	2,853,094	336,850	1,483,665	4,673,609
Finance Expense	2,536,431	1,105,586	1,574,235	5,216,252
Corporate Allocation	1,408,916	614,122	874,443	2,897,480
Net Income	339,832	148,127	210,917	698,876
Total Cost of Service	39,208,044	7,149,828	10,786,305	57,144,177

HVF	Demand	Energy	Customer	Total
Cost of Gas	6,583,088	344,193	0	6,927,280
Other Income	-16,474	-103	-9,094	-25,672
Operating & Maintenance Expenses	1,802,682	11,245	960,145	2,774,072
Depreciation & Amortization	806,493	299,213	175,809	1,281,515
Capital & Other Taxes	870,915	60,941	81,436	1,013,292
Finance Expense	772,999	199,814	79,602	1,052,416
Corporate Allocation	429,379	110,991	44,217	584,587
Net Income	103,567	26,771	10,665	141,003
Total Cost of Service	11,352,650	1,053,064	1,342,780	13,748,494

Cooperative	Demand	Energy	Customer	Total
Cost of Gas	11,534	205	0	11,740
Other Income	-20	0	-20	-40
Operating & Maintenance Expenses	2,144	10	2,117	4,271
Depreciation & Amortization	690	1	428	1,119
Capital & Other Taxes	760	62	263	1,086
Finance Expense	631	204	225	1,060
Corporate Allocation	350	113	125	589
Net Income	85	27	30	142
Total Cost of Service	16,174	624	3,169	19,967

Main Line	Demand	Energy	Customer	Total
Cost of Gas	112,216	111,897	0	224,114
Other Income	-7,604	-4	-767	-8,376
Operating & Maintenance Expenses	832,055	444	80,931	913,430
Depreciation & Amortization	282,691	99,452	15,830	397,974
Capital & Other Taxes	289,085	6,578	7,772	303,435
Finance Expense	237,029	21,602	7,668	266,300
Corporate Allocation	131,663	11,999	4,260	147,922
Net Income	31,757	2,894	1,027	35,679
Total Cost of Service	1,908,892	254,864	116,721	2,280,477

Special Contract	Demand	Energy	Customer	Total	
Cost of Gas	[redacted]				1d
Other Income	-7,061	-1	-86	-7,148	
Operating & Maintenance Expenses	772,631	92	8,563	781,286	
Depreciation & Amortization	201,506	-8	8,098	209,596	
Capital & Other Taxes	521,217	13	6,709	527,939	
Finance Expense	426,723	37	6,151	432,911	
Corporate Allocation	237,033	21	3,417	240,470	
Net Income	57,173	5	824	58,002	
Total Cost of Service	[redacted]				1e

Power Station	Demand	Energy	Customer	Total
Cost of Gas	[redacted]			
Other Income	-667	-2	-194	-862
Operating & Maintenance Expenses	72,952	181	17,129	90,263
Depreciation & Amortization	-91,909	-15	43,729	-48,195
Capital & Other Taxes	23,959	25	37,805	61,789
Finance Expense	19,073	73	34,897	54,044
Corporate Allocation	10,595	41	19,384	30,020
Net Income	2,555	10	4,675	7,241
Total Cost of Service	[redacted]			

Interruptible	Demand	Energy	Customer	Total	
Cost of Gas	690,449	190,673	0	881,122	1d
Other Income	-1,578	-25	-1,629	-3,232	
Operating & Maintenance Expenses	172,679	2,739	171,800	347,217	
Depreciation & Amortization	61,704	166	34,224	96,093	
Capital & Other Taxes	86,467	10,639	16,482	113,588	
Finance Expense	76,609	34,848	16,333	127,790	
Corporate Allocation	42,554	19,357	9,073	70,984	
Net Income	10,264	4,669	2,188	17,121	
Total Cost of Service	1,139,147	263,065	248,471	1,650,683	1e

Primary Gas	Demand	Energy	Customer	Total
Cost of Gas	[redacted]			
Other Income				
Operating & Maintenance Expenses				
Depreciation & Amortization				
Capital & Other Taxes				
Finance Expense				
Corporate Allocation				
Net Income				
Total Cost of Service				

Supplemental Gas - Firm	Demand	Energy	Customer	Total	
Cost of Gas	[redacted]				1a
Other Income					
Operating & Maintenance Expenses					
Depreciation & Amortization					1e
Capital & Other Taxes					
Finance Expense					
Corporate Allocation					
Net Income					
Total Cost of Service					1e

Supplemental Gas - Interruptible	Demand	Energy	Customer	Total
Cost of Gas	[redacted]			
Other Income				
Operating & Maintenance Expenses				
Depreciation & Amortization				
Capital & Other Taxes				
Finance Expense				
Corporate Allocation				
Net Income				
Total Cost of Service				

Fixed Price Offering	Demand	Energy	Customer	Total	
Cost of Gas	0	44,879	0	44,879	1a
Other Income	0	-4	-171	-175	
Operating & Maintenance Expenses	0	419	18,750	19,168	
Depreciation & Amortization	0	33	1,486	1,520	
Capital & Other Taxes	0	19	304	323	1e
Finance Expense	0	43	146	189	
Corporate Allocation	0	24	81	105	
Net Income	0	6	20	25	
Total Cost of Service	0	45,418	20,616	66,034	1e

Unassigned	Demand	Energy	Customer	Total
Cost of Gas	0	0	0	0
Other Income	0	0	0	0
Operating & Maintenance Expenses	0	0	0	0
Depreciation & Amortization	0	0	0	0
Capital & Other Taxes	0	0	0	0
Finance Expense	0	0	0	0
Corporate Allocation	0	0	0	0
Net Income	0	0	0	0
Total Cost of Service	0	0	0	0

Total	Demand	Energy	Customer	Total
Cost of Gas	61,836,486	115,428,348	0	177,264,835
Other Income	-153,978	-10,480	-1,025,270	-1,189,728
Operating & Maintenance Expenses	16,848,713	1,146,704	42,554,583	60,550,000
Depreciation & Amortization	8,238,176	10,035,983	14,075,643	32,349,802
Capital & Other Taxes	8,375,286	943,305	10,992,913	20,311,504
Finance Expense	7,386,869	3,048,590	11,167,803	21,603,263
Corporate Allocation	4,103,197	1,693,405	6,203,398	12,000,000
Net Income	989,696	408,451	1,496,267	2,894,415
Total Cost of Service	107,624,446	132,694,307	85,465,338	325,784,091

Schedule 10.1.1

Centra Gas Manitoba Inc.
2019/20 General Rates Application
Unit Cost Component Summary
2019/20 Test Year with PS Load Changes

		ROR	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	Interrupt ble Supplemental ISP	Fixed Price Offering FRPGS	
1	REVENUE REQUIREMENTS		[redacted]													
2	Upstream Demand ($)															
3	Upstream Commodity ($)															
4	Upstream Customer ($)															
5	Upstream Total ($)															
6																1e
7	Downstream Demand ($)															
8	Downstream Commodity ($)															
9	Downstream Customer ($)															
10	Downstream Total ($)															
11																
12	Total (incl. gas costs)															
13																
14																
15	MONTHLY BILLING DETERMINANTS		[redacted]													
16	Upstream Demand (10^3m^3-day)															
17	Upstream Commodity (10^3m^3)															
18	Upstream Customer (customers)															
19																1d
20	Downstream Demand (10^3m^3-day)															
21	Downstream Commodity (10^3m^3)															
22	Downstream Customer (customers)															
23																
24	PERCENT IN DEMAND CHARGE				0.0%	0.0%	65.0%	100.0%	100.0%	100.0%	100.0%	65.0%	100.0%	100.0%	100.0%	100.0%	
25																
26	RESULTING UNIT CHARGES															
27	Upstream Demand ($/10^3m^3$-day)		454.726	0.000	0.000	295.043	470.592	422.296	0.000	0.000	149.285	0.000	0.000	0.000	0.000	
28	Upstream Commodity ($/10^3m^3$)		80.314	49.715	48.053	15.160	2.310	2.509	0.000	0.000	8.050	76.908	134.897	134.294	80.883	
29	Upstream Customer ($/customer)		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
30																
31	Downstream Demand ($/10^3m^3$-day)		242.362	0.000	0.000	183.310	167.137	233.588	136.518	2.585	88.795	0.000	0.000	0.000	0.000	
32	Downstream Commodity ($/10^3m^3$)		7.215	41.428	37.727	10.006	0.000	1.518	0.096	5.370	6.381	0.000	0.000	0.000	0.000	
33	Downstream Customer ($/customer)		24.749	21.707	108.165	1,008.093	264.053	1,080.749	2,806.285	6,559.405	1,035.295	0.000	0.000	0.000	0.000	

Centra Gas Manitoba Inc.
2019/20 General Rates Application
Bill Impact Comparison
2019/20 Test Year with PS Load Changes

BILLED VS. BILLED

				FEB 1/19 APPROVED BILLED RATES				NOV 1/19 PROPOSED BILLED RATES				BILL IMPACTS	
	Load Factor	Annual Use 10^3m^3	Mcf	Basic Chg	Demand	Commodity	Annual	Basic Chg	Demand	Commodity	Annual	$	%
Small General Service		1.00	35	$168	$0	$236	$404	$168	$0	$219	$387	($17)	-4.3%
		1.98	70	$168	$0	$468	$636	$168	$0	$434	$602	($34)	-5.4%
(Typical Residential Customer)		2.22	78	$168	$0	$523	$691	$168	$0	$485	$653	($38)	-5.5%
		2.80	99	$168	$0	$662	$830	$168	$0	$613	$781	($48)	-5.8%
		3.20	113	$168	$0	$755	$923	$168	$0	$700	$868	($55)	-6.0%
		3.68	130	$168	$0	$869	$1,037	$168	$0	$805	$973	($64)	-6.1%
		11.33	400	$168	$0	$2,673	$2,841	$168	$0	$2,478	$2,646	($195)	-6.9%
Large General Service		11.33	400	$924	$0	$2,072	$2,996	$924	$0	$2,069	$2,993	($3)	-0.1%
		59.49	2,100	$924	$0	$10,879	$11,803	$924	$0	$10,864	$11,788	($16)	-0.1%
		679.87	24,000	$924	$0	$124,335	$125,259	$924	$0	$124,156	$125,080	($179)	-0.1%
HVF (Sales Service)	25%	850	30,000	$13,420	$51,159	$103,976	$168,555	$12,097	$77,383	$78,798	$168,278	($276)	-0.2%
	40%	850	30,000	$13,420	$31,974	$103,976	$149,370	$12,097	$48,365	$78,798	$139,259	($10,111)	-6.8%
	40%	1,416	50,000	$13,420	$53,291	$173,293	$240,004	$12,097	$80,608	$131,330	$224,034	($15,969)	-6.7%
	40%	2,833	100,000	$13,420	$106,581	$346,586	$466,588	$12,097	$161,215	$262,659	$435,972	($30,616)	-6.6%
	40%	6,200	218,866	$13,420	$233,271	$758,560	$1,005,250	$12,097	$352,846	$574,872	$939,815	($65,435)	-6.5%
	40%	12,600	444,792	$13,420	$474,066	$1,541,589	$2,029,075	$12,097	$717,074	$1,168,287	$1,897,458	($131,616)	-6.5%
	75%	685	24,181	$13,420	$13,745	$83,809	$110,974	$12,097	$20,791	$63,514	$96,402	($14,571)	-13.1%
	75%	850	30,000	$13,420	$17,053	$103,976	$134,449	$12,097	$25,794	$78,798	$116,689	($17,759)	-13.2%
	75%	1,416	50,000	$13,420	$28,422	$173,293	$215,135	$12,097	$42,991	$131,330	$186,417	($28,717)	-13.3%
	75%	2,833	100,000	$13,420	$56,843	$346,586	$416,850	$12,097	$85,982	$262,659	$360,738	($56,112)	-13.5%
	75%	6,200	218,866	$13,420	$124,411	$758,560	$896,390	$12,097	$188,184	$574,872	$775,153	($121,237)	-13.5%
	75%	12,600	444,792	$13,420	$252,835	$1,541,589	$1,807,844	$12,097	$382,439	$1,168,287	$1,562,824	($245,020)	-13.6%
HVF (T-Service)	40%	2,600	91,783	$13,420	$32,128	$18,923	$64,470	$12,097	$39,353	$25,765	$77,215	$12,745	19.8%
	40%	11,000	388,311	$13,420	$135,925	$80,057	$229,402	$12,097	$166,494	$109,005	$287,596	$58,194	25.4%
	40%	17,600	621,297	$13,420	$217,481	$128,091	$358,991	$12,097	$266,390	$174,408	$452,895	$93,904	26.2%
	75%	2,600	91,783	$13,420	$17,135	$18,923	$49,477	$12,097	$20,988	$25,765	$58,850	$9,373	18.9%
	75%	11,000	388,311	$13,420	$72,494	$80,057	$165,970	$12,097	$88,797	$109,005	$209,899	$43,929	26.5%
	75%	17,600	621,297	$13,420	$115,990	$128,091	$257,500	$12,097	$142,075	$174,408	$328,580	$71,079	27.6%
Cooperative	35%	250	8,825	$3,289	$14,042	$25,312	$42,643	$3,169	$14,975	$24,100	$42,244	($399)	-0.9%
	35%	350	12,355	$3,289	$19,659	$35,437	$58,385	$3,169	$20,965	$33,740	$57,874	($511)	-0.9%
	35%	500	17,650	$3,289	$28,084	$50,625	$81,998	$3,169	$29,951	$48,200	$81,319	($679)	-0.8%
MLC (Sales Service)	40%	2,833	100,000	$28,240	$163,725	$290,867	$482,832	$12,969	$96,838	$276,715	$386,522	($96,310)	-19.9%
	40%	14,164	500,000	$28,240	$818,626	$1,454,334	$2,301,200	$12,969	$484,190	$1,383,573	$1,880,733	($420,467)	-18.3%
	40%	28,328	1,000,000	$28,240	$1,637,252	$2,908,668	$4,574,160	$12,969	$968,380	$2,767,147	$3,748,496	($825,664)	-18.1%
	75%	2,833	100,000	$28,240	$87,320	$290,867	$406,427	$12,969	$51,647	$276,715	$341,331	($65,096)	-16.0%
	75%	14,164	500,000	$28,240	$436,601	$1,454,334	$1,919,174	$12,969	$258,235	$1,383,573	$1,654,777	($264,397)	-13.8%
	75%	28,328	1,000,000	$28,240	$873,201	$2,908,668	$3,810,109	$12,969	$516,470	$2,767,147	$3,296,585	($513,523)	-13.5%
	75%	41,000	1,447,339	$28,240	$1,263,818	$4,209,829	$5,501,888	$12,969	$747,507	$4,005,001	$4,765,476	($736,411)	-13.4%
MLC (T- Service)	40%	14,000	494,213	$28,240	$181,393	$17,293	$226,926	$12,969	$269,262	$9,891	$292,122	$65,196	28.7%
	40%	18,000	635,417	$28,240	$233,219	$22,234	$283,693	$12,969	$346,194	$12,717	$371,880	$88,187	31.1%
	40%	44,000	1,553,242	$28,240	$570,091	$54,349	$652,680	$12,969	$846,252	$31,086	$890,307	$237,626	36.4%
	75%	14,000	494,213	$28,240	$96,743	$17,293	$142,276	$12,969	$143,606	$9,891	$166,466	$24,191	17.0%
	75%	18,000	635,417	$28,240	$124,384	$22,234	$174,857	$12,969	$184,637	$12,717	$210,323	$35,466	20.3%
	75%	44,000	1,553,242	$28,240	$304,049	$54,349	$386,638	$12,969	$451,334	$31,086	$495,389	$108,752	28.1%
Special Contract	[redacted]												
Power Stations													
Interruptible Sales	25%	850	30,000	$12,513	$24,602	$100,479	$137,593	$12,423	$40,283	$79,761	$132,468	($5,125)	-3.7%
	40%	2,833	100,000	$12,513	$51,254	$334,929	$398,696	$12,423	$83,924	$265,870	$362,217	($36,478)	-9.1%
	40%	14,164	500,000	$12,513	$256,268	$1,674,647	$1,943,427	$12,423	$419,620	$1,329,349	$1,761,392	($182,035)	-9.4%
	75%	850	30,000	$12,513	$8,201	$100,479	$121,192	$12,423	$13,428	$79,761	$105,612	($15,580)	-12.9%
	75%	2,833	100,000	$12,513	$27,335	$334,929	$374,777	$12,423	$44,759	$265,870	$323,053	($51,725)	-13.8%
	75%	14,164	500,000	$12,513	$136,676	$1,674,647	$1,823,836	$12,423	$223,797	$1,329,349	$1,565,570	($258,266)	-14.2%

2d

Centra Gas Manitoba Inc.
2019/20 General Rates Application
Bill Impact Comparison
2019/20 Test Year with PS Load Changes

BASE VS. BASE

	Load Factor	Annual Use 10^3m^3	Annual Use Mcf	FEB 1/19 APPROVED BASE RATES Basic Chg	Demand	Commodity	Annual	NOV 1/19 PROPOSED BASE RATES Basic Chg	Demand	Commodity	Annual	BASE IMPACTS $	%
Small General Service		1.00	35	$168	$0	$227	$395	$168	$0	$214	$382	($13)	-3.3%
		1.98	70	$168	$0	$450	$618	$168	$0	$424	$592	($26)	-4.1%
(Typical Residential Customer)		2.22	78	$168	$0	$504	$672	$168	$0	$475	$643	($29)	-4.3%
		2.80	99	$168	$0	$637	$805	$168	$0	$601	$769	($36)	-4.5%
		3.20	113	$168	$0	$727	$895	$168	$0	$686	$854	($41)	-4.6%
		3.68	130	$168	$0	$837	$1,005	$168	$0	$789	$957	($48)	-4.7%
		11.33	400	$168	$0	$2,575	$2,743	$168	$0	$2,428	$2,596	($146)	-5.3%
Large General Service		11.33	400	$924	$0	$1,974	$2,898	$924	$0	$2,004	$2,928	$31	1.1%
		59.49	2,100	$924	$0	$10,362	$11,286	$924	$0	$10,524	$11,448	$162	1.4%
		679.87	24,000	$924	$0	$118,420	$119,344	$924	$0	$120,269	$121,193	$1,849	1.5%
HVF (Sales Service)	25%	850	30,000	$13,420	$51,159	$96,626	$161,205	$12,097	$53,454	$93,907	$159,458	($1,746)	-1.1%
	40%	850	30,001	$13,420	$31,976	$96,629	$142,024	$12,097	$33,410	$93,910	$139,417	($2,607)	-1.8%
	40%	1,416	50,000	$13,420	$53,291	$161,043	$227,753	$12,097	$55,682	$156,511	$224,290	($3,463)	-1.5%
	40%	2,833	100,000	$13,420	$106,581	$322,086	$442,087	$12,097	$111,363	$313,023	$436,483	($5,604)	-1.3%
	40%	6,200	218,866	$13,420	$233,271	$704,936	$951,626	$12,097	$243,736	$685,100	$940,934	($10,693)	-1.1%
	40%	12,600	444,792	$13,420	$474,066	$1,432,611	$1,920,097	$12,097	$495,335	$1,392,300	$1,899,732	($20,365)	-1.1%
	75%	685	24,181	$13,420	$13,745	$77,884	$105,049	$12,097	$14,362	$75,693	$102,152	($2,897)	-2.8%
	75%	850	30,000	$13,420	$17,053	$96,626	$127,098	$12,097	$17,818	$93,907	$123,822	($3,276)	-2.6%
	75%	1,416	50,000	$13,420	$28,422	$161,043	$202,884	$12,097	$29,697	$156,511	$198,305	($4,579)	-2.3%
	75%	2,833	100,000	$13,420	$56,843	$322,086	$392,349	$12,097	$59,394	$313,023	$384,513	($7,835)	-2.0%
	75%	6,200	218,866	$13,420	$124,411	$704,936	$842,767	$12,097	$129,993	$685,100	$827,190	($15,577)	-1.8%
	75%	12,600	444,792	$13,420	$252,835	$1,432,611	$1,698,866	$12,097	$264,179	$1,392,300	$1,668,576	($30,290)	-1.8%
HVF (T-Service)	40%	2,600	91,783	$13,420	$32,128	$18,923	$64,470	$12,097	$39,171	$26,000	$77,268	$12,798	19.9%
	40%	11,000	388,311	$13,420	$135,925	$80,057	$229,402	$12,097	$165,723	$110,000	$287,820	$58,418	25.5%
	40%	17,600	621,297	$13,420	$217,481	$128,091	$358,991	$12,097	$265,157	$176,000	$453,254	$94,263	26.3%
	75%	2,600	91,783	$13,420	$17,135	$18,923	$49,477	$12,097	$20,891	$26,000	$58,988	$9,511	19.2%
	75%	11,000	388,311	$13,420	$72,494	$80,057	$165,970	$12,097	$88,386	$110,000	$210,483	$44,513	26.8%
	75%	17,600	621,297	$13,420	$115,990	$128,091	$257,500	$12,097	$141,417	$176,000	$329,514	$72,014	28.0%
Cooperative	35%	250	8,825	$3,289	$14,042	$23,150	$40,481	$3,169	$14,975	$21,925	$40,069	($412)	-1.0%
	35%	350	12,355	$3,289	$19,659	$32,410	$55,358	$3,169	$20,965	$30,695	$54,829	($529)	-1.0%
	35%	500	17,650	$3,289	$28,084	$46,300	$77,673	$3,169	$29,951	$43,850	$76,969	($704)	-0.9%
MLC (Sales Service)	40%	2,833	100,000	$28,240	$163,725	$266,366	$458,331	$12,969	$152,714	$252,968	$418,651	($39,680)	-8.7%
	40%	14,164	500,000	$28,240	$818,626	$1,331,830	$2,178,696	$12,969	$763,571	$1,264,838	$2,041,378	($137,318)	-6.3%
	40%	28,328	1,000,000	$28,240	$1,637,252	$2,663,660	$4,329,152	$12,969	$1,527,142	$2,529,676	$4,069,787	($259,365)	-6.0%
	75%	2,833	100,000	$28,240	$87,320	$266,366	$381,926	$12,969	$81,448	$252,968	$347,384	($34,542)	-9.0%
	75%	14,164	500,000	$28,240	$436,601	$1,331,830	$1,796,671	$12,969	$407,238	$1,264,838	$1,685,045	($111,626)	-6.2%
	75%	28,328	1,000,000	$28,240	$873,201	$2,663,660	$3,565,101	$12,969	$814,476	$2,529,676	$3,357,121	($207,980)	-5.8%
	75%	41,000	1,447,339	$28,240	$1,263,818	$3,855,220	$5,147,279	$12,969	$1,178,823	$3,661,300	$4,853,092	($294,187)	-5.7%
MLC (T- Service)	40%	14,000	494,213	$28,240	$181,393	$17,293	$226,926	$12,969	$268,800	$21,000	$302,769	$75,843	33.4%
	40%	18,000	635,417	$28,240	$233,219	$22,234	$283,693	$12,969	$345,600	$27,000	$385,569	$101,876	35.9%
	40%	44,000	1,553,242	$28,240	$570,091	$54,349	$652,680	$12,969	$844,800	$66,000	$923,769	$271,089	41.5%
	75%	14,000	494,213	$28,240	$96,743	$17,293	$142,276	$12,969	$143,360	$21,000	$177,329	$35,053	24.6%
	75%	18,000	635,417	$28,240	$124,384	$22,234	$174,857	$12,969	$184,320	$27,000	$224,289	$49,432	28.3%
	75%	44,000	1,553,242	$28,240	$304,049	$54,349	$386,638	$12,969	$450,560	$66,000	$529,529	$142,891	37.0%
Special Contract	[redacted]												
Power Stations													
Interruptible Sales	25%	850	30,000	$12,513	$24,602	$93,682	$130,796	$12,423	$26,610	$87,873	$126,906	($3,890)	-3.0%
	40%	2,833	100,000	$12,513	$51,254	$312,273	$376,039	$12,423	$55,437	$292,910	$360,771	($15,268)	-4.1%
	40%	14,164	500,000	$12,513	$256,268	$1,561,364	$1,830,144	$12,423	$277,186	$1,464,549	$1,754,159	($75,986)	-4.2%
	75%	850	30,000	$12,513	$8,201	$93,682	$114,395	$12,423	$8,870	$87,873	$109,166	($5,229)	-4.6%
	75%	2,833	100,000	$12,513	$27,335	$312,273	$352,121	$12,423	$29,567	$292,910	$334,900	($17,221)	-4.9%
	75%	14,164	500,000	$12,513	$136,676	$1,561,364	$1,710,553	$12,423	$147,833	$1,464,549	$1,624,805	($85,748)	-5.0%

2d

REFERENCE:

Responses to CAC/Centra I-32, PUB/Centra I-141 (b) and PUB I-153 (a)

PREAMBLE TO IR (IF ANY):

Centra states in response to CAC/Centra 32 (a) that the incremental impact to overdue accounts and bad debt expense is expected to be directly proportional to the increase in energy charges as a result of the Federal Carbon Tax.

QUESTION:

a) How is Centra applying the Federal Carbon Tax? For example, is it being applied to all metered consumption?
   i. How is Centra applying the Federal Carbon Tax to T-Service Customers?
   ii. How is Centra applying the Federal Carbon Tax to WTS customers? For example, is Centra applying the Federal Carbon Tax on all metered volumes which would include those supplied by the Natural Gas Supplier/Marketer?
   iii. Please explain why Centra does not appear to be applying the Federal Carbon Tax to the Special Contract Class.

b) What are the implications of the current rate structures on the application of the Federal Carbon Tax, if any?

RESPONSE:

a)
   i. Regardless of how a customer procures their gas supply, as the registered distributor Centra applies the Federal Carbon Charge to all metered consumption, except in cases where an account has received a certified exemption from Canada Revenue Agency. The Federal Carbon Charge is applied to T-Service customers unless an exemption certificate is received stating they are participating in the Output Based Pricing System ("OBPS").

ii. The Federal Carbon Charge is applied to Western Transportation Service customers unless an exemption certificate is received.

[redacted] 2b

b) There are no implications to the current rate structure due to the implementation of the Federal Carbon Charge.

REFERENCE:

Responses to CAC/Centra I-32, PUB/Centra I-141 (b) and PUB I-153 (a)

PREAMBLE TO IR (IF ANY):

Centra states in response to CAC/Centra 32 (a) that the incremental impact to overdue accounts and bad debt expense is expected to be directly proportional to the increase in energy charges as a result of the Federal Carbon Tax.

QUESTION:

c) Please describe how Centra currently allocates bad debt expense to each customer class.
d) Please provide a sensitivity analysis of bad debt expense to each customer class based on the 2019/20 Cost Allocation Study (update) that also incorporates the proportional increase in bad debt anticipated with the imposition of the 3.91 cents per cubic meter Federal Carbon Tax, as well as at the 9.78 cents per cubic meter. Provide the results compared to those flowing from the 2019/20 Cost Allocation Study.

RESPONSE:

c) Bad debt expense is included with other collections costs in the "Billing and Collections" category of Operating and Administrative expenses. It is allocated based on the number of customers in each class, weighted by the effort required to bill and collect payment in each class. For example, the LGS customer class comprises 3% of customers, however represents 20% of the effort to bill and collect payments.

d) Centra has not included an increase in bad debt expense in the 2019/20 Approved Budget for the 3.91 cent per cubic meter or the 9.78 cent per cubic meter Federal Carbon Charge as there is no history to base an increase on. If customers choose to use their Federal Climate Action Incentive Credit to pay their utility bill, bad debt expense should not change at all. Further, it should be noted that as customer bills increase, bad debt expense may not increase in the same proportion as the increase may cause customers who were previously able to pay to become unable to pay.

That said, simply extrapolating the current forecasted bad debt expense to reflect the increase in revenue would result in an additional expense of approximately $0.2 million with a Federal Carbon Charge of 3.91 cents and approximately $0.5 million with a Federal Carbon Charge of 9.78 cents. Centra has prepared the sensitivity analysis using this estimated incremental bad debt expense. The following tables provide the allocation of incremental bad debt to each customer class.

Table 1: Allocation of estimated $200,000 increase in bad debt anticipated with 3.91 cents per cubic meter to each customer class:

		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
2019/20 GRA	Billing&Collection	7,705,172	6,769,871	780,447	119,366	1,075	9,678	1,075	2,151	21,507
CAC/Centra II -140 d)	Billing&Collection	7,905,172	6,941,933	803,335	123,259	1,110	9,994	1,110	2,221	22,209
additional 200K Bad Debt allocation		200,000	172,062	22,888	3,893	35	316	35	70	701

Table 2: Allocation of estimated $500,000 increase in bad debt anticipated with 9.78 cents per cubic meter to each customer class:

		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
2019/20 GRA	Billing&Collection	7,705,172	6,769,871	780,447	119,366	1,075	9,678	1,075	2,151	21,507
CAC/Centra II -140 d)	Billing&Collection	8,205,172	7,200,027	837,666	129,098	1,163	10,467	1,163	2,326	23,261
additional 500K Bad Debt allocation		500,000	430,156	57,219	9,732	88	789	88	175	1,753

REFERENCE:

Responses to CAC/Centra I-32, PUB/Centra I-141 (b) and PUB I-153 (a)

PREAMBLE TO IR (IF ANY):

Centra states in response to CAC/Centra 32 (a) that the incremental impact to overdue accounts and bad debt expense is expected to be directly proportional to the increase in energy charges as a result of the Federal Carbon Tax.

QUESTION:

e) Please provide a breakdown of the incremental late payment revenue anticipated to be generated by Centra on account of the Federal Carbon Tax at both the current 1.25% and proposed 1.5% late payment charges:
   i. Assuming the current 3.91 cents per cubic meter.
   ii. Assuming 9.78 cents per cubic meter.

RESPONSE:

e) As discussed in the CAC/CENTRA II-140d, Centra has not included a forecast of incremental bad debt expense or incremental late payment revenue associated with the federal carbon charge in its 2019/20 Approved Budget. The incremental late payment revenue resulting from the Federal Carbon Charge is estimated as follows:
   i. Assuming the current 3.91 cents per cubic meter and 1.25% for late payment charge, this equals an incremental $130,000 in late payment revenue. At the proposed 1.50%, the incremental late payment charges are estimated at $156,000.
   ii. Assuming 9.78 cents per cubic meter and 1.25% for late payment charges this equals an incremental $325,000 in late payment revenue. At the proposed 1.50%, the incremental late payment charges are estimated at $390,000.

REFERENCE:

Response to CAC/Centra I - 34

QUESTION:

Please provide a sensitivity analysis based on the 2019/20 Cost Allocation Study (updated) that instead functionalizes balancing fees as transmission, classifies as demand, and allocates balancing fees based on peak and average (consistent with the transmission peak and average allocator, PAVG-T, including T-Service customers):

i. Assuming the current forecast of balancing fees of $250,000 (Schedules 8.9.3 and 10.1.5).
ii. Assuming a forecast of balancing fees of $900,000 (per PUB/Centra 147 b).

Please provide a table that compares the cost allocation results for each customer class of the scenarios to the 2019/20 Cost Allocation Study (updated). Please also file Schedules 10.1.0, 10.1.1, 10.1.2, 10.1.3, 11.1.0 (pages 1 and 2) that reflect these scenarios.

RESPONSE:

i. The requested sensitivity analysis is provided below. However, it is important to recognize that simply altering the cost allocation of the balancing fees that Centra incurs from TCPL would not address the important reasons to implement Centra's proposed balancing fee structure as discussed in the response to PUB/CENTRA II-58c. Further, Centra's balancing fee proposal would provide direct line of sight for T-Service customers as to the cost of inattention to account imbalances, and would appropriately result in those customers who attend to their imbalances paying less relatively speaking than those who do not. The alternative approach of burying this information in rates would not align with the important reasons for implementing a balancing fee structure.

   Please see the attachment to this response. In addition the below table compares the cost allocation results for each customer class of the requested scenario (i) to the 2019/20 Cost Allocation Study (updated).

Comparing the cost allocation of Load Balancing Fees to customer classes

				Balance to be Allocated	Allocation Factor	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
2019/20 GRA	Load balancing functionalized to Pipeline	Classified as Demand	Allocated based on PAVG	250,000	PAVG	[redacted]							
CAC-Centra II 141 i)	Load balancing functionalized to Transmission	Classified as Demand	Allocated based on PAVG-T	250,000	PAVG-T								
Change in allocation to customer classes						-27,044	-20,570	-3,655	-10	13,632	36,964	1,112	-429

1e

ii. To clarify, the information provided in the table in PUB/CENTRA I-147b is not a forecast of balancing fees. As described in that response, these fees are pro-forma outcomes, were not charged to customers, and do not reflect what Centra expects would happen as a result of balancing fee implementation. Rather, it is likely and expected that T-Service customers will respond to the financial incentive inherent in balancing fees by improving their balancing performance. Additionally, T-Service balancing fees would represent revenue that would offset the cost of balancing fees incurred from TCPL, as well as the other direct and indirect costs described in PUB/CENTRA II-58d and IGU/CENTRA II-7c. Given these clarifications, Centra has not performed this requested sensitivity analysis.

Schedule 10.1.0

Centra Gas Manitoba Inc.
2019/20 General Rates Application
Summary of Allocated Costs by Customer Class
2019/20 Test Year

Cost of Service Elements

	SGS Demand	SGS Energy	SGS Customer	SGS Total	LGS Demand	LGS Energy	LGS Customer	LGS Total
Cost of Gas	30,806,896	1,508,864	0	32,315,760	23,554,411	1,125,616	0	24,680,027
Other Income	-68,358	-452	-971,167	-1,039,977	-52,294	-345	-42,140	-94,779
Operating & Maintenance Expenses	7,479,951	49,422	36,957,610	44,486,984	5,722,170	37,698	4,337,539	10,097,407
Depreciation & Amortization	4,151,318	5,772,166	11,448,390	21,371,874	2,830,952	3,782,173	2,347,647	8,960,773
Capital & Other Taxes	3,733,203	481,214	9,358,475	13,572,892	2,855,657	336,850	1,483,665	4,676,173
Finance Expense	3,320,156	1,579,608	9,448,546	14,348,311	2,538,521	1,105,586	1,574,235	5,218,342
Corporate Allocation	1,844,253	877,427	5,248,400	7,970,080	1,410,076	614,122	874,443	2,898,641
Net Income	444,836	211,637	1,265,921	1,922,393	340,112	148,127	210,917	699,156
Total Cost of Service	51,712,255	10,479,887	72,756,175	134,948,316	39,199,606	7,149,828	10,786,305	57,135,739

	HVF Demand	HVF Energy	HVF Customer	HVF Total	Cooperative Demand	Cooperative Energy	Cooperative Customer	Cooperative Total
Cost of Gas	6,579,470	344,193	0	6,923,662	11,525	205	0	11,730
Other Income	-16,483	-103	-9,094	-25,680	-20	0	-20	-40
Operating & Maintenance Expenses	1,803,624	11,245	960,145	2,775,014	2,146	10	2,117	4,273
Depreciation & Amortization	807,071	299,213	175,809	1,282,093	691	1	428	1,120
Capital & Other Taxes	871,571	60,941	81,436	1,013,948	761	62	263	1,087
Finance Expense	773,535	199,814	79,602	1,052,951	632	204	225	1,061
Corporate Allocation	429,677	110,991	44,217	584,885	351	113	125	589
Net Income	103,639	26,771	10,665	141,075	85	27	30	142
Total Cost of Service	11,352,103	1,053,064	1,342,780	13,747,948	16,170	624	3,169	19,962

	Main Line Demand	Main Line Energy	Main Line Customer	Main Line Total	Special Contract Demand	Special Contract Energy	Special Contract Customer	Special Contract Total	
Cost of Gas	125,866	111,897	0	237,763	[redacted]				1d
Other Income	-7,608	-4	-767	-8,380	-7,072	-1	-86	-7,159	
Operating & Maintenance Expenses	832,540	444	80,931	913,915	773,875	92	8,563	782,529	
Depreciation & Amortization	282,970	99,452	15,830	398,253	202,220	-8	8,098	210,311	
Capital & Other Taxes	289,403	6,578	7,772	303,753	522,032	13	6,709	528,754	
Finance Expense	237,300	21,602	7,668	266,570	427,416	37	6,151	433,604	
Corporate Allocation	131,813	11,999	4,260	148,072	237,418	21	3,417	240,855	
Net Income	31,794	2,894	1,027	35,715	57,265	5	824	58,094	
Total Cost of Service	1,924,078	254,864	116,721	2,295,662	[redacted]				1e

	Power Station Demand	Power Station Energy	Power Station Customer	Power Station Total	Interruptible Demand	Interruptible Energy	Interruptible Customer	Interruptible Total	
Cost of Gas	[redacted]				690,020	190,673	0	880,693	1d
Other Income	-564	-2	-194	-760	-1,578	-25	-1,629	-3,232	
Operating & Maintenance Expenses	61,730	181	17,129	79,040	172,678	2,739	171,800	347,216	
Depreciation & Amortization	-98,749	-15	43,729	-55,035	61,704	166	34,224	96,093	
Capital & Other Taxes	16,191	25	37,805	54,021	86,467	10,639	16,482	113,588	
Finance Expense	12,700	73	34,897	47,670	76,608	34,848	16,333	127,789	
Corporate Allocation	7,055	41	19,384	26,480	42,554	19,357	9,073	70,983	
Net Income	1,702	10	4,675	6,387	10,264	4,669	2,188	17,121	
Total Cost of Service	[redacted]				1,138,716	263,065	248,471	1,650,252	1e

	Primary Gas Demand	Primary Gas Energy	Primary Gas Customer	Primary Gas Total	Supplemental Gas - Firm Demand	Supplemental Gas - Firm Energy	Supplemental Gas - Firm Customer	Supplemental Gas - Firm Total	
Cost of Gas	[redacted]				[redacted]				1a
Other Income									
Operating & Maintenance Expenses									1e
Depreciation & Amortization									
Capital & Other Taxes									
Finance Expense									
Corporate Allocation									
Net Income									
Total Cost of Service									1e

	Supplemental Gas - Interruptible Demand	Supplemental Gas - Interruptible Energy	Supplemental Gas - Interruptible Customer	Supplemental Gas - Interruptible Total	Fixed Price Offering Demand	Fixed Price Offering Energy	Fixed Price Offering Customer	Fixed Price Offering Total	
Cost of Gas	[redacted]				0	44,879	0	44,879	1a
Other Income					0	-4	-171	-175	
Operating & Maintenance Expenses					0	419	18,750	19,168	
Depreciation & Amortization					0	33	1,486	1,520	
Capital & Other Taxes					0	19	304	323	1e
Finance Expense					0	43	146	189	
Corporate Allocation					0	24	81	105	
Net Income					0	6	20	25	
Total Cost of Service					0	45,418	20,616	66,034	1e

	Unassigned Demand	Unassigned Energy	Unassigned Customer	Unassigned Total	Total Demand	Total Energy	Total Customer	Total Total
Cost of Gas	0	0	0	0	61,836,486	115,428,348	0	177,264,835
Other Income	0	0	0	0	-153,978	-10,480	-1,025,270	-1,189,728
Operating & Maintenance Expenses	0	0	0	0	16,848,713	1,146,704	42,554,583	60,550,000
Depreciation & Amortization	0	0	0	0	8,238,176	10,035,983	14,075,643	32,349,802
Capital & Other Taxes	0	0	0	0	8,375,286	943,305	10,992,913	20,311,504
Finance Expense	0	0	0	0	7,386,869	3,048,590	11,167,803	21,603,263
Corporate Allocation	0	0	0	0	4,103,197	1,693,405	6,203,398	12,000,000
Net Income	0	0	0	0	989,696	408,451	1,496,267	2,894,415
Total Cost of Service	0	0	0	0	107,624,446	132,694,307	85,465,338	325,784,091

Centra Gas Manitoba Inc.
2019/20 General Rates Application
Unit Cost Component Summary
2019/20 Test Year

Schedule 10.1.1

		ROR	System Total	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Fixed Price Offering FRPGS	
1	REVENUE REQUIREMENTS															
2	Upstream Demand ($)		[redacted]													
3	Upstream Commodity ($)															
4	Upstream Customer ($)															
5	Upstream Total ($)															
6																
7	Downstream Demand ($)															1e
8	Downstream Commodity ($)															
9	Downstream Customer ($)															
10	Downstream Total ($)															
11																
12	Total (incl. gas costs)															
13																
14																
15	MONTHLY BILLING DETERMINANTS															
16	Upstream Demand (10^3m^3-day)		[redacted]													
17	Upstream Commodity (10^3m^3)															
18	Upstream Customer (customers)															
19																
20	Downstream Demand (10^3m^3-day)															1d
21	Downstream Commodity (10^3m^3)															
22	Downstream Customer (customers)															
23																
24	PERCENT IN DEMAND CHARGE			0.0%	0.0%	65.0%	100.0%	100.0%	100.0%	100.0%	65.0%	100.0%	100.0%	100.0%	100.0%	
25																
26	RESULTING UNIT CHARGES															
27	Upstream Demand ($/$10^3m^3$-day)		452.941	0.000	0.000	293.885	468.744	420.638	0.000	0.000	148.699	0.000	0.000	0.000	0.000	
28	Upstream Commodity ($/$10^3m^3$)		80.314	49.531	47.875	15.111	2.310	2.509	0.000	0.000	8.029	76.908	134.897	134.294	80.883	
29	Upstream Customer ($/customer)		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
30																
31	Downstream Demand ($/$10^3m^3$-day)		249.981	0.000	0.000	184.367	168.821	235.607	139.015	0.203	89.291	0.000	0.000	0.000	0.000	
32	Downstream Commodity ($/$10^3m^3$)		7.252	41.596	37.889	10.049	0.000	1.518	0.096	18.305	6.400	0.000	0.000	0.000	0.000	
33	Downstream Customer ($/customer)		24.749	21.707	108.165	1,008.093	264.053	1,080.749	2,806.285	6,559.405	1,035.295	0.000	0.000	0.000	0.000	

Centra Gas Manitoba Inc.
2019/20 General Rates Application
Comparison of Gas Costs vs. Non-Gas Costs
2019/20 Test Year

Schedule 10.1.2

	Gas Costs vs. Non-Gas Costs	ROR	System Total	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Fixed Price Offering FRPGS	
1	REVENUE REQUIREMENTS															
2	Upstream Demand ($)	Upstream Demand ($)														
3	Gas Costs	Gas Costs	61,388,042	30,631,640	23,420,222	6,538,264	11,459	100,678	0	0	685,780	0	0	0	0	
4	Non-gas Costs	Non-gas Costs	2,300,890	1,148,107	877,815	245,061	429	3,774	0	0	25,704	0	0	0	0	
5	Total	Total	63,688,932	31,779,747	24,298,037	6,783,325	11,888	104,451	0	0	711,484	0	0	0	0	
6			0	0	0	0	0	0	0	0	0	0	0	0	0	
7	Upstream Commodity ($)	Upstream Commodity ($)														
8	Gas Costs	Gas Costs	113,950,265	941,280	719,143	214,121	205	3,997	0	0	47,299	[redacted]			44,879	
9	Non-gas Costs	Non-gas Costs	3,663,952	1,082,974	856,047	300,482	419	6,588	0	0	71,841				539	1a,1e
10	Total	Total	117,614,218	2,024,254	1,575,190	514,603	624	10,585	0	0	119,139				45,418	
11			0	0	0	0	0	0	0	0	0	0	0	0	0	
12	Upstream Customer ($)	Upstream Customer ($)														
13	Gas Costs	Gas Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	
14	Non-gas Costs	Non-gas Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	
15	Total	Total	0	0	0	0	0	0	0	0	0	0	0	0	0	
16																
17	Upstream Total ($)	Upstream Total ($)														
18	Total Gas Costs	Total Gas Costs	175,338,308	31,572,920	24,139,365	6,752,385	11,664	104,675	0	0	733,079	[redacted]			44,879	
19	Total Non-gas Costs	Total Non-gas Costs	5,964,842	2,231,081	1,733,862	545,543	848	10,361	0	0	97,544				539	1e
20	Total Upstream Costs	Total Upstream Costs	181,303,150	33,804,001	25,873,227	7,297,928	12,512	115,036	0	0	830,623				45,418	
21			0	0	0	0	0	0	0	0	0	0	0	0	0	
22	Downstream Demand ($)	Downstream Demand ($)														
23	Gas Costs	Gas Costs	448,444	175,256	134,189	41,206	66	25,188	[redacted]		4,240	0	0	0	0	
24	Non-gas Costs	Non-gas Costs	43,487,069	19,757,252	14,767,380	4,527,573	4,216	1,794,438	2,213,154	64	422,992	0	0	0	0	2d,1e
25	Total	Total	43,935,513	19,932,508	14,901,569	4,568,779	4,282	1,819,626	[redacted]		427,232	0	0	0	0	
26																
27	Downstream Commodity ($)	Downstream Commodity ($)														
28	Gas Costs	Gas Costs	1,478,083	567,584	406,473	130,071	0	107,900	[redacted]		143,374	0	0	0	0	
29	Non-gas Costs	Non-gas Costs	13,602,006	7,888,049	5,168,165	408,390	0	136,378	159	313	552	0	0	0	0	2d,1e
30	Total	Total	15,080,090	8,455,633	5,574,638	538,461	0	244,278	[redacted]		143,926	0	0	0	0	
31																
32	Downstream Customer ($)	Downstream Customer ($)														
33	Gas Costs	Gas Costs	0	0	0	0	0	0	[redacted]		0	0	0	0	0	
34	Non-gas Costs	Non-gas Costs	85,465,338	72,756,175	10,786,305	1,342,780	3,169	116,721	33,675	157,426	248,471	0	0	0	20,616	2d,1e
35	Total	Total	85,465,338	72,756,175	10,786,305	1,342,780	3,169	116,721	[redacted]		248,471	0	0	0	20,616	
36																
37	Downstream Total ($)	Downstream Total ($)														
38	Total Gas Costs	Total Gas Costs	1,926,527	742,840	540,662	171,277	66	133,088	[redacted]		147,614	0	0	0	0	
39	Total Non-gas Costs	Total Non-gas Costs	142,554,413	100,401,476	30,721,850	6,278,743	7,385	2,047,537	2,246,988	157,803	672,015	0	0	0	20,616	2d,1e
40	Total Downstream Costs	Total Downstream Costs	144,480,941	101,144,315	31,262,512	6,450,020	7,450	2,180,626	[redacted]		819,629	0	0	0	20,616	
41																
42	Grand Total Gas Costs	Grand Total Gas Costs	177,264,835	32,315,760	24,680,027	6,923,662	11,730	237,763	[redacted]		880,693	[redacted]			44,879	
43	Grand Total Non-gas Costs	Grand Total Non-gas Costs	148,519,256	102,632,556	32,455,712	6,824,286	8,233	2,057,899	2,246,988	157,803	769,559				21,155	2d,1e
44	Grand Total	Grand Total	325,784,091	134,948,316	57,135,739	13,747,948	19,962	2,295,662	[redacted]		1,650,252				66,034	
45																
46																

47 Calculation of the Primary Gas Overhead Rate: [redacted] line 9, PG column)
48 10^3m^3 (Schedule 10.1.1, line 17, PG column)
49 0.91 10^3m^3

Calculation of the Fixed Rate Primary Gas PCR
21,155 (lines 9 & 34, FPO column)
562 (10^3m^3 (Schedule 10.1.1, line 17, FPO column)
37.67 per 10^3m^3

1e

Centra Gas Manitoba Inc.
2019/20 General Rate Application
Total Functionalization By Customer Class
2019/20 Test Year

Schedule 10.1.3

		System Total	Residential SGS-R	Small Commercial SGS-C	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Fixed Price Offering FPO	
1	PRODUCTION																
2	Demand	0	[redacted]														
3	Energy	113,369,822	[redacted]														1a
4	Customer	0	[redacted]														
5	Total	113,369,822	[redacted]														
6			[redacted]														
7	PIPELINE		[redacted]														
8	Demand	44,624,172	[redacted]														
9	Energy	0	[redacted]														1a
10	Customer	0	[redacted]														
11	Total	44,624,172	[redacted]														
12			[redacted]														
13	STORAGE		[redacted]														
14	Demand	19,064,760	[redacted]														
15	Energy	4,244,395	[redacted]														
16	Customer	0	[redacted]														1a
17	Total	23,309,156	[redacted]														
18			[redacted]														
19	TRANSMISSION		[redacted]														
20	Demand	17,359,699	[redacted]														
21	Energy	15,080,090	[redacted]														
22	Customer	0	[redacted]														1a
23	Total	32,439,789	[redacted]														
24																	
25	DISTRIBUTION																
26	Demand	26,575,814	10,743,211	2,053,884	12,797,095	9,786,354	2,973,551	1,930	727,100	[redacted]		289,784	[redacted]			0	
27	Energy	0	0	0	0	0	0	0		[redacted]			[redacted]			0	
28	Customer	11,024,589	10,001,064	700,104	10,701,168	318,376	4,253	2	20	[redacted]		766	[redacted]			0	2d,1e
29	Total	37,600,403	20,744,275	2,753,988	23,498,263	10,104,729	2,977,804	1,932	727,120	[redacted]		290,550	[redacted]			0	
30										[redacted]			[redacted]				
31	ONSITE									[redacted]			[redacted]				
32	Demand	0	0	0	0	0	0	0		[redacted]			[redacted]			0	
33	Energy	0	0	0	0	0	0	0		[redacted]			[redacted]			0	
34	Customer	74,440,749	55,660,937	6,394,071	62,055,007	10,467,929	1,338,527	3,166	116,701	[redacted]		247,705	[redacted]			20,616	2d,1e
35	Total	74,440,749	55,660,937	6,394,071	62,055,007	10,467,929	1,338,527	3,166	116,701	[redacted]		247,705	[redacted]			20,616	
36										[redacted]			[redacted]				
37	TOTAL SERVICE									[redacted]			[redacted]				
38	Demand	107,624,446	43,366,529	8,345,726	51,712,255	39,199,606	11,352,103	16,170	1,924,078	[redacted]		1,138,716	[redacted]			0	
39	Energy	132,694,307	8,027,388	2,452,499	10,479,887	7,149,828	1,053,064	624	254,864	[redacted]		263,065	[redacted]			45,418	
40	Customer	85,465,338	65,662,001	7,094,174	72,756,175	10,786,305	1,342,780	3,169	116,721	[redacted]		248,471	[redacted]			20,616	2d,1e
41	Total	325,784,091	117,055,917	17,892,399	134,948,316	57,135,739	13,747,948	19,962	2,295,662	[redacted]		1,650,252	[redacted]			66,034	

Centra Gas Manitoba Inc.
2019/20 General Rates Application
Bill Impact Comparison
2019/20 Test Year

1	**BILLED VS. BILLED**													
2														
3					**FEB 1/19 APPROVED BILLED RATES**				**NOV 1/19 PROPOSED BILLED RATES**				**BILL IMPACTS**	
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	$236	$404	$168	$0	$219	$387	($17)	-4.3%
9			1.98	70	$168	$0	$468	$636	$168	$0	$433	$601	($34)	-5.4%
10	*(Typical Residential Customer)*		**2.22**	78	$168	$0	$523	$691	$168	$0	$485	$653	($38)	-5.6%
11			2.80	99	$168	$0	$662	$830	$168	$0	$613	$781	($49)	-5.9%
12			3.20	113	$168	$0	$755	$923	$168	$0	$700	$868	($56)	-6.0%
13			3.68	130	$168	$0	$869	$1,037	$168	$0	$805	$973	($64)	-6.2%
14			11.33	400	$168	$0	$2,673	$2,841	$168	$0	$2,477	$2,645	($197)	-6.9%
15														
16	Large General Service		11.33	400	$924	$0	$2,072	$2,996	$924	$0	$2,068	$2,992	($4)	-0.1%
17			59.49	2,100	$924	$0	$10,879	$11,803	$924	$0	$10,858	$11,782	($22)	-0.2%
18			679.87	24,000	$924	$0	$124,335	$125,259	$924	$0	$124,088	$125,012	($247)	-0.2%
19														
20	HVF (Sales Service)	25%	850	30,000	$13,420	$51,159	$103,976	$168,555	$12,097	$77,383	$78,713	$168,193	($361)	-0.2%
21		40%	850	30,000	$13,420	$31,974	$103,976	$149,370	$12,097	$48,365	$78,713	$139,175	($10,196)	-6.8%
22		40%	1,416	50,000	$13,420	$53,291	$173,293	$240,004	$12,097	$80,608	$131,188	$223,893	($16,111)	-6.7%
23		40%	2,833	100,000	$13,420	$106,581	$346,586	$466,588	$12,097	$161,215	$262,376	$435,689	($30,899)	-6.6%
24		40%	6,200	218,866	$13,420	$233,271	$758,560	$1,005,250	$12,097	$352,846	$574,252	$939,195	($66,055)	-6.6%
25		40%	12,600	444,792	$13,420	$474,066	$1,541,589	$2,029,075	$12,097	$717,074	$1,167,027	$1,896,198	($132,876)	-6.5%
26		75%	685	24,181	$13,420	$13,745	$83,809	$110,974	$12,097	$20,791	$63,446	$96,334	($14,640)	-13.2%
27		75%	850	30,000	$13,420	$17,053	$103,976	$134,449	$12,097	$25,794	$78,713	$116,604	($17,844)	-13.3%
28		75%	1,416	50,000	$13,420	$28,422	$173,293	$215,135	$12,097	$42,991	$131,188	$186,276	($28,859)	-13.4%
29		75%	2,833	100,000	$13,420	$56,843	$346,586	$416,850	$12,097	$85,982	$262,376	$360,455	($56,395)	-13.5%
30		75%	6,200	218,866	$13,420	$124,411	$758,560	$896,390	$12,097	$188,184	$574,252	$774,533	($121,857)	-13.6%
31		75%	12,600	444,792	$13,420	$252,835	$1,541,589	$1,807,844	$12,097	$382,439	$1,167,027	$1,561,564	($246,280)	-13.6%
32														
33	HVF (T-Service)	40%	2,600	91,783	$13,420	$32,128	$18,923	$64,470	$12,097	$39,588	$25,765	$77,450	$12,980	20.1%
34		40%	11,000	388,311	$13,420	$135,925	$80,057	$229,402	$12,097	$167,488	$109,005	$288,590	$59,188	25.8%
35		40%	17,600	621,297	$13,420	$217,481	$128,091	$358,991	$12,097	$267,981	$174,408	$454,486	$95,495	26.6%
36		75%	2,600	91,783	$13,420	$17,135	$18,923	$49,477	$12,097	$21,114	$25,765	$58,976	$9,498	19.2%
37		75%	11,000	388,311	$13,420	$72,494	$80,057	$165,970	$12,097	$89,327	$109,005	$210,429	$44,459	26.8%
38		75%	17,600	621,297	$13,420	$115,990	$128,091	$257,500	$12,097	$142,923	$174,408	$329,428	$71,928	27.9%
39														
40	Cooperative	35%	250	8,825	$3,289	$14,042	$25,312	$42,643	$3,169	$14,971	$24,100	$42,239	($404)	-0.9%
41		35%	350	12,355	$3,289	$19,659	$35,437	$58,385	$3,169	$20,959	$33,740	$57,868	($518)	-0.9%
42		35%	500	17,650	$3,289	$28,084	$50,625	$81,998	$3,169	$29,941	$48,200	$81,310	($688)	-0.8%
43														
44	MLC (Sales Service)	40%	2,833	100,000	$28,240	$163,725	$290,867	$482,832	$12,969	$96,908	$276,715	$386,592	($96,240)	-19.9%
45		40%	14,164	500,000	$28,240	$818,626	$1,454,334	$2,301,200	$12,969	$484,539	$1,383,573	$1,881,082	($420,118)	-18.3%
46		40%	28,328	1,000,000	$28,240	$1,637,252	$2,908,668	$4,574,160	$12,969	$969,079	$2,767,147	$3,749,195	($824,965)	-18.0%
47		75%	2,833	100,000	$28,240	$87,320	$290,867	$406,427	$12,969	$51,684	$276,715	$341,368	($65,059)	-16.0%
48		75%	14,164	500,000	$28,240	$436,601	$1,454,334	$1,919,174	$12,969	$258,421	$1,383,573	$1,654,963	($264,211)	-13.8%
49		75%	28,328	1,000,000	$28,240	$873,201	$2,908,668	$3,810,109	$12,969	$516,842	$2,767,147	$3,296,958	($513,151)	-13.5%
50		75%	41,000	1,447,339	$28,240	$1,263,818	$4,209,829	$5,501,888	$12,969	$748,046	$4,005,001	$4,766,015	($735,872)	-13.4%
51														
52	MLC (T- Service)	40%	14,000	494,213	$28,240	$181,393	$17,293	$226,926	$12,969	$271,563	$9,891	$294,423	$67,498	29.7%
53		40%	18,000	635,417	$28,240	$233,219	$22,234	$283,693	$12,969	$349,153	$12,717	$374,839	$91,146	32.1%
54		40%	44,000	1,553,242	$28,240	$570,091	$54,349	$652,680	$12,969	$853,484	$31,086	$897,540	$244,859	37.5%
55		75%	14,000	494,213	$28,240	$96,743	$17,293	$142,276	$12,969	$144,834	$9,891	$167,694	$25,418	17.9%
56		75%	18,000	635,417	$28,240	$124,384	$22,234	$174,857	$12,969	$186,215	$12,717	$211,901	$37,044	21.2%
57		75%	44,000	1,553,242	$28,240	$304,049	$54,349	$386,638	$12,969	$455,192	$31,086	$499,247	$112,609	29.1%
58														
59	Special Contract	[redacted]												
60														
61	Power Stations													
62														
63	Interruptible Sales	25%	850	30,000	$12,513	$24,602	$100,479	$137,593	$12,423	$40,272	$79,761	$132,457	($5,136)	-3.7%
64		40%	2,833	100,000	$12,513	$51,254	$334,929	$398,696	$12,423	$83,901	$265,870	$362,194	($36,502)	-9.2%
65		40%	14,164	500,000	$12,513	$256,268	$1,674,647	$1,943,427	$12,423	$419,503	$1,329,349	$1,761,276	($182,152)	-9.4%
66		75%	850	30,000	$12,513	$8,201	$100,479	$121,192	$12,423	$13,424	$79,761	$105,609	($15,584)	-12.9%
67		75%	2,833	100,000	$12,513	$27,335	$334,929	$374,777	$12,423	$44,747	$265,870	$323,040	($51,737)	-13.8%
68		75%	14,164	500,000	$12,513	$136,676	$1,674,647	$1,823,836	$12,423	$223,735	$1,329,349	$1,565,508	($258,328)	-14.2%

2d

Centra Gas Manitoba Inc.
2019/20 General Rates Application
Bill Impact Comparison
2019/20 Test Year

BASE VS. BASE

				FEB 1/19 APPROVED BASE RATES				NOV 1/19 PROPOSED BASE RATES				BASE IMPACTS	
	Load Factor	Annual Use 10^3m^3	Mcf	Basic Chg	Demand	Commodity	Annual	Basic Chg	Demand	Commodity	Annual	$	%
Small General Service		1.00	35	$168	$0	$227	$395	$168	$0	$214	$382	($13)	-3.3%
		1.98	70	$168	$0	$450	$618	$168	$0	$424	$592	($26)	-4.2%
(Typical Residential Customer)		2.22	78	$168	$0	$504	$672	$168	$0	$475	$643	($29)	-4.3%
		2.80	99	$168	$0	$637	$805	$168	$0	$601	$769	($36)	-4.5%
		3.20	113	$168	$0	$727	$895	$168	$0	$686	$854	($42)	-4.7%
		3.68	130	$168	$0	$837	$1,005	$168	$0	$789	$957	($48)	-4.8%
		11.33	400	$168	$0	$2,575	$2,743	$168	$0	$2,427	$2,595	($147)	-5.4%
Large General Service		11.33	400	$924	$0	$1,974	$2,898	$924	$0	$2,003	$2,927	$30	1.0%
		59.49	2,100	$924	$0	$10,362	$11,286	$924	$0	$10,518	$11,442	$156	1.4%
		679.87	24,000	$924	$0	$118,420	$119,344	$924	$0	$120,201	$121,125	$1,781	1.5%
HVF (Sales Service)	25%	850	30,000	$13,420	$51,159	$96,626	$161,205	$12,097	$53,454	$93,822	$159,373	($1,831)	-1.1%
	40%	850	30,001	$13,420	$31,976	$96,629	$142,024	$12,097	$33,410	$93,825	$139,332	($2,692)	-1.9%
	40%	1,416	50,000	$13,420	$53,291	$161,043	$227,753	$12,097	$55,682	$156,370	$224,148	($3,605)	-1.6%
	40%	2,833	100,000	$13,420	$106,581	$322,086	$442,087	$12,097	$111,363	$312,739	$436,200	($5,887)	-1.3%
	40%	6,200	218,866	$13,420	$233,271	$704,936	$951,626	$12,097	$243,736	$684,480	$940,314	($11,313)	-1.2%
	40%	12,600	444,792	$13,420	$474,066	$1,432,611	$1,920,097	$12,097	$495,335	$1,391,040	$1,898,472	($21,625)	-1.1%
	75%	685	24,181	$13,420	$13,745	$77,884	$105,049	$12,097	$14,362	$75,624	$102,083	($2,966)	-2.8%
	75%	850	30,000	$13,420	$17,053	$96,626	$127,098	$12,097	$17,818	$93,822	$123,737	($3,361)	-2.6%
	75%	1,416	50,000	$13,420	$28,422	$161,043	$202,884	$12,097	$29,697	$156,370	$198,164	($4,721)	-2.3%
	75%	2,833	100,000	$13,420	$56,843	$322,086	$392,349	$12,097	$59,394	$312,739	$384,230	($8,119)	-2.1%
	75%	6,200	218,866	$13,420	$124,411	$704,936	$842,767	$12,097	$129,993	$684,480	$826,570	($16,197)	-1.9%
	75%	12,600	444,792	$13,420	$252,835	$1,432,611	$1,698,866	$12,097	$264,179	$1,391,040	$1,667,316	($31,550)	-1.9%
HVF (T-Service)	40%	2,600	91,783	$13,420	$32,128	$18,923	$64,470	$12,097	$39,406	$26,000	$77,503	$13,033	20.2%
	40%	11,000	388,311	$13,420	$135,925	$80,057	$229,402	$12,097	$166,718	$110,000	$288,815	$59,413	25.9%
	40%	17,600	621,297	$13,420	$217,481	$128,091	$358,991	$12,097	$266,748	$176,000	$454,846	$95,854	26.7%
	75%	2,600	91,783	$13,420	$17,135	$18,923	$49,477	$12,097	$21,017	$26,000	$59,114	$9,637	19.5%
	75%	11,000	388,311	$13,420	$72,494	$80,057	$165,970	$12,097	$88,916	$110,000	$211,013	$45,043	27.1%
	75%	17,600	621,297	$13,420	$115,990	$128,091	$257,500	$12,097	$142,266	$176,000	$330,363	$72,863	28.3%
Cooperative	35%	250	8,825	$3,289	$14,042	$23,150	$40,481	$3,169	$14,971	$21,925	$40,064	($417)	-1.0%
	35%	350	12,355	$3,289	$19,659	$32,410	$55,358	$3,169	$20,959	$30,695	$54,823	($535)	-1.0%
	35%	500	17,650	$3,289	$28,084	$46,300	$77,673	$3,169	$29,941	$43,850	$76,960	($714)	-0.9%
MLC (Sales Service)	40%	2,833	100,000	$28,240	$163,725	$266,366	$458,331	$12,969	$152,784	$252,968	$418,721	($39,610)	-8.6%
	40%	14,164	500,000	$28,240	$818,626	$1,331,830	$2,178,696	$12,969	$763,920	$1,264,838	$2,041,727	($136,969)	-6.3%
	40%	28,328	1,000,000	$28,240	$1,637,252	$2,663,660	$4,329,152	$12,969	$1,527,841	$2,529,676	$4,070,486	($258,666)	-6.0%
	75%	2,833	100,000	$28,240	$87,320	$266,366	$381,926	$12,969	$81,485	$252,968	$347,421	($34,505)	-9.0%
	75%	14,164	500,000	$28,240	$436,601	$1,331,830	$1,796,671	$12,969	$407,424	$1,264,838	$1,685,231	($111,439)	-6.2%
	75%	28,328	1,000,000	$28,240	$873,201	$2,663,660	$3,565,101	$12,969	$814,848	$2,529,676	$3,357,493	($207,608)	-5.8%
	75%	41,000	1,447,339	$28,240	$1,263,818	$3,855,220	$5,147,279	$12,969	$1,179,362	$3,661,300	$4,853,631	($293,648)	-5.7%
MLC (T- Service)	40%	14,000	494,213	$28,240	$181,393	$17,293	$226,926	$12,969	$271,101	$21,000	$305,070	$78,145	34.4%
	40%	18,000	635,417	$28,240	$233,219	$22,234	$283,693	$12,969	$348,559	$27,000	$388,528	$104,835	37.0%
	40%	44,000	1,553,242	$28,240	$570,091	$54,349	$652,680	$12,969	$852,033	$66,000	$931,002	$278,322	42.6%
	75%	14,000	494,213	$28,240	$96,743	$17,293	$142,276	$12,969	$144,587	$21,000	$178,556	$36,281	25.5%
	75%	18,000	635,417	$28,240	$124,384	$22,234	$174,857	$12,969	$185,898	$27,000	$225,867	$51,010	29.2%
	75%	44,000	1,553,242	$28,240	$304,049	$54,349	$386,638	$12,969	$454,418	$66,000	$533,387	$146,749	38.0%
Special Contract	[redacted] 2d												
Power Stations													
Interruptible Sales	25%	850	30,000	$12,513	$24,602	$93,682	$130,796	$12,423	$26,599	$87,873	$126,895	($3,901)	-3.0%
	40%	2,833	100,000	$12,513	$51,254	$312,273	$376,039	$12,423	$55,414	$292,910	$360,747	($15,292)	-4.1%
	40%	14,164	500,000	$12,513	$256,268	$1,561,364	$1,830,144	$12,423	$277,070	$1,464,549	$1,754,042	($76,102)	-4.2%
	75%	850	30,000	$12,513	$8,201	$93,682	$114,395	$12,423	$8,866	$87,873	$109,163	($5,232)	-4.6%
	75%	2,833	100,000	$12,513	$27,335	$312,273	$352,121	$12,423	$29,554	$292,910	$334,887	($17,233)	-4.9%
	75%	14,164	500,000	$12,513	$136,676	$1,561,364	$1,710,553	$12,423	$147,770	$1,464,549	$1,624,743	($85,810)	-5.0%

REFERENCE:

Responses to PUB/Centra I – 105, IGU/Centra I-27

QUESTION:

a) Provide a cost allocation sensitivity analysis that assumes the heating value deferral amount is added to Net Income and allocated consistent with Net Income in the current 2019/20 Cost Allocation Study:
   i. Assuming a heating value deferral of $1.0 million
   ii. Assuming a heating value deferral of the combined amounts in Centra's 2019/20 GRA.

   In both scenarios, please assume that no heating value deferral remains to be recovered through rate riders.

b) Please provide a table that compares the cost allocation results for each customer class of the scenarios in part (b) to the 2019/20 Cost Allocation Study (updated).

c) Please file the cost allocation schedules for the scenarios in part (b) including Schedules 10.1.0, 10.1.1, 10.1.2, 10.1.3, 11.1.0 (pages 1 and 2),11.3.0, and 11.3.1.

RESPONSE:

Response to part a) and b):

Centra has created two sensitivity analyses by adding the Heating Value Deferral Account to Net Income and allocated to customer classes consistent with 2019/20 cost allocation study:

- Scenario i) assumes that a heating value of $1.0 million is added to Net Income
- Scenario ii) assumes that the total Heating Value deferral for the 2015/16, 2016/17 and 2017/18 gas years of $2,519,879 is added to Net Income

The following table compares the total 2019/20 Revenue Requirement by customer class to the requested scenarios:

	Total	SGS	LGS	HVF	CO-OP	ML	SC	GS	INT	PG	FSP	ISP	FPO	
CAC-II-142 b) part i														
$1M HV deferral to NI (total Rev Req)	326,784,091	135,639,650	57,397,947	13,800,360	20,022	2,294,312	[redacted]		1,656,599	[redacted]			66,043	1e
Per Filing (total Rev Req)	325,784,091	134,975,474	57,156,395	13,751,619	19,972	2,281,973			1,650,683				66,034	
Rev Req. Difference	1,000,000	664,176	241,552	48,742	49	12,339	20,070	2,206	5,915	4,321	584	38	9	
CAC-II-142 b) part ii														
$2.5M HV deferral to NI (total Rev Req)	328,303,970	136,651,350	57,765,671	13,874,500	20,096	2,313,113	[redacted]		1,665,597	[redacted]			66,055	1e
Per Filing (total Rev Req)	325,784,091	134,975,474	57,156,395	13,751,619	19,972	2,281,973			1,650,683				66,034	
Rev Req. Difference	2,519,879	1,675,876	609,275	122,882	124	31,140	50,689	5,573	14,914	8,205	1,109	71	20	

c) Please see the attached schedules.

CAC/CENTRA II-142 c) Part i)
Schedule 10.1.0

Centra Gas Manitoba Inc.
2019/20 General Rates Application
Summary of Allocated Costs by Customer Class
2019/20 Test Year add $1.0M to Net Income

Cost of Service Elements

SGS

	Demand	Energy	Customer	Total
Cost of Gas	30,833,940	1,508,864	0	32,342,804
Other Income	-68,359	-452	-971,166	-1,039,976
Operating & Maintenance Expenses	7,480,011	49,422	36,957,610	44,487,044
Depreciation & Amortization	4,151,323	5,772,166	11,448,390	21,371,879
Capital & Other Taxes	3,733,206	481,267	9,358,747	13,573,220
Finance Expense	3,320,159	1,579,782	9,449,454	14,349,395
Corporate Allocation	1,844,254	877,524	5,248,904	7,970,682
Net Income	598,524	284,787	1,703,451	2,586,762
Total Cost of Service	51,893,059	10,553,360	73,195,391	135,641,809

LGS

	Demand	Energy	Customer	Total
Cost of Gas	23,574,981	1,125,616	0	24,700,597
Other Income	-52,295	-345	-42,143	-94,782
Operating & Maintenance Expenses	5,722,216	37,698	4,337,539	10,097,453
Depreciation & Amortization	2,830,956	3,782,173	2,347,647	8,960,777
Capital & Other Taxes	2,855,662	336,888	1,483,716	4,676,266
Finance Expense	2,538,527	1,105,710	1,574,403	5,218,641
Corporate Allocation	1,410,080	614,191	874,536	2,898,807
Net Income	457,620	199,326	283,817	940,763
Total Cost of Service	39,337,746	7,201,258	10,859,517	57,398,521

HVF

	Demand	Energy	Customer	Total
Cost of Gas	6,583,125	344,193	0	6,927,317
Other Income	-16,483	-103	-9,093	-25,679
Operating & Maintenance Expenses	1,803,632	11,245	960,145	2,775,022
Depreciation & Amortization	807,071	299,213	175,809	1,282,093
Capital & Other Taxes	871,574	60,949	81,436	1,013,958
Finance Expense	773,543	199,840	79,600	1,052,982
Corporate Allocation	429,681	111,005	44,216	584,902
Net Income	139,446	36,025	14,350	189,821
Total Cost of Service	11,391,589	1,062,366	1,346,462	13,800,417

Cooperative

	Demand	Energy	Customer	Total
Cost of Gas	11,535	205	0	11,740
Other Income	-20	0	-20	-40
Operating & Maintenance Expenses	2,146	10	2,117	4,273
Depreciation & Amortization	691	1	428	1,120
Capital & Other Taxes	761	62	263	1,087
Finance Expense	632	204	225	1,061
Corporate Allocation	351	114	125	589
Net Income	114	37	41	191
Total Cost of Service	16,209	633	3,179	20,021

Main Line

	Demand	Energy	Customer	Total
Cost of Gas	112,234	111,897	0	224,131
Other Income	-7,608	-4	-767	-8,380
Operating & Maintenance Expenses	832,509	444	80,931	913,884
Depreciation & Amortization	282,968	99,452	15,830	398,251
Capital & Other Taxes	289,406	6,578	7,772	303,756
Finance Expense	237,309	21,603	7,668	266,581
Corporate Allocation	131,819	12,000	4,260	148,078
Net Income	42,780	3,894	1,382	48,056
Total Cost of Service	1,921,416	255,866	117,076	2,294,358

Special Contract

	Demand	Energy	Customer	Total	
Cost of Gas	[redacted]				1d
Other Income	-7,072	-1	-86	-7,159	
Operating & Maintenance Expenses	773,792	92	8,563	782,447	
Depreciation & Amortization	202,213	-8	8,098	210,304	
Capital & Other Taxes	522,038	12	6,710	528,760	
Finance Expense	427,438	37	6,151	433,626	
Corporate Allocation	237,430	20	3,417	240,867	
Net Income	77,054	7	1,109	78,170	
Total Cost of Service	[redacted]				1e

Power Station

	Demand	Energy	Customer	Total
Cost of Gas	[redacted]			
Other Income	-564	-2	-194	-760
Operating & Maintenance Expenses	61,728	181	17,129	79,038
Depreciation & Amortization	-98,749	-15	43,729	-55,035
Capital & Other Taxes	16,191	24	37,806	54,022
Finance Expense	12,702	72	34,902	47,676
Corporate Allocation	7,055	40	19,387	26,482
Net Income	2,290	13	6,292	8,594
Total Cost of Service	[redacted]			

Interruptible

	Demand	Energy	Customer	Total	
Cost of Gas	690,449	190,673	0	881,122	1d
Other Income	-1,578	-25	-1,629	-3,232	
Operating & Maintenance Expenses	172,679	2,739	171,800	347,217	
Depreciation & Amortization	61,704	166	34,224	96,093	
Capital & Other Taxes	86,467	10,640	16,482	113,589	
Finance Expense	76,609	34,851	16,333	127,793	
Corporate Allocation	42,554	19,359	9,073	70,986	
Net Income	13,810	6,283	2,944	23,037	
Total Cost of Service	1,142,694	264,685	249,227	1,656,606	1e

Primary Gas

	Demand	Energy	Customer	Total
Cost of Gas	[redacted]		[redacted]	
Other Income				
Operating & Maintenance Expenses				
Depreciation & Amortization				
Capital & Other Taxes				
Finance Expense				
Corporate Allocation				
Net Income				
Total Cost of Service				

Supplemental Gas - Firm

	Demand	Energy	Customer	Total	
Cost of Gas	[redacted]		[redacted]		1a
Other Income					
Operating & Maintenance Expenses					
Depreciation & Amortization					
Capital & Other Taxes					1e
Finance Expense					
Corporate Allocation					
Net Income					
Total Cost of Service					1e

Supplemental Gas - Interruptible

	Demand	Energy	Customer	Total
Cost of Gas	[redacted]		[redacted]	
Other Income				
Operating & Maintenance Expenses				
Depreciation & Amortization				
Capital & Other Taxes				
Finance Expense				
Corporate Allocation				
Net Income				
Total Cost of Service				

Fixed Price Offering

	Demand	Energy	Customer	Total	
Cost of Gas	0	44,879	0	44,879	1a
Other Income	0	-4	-171	-175	
Operating & Maintenance Expenses	0	419	18,750	19,168	
Depreciation & Amortization	0	33	1,486	1,520	
Capital & Other Taxes	0	19	304	323	1e
Finance Expense	0	42	146	188	
Corporate Allocation	0	23	81	105	
Net Income	0	8	26	34	
Total Cost of Service	0	45,419	20,623	66,041	1e

Unassigned

	Demand	Energy	Customer	Total
Cost of Gas	0	0	0	0
Other Income	0	0	0	0
Operating & Maintenance Expenses	0	0	0	0
Depreciation & Amortization	0	0	0	0
Capital & Other Taxes	0	0	0	0
Finance Expense	0	0	0	0
Corporate Allocation	0	0	0	0
Net Income	0	0	0	0
Total Cost of Service	0	0	0	0

Total

	Demand	Energy	Customer	Total
Cost of Gas	61,836,486	115,428,348	0	177,264,835
Other Income	-153,978	-10,480	-1,025,270	-1,189,728
Operating & Maintenance Expenses	16,848,713	1,146,704	42,554,583	60,550,000
Depreciation & Amortization	8,238,176	10,035,983	14,075,643	32,349,802
Capital & Other Taxes	8,375,305	942,962	10,993,237	20,311,504
Finance Expense	7,386,919	3,047,461	11,168,883	21,603,263
Corporate Allocation	4,103,224	1,692,778	6,203,998	12,000,000
Net Income	1,331,638	549,365	2,013,412	3,894,415
Total Cost of Service	107,966,483	132,833,121	85,984,486	326,784,091

CAC/CENTRA II-142 c) Part i)
Schedule 10.1.1

Centra Gas Manitoba Inc.
2019/20 General Rates Application
Unit Cost Component Summary
2019/20 Test Year add $1.0M to Net Income

	ROR	System Total	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Fixed Price Offering FRPGS	
1 REVENUE REQUIREMENTS															
2 Upstream Demand ($)		[redacted]													
3 Upstream Commodity ($)															
4 Upstream Customer ($)															
5 Upstream Total ($)															
6															1e
7 Downstream Demand ($)															
8 Downstream Commodity ($)															
9 Downstream Customer ($)															
10 Downstream Total ($)															
11															
12 Total (incl. gas costs)															
13															
14															
15 MONTHLY BILLING DETERMINANTS															
16 Upstream Demand (10^3m^3-day)		[redacted]													
17 Upstream Commodity (10^3m^3)															
18 Upstream Customer (customers)															
19															1d
20 Downstream Demand (10^3m^3-day)															
21 Downstream Commodity (10^3m^3)															
22 Downstream Customer (customers)															
23															
24 PERCENT IN DEMAND CHARGE			0.0%	0.0%	65.0%	100.0%	100.0%	100.0%	100.0%	65.0%	100.0%	100.0%	100.0%	100.0%	
25															
26 RESULTING UNIT CHARGES															
27 Upstream Demand ($/10^3m^3$-day)		454.737	0.000	0.000	295.050	470.603	422.306	0.000	0.000	149.289	0.000	0.000	0.000	0.000	
28 Upstream Commodity ($/10^3m^3$)		80.351	49.751	48.089	15.195	2.346	2.545	0.000	0.000	8.085	76.909	134.899	134.297	80.884	
29 Upstream Customer ($/customer)		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
30															
31 Downstream Demand ($/10^3m^3$-day)		250.489	0.000	0.000	184.875	168.505	235.209	137.964	0.151	89.533	0.000	0.000	0.000	0.000	
32 Downstream Commodity ($/10^3m^3$)		7.293	41.748	38.026	10.081	0.000	1.523	0.096	18.305	6.408	0.000	0.000	0.000	0.000	
33 Downstream Customer ($/customer)		24.900	21.838	108.899	1,010.857	264.921	1,084.036	2,830.140	6,627.113	1,038.446	0.000	0.000	0.000	0.000	

CAC/CENTRA II-142 c) Part i)
Schedule 10.1.2

Centra Gas Manitoba Inc.
2019/20 General Rates Application
Comparison of Gas Costs vs. Non-Gas Costs
2019/20 Test Year add $1.0M to Net Income

	Gas Costs vs. Non-Gas Costs	ROR	System Total	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Fixed Price Offering FRPGS	
1	REVENUE REQUIREMENTS															
2	Upstream Demand ($)	Upstream Demand ($)														
3	Gas Costs	Gas Costs	61,638,042	30,756,386	23,515,600	6,564,891	11,505	101,088	0	0	688,573	0	0	0	0	
4	Non-gas Costs	Non-gas Costs	2,303,503	1,149,411	878,812	245,340	430	3,778	0	0	25,733	0	0	0	0	
5	Total	Total	63,941,546	31,905,797	24,394,412	6,810,230	11,935	104,865	0	0	714,306	0	0	0	0	
6			0	0	0	0	0	0	0	0	0	0	0	0	0	
7	Upstream Commodity ($)	Upstream Commodity ($)														
8	Gas Costs	Gas Costs	113,950,265	941,280	719,143	214,121	205	3,997	0	0	47,299	[redacted]			44,879	
9	Non-gas Costs	Non-gas Costs	3,717,608	1,107,060	875,119	307,227	428	6,737	0	0	73,458				540	1a,1e
10	Total	Total	117,667,874	2,048,340	1,594,262	521,348	633	10,734	0	0	120,757				45,419	
11			0	0	0	0	0	0	0	0	0	0	0	0	0	
12	Upstream Customer ($)	Upstream Customer ($)														
13	Gas Costs	Gas Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	
14	Non-gas Costs	Non-gas Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	
15	Total	Total	0	0	0	0	0	0	0	0	0	0	0	0	0	
16																
17	Upstream Total ($)	Upstream Total ($)														
18	Total Gas Costs	Total Gas Costs	175,588,308	31,697,666	24,234,743	6,779,012	11,711	105,085	0	0	735,872	[redacted]			44,879	
19	Total Non-gas Costs	Total Non-gas Costs	6,021,111	2,256,471	1,753,931	552,566	858	10,514	0	0	99,191				540	1e
20	Total Upstream Costs	Total Upstream Costs	181,609,419	33,954,137	25,988,674	7,331,578	12,569	115,599	0	0	835,063				45,419	
21			0	0	0	0	0	0	0	0	0	0	0	0	0	
22	Downstream Demand ($)	Downstream Demand ($)														
23	Gas Costs	Gas Costs	198,444	77,554	59,381	18,234	29	11,146	[redacted]		1,876	0	0	0	0	
24	Non-gas Costs	Non-gas Costs	43,826,494	19,909,708	14,883,954	4,563,125	4,245	1,805,405	2,232,893	652	426,512	0	0	0	0	2d,1e
25	Total	Total	44,024,938	19,987,262	14,943,335	4,581,359	4,274	1,816,551	[redacted]		428,388	0	0	0	0	
26																
27	Downstream Commodity ($)	Downstream Commodity ($)														
28	Gas Costs	Gas Costs	1,478,083	567,584	406,473	130,071	0	107,900	[redacted]		143,374	0	0	0	0	
29	Non-gas Costs	Non-gas Costs	13,687,165	7,937,436	5,200,523	410,946	0	137,231	160	314	554	0	0	0	0	2d,1e
30	Total	Total	15,165,248	8,505,020	5,606,996	541,017	0	245,132	[redacted]		143,928	0	0	0	0	
31																
32	Downstream Customer ($)	Downstream Customer ($)														
33	Gas Costs	Gas Costs	0	0	0	0	0	0	[redacted]		0	0	0	0	0	
34	Non-gas Costs	Non-gas Costs	85,984,486	73,195,391	10,859,517	1,346,462	3,179	117,076	33,962	159,051	249,227	0	0	0	20,623	2d,1e
35	Total	Total	85,984,486	73,195,391	10,859,517	1,346,462	3,179	117,076	[redacted]		249,227	0	0	0	20,623	
36																
37	Downstream Total ($)	Downstream Total ($)														
38	Total Gas Costs	Total Gas Costs	1,676,527	645,137	465,854	148,306	29	119,046	[redacted]		145,250	0	0	0	0	
39	Total Non-gas Costs	Total Non-gas Costs	143,498,144	101,042,535	30,943,993	6,320,533	7,424	2,059,712	2,267,015	160,017	676,293	0	0	0	20,623	2d,1e
40	Total Downstream Costs	Total Downstream Costs	145,174,671	101,687,672	31,409,847	6,468,839	7,453	2,178,758	[redacted]		821,543	0	0	0	20,623	
41																
42	Grand Total Gas Costs	Grand Total Gas Costs	177,264,835	32,342,804	24,700,597	6,927,317	11,740	224,131	[redacted]		881,122	[redacted]			44,879	2d,1e
43	Grand Total Non-gas Costs	Grand Total Non-gas Costs	149,519,256	103,299,005	32,697,924	6,873,100	8,282	2,070,226	2,267,015	160,017	775,484				21,162	
44	Grand Total	Grand Total	326,784,091	135,641,809	57,398,521	13,800,417	20,021	2,294,358	[redacted]		1,656,606				66,041	
45																
46																

47 Calculation of the Primary Gas Overhead Rate: [redacted] line 9, PG column)
48 10^3m^3 (Schedule 10.1.1, line 17, PG column)
49 0.91 10^3m^3

Calculation of the Fixed Rate Primary Gas PCR
21,162 (lines 9 & 34, FPO column)
562 (10^3m^3 (Schedule 10.1.1, line 17, FPO column)
37.69 per 10^3m^3 1e

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Schedule 10.1.3

Centra Gas Manitoba Inc.
2019/20 General Rate Application
Total Functionalization By Customer Class
2019/20 Test Year add $1.0M to Net Income

		System Total	Residential SGS-R	Small Commercial SGS-C	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Fixed Price Offering FPO	
1	PRODUCTION		[redacted]														
2	Demand	0	[redacted]														
3	Energy	113,371,799	[redacted]														1a
4	Customer	0	[redacted]														
5	Total	113,371,799	[redacted]														
6			[redacted]														
7	PIPELINE		[redacted]														
8	Demand	44,876,215	[redacted]														
9	Energy	0	[redacted]														1a
10	Customer	0	[redacted]														
11	Total	44,876,215	[redacted]														
12			[redacted]														
13	STORAGE		[redacted]														
14	Demand	19,065,331	[redacted]														
15	Energy	4,296,075	[redacted]														1a
16	Customer	0	[redacted]														
17	Total	23,361,405	[redacted]														
18			[redacted]														
19	TRANSMISSION		[redacted]														
20	Demand	17,243,560	[redacted]														
21	Energy	15,165,248	[redacted]														
22	Customer	0	[redacted]														1a
23	Total	32,408,808	[redacted]														
24			[redacted]														
25	DISTRIBUTION									[redacted]			[redacted]				
26	Demand	26,781,378	10,827,244	2,069,950	12,897,195	9,862,898	2,996,796	1,939	730,508	[redacted]		292,043	[redacted]			0	
27	Energy	0	0	0	0	0	0	0	0	[redacted]		0	[redacted]			0	
28	Customer	11,107,279	10,076,078	705,355	10,781,432	320,764	4,285	2	20	[redacted]		772	[redacted]			0	2d,1e
29	Total	37,888,656	20,903,322	2,775,305	23,678,627	10,183,662	3,001,081	1,941	730,527	[redacted]		292,815	[redacted]			0	
30										[redacted]			[redacted]				
31	ONSITE									[redacted]			[redacted]				
32	Demand	0	0	0	0	0	0	0	0	[redacted]		0	[redacted]			0	
33	Energy	0	0	0	0	0	0	0	0	[redacted]		0	[redacted]			0	
34	Customer	74,877,207	55,974,826	6,439,133	62,413,958	10,538,753	1,342,178	3,177	117,056	[redacted]		248,455	[redacted]			20,623	2d,1e
35	Total	74,877,207	55,974,826	6,439,133	62,413,958	10,538,753	1,342,178	3,177	117,056	[redacted]		248,455	[redacted]			20,623	
36										[redacted]			[redacted]				
37	TOTAL SERVICE									[redacted]			[redacted]				
38	Demand	107,966,483	43,518,301	8,374,758	51,893,059	39,337,746	11,391,589	16,209	1,921,416	[redacted]		1,142,694	[redacted]			0	
39	Energy	132,833,121	8,084,280	2,469,079	10,553,360	7,201,258	1,062,366	633	255,866	[redacted]		264,685	[redacted]			45,419	2d,1e
40	Customer	85,984,486	66,050,903	7,144,487	73,195,391	10,859,517	1,346,462	3,179	117,076	[redacted]		249,227	[redacted]			20,623	
41	Total	326,784,091	117,653,485	17,988,325	135,641,809	57,398,521	13,800,417	20,021	2,294,358	[redacted]		1,656,606	[redacted]			66,041	

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Centra Gas Manitoba Inc.
2019/20 General Rates Application
Bill Impact Comparison
2019/20 Test Year add $1.0M to Net Income

BILLED VS. BILLED

				FEB 1/19 APPROVED BILLED RATES				NOV 1/19 PROPOSED BILLED RATES				BILL IMPACTS	
	Load Factor	Annual Use 10³m³	Mcf	Basic Chg	Demand	Commodity	Annual	Basic Chg	Demand	Commodity	Annual	$	%
Small General Service		1.00	35	$168	$0	$236	$404	$168	$0	$218	$386	($17)	-4.3%
		1.98	70	$168	$0	$468	$636	$168	$0	$433	$601	($35)	-5.4%
(Typical Residential Customer)		2.22	78	$168	$0	$523	$691	$168	$0	$485	$653	($39)	-5.6%
		2.80	99	$168	$0	$662	$830	$168	$0	$613	$781	($49)	-5.9%
		3.20	113	$168	$0	$755	$923	$168	$0	$699	$867	($56)	-6.0%
		3.68	130	$168	$0	$869	$1,037	$168	$0	$805	$973	($64)	-6.2%
		11.33	400	$168	$0	$2,673	$2,841	$168	$0	$2,475	$2,643	($198)	-7.0%
Large General Service		11.33	400	$924	$0	$2,072	$2,996	$924	$0	$2,060	$2,984	($12)	-0.4%
		59.49	2,100	$924	$0	$10,879	$11,803	$924	$0	$10,816	$11,740	($63)	-0.5%
		679.87	24,000	$924	$0	$124,335	$125,259	$924	$0	$123,612	$124,536	($723)	-0.6%
HVF (Sales Service)	25%	850	30,000	$13,420	$51,159	$103,976	$168,555	$12,130	$77,573	$77,850	$167,554	($1,001)	-0.6%
	40%	850	30,000	$13,420	$31,974	$103,976	$149,370	$12,130	$48,483	$77,850	$138,464	($10,906)	-7.3%
	40%	1,416	50,000	$13,420	$53,291	$173,293	$240,004	$12,130	$80,806	$129,751	$222,687	($17,317)	-7.2%
	40%	2,833	100,000	$13,420	$106,581	$346,586	$466,588	$12,130	$161,611	$259,501	$433,243	($33,345)	-7.1%
	40%	6,200	218,866	$13,420	$233,271	$758,560	$1,005,250	$12,130	$353,712	$567,960	$933,802	($71,448)	-7.1%
	40%	12,600	444,792	$13,420	$474,066	$1,541,589	$2,029,075	$12,130	$718,834	$1,154,241	$1,885,205	($143,869)	-7.1%
	75%	685	24,181	$13,420	$13,745	$83,809	$110,974	$12,130	$20,842	$62,750	$95,723	($15,251)	-13.7%
	75%	850	30,000	$13,420	$17,053	$103,976	$134,449	$12,130	$25,858	$77,850	$115,838	($18,610)	-13.8%
	75%	1,416	50,000	$13,420	$28,422	$173,293	$215,135	$12,130	$43,096	$129,751	$184,977	($30,157)	-14.0%
	75%	2,833	100,000	$13,420	$56,843	$346,586	$416,850	$12,130	$86,193	$259,501	$357,824	($59,025)	-14.2%
	75%	6,200	218,866	$13,420	$124,411	$758,560	$896,390	$12,130	$188,646	$567,960	$768,737	($127,654)	-14.2%
	75%	12,600	444,792	$13,420	$252,835	$1,541,589	$1,807,844	$12,130	$383,378	$1,154,241	$1,549,749	($258,094)	-14.3%
HVF (T-Service)	40%	2,600	91,783	$13,420	$32,128	$18,923	$64,470	$12,130	$39,695	$22,866	$74,692	$10,222	15.9%
	40%	11,000	388,311	$13,420	$135,925	$80,057	$229,402	$12,130	$167,940	$96,742	$276,813	$47,411	20.7%
	40%	17,600	621,297	$13,420	$217,481	$128,091	$358,991	$12,130	$268,705	$154,787	$435,622	$76,631	21.3%
	75%	2,600	91,783	$13,420	$17,135	$18,923	$49,477	$12,130	$21,171	$22,866	$56,167	$6,690	13.5%
	75%	11,000	388,311	$13,420	$72,494	$80,057	$165,970	$12,130	$89,568	$96,742	$198,440	$32,470	19.6%
	75%	17,600	621,297	$13,420	$115,990	$128,091	$257,500	$12,130	$143,309	$154,787	$310,227	$52,726	20.5%
Cooperative	35%	250	8,825	$3,289	$14,042	$25,312	$42,643	$3,179	$15,008	$24,100	$42,287	($356)	-0.8%
	35%	350	12,355	$3,289	$19,659	$35,437	$58,385	$3,179	$21,012	$33,740	$57,931	($455)	-0.8%
	35%	500	17,650	$3,289	$28,084	$50,625	$81,998	$3,179	$30,016	$48,200	$81,395	($602)	-0.7%
MLC (Sales Service)	40%	2,833	100,000	$28,240	$163,725	$290,867	$482,832	$13,008	$97,211	$273,528	$383,747	($99,085)	-20.5%
	40%	14,164	500,000	$28,240	$818,626	$1,454,334	$2,301,200	$13,008	$486,053	$1,367,638	$1,866,700	($434,500)	-18.9%
	40%	28,328	1,000,000	$28,240	$1,637,252	$2,908,668	$4,574,160	$13,008	$972,106	$2,735,277	$3,720,391	($853,769)	-18.7%
	75%	2,833	100,000	$28,240	$87,320	$290,867	$406,427	$13,008	$51,846	$273,528	$338,382	($68,045)	-16.7%
	75%	14,164	500,000	$28,240	$436,601	$1,454,334	$1,919,174	$13,008	$259,228	$1,367,638	$1,639,875	($279,299)	-14.6%
	75%	28,328	1,000,000	$28,240	$873,201	$2,908,668	$3,810,109	$13,008	$518,456	$2,735,277	$3,266,741	($543,367)	-14.3%
	75%	41,000	1,447,339	$28,240	$1,263,818	$4,209,829	$5,501,888	$13,008	$750,382	$3,958,874	$4,722,264	($779,623)	-14.2%
MLC (T- Service)	40%	14,000	494,213	$28,240	$181,393	$17,293	$226,926	$13,008	$271,103	-$5,860	$278,252	$51,326	22.6%
	40%	18,000	635,417	$28,240	$233,219	$22,234	$283,693	$13,008	$348,561	-$7,534	$354,036	$70,343	24.8%
	40%	44,000	1,553,242	$28,240	$570,091	$54,349	$652,680	$13,008	$852,038	-$18,416	$846,630	$193,950	29.7%
	75%	14,000	494,213	$28,240	$96,743	$17,293	$142,276	$13,008	$144,588	-$5,860	$151,737	$9,461	6.7%
	75%	18,000	635,417	$28,240	$124,384	$22,234	$174,857	$13,008	$185,899	-$7,534	$191,374	$16,517	9.4%
	75%	44,000	1,553,242	$28,240	$304,049	$54,349	$386,638	$13,008	$454,420	-$18,416	$449,013	$62,375	16.1%
Special Contract	[redacted]												
Power Stations													
Interruptible Sales	25%	850	30,000	$12,513	$24,602	$100,479	$137,593	$12,461	$40,362	$78,702	$131,525	($6,068)	-4.4%
	40%	2,833	100,000	$12,513	$51,254	$334,929	$398,696	$12,461	$84,087	$262,341	$358,889	($39,807)	-10.0%
	40%	14,164	500,000	$12,513	$256,268	$1,674,647	$1,943,427	$12,461	$420,434	$1,311,703	$1,744,599	($198,828)	-10.2%
	75%	850	30,000	$12,513	$8,201	$100,479	$121,192	$12,461	$13,454	$78,702	$104,618	($16,575)	-13.7%
	75%	2,833	100,000	$12,513	$27,335	$334,929	$374,777	$12,461	$44,846	$262,341	$319,648	($55,129)	-14.7%
	75%	14,164	500,000	$12,513	$136,676	$1,674,647	$1,823,836	$12,461	$224,232	$1,311,703	$1,548,396	($275,439)	-15.1%

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Centra Gas Manitoba Inc.
2019/20 General Rates Application
Bill Impact Comparison
2019/20 Test Year add $1.0M to Net Income

BASE VS. BASE

				FEB 1/19 APPROVED BASE RATES				NOV 1/19 PROPOSED BASE RATES				BASE IMPACTS		
	Load Factor	Annual Use 10^3m^3	Mcf	Basic Chg	Demand	Commodity	Annual	Basic Chg	Demand	Commodity	Annual	$	%	
Small General Service		1.00	35	$168	$0	$227	$395	$168	$0	$215	$383	($12)	-3.0%	
		1.98	70	$168	$0	$450	$618	$168	$0	$426	$594	($24)	-3.8%	
(Typical Residential Customer)		2.22	78	$168	$0	$504	$672	$168	$0	$478	$646	($26)	-3.9%	
		2.80	99	$168	$0	$637	$805	$168	$0	$604	$772	($33)	-4.1%	
		3.20	113	$168	$0	$727	$895	$168	$0	$689	$857	($38)	-4.3%	
		3.68	130	$168	$0	$837	$1,005	$168	$0	$793	$961	($44)	-4.4%	
		11.33	400	$168	$0	$2,575	$2,743	$168	$0	$2,440	$2,608	($135)	-4.9%	
Large General Service		11.33	400	$924	$0	$1,974	$2,898	$924	$0	$2,009	$2,933	$35	1.2%	
		59.49	2,100	$924	$0	$10,362	$11,286	$924	$0	$10,547	$11,471	$186	1.6%	
		679.87	24,000	$924	$0	$118,420	$119,344	$924	$0	$120,541	$121,465	$2,121	1.8%	
HVF (Sales Service)	25%	850	30,000	$13,420	$51,159	$96,626	$161,205	$12,130	$53,644	$93,992	$159,766	($1,438)	-0.9%	
	40%	850	30,001	$13,420	$31,976	$96,629	$142,024	$12,130	$33,529	$93,995	$139,654	($2,370)	-1.7%	
	40%	1,416	50,000	$13,420	$53,291	$161,043	$227,753	$12,130	$55,880	$156,653	$224,663	($3,090)	-1.4%	
	40%	2,833	100,000	$13,420	$106,581	$322,086	$442,087	$12,130	$111,759	$313,306	$437,195	($4,891)	-1.1%	
	40%	6,200	218,866	$13,420	$233,271	$704,936	$951,626	$12,130	$244,603	$685,720	$942,453	($9,173)	-1.0%	
	40%	12,600	444,792	$13,420	$474,066	$1,432,611	$1,920,097	$12,130	$497,096	$1,393,560	$1,902,786	($17,311)	-0.9%	
	75%	685	24,181	$13,420	$13,745	$77,884	$105,049	$12,130	$14,413	$75,761	$102,304	($2,745)	-2.6%	
	75%	850	30,000	$13,420	$17,053	$96,626	$127,098	$12,130	$17,881	$93,992	$124,004	($3,095)	-2.4%	
	75%	1,416	50,000	$13,420	$28,422	$161,043	$202,884	$12,130	$29,802	$156,653	$198,586	($4,299)	-2.1%	
	75%	2,833	100,000	$13,420	$56,843	$322,086	$392,349	$12,130	$59,605	$313,306	$385,041	($7,308)	-1.9%	
	75%	6,200	218,866	$13,420	$124,411	$704,936	$842,767	$12,130	$130,455	$685,720	$828,305	($14,461)	-1.7%	
	75%	12,600	444,792	$13,420	$252,835	$1,432,611	$1,698,866	$12,130	$265,118	$1,393,560	$1,670,808	($28,058)	-1.7%	
HVF (T-Service)	40%	2,600	91,783	$13,420	$32,128	$18,923	$64,470	$12,130	$39,513	$26,260	$77,903	$13,433	20.8%	
	40%	11,000	388,311	$13,420	$135,925	$80,057	$229,402	$12,130	$167,170	$111,100	$290,400	$60,998	26.6%	
	40%	17,600	621,297	$13,420	$217,481	$128,091	$358,991	$12,130	$267,472	$177,760	$457,362	$98,371	27.4%	
	75%	2,600	91,783	$13,420	$17,135	$18,923	$49,477	$12,130	$21,074	$26,260	$59,464	$9,987	20.2%	
	75%	11,000	388,311	$13,420	$72,494	$80,057	$165,970	$12,130	$89,157	$111,100	$212,388	$46,417	28.0%	
	75%	17,600	621,297	$13,420	$115,990	$128,091	$257,500	$12,130	$142,652	$177,760	$332,542	$75,042	29.1%	
Cooperative	35%	250	8,825	$3,289	$14,042	$23,150	$40,481	$3,179	$15,008	$21,925	$40,112	($369)	-0.9%	
	35%	350	12,355	$3,289	$19,659	$32,410	$55,358	$3,179	$21,012	$30,695	$54,886	($472)	-0.9%	
	35%	500	17,650	$3,289	$28,084	$46,300	$77,673	$3,179	$30,016	$43,850	$77,045	($628)	-0.8%	
MLC (Sales Service)	40%	2,833	100,000	$28,240	$163,725	$266,366	$458,331	$13,008	$153,087	$252,968	$419,063	($39,268)	-8.6%	
	40%	14,164	500,000	$28,240	$818,626	$1,331,830	$2,178,696	$13,008	$765,434	$1,264,838	$2,043,280	($135,416)	-6.2%	
	40%	28,328	1,000,000	$28,240	$1,637,252	$2,663,660	$4,329,152	$13,008	$1,530,868	$2,529,676	$4,073,552	($255,600)	-5.9%	
	75%	2,833	100,000	$28,240	$87,320	$266,366	$381,926	$13,008	$81,646	$252,968	$347,622	($34,304)	-9.0%	
	75%	14,164	500,000	$28,240	$436,601	$1,331,830	$1,796,671	$13,008	$408,231	$1,264,838	$1,686,078	($110,593)	-6.2%	
	75%	28,328	1,000,000	$28,240	$873,201	$2,663,660	$3,565,101	$13,008	$816,463	$2,529,676	$3,359,147	($205,954)	-5.8%	
	75%	41,000	1,447,339	$28,240	$1,263,818	$3,855,220	$5,147,279	$13,008	$1,181,699	$3,661,300	$4,856,007	($291,272)	-5.7%	
MLC (T- Service)	40%	14,000	494,213	$28,240	$181,393	$17,293	$226,926	$13,008	$270,641	$21,000	$304,650	$77,724	34.3%	
	40%	18,000	635,417	$28,240	$233,219	$22,234	$283,693	$13,008	$347,967	$27,000	$387,976	$104,283	36.8%	
	40%	44,000	1,553,242	$28,240	$570,091	$54,349	$652,680	$13,008	$850,586	$66,000	$929,595	$276,914	42.4%	
	75%	14,000	494,213	$28,240	$96,743	$17,293	$142,276	$13,008	$144,342	$21,000	$178,350	$36,075	25.4%	
	75%	18,000	635,417	$28,240	$124,384	$22,234	$174,857	$13,008	$185,582	$27,000	$225,591	$50,734	29.0%	
	75%	44,000	1,553,242	$28,240	$304,049	$54,349	$386,638	$13,008	$453,646	$66,000	$532,655	$146,017	37.8%	
Special Contract	[redacted]													2d
Power Stations														
Interruptible Sales	25%	850	30,000	$12,513	$24,602	$93,682	$130,796	$12,461	$26,688	$87,958	$127,107	($3,689)	-2.8%	
	40%	2,833	100,000	$12,513	$51,254	$312,273	$376,039	$12,461	$55,600	$293,193	$361,255	($14,784)	-3.9%	
	40%	14,164	500,000	$12,513	$256,268	$1,561,364	$1,830,144	$12,461	$278,001	$1,465,966	$1,756,428	($73,716)	-4.0%	
	75%	850	30,000	$12,513	$8,201	$93,682	$114,395	$12,461	$8,896	$87,958	$109,315	($5,080)	-4.4%	
	75%	2,833	100,000	$12,513	$27,335	$312,273	$352,121	$12,461	$29,653	$293,193	$335,308	($16,813)	-4.8%	
	75%	14,164	500,000	$12,513	$136,676	$1,561,364	$1,710,553	$12,461	$148,267	$1,465,966	$1,626,694	($83,859)	-4.9%	

Centra Gas Manitoba Inc.
2019/20 General Rates Application
Summary of Allocated Costs by Customer Class
2019/20 Test Year add $2.5M to Net Income

CAC/CENTRA II-142 c) Part ii)
Schedule 10.1.0

Cost of Service Elements

	SGS				LGS				
	Demand	Energy	Customer	Total	Demand	Energy	Customer	Total	
Cost of Gas	30,833,940	1,508,864	0	32,342,804	23,574,981	1,125,616	0	24,700,597	
Other Income	-68,359	-452	-971,164	-1,039,974	-52,295	-345	-42,146	-94,785	
Operating & Maintenance Expenses	7,480,011	49,422	36,957,610	44,487,044	5,722,216	37,698	4,337,539	10,097,453	
Depreciation & Amortization	4,151,323	5,772,166	11,448,390	21,371,879	2,830,956	3,782,173	2,347,647	8,960,777	
Capital & Other Taxes	3,733,200	481,347	9,359,157	13,573,703	2,855,659	336,945	1,483,793	4,676,397	
Finance Expense	3,320,126	1,580,044	9,450,824	14,350,994	2,538,509	1,105,897	1,574,658	5,219,064	
Corporate Allocation	1,844,236	877,669	5,249,665	7,971,570	1,410,070	614,295	874,678	2,899,042	
Net Income	832,103	395,997	2,368,602	3,596,702	636,211	277,164	394,647	1,308,022	
Total Cost of Service	52,126,580	10,665,057	73,863,085	136,654,722	39,516,306	7,279,444	10,970,816	57,766,566	

	HVF				Cooperative				
	Demand	Energy	Customer	Total	Demand	Energy	Customer	Total	
Cost of Gas	6,583,125	344,193	0	6,927,317	11,535	205	0	11,740	
Other Income	-16,483	-103	-9,092	-25,678	-20	0	-20	-40	
Operating & Maintenance Expenses	1,803,632	11,245	960,145	2,775,022	2,146	10	2,117	4,273	
Depreciation & Amortization	807,071	299,213	175,809	1,282,093	691	1	428	1,120	
Capital & Other Taxes	871,577	60,960	81,435	1,013,972	761	62	263	1,087	
Finance Expense	773,549	199,878	79,597	1,053,024	631	204	225	1,061	
Corporate Allocation	429,684	111,027	44,214	584,925	351	114	125	589	
Net Income	193,870	50,094	19,949	263,913	158	51	56	266	
Total Cost of Service	11,446,025	1,076,506	1,352,058	13,874,589	16,253	648	3,195	20,096	

	Main Line				Special Contract				
	Demand	Energy	Customer	Total	Demand	Energy	Customer	Total	
Cost of Gas	112,234	111,897	0	224,131	[redacted]				1d
Other Income	-7,608	-4	-767	-8,380	-7,072	-1	-86	-7,159	
Operating & Maintenance Expenses	832,509	444	80,931	913,884	773,792	92	8,563	782,447	
Depreciation & Amortization	282,968	99,452	15,830	398,251	202,213	-8	8,098	210,304	
Capital & Other Taxes	289,416	6,578	7,772	303,766	522,063	12	6,710	528,785	
Finance Expense	237,342	21,604	7,668	266,615	427,520	36	6,153	433,709	
Corporate Allocation	131,837	12,001	4,260	148,097	237,475	20	3,418	240,913	
Net Income	59,484	5,415	1,922	66,820	107,147	9	1,542	108,698	
Total Cost of Service	1,938,181	257,388	117,615	2,313,185	[redacted]				1e

	Power Station				Interruptible				
	Demand	Energy	Customer	Total	Demand	Energy	Customer	Total	
Cost of Gas	[redacted]				690,449	190,673	0	881,122	1d
Other Income	-564	-2	-195	-760	-1,578	-25	-1,629	-3,232	
Operating & Maintenance Expenses	61,728	181	17,129	79,038	172,679	2,739	171,800	347,217	
Depreciation & Amortization	-98,749	-15	43,729	-55,035	61,704	166	34,224	96,093	
Capital & Other Taxes	16,193	24	37,809	54,025	86,467	10,642	16,482	113,591	
Finance Expense	12,705	71	34,909	47,685	76,609	34,857	16,333	127,799	
Corporate Allocation	7,058	39	19,391	26,488	42,554	19,362	9,072	70,989	
Net Income	3,184	18	8,749	11,951	19,200	8,736	4,093	32,029	
Total Cost of Service	[redacted]				1,148,084	267,148	250,376	1,665,608	1e

	Primary Gas				Supplemental Gas - Firm				
	Demand	Energy	Customer	Total	Demand	Energy	Customer	Total	
Cost of Gas	[redacted]				[redacted]				1a
Other Income									
Operating & Maintenance Expenses									
Depreciation & Amortization									
Capital & Other Taxes									1e
Finance Expense									
Corporate Allocation									
Net Income									
Total Cost of Service									1e

	Supplemental Gas - Interruptible				Fixed Price Offering				
	Demand	Energy	Customer	Total	Demand	Energy	Customer	Total	
Cost of Gas	[redacted]				0	44,879	0	44,879	1a
Other Income					0	-4	-171	-175	
Operating & Maintenance Expenses					0	419	18,750	19,168	
Depreciation & Amortization					0	33	1,486	1,520	
Capital & Other Taxes					0	18	304	323	1e
Finance Expense					0	41	146	187	
Corporate Allocation					0	23	81	104	
Net Income					0	10	36	47	
Total Cost of Service					0	45,420	20,632	66,052	1e

	Unassigned				Total			
	Demand	Energy	Customer	Total	Demand	Energy	Customer	Total
Cost of Gas	0	0	0	0	61,836,486	115,428,348	0	177,264,835
Other Income	0	0	0	0	-153,978	-10,480	-1,025,270	-1,189,728
Operating & Maintenance Expenses	0	0	0	0	16,848,713	1,146,704	42,554,583	60,550,000
Depreciation & Amortization	0	0	0	0	8,238,176	10,035,983	14,075,643	32,349,802
Capital & Other Taxes	0	0	0	0	8,375,335	942,443	10,993,726	20,311,504
Finance Expense	0	0	0	0	7,386,993	3,045,757	11,170,512	21,603,263
Corporate Allocation	0	0	0	0	4,103,265	1,691,832	6,204,903	12,000,000
Net Income	0	0	0	0	1,851,357	763,340	2,799,597	5,414,294
Total Cost of Service	0	0	0	0	108,486,347	133,043,928	86,773,695	328,303,970

CAC/CENTRA II-142 c) Part ii)
Schedule 10.1.1

Centra Gas Manitoba Inc.
2019/20 General Rates Application
Unit Cost Component Summary
2019/20 Test Year add $2.5M to Net Income

		ROR	System Total	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Fixed Price Offering FRPGS	
1	REVENUE REQUIREMENTS		[redacted]													
2	Upstream Demand ($)															
3	Upstream Commodity ($)															
4	Upstream Customer ($)															
5	Upstream Total ($)															
6																1e
7	Downstream Demand ($)															
8	Downstream Commodity ($)															
9	Downstream Customer ($)															
10	Downstream Total ($)															
11																
12	Total (incl. gas costs)															
13																
14																
15	MONTHLY BILLING DETERMINANTS		[redacted]													
16	Upstream Demand (10^3m^3-day)															
17	Upstream Commodity (10^3m^3)															
18	Upstream Customer (customers)															
19																
20	Downstream Demand (10^3m^3-day)															1d
21	Downstream Commodity (10^3m^3)															
22	Downstream Customer (customers)															
23																
24	PERCENT IN DEMAND CHARGE			0.0%	0.0%	65.0%	100.0%	100.0%	100.0%	100.0%	65.0%	100.0%	100.0%	100.0%	100.0%	
25																
26	RESULTING UNIT CHARGES															
27	Upstream Demand ($/$10^3m^3$-day)		454.753	0.000	0.000	295.061	470.620	422.321	0.000	0.000	149.294	0.000	0.000	0.000	0.000	
28	Upstream Commodity ($/$10^3m^3$)		80.407	49.807	48.144	15.250	2.399	2.598	0.000	0.000	8.139	76.911	134.903	134.300	80.886	
29	Upstream Customer ($/customer)		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
30																
31	Downstream Demand ($/$10^3m^3$-day)		253.434	0.000	0.000	187.062	170.229	237.379	139.809	0.240	90.654	0.000	0.000	0.000	0.000	
32	Downstream Commodity ($/$10^3m^3$)		7.356	42.199	38.446	10.189	0.000	1.531	0.096	18.306	6.449	0.000	0.000	0.000	0.000	
33	Downstream Customer ($/customer)		25.128	22.037	110.015	1,015.058	266.241	1,089.032	2,866.406	6,730.051	1,043.234	0.000	0.000	0.000	0.000	

CAC/CENTRA II-142 c) Part ii)
Schedule 10.1.2

Centra Gas Manitoba Inc.
2019/20 General Rates Application
Comparison of Gas Costs vs. Non-Gas Costs
2019/20 Test Year add $2.5M to Net Income

Line	Gas Costs vs. Non-Gas Costs	ROR	System Total	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Fixed Price Offering FRPGS	
1	REVENUE REQUIREMENTS															
2	Upstream Demand ($)	Upstream Demand ($)														
3	Gas Costs	Gas Costs	61,638,042	30,756,386	23,515,600	6,564,891	11,505	101,088	0	0	688,573	0	0	0	0	
4	Non-gas Costs	Non-gas Costs	2,305,753	1,150,533	879,670	245,579	430	3,781	0	0	25,758	0	0	0	0	
5	Total	Total	63,943,795	31,906,920	24,395,270	6,810,470	11,936	104,869	0	0	714,331	0	0	0	0	
6			0	0	0	0	0	0	0	0	0	0	0	0	0	
7	Upstream Commodity ($)	Upstream Commodity ($)														
8	Gas Costs	Gas Costs	113,950,265	941,280	719,143	214,121	205	3,997	0	0	47,299	[redacted]			44,879	
9	Non-gas Costs	Non-gas Costs	3,798,959	1,143,679	904,115	317,482	443	6,963	0	0	75,918				541	1a,1e
10	Total	Total	117,749,225	2,084,959	1,623,259	531,603	648	10,960	0	0	123,217				45,420	
11			0	0	0	0	0	0	0	0	0	0	0	0	0	
12	Upstream Customer ($)	Upstream Customer ($)														
13	Gas Costs	Gas Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	
14	Non-gas Costs	Non-gas Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	
15	Total	Total	0	0	0	0	0	0	0	0	0	0	0	0	0	
16																
17	Upstream Total ($)	Upstream Total ($)														
18	Total Gas Costs	Total Gas Costs	175,588,308	31,697,666	24,234,743	6,779,012	11,711	105,085	0	0	735,872	[redacted]			44,879	1e
19	Total Non-gas Costs	Total Non-gas Costs	6,104,712	2,294,212	1,783,786	563,061	873	10,744	0	0	101,676				541	
20	Total Upstream Costs	Total Upstream Costs	181,693,020	33,991,879	26,018,529	7,342,073	12,584	115,829	0	0	837,548				45,420	
21			0	0	0	0	0	0	0	0	0	0	0	0	0	
22	Downstream Demand ($)	Downstream Demand ($)														
23	Gas Costs	Gas Costs	198,444	77,554	59,381	18,234	29	11,146	[redacted]		1,876	0	0	0	0	2d,1e
24	Non-gas Costs	Non-gas Costs	44,344,107	20,142,107	15,061,655	4,617,321	4,288	1,822,166	2,263,140	1,554	431,877	0	0	0	0	
25	Total	Total	44,542,551	20,219,660	15,121,036	4,635,555	4,317	1,833,312	[redacted]		433,753	0	0	0	0	
26																
27	Downstream Commodity ($)	Downstream Commodity ($)														
28	Gas Costs	Gas Costs	1,478,083	567,584	406,473	130,071	0	107,900	[redacted]		143,374	0	0	0	0	2d,1e
29	Non-gas Costs	Non-gas Costs	13,816,620	8,012,514	5,249,713	414,832	0	138,528	161	316	557	0	0	0	0	
30	Total	Total	15,294,703	8,580,098	5,656,185	544,903	0	246,428	[redacted]		143,931	0	0	0	0	
31																
32	Downstream Customer ($)	Downstream Customer ($)														
33	Gas Costs	Gas Costs	0	0	0	0	0	0	[redacted]		0	0	0	0	0	
34	Non-gas Costs	Non-gas Costs	86,773,695	73,863,085	10,970,816	1,352,058	3,195	117,615	34,397	161,521	250,376	0	0	0	20,632	2d,1e
35	Total	Total	86,773,695	73,863,085	10,970,816	1,352,058	3,195	117,615	[redacted]		250,376	0	0	0	20,632	
36																
37	Downstream Total ($)	Downstream Total ($)														
38	Total Gas Costs	Total Gas Costs	1,676,527	645,137	465,854	148,306	29	119,046	[redacted]		145,250	0	0	0	0	
39	Total Non-gas Costs	Total Non-gas Costs	144,934,422	102,017,705	31,282,183	6,384,211	7,483	2,078,309	2,297,697	163,391	682,810	0	0	0	20,632	2d,1e
40	Total Downstream Costs	Total Downstream Costs	146,610,949	102,662,843	31,748,037	6,532,516	7,512	2,197,356	[redacted]		828,061	0	0	0	20,632	
41																
42	Grand Total Gas Costs	Grand Total Gas Costs	177,264,835	32,342,804	24,700,597	6,927,317	11,740	224,131	[redacted]		881,122	[redacted]			44,879	
43	Grand Total Non-gas Costs	Grand Total Non-gas Costs	151,039,135	104,311,918	33,065,969	6,947,272	8,356	2,089,054	2,297,697	163,391	784,487				21,173	2d,1e
44	Grand Total	Grand Total	328,303,970	136,654,722	57,766,566	13,874,589	20,096	2,313,185	[redacted]		1,665,608				66,052	
45																
46																

47 Calculation of the Primary Gas Overhead Rate: [redacted] line 9, PG column)
48 10³m³ (Schedule 10.1.1, line 17, PG column)
49 0.92 10³m³

Calculation of the Fixed Rate Primary Gas PCR
21,173 (lines 9 & 34, FPO column)
562 (10^3m^3 (Schedule 10.1.1, line 17, FPO column) 1e
37.71 per 10^3m^3

CAC/CENTRA II-142 c) Part ii)
Schedule 10.1.3

Centra Gas Manitoba Inc.
2019/20 General Rate Application
Total Functionalization By Customer Class
2019/20 Test Year add $2.5M to Net Income

		System Total	Residential SGS-R	Small Commercial SGS-C	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Fixed Price Offering FPO	
1	PRODUCTION		[redacted]														
2	Demand	0															
3	Energy	113,374,579															1a
4	Customer	0															
5	Total	113,374,579															
6																	
7	PIPELINE																
8	Demand	44,877,635															
9	Energy	0															1a
10	Customer	0															
11	Total	44,877,635															
12																	
13	STORAGE																
14	Demand	19,066,160															
15	Energy	4,374,646															1a
16	Customer	0															
17	Total	23,440,806															
18																	
19	TRANSMISSION																
20	Demand	17,448,662															
21	Energy	15,294,703															1a
22	Customer	0															
23	Total	32,743,365															
24																	
25	DISTRIBUTION									[redacted]			[redacted]				
26	Demand	27,093,890	10,954,998	2,094,375	13,049,373	9,979,266	3,032,135	1,953	735,687			295,476				0	
27	Energy	0	0	0	0	0	0	0	0			0				0	
28	Customer	11,232,989	10,190,117	713,338	10,903,455	324,394	4,333	2	20			781				0	2d,1e
29	Total	38,326,879	21,145,115	2,807,713	23,952,828	10,303,660	3,036,468	1,955	735,707			296,257				0	
30																	
31	ONSITE																
32	Demand	0	0	0	0	0	0	0	0			0				0	
33	Energy	0	0	0	0	0	0	0	0			0				0	2d,1e
34	Customer	75,540,706	56,451,991	6,507,638	62,959,629	10,646,422	1,347,725	3,193	117,596			249,595				20,632	
35	Total	75,540,706	56,451,991	6,507,638	62,959,629	10,646,422	1,347,725	3,193	117,596			249,595				20,632	
36																	
37	TOTAL SERVICE																
38	Demand	108,486,347	43,714,337	8,412,243	52,126,580	39,516,306	11,446,025	16,253	1,938,181			1,148,084				0	
39	Energy	133,043,928	8,170,772	2,494,285	10,665,057	7,279,444	1,076,506	648	257,388			267,148				45,420	2d,1e
40	Customer	86,773,695	66,642,109	7,220,976	73,863,085	10,970,816	1,352,058	3,195	117,615			250,376				20,632	
41	Total	328,303,970	118,527,218	18,127,504	136,654,722	57,766,566	13,874,589	20,096	2,313,185			1,665,608				66,052	

CAC/CENTRA II-142 c) Part ii)
Schedule 11.1.0
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Centra Gas Manitoba Inc.
2019/20 General Rates Application
Bill Impact Comparison
2019/20 Test Year add $2.5M to Net Income

BILLED VS. BILLED

	Load Factor	Annual Use 10^3m^3	Mcf	FEB 1/19 APPROVED BILLED RATES Basic Chg	Demand	Commodity	Annual	NOV 1/19 PROPOSED BILLED RATES Basic Chg	Demand	Commodity	Annual	BILL IMPACTS $	%
Small General Service		1.00	35	$168	$0	$236	$404	$168	$0	$220	$388	($16)	-3.9%
		1.98	70	$168	$0	$468	$636	$168	$0	$436	$604	($32)	-5.0%
(Typical Residential Customer)		2.22	78	$168	$0	$523	$691	$168	$0	$488	$656	($35)	-5.1%
		2.80	99	$168	$0	$662	$830	$168	$0	$617	$785	($45)	-5.4%
		3.20	113	$168	$0	$755	$923	$168	$0	$704	$872	($51)	-5.5%
		3.68	130	$168	$0	$869	$1,037	$168	$0	$810	$978	($59)	-5.7%
		11.33	400	$168	$0	$2,673	$2,841	$168	$0	$2,492	$2,660	($181)	-6.4%
Large General Service		11.33	400	$924	$0	$2,072	$2,996	$924	$0	$2,067	$2,991	($5)	-0.2%
		59.49	2,100	$924	$0	$10,879	$11,803	$924	$0	$10,852	$11,776	($28)	-0.2%
		679.87	24,000	$924	$0	$124,335	$125,259	$924	$0	$124,020	$124,944	($315)	-0.3%
HVF (Sales Service)	25%	850	30,000	$13,420	$51,159	$103,976	$168,555	$12,181	$77,819	$77,935	$167,935	($619)	-0.4%
	40%	850	30,000	$13,420	$31,974	$103,976	$149,370	$12,181	$48,637	$77,935	$138,753	($10,617)	-7.1%
	40%	1,416	50,000	$13,420	$53,291	$173,293	$240,004	$12,181	$81,062	$129,892	$223,135	($16,869)	-7.0%
	40%	2,833	100,000	$13,420	$106,581	$346,586	$466,588	$12,181	$162,124	$259,784	$434,089	($32,499)	-7.0%
	40%	6,200	218,866	$13,420	$233,271	$758,560	$1,005,250	$12,181	$354,833	$568,580	$935,594	($69,656)	-6.9%
	40%	12,600	444,792	$13,420	$474,066	$1,541,589	$2,029,075	$12,181	$721,113	$1,155,501	$1,888,794	($140,280)	-6.9%
	75%	685	24,181	$13,420	$13,745	$83,809	$110,974	$12,181	$20,908	$62,819	$95,908	($15,066)	-13.6%
	75%	850	30,000	$13,420	$17,053	$103,976	$134,449	$12,181	$25,940	$77,935	$116,056	($18,393)	-13.7%
	75%	1,416	50,000	$13,420	$28,422	$173,293	$215,135	$12,181	$43,233	$129,892	$185,306	($29,829)	-13.9%
	75%	2,833	100,000	$13,420	$56,843	$346,586	$416,850	$12,181	$86,466	$259,784	$358,431	($58,418)	-14.0%
	75%	6,200	218,866	$13,420	$124,411	$758,560	$896,390	$12,181	$189,244	$568,580	$770,005	($126,385)	-14.1%
	75%	12,600	444,792	$13,420	$252,835	$1,541,589	$1,807,844	$12,181	$384,593	$1,155,501	$1,552,275	($255,569)	-14.1%
HVF (T-Service)	40%	2,600	91,783	$13,420	$32,128	$18,923	$64,470	$12,181	$40,165	$23,126	$75,472	$11,002	17.1%
	40%	11,000	388,311	$13,420	$135,925	$80,057	$229,402	$12,181	$169,930	$97,842	$279,952	$50,550	22.0%
	40%	17,600	621,297	$13,420	$217,481	$128,091	$358,991	$12,181	$271,887	$156,547	$440,615	$81,624	22.7%
	75%	2,600	91,783	$13,420	$17,135	$18,923	$49,477	$12,181	$21,421	$23,126	$56,728	$7,251	14.7%
	75%	11,000	388,311	$13,420	$72,494	$80,057	$165,970	$12,181	$90,629	$97,842	$200,652	$34,682	20.9%
	75%	17,600	621,297	$13,420	$115,990	$128,091	$257,500	$12,181	$145,007	$156,547	$313,734	$56,234	21.8%
Cooperative	35%	250	8,825	$3,289	$14,042	$25,312	$42,643	$3,195	$15,048	$24,125	$42,368	($275)	-0.6%
	35%	350	12,355	$3,289	$19,659	$35,437	$58,385	$3,195	$21,067	$33,775	$58,037	($348)	-0.6%
	35%	500	17,650	$3,289	$28,084	$50,625	$81,998	$3,195	$30,096	$48,250	$81,541	($457)	-0.6%
MLC (Sales Service)	40%	2,833	100,000	$28,240	$163,725	$290,867	$482,832	$13,068	$97,723	$273,811	$384,602	($98,230)	-20.3%
	40%	14,164	500,000	$28,240	$818,626	$1,454,334	$2,301,200	$13,068	$488,614	$1,369,055	$1,870,737	($430,463)	-18.7%
	40%	28,328	1,000,000	$28,240	$1,637,252	$2,908,668	$4,574,160	$13,068	$977,228	$2,738,109	$3,728,406	($845,754)	-18.5%
	75%	2,833	100,000	$28,240	$87,320	$290,867	$406,427	$13,068	$52,119	$273,811	$338,998	($67,429)	-16.6%
	75%	14,164	500,000	$28,240	$436,601	$1,454,334	$1,919,174	$13,068	$260,594	$1,369,055	$1,642,717	($276,457)	-14.4%
	75%	28,328	1,000,000	$28,240	$873,201	$2,908,668	$3,810,109	$13,068	$521,188	$2,738,109	$3,272,366	($537,743)	-14.1%
	75%	41,000	1,447,339	$28,240	$1,263,818	$4,209,829	$5,501,888	$13,068	$754,336	$3,962,974	$4,730,378	($771,509)	-14.0%
MLC (T- Service)	40%	14,000	494,213	$28,240	$181,393	$17,293	$226,926	$13,068	$273,634	-$5,860	$280,843	$53,918	23.8%
	40%	18,000	635,417	$28,240	$233,219	$22,234	$283,693	$13,068	$351,816	-$7,534	$357,350	$73,657	26.0%
	40%	44,000	1,553,242	$28,240	$570,091	$54,349	$652,680	$13,068	$859,994	-$18,416	$854,646	$201,966	30.9%
	75%	14,000	494,213	$28,240	$96,743	$17,293	$142,276	$13,068	$145,938	-$5,860	$153,147	$10,872	7.6%
	75%	18,000	635,417	$28,240	$124,384	$22,234	$174,857	$13,068	$187,635	-$7,534	$193,170	$18,312	10.5%
	75%	44,000	1,553,242	$28,240	$304,049	$54,349	$386,638	$13,068	$458,664	-$18,416	$453,316	$66,678	17.2%
Special Contract	[redacted]												2d
Power Stations													
Interruptible Sales	25%	850	30,000	$12,513	$24,602	$100,479	$137,593	$12,519	$40,496	$78,702	$131,717	($5,876)	-4.3%
	40%	2,833	100,000	$12,513	$51,254	$334,929	$398,696	$12,519	$84,366	$262,341	$359,226	($39,470)	-9.9%
	40%	14,164	500,000	$12,513	$256,268	$1,674,647	$1,943,427	$12,519	$421,831	$1,311,703	$1,746,054	($197,374)	-10.2%
	75%	850	30,000	$12,513	$8,201	$100,479	$121,192	$12,519	$13,499	$78,702	$104,720	($16,472)	-13.6%
	75%	2,833	100,000	$12,513	$27,335	$334,929	$374,777	$12,519	$44,995	$262,341	$319,855	($54,923)	-14.7%
	75%	14,164	500,000	$12,513	$136,676	$1,674,647	$1,823,836	$12,519	$224,977	$1,311,703	$1,549,199	($274,637)	-15.1%

CAC/CENTRA II-142 c) Part ii)
Schedule 11.1.0
Page 2 of 2

Centra Gas Manitoba Inc.
2019/20 General Rates Application
Bill Impact Comparison
2019/20 Test Year add $2.5M to Net Income

BASE VS. BASE

	Load Factor	Annual Use 10^3m^3	Annual Use Mcf	FEB 1/19 APPROVED BASE RATES Basic Chg	Demand	Commodity	Annual	NOV 1/19 PROPOSED BASE RATES Basic Chg	Demand	Commodity	Annual	BASE IMPACTS $	%
Small General Service		1.00	35	$168	$0	$227	$395	$168	$0	$217	$385	($10)	-2.6%
		1.98	70	$168	$0	$450	$618	$168	$0	$429	$597	($21)	-3.3%
(Typical Residential Customer)		2.22	78	$168	$0	$504	$672	$168	$0	$481	$649	($23)	-3.4%
		2.80	99	$168	$0	$637	$805	$168	$0	$608	$776	($29)	-3.6%
		3.20	113	$168	$0	$727	$895	$168	$0	$694	$862	($33)	-3.7%
		3.68	130	$168	$0	$837	$1,005	$168	$0	$798	$966	($38)	-3.8%
		11.33	400	$168	$0	$2,575	$2,743	$168	$0	$2,457	$2,625	($118)	-4.3%
Large General Service		11.33	400	$924	$0	$1,974	$2,898	$924	$0	$2,016	$2,940	$42	1.5%
		59.49	2,100	$924	$0	$10,362	$11,286	$924	$0	$10,583	$11,507	$221	2.0%
		679.87	24,000	$924	$0	$118,420	$119,344	$924	$0	$120,949	$121,873	$2,529	2.1%
HVF (Sales Service)	25%	850	30,000	$13,420	$51,159	$96,626	$161,205	$12,181	$53,890	$94,077	$160,148	($1,057)	-0.7%
	40%	850	30,001	$13,420	$31,976	$96,629	$142,024	$12,181	$33,683	$94,080	$139,943	($2,081)	-1.5%
	40%	1,416	50,000	$13,420	$53,291	$161,043	$227,753	$12,181	$56,136	$156,795	$225,111	($2,642)	-1.2%
	40%	2,833	100,000	$13,420	$106,581	$322,086	$442,087	$12,181	$112,271	$313,589	$438,041	($4,046)	-0.9%
	40%	6,200	218,866	$13,420	$233,271	$704,936	$951,626	$12,181	$245,724	$686,340	$944,245	($7,382)	-0.8%
	40%	12,600	444,792	$13,420	$474,066	$1,432,611	$1,920,097	$12,181	$499,374	$1,394,820	$1,906,375	($13,722)	-0.7%
	75%	685	24,181	$13,420	$13,745	$77,884	$105,049	$12,181	$14,479	$75,830	$102,489	($2,560)	-2.4%
	75%	850	30,000	$13,420	$17,053	$96,626	$127,098	$12,181	$17,963	$94,077	$124,221	($2,878)	-2.3%
	75%	1,416	50,000	$13,420	$28,422	$161,043	$202,884	$12,181	$29,939	$156,795	$198,914	($3,970)	-2.0%
	75%	2,833	100,000	$13,420	$56,843	$322,086	$392,349	$12,181	$59,878	$313,589	$385,648	($6,701)	-1.7%
	75%	6,200	218,866	$13,420	$124,411	$704,936	$842,767	$12,181	$131,053	$686,340	$829,573	($13,193)	-1.6%
	75%	12,600	444,792	$13,420	$252,835	$1,432,611	$1,698,866	$12,181	$266,333	$1,394,820	$1,673,334	($25,533)	-1.5%
HVF (T-Service)	40%	2,600	91,783	$13,420	$32,128	$18,923	$64,470	$12,181	$39,983	$26,520	$78,684	$14,214	22.0%
	40%	11,000	388,311	$13,420	$135,925	$80,057	$229,402	$12,181	$169,159	$112,200	$293,540	$64,138	28.0%
	40%	17,600	621,297	$13,420	$217,481	$128,091	$358,991	$12,181	$270,654	$179,520	$462,355	$103,364	28.8%
	75%	2,600	91,783	$13,420	$17,135	$18,923	$49,477	$12,181	$21,324	$26,520	$60,025	$10,548	21.3%
	75%	11,000	388,311	$13,420	$72,494	$80,057	$165,970	$12,181	$90,218	$112,200	$214,599	$48,629	29.3%
	75%	17,600	621,297	$13,420	$115,990	$128,091	$257,500	$12,181	$144,349	$179,520	$336,050	$78,549	30.5%
Cooperative	35%	250	8,825	$3,289	$14,042	$23,150	$40,481	$3,195	$15,048	$21,950	$40,193	($288)	-0.7%
	35%	350	12,355	$3,289	$19,659	$32,410	$55,358	$3,195	$21,067	$30,730	$54,992	($366)	-0.7%
	35%	500	17,650	$3,289	$28,084	$46,300	$77,673	$3,195	$30,096	$43,900	$77,191	($482)	-0.6%
MLC (Sales Service)	40%	2,833	100,000	$28,240	$163,725	$266,366	$458,331	$13,068	$153,599	$253,251	$419,918	($38,413)	-8.4%
	40%	14,164	500,000	$28,240	$818,626	$1,331,830	$2,178,696	$13,068	$767,995	$1,266,254	$2,047,318	($131,378)	-6.0%
	40%	28,328	1,000,000	$28,240	$1,637,252	$2,663,660	$4,329,152	$13,068	$1,535,990	$2,532,509	$4,081,567	($247,585)	-5.7%
	75%	2,833	100,000	$28,240	$87,320	$266,366	$381,926	$13,068	$81,919	$253,251	$348,239	($33,687)	-8.8%
	75%	14,164	500,000	$28,240	$436,601	$1,331,830	$1,796,671	$13,068	$409,597	$1,266,254	$1,688,920	($107,751)	-6.0%
	75%	28,328	1,000,000	$28,240	$873,201	$2,663,660	$3,565,101	$13,068	$819,195	$2,532,509	$3,364,772	($200,329)	-5.6%
	75%	41,000	1,447,339	$28,240	$1,263,818	$3,855,220	$5,147,279	$13,068	$1,185,653	$3,665,400	$4,864,121	($283,158)	-5.5%
MLC (T- Service)	40%	14,000	494,213	$28,240	$181,393	$17,293	$226,926	$13,068	$273,173	$21,000	$307,241	$80,315	35.4%
	40%	18,000	635,417	$28,240	$233,219	$22,234	$283,693	$13,068	$351,222	$27,000	$391,290	$107,597	37.9%
	40%	44,000	1,553,242	$28,240	$570,091	$54,349	$652,680	$13,068	$858,542	$66,000	$937,611	$284,931	43.7%
	75%	14,000	494,213	$28,240	$96,743	$17,293	$142,276	$13,068	$145,692	$21,000	$179,760	$37,485	26.3%
	75%	18,000	635,417	$28,240	$124,384	$22,234	$174,857	$13,068	$187,318	$27,000	$227,387	$52,529	30.0%
	75%	44,000	1,553,242	$28,240	$304,049	$54,349	$386,638	$13,068	$457,889	$66,000	$536,958	$150,320	38.9%
Special Contract	[redacted]												
Power Stations													
Interruptible Sales	25%	850	30,000	$12,513	$24,602	$93,682	$130,796	$12,519	$26,822	$87,958	$127,299	($3,497)	-2.7%
	40%	2,833	100,000	$12,513	$51,254	$312,273	$376,039	$12,519	$55,880	$293,193	$361,591	($14,448)	-3.8%
	40%	14,164	500,000	$12,513	$256,268	$1,561,364	$1,830,144	$12,519	$279,398	$1,465,966	$1,757,882	($72,262)	-3.9%
	75%	850	30,000	$12,513	$8,201	$93,682	$114,395	$12,519	$8,941	$87,958	$109,417	($4,978)	-4.4%
	75%	2,833	100,000	$12,513	$27,335	$312,273	$352,121	$12,519	$29,802	$293,193	$335,514	($16,606)	-4.7%
	75%	14,164	500,000	$12,513	$136,676	$1,561,364	$1,710,553	$12,519	$149,012	$1,465,966	$1,627,497	($83,056)	-4.9%

2d

Centra Gas Manitoba Inc.
2019/20 General Rate Application
Allocation Results - Riders 2015/16 Gas Year
Removal of Heating Value per CAC-II-142

CAC/CENTRA II-142 c)
Schedule 11.3.0 (a)

Calculation of Riders for 2019/20 Rates
Fixed Costs

		SGS		LGS		High Volume Firm		Co-op		Mainline		Interruptible		Special Contract		Power Stations		
		Transportation	Distribution	Transportation	Distribution	Transportation	Distribution	Transportation	Distribution	Transportation	Distribution	Transportation	Distribution	Transportation	Distribution	Transportation	Distribution	
														2d		1e		
1																		
2	Year 2015/16 Allocated Gas Costs--INFLOWS	30,363,839	75,464	23,092,431	57,518	6,289,521	19,365	0	0	144,340	10,431	691,310	2,567	[redacted]				
3	Year 2015/16 WACOG--OUTFLOWS	0	0	0	0	3,767,733	9,882	0	0	124,774	7,886	409,344	525					
4																		
5	Year 2015/16 PGVA (Principal Only)	30,363,839	75,464	23,092,431	57,518	2,521,788	9,483	0	0	19,566	2,545	281,966	2,042					
6																		
7	2015/16 Cap Mgmt (incl carrying costs)	-2,719,797		-2,068,471		-563,375		0		-12,929		-61,923						
8																		
9	Total	27,644,042	75,464	21,023,960	57,518	1,958,413	9,483	0	0	6,637	2,545	220,043	2,042					
10																		
11	Transfer to Variable	[redacted]																1e
12	Balance in Demand																	1e
13																		
14	**NET REFUND/RECOVERY**																	1e
15																		

16 **Variable Costs**

		SGS		LGS		High Volume Firm		Co-op		Mainline		Interruptible		Special Contract		Power Stations		Supplemental	Supplemental	Total	
17																					
18		Transportation	Distribution	Transportation	Distribution	Transportation	Distribution	Transportation	Distribution	Transportation	Distribution	Transportation	Distribution	Transportation	Distribution	Transportation	Distribution	Firm	Interruptible		
19																					
20																					
21	Year 2015/16 Allocated Gas Costs--INFLOWS	2,523,337	140,414	1,973,982	100,557	611,239	32,178	0	0	15,249	26,693	156,621	35,469	[redacted]							1a,1e
22	Year 2015/16 WACOG--OUTFLOWS	27,960,815	836,552	21,177,611	616,827	2,266,564	179,386	0	0	5,719	157,950	259,772	227,701								
23																					
24	Year 2015/16 PGVA (Principal Only)	-25,437,477	-696,137	-19,203,629	-516,270	-1,655,325	-147,207	0	0	9,530	-131,256	-103,151	-192,232								1e
25																					
26	2015/16 Heating Value (incl carrying costs)		0		0		0		0		0		0		0		0				
27																					
28	Prior Period Residuals (incl. carrying costs)	[redacted]																			1e
29																					
30	2015/16 Carrying Costs	298,131	-43,085	226,736	-31,845	61,754	-9,560	0	0	1,417	-8,935	6,788	-13,202								1e
31																					
32	Transfer from Fixed	[redacted]																			1e
33																					
34	Total Variable																				1e
35																					
36	**NET REFUND/RECOVERY**																				1e
37																					

38 **Summary of Schedule 8.8.6**

		Principal	Carrying Cost	Total	Per Schedule 8.8.6 (line 14)	Per Schedule 8.8.6 (line 15)	Per Schedule 8.8.6 (line 16)	Per Schedule 8.8.6 (line 15)	Per Schedule 8.8.6 (line 17)	Per Schedule 8.8.6 (line 20)	Total		
39													
40													
41	Supplemental PGVA	[redacted]									[redacted]		1a, 1e
42	Transportation PGVA[1]	9,889,537	594,825	10,484,363		10,484,363					10,484,363		
43	Distribution PGVA	-1,576,738	-109,450	-1,686,188			-1,686,188				-1,686,188		
44	Capacity Management			-5,426,495				-5,426,495			-5,426,495		
45	Heating Value			0					0		0		
46	Prior Period			[redacted]						[redacted]			1e
47	Total (per Sch.8.8.6, Line 14 to Line 20)										[redacted]	(Line 36 above)	1e
48													
49													
50													

51 Note[1]: Total Transportation PGVA Balance (Schedule 8.8.6 line 15) = Total Transportation PGVA (line 42) + Capacity Management (line 44)

Centra Gas Manitoba Inc.
2019/20 General Rate Application
Allocation Results - Riders 2016/17 Gas Year
Removal of Heating Value per CAC-II-142

CAC/CENTRA II-142 c)
Schedule 11.3.0 (b)

Calculation of Riders for 2019/20 Rates
Fixed Costs

2d 1e

Line		SGS		LGS		High Volume Firm		Co-op		Mainline		Interruptible		Special Contract		Power Stations		
		Transportation	Distribution	Transportation	Distribution	Transportation	Distribution	Transportation	Distribution	Transportation	Distribution	Transportation	Distribution	Transportation	Distribution	Transportation	Distribution	
2	Year 2016/17 Allocated Gas Costs--INFLOWS	30,377,406	76,089	23,515,330	59,011	6,482,665	19,533	0	0	112,392	10,843	647,250	1,747	[redacted]				
3	Year 2016/17 WACOG--OUTFLOWS	0	0	0	0	4,109,574	12,483	0	0	128,755	10,190	420,928	1,203					
5	Year 2016/17 PGVA (Principal Only)	30,377,406	76,089	23,515,330	59,011	2,373,091	7,050	0	0	-16,363	653	226,322	544					
7	2016/17 Cap Mgmt (incl carrying costs)	-2,478,434		-1,918,570		-528,908		0		-9,170		-52,808						
9	Total	27,898,973	76,089	21,596,760	59,011	1,844,183	7,050	0	0	-25,533	653	173,514	544					
11	Transfer to Variable	[redacted]																1e
12	Balance in Demand																	1e
14	NET REFUND/RECOVERY																	1e

16 Variable Costs

Line		SGS		LGS		High Volume Firm		Co-op		Mainline		Interruptible		Special Contract		Power Stations		Supplemental	Supplementa	Total	
18		Transportation	Distribution	Transportation	Distribution	Transportation	Distribution	Transportation	Distribution	Transportation	Distribution	Transportation	Distribution	Transportation	Distribution	Transportation	Distribution	Firm	Interruptible		
21	Year 2016/17 Allocated Gas Costs--INFLOWS	3,068,433	419,965	2,457,181	300,756	755,349	96,242	0	0	17,387	79,837	181,605	106,085	[redacted]							1a,1e
22	Year 2016/17 WACOG--OUTFLOWS	28,624,316	856,146	22,196,915	646,259	2,427,841	181,167	0	0	5,591	182,634	249,172	162,836								
24	Year 2016/17 PGVA (Principal Only)	-25,555,884	-436,181	-19,739,734	-345,503	-1,672,492	-84,925	0	0	11,797	-102,797	-67,567	-56,752								1e
26	2016/17 Heating Value (incl carrying costs)		0		0	0	0		0		0		0								
28	Prior Period Residuals (incl. carrying costs)	[redacted]																			1e
30	2016/17 Carrying Costs	199,648	-24,267	154,549	-19,307	42,606	-5,248	0	0	739	-6,883	4,254	-3,788	[redacted]							1e
32	Transfer from Fixed	[redacted]																			1e
34	Total Variable																				1e
36	NET REFUND/RECOVERY																				1e

38 Summary of Schedule 8.8.6

Line		Principal	Carrying Cost	Total	Per Schedule 8.8.6 (line 8)	Per Schedule 8.8.6 (line 9)	Per Schedule 8.8.6 (line 10)	Per Schedule 8.8.6 (line 9)	Per Schedule 8.8.6 (line 11)	Per Schedule 8.8.6	Total		
41	Supplemental PGVA	[redacted]									[redacted]		1a, 1e
42	Transportation PGVA[1]	9,451,907	401,796	9,853,703		9,853,703					9,853,703		
43	Distribution PGVA	-887,314	-59,796	-947,110			-947,110				-947,110		
44	Capacity Management			-4,987,890				-4,987,890			-4,987,890		
45	Heating Value								0		0		
46	Prior Period			[redacted]							[redacted]		1e
47	Total (per Sch.8.8.6, Line 8 to Line 11)											(Line 36 above)	1e

51 Note[1]: Total Transportation PGVA Balance (Schedule 8.8.6 line 9) = Total Transportation PGVA (line 42) + Capacity Management (line 44)

Centra Gas Manitoba Inc.
2019/20 General Rate Application
Allocation Results - Riders 2017/18 Gas Year
Removal of Heating Value per CAC-II-142

CAC/CENTRA II-142 c)
Schedule 11.3.0 (c)

Calculation of Riders for 2019/20 Rates
Fixed Costs

Line		SGS Transportation	SGS Distribution	LGS Transportation	LGS Distribution	High Volume Firm Transportation	High Volume Firm Distribution	Co-op Transportation	Co-op Distribution	Mainline Transportation	Mainline Distribution	Interruptible Transportation	Interruptible Distribution	Special Contract (2d) Transportation	Special Contract Distribution	Power Stations (1e) Transportation	Power Stations Distribution	
1																		
2	Year 2017/18 Allocated Gas Costs--INFLOWS	29,949,835	78,067	22,947,221	59,886	6,048,847	17,413	0	0	99,088	10,311	682,139	1,928	[redacted]				
3	Year 2017/18 WACOG--OUTFLOWS	0	0	0	0	4,489,135	12,825	0	0	132,677	10,410	443,925	1,268					
4																		
5	Year 2017/18 PGVA (Principal Only)	29,949,835	78,067	22,947,221	59,886	1,559,712	4,588	0	0	-33,589	-98	238,214	659					
6																		
7	2017/18 Cap Mgmt (incl carrying costs)	-2,178,205		-1,668,916		-439,923		0		-7,206		-49,611						
8																		
9	Total	27,771,629	78,067	21,278,305	59,886	1,119,788	4,588	0	0	-40,796	-98	188,603	659					
10																		
11	Transfer to Variable	[redacted]																1e
12	Balance in Demand																	1e
13																		
14	**NET REFUND/RECOVERY**																	1e
15																		

16 **Variable Costs**

Line		SGS Transportation	SGS Distribution	LGS Transportation	LGS Distribution	High Volume Firm Transportation	High Volume Firm Distribution	Co-op Transportation	Co-op Distribution	Mainline Transportation	Mainline Distribution	Interruptible Transportation	Interruptible Distribution	Special Contract Transportation	Special Contract Distribution	Power Stations Transportation	Power Stations Distribution	Supplemental Firm	Supplemental Interruptible	Total	
17																					
18																					
19																					
20																					
21	Year 2017/18 Allocated Gas Costs--INFLOWS	3,397,208	600,207	2,645,026	429,836	865,129	137,547	0	0	19,017	114,102	200,005	151,615	[redacted]							1a,1e
22	Year 2017/18 WACOG--OUTFLOWS	33,382,730	998,492	25,014,962	728,487	2,837,095	193,327	0	0	6,192	183,370	294,099	175,717								
23																					
24	Year 2017/18 PGVA (Principal Only)	-29,985,523	-398,285	-22,369,935	-298,652	-1,971,966	-55,779	0	0	12,825	-69,268	-94,094	-24,102	[redacted]							1e
25																					
26	2016/17 Heating Value (incl carrying costs)		0		0		0		0		0		0		0		0				
27																					
28	Prior Period Residuals (incl. carrying costs)	[redacted]																			1e
29																					
30	2017/18 Carrying Costs	-121,505	-11,582	-93,095	-8,636	-24,540	-1,852	0	0	-402	-2,509	-2,767	-848	[redacted]							1e
31																					
32	Transfer from Fixed	[redacted]																			1e
33																					
34	Total Variable	[redacted]																			1e
35																					
36	**NET REFUND/RECOVERY**																				1e
37																					

38 **Summary of Schedule 8.8.6**

Line		Principal	Carrying Cost	Total	Per Schedule 8.8.6 (line 2)	Per Schedule 8.8.6 (line 3)	Per Schedule 8.8.6 (line 4)	Per Schedule 8.8.6 (line 3)	Per Schedule 8.8.6 (line 5)	Per Schedule 8.8.6	Total	
39												
40												
41	Supplemental PGVA	[redacted]									[redacted]	1a, 1e
42	Transportation PGVA[1]	252,700	-242,309	10,391		10,391					10,391	
43	Distribution PGVA	-660,790	-23,900	-684,690			-684,690				-684,690	
44	Capacity Management			-4,343,862				-4,343,862			-4,343,862	
45	Heating Value			0					0		0	
46	Prior Period			[redacted]							[redacted]	1e
47	Total (per Sch. 8.8.6, Line 2 to Line 5)											(Line 36 above) 1e
48												
49												
50												

51 Note[1]: Total Transportation PGVA Balance (Schedule 8.8.6 line3) = Total Transportation PGVA (line 42) + Capacity Management (line 44)

CAC/CENTRA II-142 c)
Schedule 11.3.0 (d)

Centra Gas Manitoba Inc.
2019/20 General Rate Application
Rider Calculation Summary - 2015/16 and 2016/17 and 2017/18 Gas Years
Removal of Heating Value per CAC-II-142

	SGS		LGS		High Volume Firm		Co-op		Mainline		Interruptible		Special Contract		Power Stations		Supplemental	Supplemental	Total	
	Transportation	Distribution	Transportation	Distribution	Transportation	Distribution	Transportation	Distribution	Transportation	Distribution	Transportation	Distribution	Transportation	Distribution	Transportation	Distribution	Firm	Interruptible		
1 Fixed Costs																				
2 Schedule 11.3.0 (a) line 14	[redacted]																			1e
3 Schedule 11.3.0 (b) line 14																				
4 Schedule 11.3.0 (c) line 14																				
5																				
6 Fixed Cost Subtotal																				1e
7																				
8 Variable Costs	[redacted]																			
9 Schedule 11.3.0 (a) line 34																				
10 Schedule 11.3.0 (b) line 34																				1e
11 Schedule 11.3.0 (c) line 34																				
12																				
13 Variable Cost Subtotal																				
14																				
15 Total Rate Rider					-14,496	-263,925	0	0	-17,290	-305,608	356,738	-282,123	[redacted]						-8,956,996	1e

Centra Gas Manitoba Inc.
2019/20 General Rate Application
2019/20 Proposed Rate Riders - 2015/16 Gas Year & 2016/17 Gas Year & 2017/18 Gas Year
12-month Rate Riders (Unit Cost - to be implemented Nov 1, 2019)
Removal of Heating Value per CAC-II-142

CAC/CENTRA II-142 c)
Schedule 11.3.1

	SGS		LGS		HVF				Co-op				MAINLINE				
	Transportation Commodity	Distribution Commodity	Transportation Commodity	Distribution Commodity	Transportation Commodity	Transportation Demand	Distribution Commodity	Distribution Demand	Transportation Commodity	Transportation Demand	Distribution Commodity	Distribution Demand	Transportation Commodity	Transportation Demand	Distribution Commodity	Distribution Demand	
$ (Lines 6 & 13 of Schedule 11.3.0(d))	[redacted]												[redacted]				1e
Billing Determinant																	1d
$/10³m³	5.976	(1.935)	7.237	(1.843)	(16.812)	213.260	(1.305)	0.852					10.052	(240.387)	(1.919)	0.401	
Rate Rider ($/m3)	0.0060	(0.0019)	0.0072	(0.0018)	(0.0168)	0.2133	(0.0013)	0.0009					0.0101	(0.2404)	(0.0019)	0.0004	

	INTERRUPTIBLE				SPECIAL				POWER STATIONS				SUPPLEMENTAL (INCL. IN DIST COMM)		TOTAL	
	Transportation Commodity	Transportation Demand	Distribution Commodity	Distribution Demand	Transportation Commodity	Transportation Demand	Distribution Commodity	Distribution Demand	Transportation Commodity	Transportation Demand	Distribution Commodity	Distribution Demand	Firm	Interruptible		
$ (Lines 6 & 13 of Schedule 11.3.0(d))	[redacted]														-8,956,996	1e
Billing Determinant																1d
$/10³m³	(0.472)	121.671	(6.198)	0.678			(0.007)				12.602	(1.589)	(9.576)	(12.220)		
Rate Rider ($/m3)	(0.0005)	0.1217	(0.0062)	0.0007			(0.0000)				0.0126	(0.0016)	(0.0096)	(0.0122)		
Lump Sum Payment							[redacted]				[redacted]					2d

REFERENCE:

Responses to PUB/Centra I- 28 and I - 33

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide the diagram in PUB/Centra 33, page 2, that includes dollars and percentages in each of the boxes starting at O&A and FD&T up to and including the Natural Gas Income Statement. Please use the 2019/20 Test Year data. For example, of the total cost components of the Corporation (electric and natural gas), what are the total dollars and percentage that is O&A vs. FD&T? Similarly, of the total O&A expenses, what are the dollars and percentages that are time-carded, in overhead, procurement, and system postings? Of the total FD&T costs, what are the dollars and percentages that are time-carded, in overhead, procurement, and system postings? Of the total O&A expenses, how much are directly assigned 100% to natural gas vs. shared? Of the total FD&T costs, how much are 100% natural gas vs. shared, and so on.

b) To the extent not already provided in response to part (a), please provide the total annualized costs that are deemed to be shared between electric and natural gas operations. In response to PUB/Centra 28 (a) Centra states that total O&A for the 2019/20 Test Year is $61.3 million. How much of this total is directly assigned to Centra vs. allocated? Provide the same related to FD&T, that is, how much is directly assigned to Centra vs. allocated?

c) What degree of confidence does Centra have on the accuracy of time-carding?
    i. Please also describe the internal control processes Centra has to review the accuracy of time-carding.

d) Of the costs that are allocated based on time-carding, for purposes of the 2019/20 Test Year, has Centra forecasted “employee’s hours” based on one year of actual results or is this based on an average of several years of actual results? Please explain.

e) At page 3 of the response to PUB/Centra 33, Centra defines available hours to work. How are the costs associated with those deemed non-specific to a job such as vacation and sick time (non-productive time) allocated?

f) At page 4 of the response to PUB/Centra 33, Centra states that the second type of posting is the allocation of finance, depreciation, and taxes on common assets using "various natural gas cost drivers".
   i. Please explain what these various natural gas cost drivers are.
   ii. Given that this section is discussing the allocation of common assets, are the cost drivers different for the allocation of common assets for gas operations than electric operations? Why?

g) At page 5 of the response to PUB/Centra 33, Centra states that shared costs are allocated based on number of customers, corporate assets, corporate activity charges and management estimates. Of the shared costs allocated to Centra (based on the 2019/20 Test Year), please provide the dollars and percentages of these costs that are allocated based on number of customers, corporate assets, corporate activity charges, and management estimates.

h) Please explain how Centra defines "corporate assets" for purposes of internal cost allocation.

i) In a format similar to the table provided in PUB/Centra 28, page 3 that provides examples of shared costs, allocator, and split between gas and electric, please provide a list of all shared O&A and FD&T costs that are allocated on the basis of total assets, activity charges, and management estimate (those allocated on customer numbers are not necessary). In the event this request is onerous, provide at least 10 examples of each allocator (other than those already provided) focused on those most material in terms of cost.

RESPONSE:

a) and b)

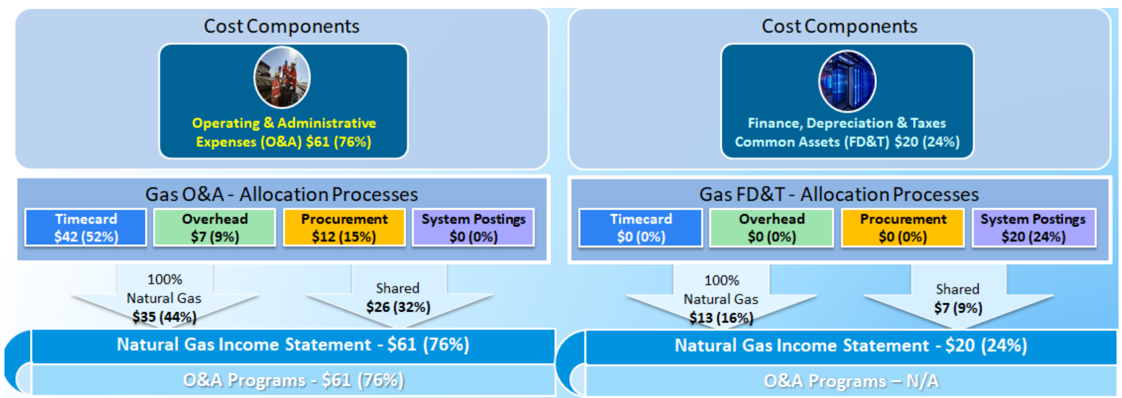
The table below provides the breakdown of Operating & Administrative Expenses ("O&A") and Finance Depreciation & Taxes Common Assets ("FDT") in dollars and percentages between the gas and electric segments, using 2019/20 Test Year as the basis.

CENTRA GAS MANITOBA INC.
O&A AND FD&T EXPENDITURES
(in millions)

(Millions)	O&A Expenses	FDT*	Total		O&A Expenses	FDT*	Total
Gas	61	20	81		76%	24%	100%
Electric	511	78	589		87%	13%	100%
Total	572	98	670		85%	15%	100%

* Includes expenses for common and 100% gas assets

The table below illustrates the dollars and percentages of the O&A and FD&T expenses charged to Centra for each allocation process, as well as the dollars and percentages which are allocated either 100% Natural Gas or Shared.



c) As discussed in Appendix 5.10 Manitoba Hydro ICAM Technical Conference, there are internal control processes with respect to the time carding practice, specifically:

- Activity rates used in the timecard process are reviewed and approved by the respective Department Manager and the Finance Department Supervisor to ensure that the activity rate properly reflects the costs of the workgroup;
- Timecard entries are reviewed and approved by the supervisor of the employee;
- Month end processing validation is performed to ensure that the posting of the employee timecards has worked as intended and there is no missing information; and
- The corporation is subject to an annual external audit and periodic internal audits. Centra and Manitoba Hydro continue to receive a clean audit opinion on their financial statements.

Internal and external controls, no matter how well designed and operated, cannot provide absolute assurance, rather they provide reasonable assurance that the activities are working as intended. Given the number of internal controls in place, Centra has a high degree of confidence that the time carding process is working as intended and there are no material misstatements.

d) Centra forecasts employee time based upon historical trends over a number of years. However, Centra also takes into account current information available at the time of forecasting. For example, for the 2019/20 Test Year, the activity charges in the metering program were reduced to align with the proposal to capitalize the functions of meter sampling, testing and replacement, thus reducing O&A program costs.

e) As outlined in PUB/CENTRA I-33, vacation and sick time (non-productive time) is not considered to be a component of capacity hours (those available for work) used in the calculation of an activity rate. The cost components of an activity rate are comprised of wages, salaries and benefits, motor vehicles, small tools, safety clothing and travel. The total costs 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. As such, by not including the non-productive hours, the activity rate is increased to account for these non-productive hours.

f) The natural cost drivers for the allocation of finance, depreciation, and taxes on common assets include:
- Number of Customers
- Corporate Activity Charges
- Management Estimates for DSM and Web Trader

The same cost drivers are used for the allocation of common assets for both gas and electric operations.

g) Please refer to PUB/CENTRA II-23a-d for the dollars and percentages of costs that are allocated based on Number of Customers, Corporate Assets, Corporate Activity Charges as well as Management Estimates.

h) Please refer to PUB/CENTRA II-23b for the calculation of corporate assets, which includes the value of the total Electric and Gas assets (PP&E, Current and Non-Current Assets, Regulatory Deferrals).

i) Please refer to PUB/CENTRA II-23a-e for a list of all shared O&A and FD&T costs that are allocated on the basis of total assets, activity charges, and management estimate.

REFERENCE:

CAC/CENTRA I-38

PREAMBLE TO IR (IF ANY):

In the response to the referenced IR, Centra states that the cost forecast changes between CEF 16 and CEF 18 driven by the insights from Natural Gas System Asset Condition Assessment (Appendix 4.4) and the Report of Pipeline Risk Methodology (Completeness Filing Attachment 3), amount to $6.42 million allocated to the in-line inspection project due to the information gaps identified in the Asset Condition Assessment Report.

QUESTION:

Please confirm the CAC's understanding of the Applicant's response, that as of CEF 18:

i. Centra's latest iteration of Risk Assessment Work led to no changes to the forecasted expenditures over the coming 10 plan years.
ii. The only planned expenditure changes driven by the Asset Condition Assessment work was to invest in more data collection.

RATIONALE FOR QUESTION:

To clarify the inferences made from Centra's original IR response.

RESPONSE:

i. As of CEF 18, the 2017 Pipeline Risk Assessment report has not directly lead to changes to the forecast expenditures.

ii. As of CEF 18, the only planned expenditures in response to the Asset Condition Assessment report were to address identified gaps in asset condition information. This information will be the foundation to develop a long term plan to address aging infrastructure.

REFERENCE:

CAC/CENTRA I-40a-b, Tab 4, Figure 4.9

PREAMBLE TO IR (IF ANY):

In the response to the referenced IR, Centra has filed a comprehensive table showcasing its currently available data inputs across the different asset classes. The table showcases a relatively high level of data availability with most categories having availability of 90% and above, aside from a few notable gaps.

QUESTION:

a) Given the reported levels of data availability across the requisite types of information inputs into maintenance strategies, please explain why Centra's current-state maintenance strategies have not advanced beyond the Risk-Based maintenance methodology for two asset types (Pipelines and Meters), while most other asset types have not advanced beyond the Condition-Based Maintenance strategy.
b) If data availability is not the only or major barrier towards implementing more advanced maintenance strategies please discuss these other types of barriers, along with any applicable managerial considerations underlying Centra's current position on the Maintenance Strategy Continuum depicted on the Figure 4.9 of Tab 4.

RATIONALE FOR QUESTION:

To reconcile Centra's response with other statements regarding data availability and its implications throughout the asset management function.

RESPONSE:

a) Centra has reported on the current status of its maintenance strategies and that the Centra Asset Management Plan is being developed. The value of progression of maintenance strategies for the different asset types and the work, resources and time needed to provide this progression has not been determined. The completion of the

Centra Asset Management Plan is considered an initial step in determining the value and possible prioritization of changes to the maintenance strategies. This work may indicate that the current maintenance strategy in use may be the most appropriate strategy for some of the individual assets.

b) The completion of an Asset Management Plan will provide direction on the appropriate maintenance strategy to be applied each asset. The lack of this Asset Management Plan would be considered a barrier.

REFERENCE:

CAC/CENTRA I-39a, I-41c

PREAMBLE TO IR (IF ANY):

In the first referenced IR Centra states that it has not undertaken any benchmarking studies related to the natural as asset management function. In the second referenced IR response, Centra states that it considers the asset life expectancy ranges developed by subject matter experts in lieu of statistical failure analysis, to be conservative on average.

QUESTION:

Given that Centra is yet to conduct any benchmarking work in the area of natural gas asset management, what is the basis for Centra's claim that the asset life expectancy ranges used today are conservative?

RATIONALE FOR QUESTION:

To reconcile Centra's response with related statements from other IR responses.

RESPONSE:

To clarify, the asset life expectancy ranges shown in the Asset Condition Assessment report are considered conservative for steel pipelines, steel service lines and services.

For steel pipelines and steel service lines, the primary mode of age related failure is corrosion resulting in leaks. A pipeline or service is considered to have failed when replacement is necessary as the number or frequency of corrosion leaks on the pipeline or service increases to a point when it is more economical to install a new pipeline or service than to accept higher repair costs. On average, 26 corrosion leaks have occurred annually for the past 10 years, with comparable rates in the 20 years prior, Centra has strong records for corrosion leaks over the last 30 years over which there has not been an upward trend in the rate of corrosion leak occurrence. This suggests that degradation is not accelerating, when 30 years of leak history is compared to the median age of 50 years for steel pipelines in the Centra system.

Centra has performed in-line inspection of three pipelines; the LaSalle NPS 8 and NPS 12 and the Ile des Chenes NPS 16. These pipelines were 34, 58 and 56 years old respectively at the time of the inspections. Two corrosion degradation related defects meeting the CSA Z662 Oil and Gas Pipeline standard definition and requiring replacement were found on the LaSalle NPS 12 pipeline, cut out and new pipe sections installed. No corrosion degradation related defects were identified on the NPS 8 or NPS 16 pipelines. With maintenance of the cathodic protection systems at similar or improved over historic levels, plans to repeat the in-line inspections on a nominal 10 year cycle would allow for the pipelines to achieve an expected minimum asset life of 80 years with the asset life re-evaluated following the in-line inspection. For steel assets that are not examined by in-line inspection, information on the leak history of the individual asset with the general information on steel pipeline performance provided by the in-line inspection work will be used to assist in defining the asset life.

For services, the estimated average life expectancy range is 25 to 70 years. This is considered conservative on the basis that the median age of services is 39 years of age and the number of annual service replacements due to failure is low.

The estimated life expectancy ranges for plastic pipelines, plastic service lines, and stations are not considered conservative. Centra's response to CAC/CENTRA I-41 should have distinguished between these assets and steel pipelines, steel service lines and services.

REFERENCE:

CAC/CENTRA I-42a-c

PREAMBLE TO IR (IF ANY):

In the IR in question Centra provides details on the costs and data outputs obtained from its maintenance / inspection programs.

QUESTION:

a) Please complete the table provided in response to I-42a by adding a “Total” line at the bottom of the table to showcase the sum of all program functions showcased, including those for which the functions are not discretely captured.
b) Please explain, using examples where helpful, why functions for nearly half of all inspection and maintenance program type are not discretely captured at this time.
c) Please provide a 2019/20 Test Year expenditure estimate (if material) for the new Coating Shielding corrosion program.

RATIONALE FOR QUESTION:

To obtained more detail regarding the information provided in the response.

RESPONSE:

a), b) and c)

The table from CAC/CENTRA I-42a has been restated below with a total line that includes only those functions that can be discretely costed.

CENTRA GAS MANITOBA INC.
INSPECTION & MAINTENANCE FUNCTIONS
($000s)

No.	Inspection and Maintenance Functions	2015/16 Actual	2016/17 Actual	2017/18 Actual	2018/19 Forecast	2019/20 Test Year
1	Cathodic Protection System Monitoring	$ 906	$ 898	$ 1,328	$ 915	$ 934
2	Close Interval Potential Survey	180	179	169	179	183
3	Coating Shielding Corrosion	*New function*				
4	External Corrosion Direct Assessment	3	117	118	120	122
5	Monitoring of Steel Risers on Plastic Services	*Functions not discretely captured*				
6	Depth of Cover Surveys	20	120	103	98	100
7	Geotechnical Monitoring of Pipelines in Slopes	17	37	23	28	28
8	Hydro Geotechnical Monitoring of Pipelines in Water courses	5	31	34	32	33
9	In-line Inspection	*This function is capitalized*				
10	Aerial Pipeline Inspection	*Functions not discretely captured*				
11	Leak Inspection	*Costs captured in 15, 17, 18, 19 & 20.*				
12	Strained Service Failure Reporting	*Functions not discretely captured*				
13	Customer Meter Set Maintenance Survey					
14	Station Inspections					
15	Station Leak Survey					
16	Odourization Equipment Inspection					
17	Distribution Mains and Services Leak Survey	210	178	174	360	367
18	Transmission and High Pressure Mains Leak Survey	77	106	51	105	107
19	Public Building Leak Survey	282	253	347	302	308
20	Business District Leak Survey	175	197	296	186	189
21	Meters-Maintaining Compliance with Measurement Canada Requirements*	5,555	4,601	4,357	3,555	574
22	Station Valve Inspection and Maintenance	*Functions not discretely captured*				
23	Transmission Valve Inspection and Maintenance					
24	Distribution Buried Valve Maintenance					
25	Downtown Winnipeg- Emergency Sectionalization Valve Maintenance					
	Total (for discretely costed functions only)	$ 7,428	$ 6,717	$ 7,002	$ 5,879	$ 2,944

*As per Section 2 of Appendix 5.9, meter sampling, testing & exchange costs are proposed for capitalization in 2019/20.

The inspection and maintenance functions showcased in Figure 4.7 of Tab 4 of the Application are imbedded within various Operating & Administrative ("O&A") programs shown in Appendix 5.9 of the Application. A description and nature of Centra's O&A programs are documented on pages 12 to 20 of Appendix 5.9; the actual program costs from 2011/12 through 2017/18 and the forecast for 2018/19 to 2019/20 are shown in Figures 5.4 and 5.5 of the same appendix.

The inspection and maintenance work functions which have been costed in the table above are related to direct components of various O&A programs listed in Appendix 5.9. The functions shown as '*not discretely captured*' are also related to components of the O&A programs; however, '*not discretely captured*' functions are those which have been combined and costed with other associated work functions within the O&A programs and as such, costs cannot be easily apportioned. As an example, the functions of station inspections, station leak survey, station valve inspection and maintenance, and transmission valve inspection and maintenance are grouped and costed with the functions of calibration of instrumentation, testing of regulator functionality, testing of meters, and annual site safety audits & conditional assessments.

The new function for coating shielding corrosion was not forecasted in either the 2018/19 or 2019/20 fiscal years.

REFERENCE:

CAC/CENTRA I-43a-b

PREAMBLE TO IR (IF ANY):

In the referenced IR, Centra provides an example of its Multi-Point Gas Facility Assessment Document, including its final numerical output expressed as a percentage.

QUESTION:

a) Please explain the significance of the 43% Grad Total Score. Does it indicate the percentage of the station's remaining life? The percentage of degradation to date? Any other insights?
b) Please provide the quantitative results (i.e. the Assessment Document Grand Total Scores) in a table form for the last three years of multi-point assessments for all Centra stations.
c) Please describe whether and how the results of these assessments have influenced the Asset Condition Assessment Document filed in this application.
d) Please discuss whether Centra has considered assigning different weightings across the eight categories of assessment. If not, please indicate whether Centra sees any potential value in doing so in the future.

RATIONALE FOR QUESTION:

To gain additional insights into the state of Centra's asset condition information tracking by clarifying the information provided in the first round of IRs.

RESPONSE:

a) The 43% grade is the total condition assessment score. A score of 0% would indicate that the asset is in perfect condition, not requiring investment. The highest scores are prioritized for upgrades.

b) Please see attachment to this response for the Station Condition Assessment Listing.

c) The results documented on the Station Condition Assessment forms have not directly influenced the Asset Condition Assessment document filed in the Application.

d) Centra will be reviewing and revising the condition assessment forms and format this year. Weighing the eight assessment categories will be a part of this process.

Gate Station #	Gate Station Name	Year of Inspection	Condition Score
GS-001	City Gate	2015	23%
GS-001	City Gate	2018	2%
GS-002	St. Norbert	2015	28%
GS-002	St. Norbert	2018	27%
GS-003	Transcona	2015	38%
GS-003	Transcona	2018	48%
GS-004	Selkirk	2015	3%
GS-004	Selkirk	2017	5%
GS-004	Selkirk	2018	5%
GS-005	Clandeboye	2015	30%
GS-005	Clandeboye	2016	20%
GS-005	Clandeboye	2018	43%
GS-006	Matlock	2015	28%
GS-006	Matlock	2017	32%
GS-006	Matlock	2018	62%
GS-007	Winnipeg Beach	2015	27%
GS-007	Winnipeg Beach	2017	13%
GS-007	Winnipeg Beach	2018	42%
GS-008	Gimli	2015	37%
GS-008	Gimli	2016	22%
GS-008	Gimli	2017	23%
GS-008	Gimli	2018	0%
GS-009	Stony Mountain	2015	30%
GS-009	Stony Mountain	2017	30%
GS-009	Stony Mountain	2018	33%
GS-010	Stonewall	2015	20%
GS-010	Stonewall	2017	0%
GS-010	Stonewall	2018	0%
GS-011	East Selkirk	2015	18%
GS-011	East Selkirk	2016	3%
GS-011	East Selkirk	2017	27%
GS-011	East Selkirk	2018	32%
GS-012	Garson	2015	20%
GS-012	Garson	2016	13%
GS-012	Garson	2017	17%
GS-012	Garson	2017	18%
GS-012	Garson	2018	35%
GS-013	Tyndall	2017	23%
GS-013	Tyndall	2018	33%
GS-014	Beausejour	2017	0%
GS-014	Beausejour	2018	2%

Gate Station #	Gate Station Name	Year of Inspection	Condition Score
GS-029	La Salle TBS	2015	18%
GS-015	La Salle TBS	2018	0%
GS-016	IDC TBS	2015	20%
GS-016	IDC TBS	2017	5%
GS-016	IDC TBS	2018	5%
GS-017	IDC Primary	2015	20%
GS-017	IDC Primary	2017	5%
GS-017	IDC Primary	2018	7%
GS-018	Landmark East Selkirk	2015	22%
GS-018	Landmark Town	2015	48%
GS-018	Landmark East Selkirk	2018	20%
GS-018	Landmark Town	2018	7%
GS-019	St. Boniface and Plessis	2017	13%
GS-019	St. Boniface and Plessis	2018	22%
GS-020	Fort Whyte	2015	23%
GS-020	Fort Whyte	2016	3%
GS-020	Fort Whyte	2018	18%
GS-021	North Petersfield	2015	20%
GS-021	North Petersfield	2018	33%
GS-023	Symington and Perimeter	2015	18%
GS-023	Symington and Perimeter	2017	10%
GS-023	Symington and Perimeter	2018	5%
GS-024	Raleigh	2015	20%
GS-024	Raleigh	2017	25%
GS-024	Raleigh	2018	33%
GS-025	East Lockport	2017	30%
GS-025	East Lockport	2017	33%
GS-025	East Lockport	2018	37%
GS-026	St. Adolphe	2015	18%
GS-026	St. Adolphe	2017	7%
GS-026	St. Adolphe	2018	8%
GS-027	Lockport	2017	28%
GS-027	Lockport	2017	25%
GS-027	Lockport Rd	2018	32%
GS-028	Concord Colony	2015	18%
GS-028	Concord Colony	2016	17%
GS-028	Concord Colony	2017	18%
GS-028	Concord Colony	2018	30%
GS-029	La Salle TBS	2018	43%
GS-030	Oakbluff PGS	2015	25%
GS-030	Oakbluff	2017	7%

Gate Station #	Gate Station Name	Year of Inspection	Condition Score
GS-030	Oakbluff	2017	28%
GS-030	Oakbluff TBS	2018	10%
GS-031	Rosser	2015	22%
GS-031	Rosser	2017	17%
GS-031	Rosser	2018	18%
GS-032	Oakbluff TBS	2015	18%
GS-032	Oakbluff TBS	2018	45%
GS-033	Sanford	2015	17%
GS-033	Sanford	2018	15%
GS-034	South Petersfield	2015	13%
GS-034	Petersfield South	2018	10%
GS-035	Brady Road	2015	22%
GS-035	Brady Road	2018	20%
GS-036	Arborg	2015	20%
GS-036	Arborg	2017	0%
GS-036	Arborg	2018	10%
GS-037	Riverton	2015	18%
GS-037	Riverton	2017	0%
GS-037	Riverton	2018	12%
GS-038	Warren	2015	18%
GS-038	Warren	2017	10%
GS-038	Warren	2018	18%
GS-039	Teulon	2017	0%
GS-039	Teulon	2018	8%
GS-040	Hewitson	2015	20%
GS-040	Hewitson	2017	0%
GS-041	East Selkirk Generation	2015	20%
GS-041	East Selkirk Generation	2016	0%
GS-041	East Selkirk Generating Station	2017	0%
GS-041	East Selkirk Generating Station	2018	0%
GS-042	St. Francois Xavier	2015	13%
GS-042	St. Francois Xavier	2018	0%
GS-043	St. Andrews	2018	0%
GS-044	Symington and Perimeter	2017	5%
GS-044	Symington Road	2018	5%
GS-100	McAuley	2018	18%
GS-101	St. Lazare	2018	10%
GS-102	Binscarth	2018	10%
GS-105	Harrowby	2018	22%
GS-106	Inglis	2018	13%
GS-107	Roblin	2018	38%

Gate Station #	Gate Station Name	Year of Inspection	Condition Score
GS-108	Grandview GS	2018	47%
GS-109	Gilbert Plains GS	2018	47%
GS-109	Gilbert Plains GS	2018	12%
GS-110	Dauphin GS	2015	15%
GS-110	Dauphin TBS	2018	15%
GS-111	Miniota PGS	2015	20%
GS-111	Miniota_Virden Primary	2018	35%
GS-113	Virden	2018	5%
GS-114	Hamiota Primary	2018	22%
GS-115	Hamiota TBS	2018	3%
GS-116	Oo-Za-Wee-Kwun	2018	15%
GS-117	Rivers Primary	2018	12%
GS-118	Rivers TBS	2018	27%
GS-119	Moore Park Primary	2018	22%
GS-120	Minnedosa	2018	3%
GS-121	Neepawa Primary	2018	15%
GS-122	Neepawa GS	2018	27%
GS-123	Brandon Primary	2018	5%
GS-124	Brandon #1	2018	45%
GS-125	Brandon 2	2016	17%
GS-125	Brandon #2	2018	23%
GS-126	Forrest TBS	2018	15%
GS-127	Carberry Primary	2016	8%
GS-127	Carberry Primary	2018	10%
GS-128	Carberry	2015	10%
GS-128	Carberry TBS	2018	10%
GS-129	CFB Shilo	2015	22%
GS-130	MacGregor PGS	2016	15%
GS-130	MacGregor PGS	2018	7%
GS-131	MacGregor	2016	10%
GS-131	MacGregor	2018	7%
GS-132	Portage Primary	2017	12%
GS-132	Portage Primary	2018	27%
GS-133	Portage Crescent	2017	10%
GS-133	Portage Crescent Rd	2018	18%
GS-134	Southport	2015	12%
GS-134	Southport	2017	12%
GS-134	Portage Southport	2018	20%
GS-135	Portage North River	2017	8%
GS-135	Portage North River	2018	10%
GS-136	Oakville Primary	2017	8%

Gate Station #	Gate Station Name	Year of Inspection	Condition Score
GS-136	Oakville Primary	2018	12%
GS-137	Carman	2017	5%
GS-137	Carman	2018	18%
GS-138	Elm Creek	2015	18%
GS-138	Elm Creek	2016	2%
GS-138	Elm Creek	2018	8%
GS-139	Morden	2017	2%
GS-139	Morden	2017	18%
GS-139	Morden	2018	28%
GS-140	Winkler	2017	12%
GS-140	Winkler	2018	22%
GS-142	Plum Coulee	2015	13%
GS-142	Plum Coulee	2017	18%
GS-142	Plum Coulee	2018	25%
GS-143	Altona	2015	20%
GS-143	Altona	2018	33%
GS-144	St. Joseph	2018	17%
GS-145	Letellier	2018	25%
GS-146	Dominion City	2016	8%
GS-146	Dominion City	2017	12%
GS-146	Dominion City	2018	20%
GS-147	DC TBS	2015	20%
GS-147	Dominion City TBS	2016	8%
GS-147	Dominion City TBS	2018	18%
GS-148	St. Jean	2018	25%
GS-149	Morris	2018	28%
GS-150	Niverville	2017	13%
GS-150	Niverville	2018	32%
GS-151	Twin Creeks	2015	18%
GS-151	Twin Creeks	2018	23%
GS-152	Otterburne	2015	18%
GS-152	Otterburne	2017	13%
GS-152	Otterburne	2018	25%
GS-153	St. Pierre PGS	2017	3%
GS-153	St. Pierre	2018	15%
GS-154	St. Pierre	2017	10%
GS-154	St. Pierre	2018	30%
GS-155	Grunthal	2015	15%
GS-155	Steinbach	2015	18%
GS-155	Grunthal	2018	27%
GS-156	Steinbach	2018	38%

Gate Station #	Gate Station Name	Year of Inspection	Condition Score
GS-157	Blumenort	2015	25%
GS-157	Blumenort	2017	3%
GS-157	Blumenort	2018	40%
GS-158	New Bothwell	2015	30%
GS-158	New Bothwell	2018	35%
GS-159	Ste. Anne's	2017	5%
GS-159	Ste. Anne	2018	10%
GS-160	Ste. Anne's TBS	2017	8%
GS-160	Ste. Anne TBS	2018	0%
GS-163	St. Claude	2015	22%
GS-163	St. Claude	2017	2%
GS-163	St. Claude	2018	7%
GS-164	Elie	2015	5%
GS-164	Elie	2016	2%
GS-164	Elie	2018	5%
GS-165	Starbuck	2015	22%
GS-165	Starbuck	2018	18%
GS-166	Oakville TBS	2015	8%
GS-166	Oakville TBS	2017	8%
GS-166	Oakville TBS	2018	13%
GS-167	St. Malo	2017	2%
GS-167	St. Malo	2018	7%
GS-168	South West	2018	8%
GS-169	Souris North	2018	5%
GS-170	Souris South	2018	22%
GS-171	Hartney	2018	13%
GS-172	Melita TBS	2018	13%
GS-173	Deloraine GS	2018	17%
GS-174	Boissevain TBS	2018	17%
GS-175	Killarney	2015	13%
GS-175	Killarney TBS	2018	13%
GS-176	Elkhorn	2018	12%
GS-177	Pineland Hadashville	2015	8%
GS-177	Hadishville	2017	8%
GS-177	Pineland / Hadashville	2018	13%
GS-178	Lincoln Rd / Portage	2015	13%
GS-178	Lincoln Rd	2017	8%
GS-178	Lincoln Rd	2018	12%
GS-179	Cromer	2016	12%
GS-179	Cromer	2018	12%
GS-180	Ste. Agathe PGS	2015	22%

Gate Station #	Gate Station Name	Year of Inspection	Condition Score
GS-180	Ste. Agathe PGS	2017	10%
GS-180	Ste. Agathe PGS	2018	12%
GS-181	Ste. Agathe TBS	2015	13%
GS-181	Ste. Agathe TBS	2018	12%
GS-182	Angle Rd Portage	2015	8%
GS-182	Portage Angle Rd	2018	15%
GS-183	Kleefeld	2015	15%
GS-183	Kleefeld	2018	15%
GS-184	Harms Rd	2018	7%
GS-185	PTH 12	2018	13%
GS-186	North Labroquerie	2017	12%
GS-186	North Labroquerie	2018	15%
GS-187	Moosemeadow	2018	18%
GS-188	Bunge Plant	2018	5%
GS-189	McCains Carberry	2015	20%
GS-189	McCains Carberry	2018	33%
GS-190	Richmond / Canexus	2015	13%
GS-190	Chentrade Brandon	2018	13%
GS-191	Maple Leaf / Brandon	2015	32%
GS-191	Maple Leaf Brandon	2018	33%
GS-192	Brandon CT	2016	10%
GS-192	Brandon CT	2018	3%
GS-193	Simplot Primary	2015	30%
GS-193	Portage Simplot Primary	2017	0%
GS-193	Portage Simplot Primary	2018	0%
GS-194	Simplot	2015	3%
GS-194	Portage Simplot	2017	0%
GS-194	Portage Simplot TBS	2018	0%
GS-195	Austin PGS	2016	12%
GS-195	Austin Primary	2018	13%
GS-196	Austin TBS	2016	5%
GS-196	Austin TBS	2018	3%
GS-197	Cibula GANG	2015	7%
GS-197	Cibula GANG	2018	7%
GS-198	Novak GANG	2015	7%
GS-198	Novak GANG	2018	7%
GS-199	Gladstone TBS	2016	8%
GS-199	Gladstone TBS	2018	3%
GS-200	Neauschwander GANG	2016	3%
GS-200	Neauschwander GANG	2018	7%
GS-201	Jarvis GANG	2016	3%

Gate Station #	Gate Station Name	Year of Inspection	Condition Score
GS-201	Jarvis GANG	2018	7%
GS-202	Shoal Lake TBS	2015	17%
GS-202	Shoal Lake TBS	2018	10%
GS-203	Assiniboine Downs	2015	18%
GS-203	Assiniboine Downs	2018	20%
GS-204	Bird's Hill	2015	20%
GS-204	Bird's Hill	2017	0%
GS-204	Bird's Hill	2017	0%
GS-204	Bird's Hill	2018	3%
GS-205	Husky Stn	2016	5%
GS-205	Husky Stn	2018	5%
GS-207	Benito TBS	2015	35%
GS-207	Benito TBS	2018	35%
GS-208	Swan River TBS	2015	30%
GS-208	Swan River TBS	2018	25%
GS-209	Minotas TBS	2015	12%
GS-209	Minotas TBS	2018	8%

Regulator Station #	Regulator Station Name	Year of Inspection	Condition Score
RS-001	William Newton Watt	2018	18%
RS-002	Harbison	2016	10%
RS-002	Harbison and Brazier	2017	12%
RS-002	Harbison Brazier	2018	32%
RS-003	Henderson and Perimeter	2017	17%
RS-003	Henderson Perimeter	2018	25%
RS-004	Archibald Doucet	2018	5%
RS-005	Marion Youville	2018	10%
RS-006	St Annes Sherwood	2018	10%
RS-007	Mission and Panet	2017	13%
RS-007	Mission Panet	2018	30%
RS-008	Jubilee and Daly	2017	15%
RS-008	Jubilee Daly	2018	32%
RS-009	Pembina Parker	2018	7%
RS-010	Lorette and Harrow	2017	5%
RS-010	Lorette and Harrow	2017	10%
RS-010	Lorette Harrow	2018	32%
RS-011	Waverly Wilkes	2018	7%
RS-012	Kenaston and Grant	2017	20%
RS-012	Kenaston Grant	2018	20%
RS-013	Kenaston and Willow	2017	8%
RS-013	Kenaston Willow	2018	13%
RS-014	Roblin and Berkley	2017	15%
RS-014	Roblin Berkley	2018	15%
RS-015	Pembina Trappistes	2018	5%
RS-016	May and Macdonald	2017	23%
RS-016	Waterfront Madonald	2018	27%
RS-017	Ross and Tecumseh	2017	2%
RS-017	Ross and Tecumseh	2017	8%
RS-017	Ross and Tecumseh	2018	18%
RS-019	Furby and Ellice	2017	3%
RS-019	Furby and Ellice	2017	10%
RS-019	Furby Ellice	2018	15%
RS-020	Furby and Westminster	2017	5%
RS-020	Furby and Westminster	2017	8%
RS-020	Furby Westminster	2018	12%
RS-021	Wilkes Community Row	2018	10%
RS-022	Madison St Matthews	2018	5%
RS-023	Century Wellington	2018	7%
RS-024	Saskatchewan Buchanan	2018	12%
RS-025	Portage Bedson	2018	7%

Regulator Station #	Regulator Station Name	Year of Inspection	Condition Score
RS-026	Inkster and Powers	2017	15%
RS-026	Inkster Powers	2018	13%
RS-027	Inkster and Lansdowne	2017	12%
RS-027	Inkster Lansdowne	2018	10%
RS-028	Main and Perimeter	2017	13%
RS-028	Main 101	2018	23%
RS-030	Mercy and Clandeboye Selkirk	2015	25%
RS-030	Selkirk Mercy and Clandeboye	2017	17%
RS-030	Mercy Clandeboye	2018	13%
RS-031	7th Ave Gimli	2015	17%
RS-031	Gimli 7th St	2016	12%
RS-031	Gimli 7th	2017	13%
RS-031	Gimli 7th	2018	23%
RS-032	Solvin Rd Gimli	2015	50%
RS-032	Gimli Solvin Ave	2016	27%
RS-032	Gimli Solvin	2017	13%
RS-032	Gimli Solvin Ave	2018	32%
RS-033	Aspen Park Gimli	2015	37%
RS-033	Gimli Aspen Park	2016	8%
RS-033	Gimli Aspen Park	2017	13%
RS-033	Gimli Aspen Park	2018	32%
RS-035	Kotelko	2017	8%
RS-035	Kotelko	2018	8%
RS-036	Dugald	2016	2%
RS-036	Dugald	2017	17%
RS-036	Dugald	2018	33%
RS-037	IDC Trailer Park	2017	27%
RS-037	IDC Trailer Park	2018	47%
RS-040	Transcona	2018	22%
RS-041	Lorette	2017	27%
RS-041	Lorette	2018	33%
RS-042	Oakbank	2017	13%
RS-042	Oakbank	2018	48%
RS-043	St Marys Perimeter	2018	0%
RS-044	St Annes Creek Bend	2018	5%
RS-045	Turnbull Dr	2018	48%
RS-046	King Edward Kinver	2018	0%
RS-047	Bishop Grandin	2017	2%
RS-047	Bishop Grandin	2018	12%
RS-049	Centerport	2017	8%
RS-049	Centerport	2018	0%

Regulator Station #	Regulator Station Name	Year of Inspection	Condition Score
RS-104	Kirkcaldy / Brandon	2015	10%
RS-104	Kirkcaldy Brandon	2018	10%
RS-106	Louise Brandon	2015	8%
RS-106	Louise Ave Brandon	2018	8%
RS-107	Victoria Brandon	2015	10%
RS-107	10th and Vic Brandon	2018	10%
RS-109	Park Brandon	2015	7%
RS-109	Park St Brandon	2018	7%
RS-111	34th Street / Brandon	2015	12%
RS-111	34th and CNR Brandon	2018	12%
RS-114	Keystone / Brandon	2015	7%
RS-114	Keystone RS Brandon	2018	7%
RS-115	Emerson	2016	2%
RS-115	Emerson	2017	13%
RS-115	Emerson	2018	17%
RS-125	Crystal Springs	2015	32%
RS-125	Crystal Springs	2017	33%
RS-125	Crystal Springs	2018	70%
RS-126	Labroquerie	2018	22%
RS-127	Marchand	2015	15%
RS-127	Marchand	2017	13%
RS-127	Marchand	2018	27%
RS-128	Kola	2016	12%
RS-128	Kola TBS	2018	7%

REFERENCE:

CAC/CENTRA I-44a-c

PREAMBLE TO IR (IF ANY):

Centra describes the evolution of its Pipeline Risk Assessment and Risk Analysis methodology, describes its utilization to date and provides the original 2014 Risk Assessment report. The Applicant states that the 2014 Risk Assessment report, which appears to contain additional technical detail relative to the most recent 2017 Results iteration, was never used in capital investment planning.

QUESTION:

a) Please explain why the 2014 Risk Assessment report was never used for investment planning.
b) Please confirm whether the Pipeline Risk Assessment Structure methodology depicted in Figure 1 of the 2014 report was used in preparation of the 2017 report.
c) Please explain why the 2017 report did not feature the detailed listing of Risk Estimation for the top 100 segments and the Risk Evaluation for the 10 Highest Pipe Segments. If the comparable analysis has been done but simply not included in the latest report, please provide it along with the response.
d) Please explain why the 2014 report did not include the colour-coded risk matrices featured in the 2017 Results report.

RATIONALE FOR QUESTION:

To understand the evolution of Centra's approach to asset risk assessment over the past five years based on the Round 1 IR responses.

RESPONSE:

a) The 2014 Pipeline Risk Assessment Report did not identify any projects that would be required to replace or decommission an asset. The report has been used to better understand the highest risk pipeline segments and support/validate risk control operating decisions.

b) The Pipeline Risk Assessment Structure methodology, which is depicted in Figure 1 of the 2014 Report was intended to be a visual representation of the algorithm used to calculate the Risk Score. At that time, the Risk Score was not expressed in specific dimensions. In 2017, the risk score is expressed in units/km-yr. The updated structure diagram in the 2017 Pipeline Risk Methodology was provided in Figure 5: Pipeline Risk Analysis Structure.

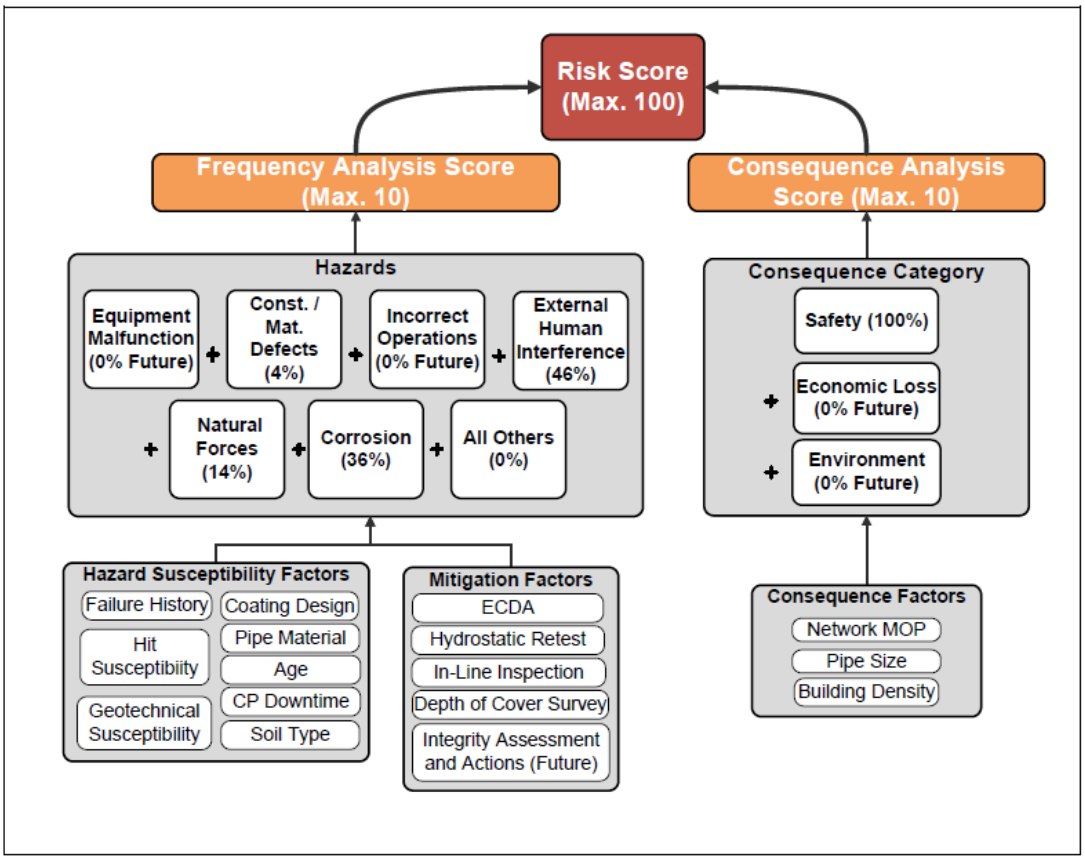


Figure 1: Pipeline Risk Assessment Structure

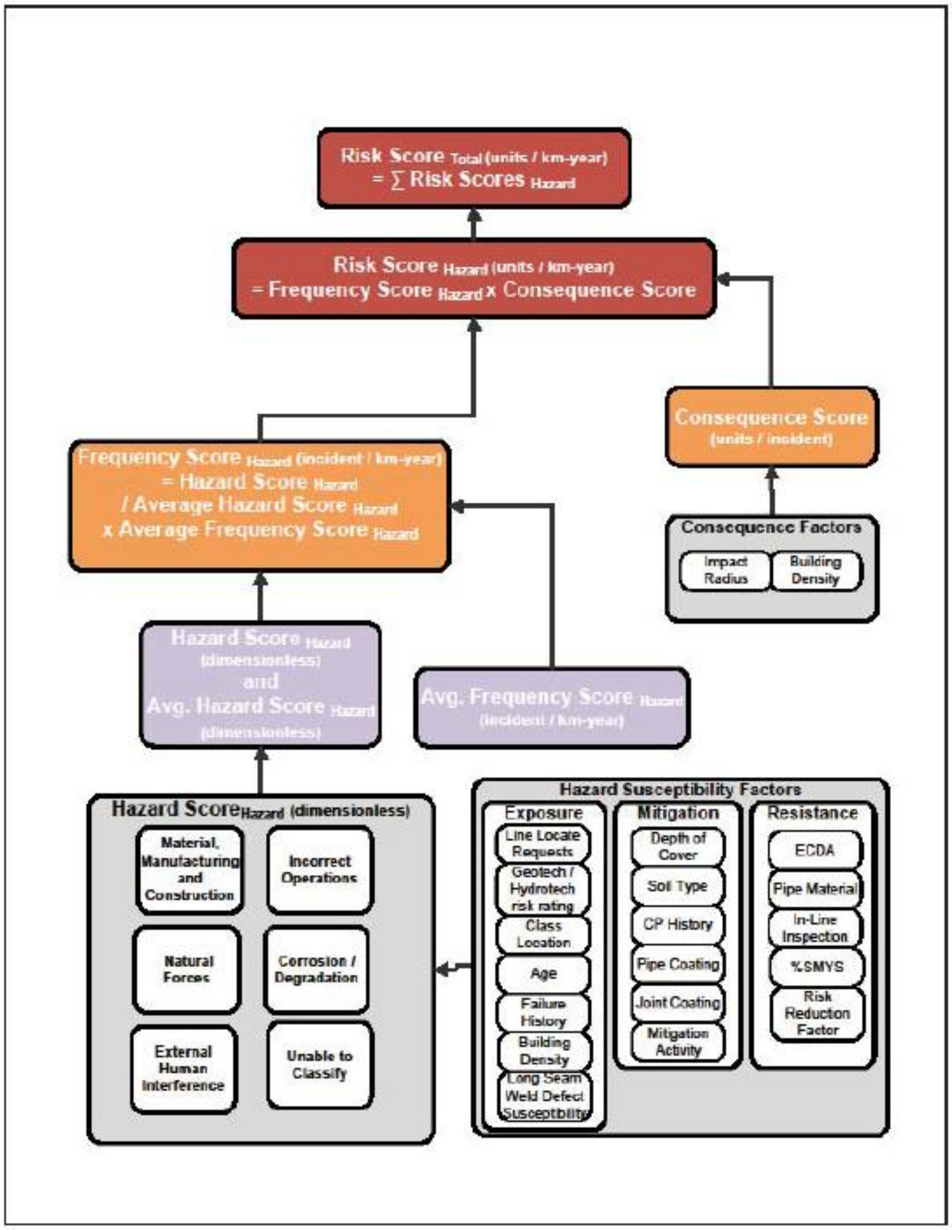


Figure 5: Pipeline Risk Analysis Structure

c) and d)

CSA Z662 Annex B.2.2.1 defines risk assessment as both risk analysis (hazard identification, frequency analysis, consequence analysis, risk estimation) and risk evaluation (risk significance and options).

In the 2014 methodology, the risk analysis portion was considered complete after determining the final Risk score, a number not expressed in specific units. This resulted in a relative risk table of all segments from highest risk score down. In the report, a summary of the 100 highest risk scores was provided as Table 1: Risk Estimation Top 100 Segments. The risk evaluation portion was undertaken for the 10 highest ranking pipe segments only.

In the 2017 methodology, a number of significant changes were made to the risk analysis approach. The pipeline network was separated into two asset groupings for risk assessment, Distribution and Transmission, as the two are designed and maintained very differently. The Frequency Score, Consequence Score, and the resulting Risk Score were expressed as incidents/1000kmyr, units/incident, and units/1000kmyr respectively. This represents a move towards quantitative risk analysis. Please see Attachments 1 and 2 to this response for the 2017 Transmission Risk Estimation table and 2017 Distribution Risk Estimation table, respectively.

In the 2017 methodology, changes were also made to the risk evaluation approach. The significance of the frequency and consequence scores were evaluated separately and visually represented in colour-coded risk matrices. It was aesthetically aligned with other corporate documents for purposes of familiarity.

The field of natural gas asset risk assessment is continually evolving and further changes to the methodology should be anticipated in the future.

The methodology changed from 2014 to 2017.

REFERENCE:

CAC/CENTRA I-53a

PREAMBLE TO IR (IF ANY):

To substantiate the use of increasingly larger Planning Item line item category used in the out-years of the five-year plan, the Applicant states that the absence of this category would create an incorrect indication that there would be reduced capital requirements in the future years, while the planning departments may have potential projects or issues that necessitate further scoping.

QUESTION:

Please describe the process by which the out-year plan estimate values are confirmed with the relevant departments and subject matter experts in possession of information and/or professional experience and judgment to support or challenge the estimated out-year values.

RATIONALE FOR QUESTION:

To gain a better understanding of the extent to which the out-year plan estimates reflect engineering rigour.

RESPONSE:

Senior Gas Engineering & Construction personnel working with financial personnel provide an estimate of the Planning Item for each year independently of other groups. The definition of known capital program and project costs is provided by the individual departments and subject matter experts with assistance from financial personnel. The Planning Item reflects capital requirements for future projects that are not yet defined at this time and the increasing value of the Planning Item in the out years reflects that further out in the forecast there are few approved projects thereby increasing the required level of the Planning Item in each year. As shown in the Cost Summary (page 10 and 11 of The

Natural Gas Asset Management Capital Investment Plan 2018-23), the number of identified projects decrease each year and by fiscal 2022/23 there are no identified projects. In the absence of a Planning Item, the required Projects capital would be shown as $0 for 2022/23. This would be misleading as each year projects are performed to address identified requirements and the Planning Item provides an indication that there will be an associated capital requirement. The Planning Item is considered an estimate and the Projects capital cost is refined in the near years.

REFERENCE:

CAC/CENTRA I-57b

QUESTION:

Please explain why no customer contributions to the Plant Relocation program costs appear to have been received in each of the 2012/213, 2013/14, and 2014/15 Plan Years.

RATIONALE FOR QUESTION:

To understand why customer contributions for externally-driven relocation projects were not collected for three consecutive years during which a total of nearly $3 million of relocation capital work took place.

RESPONSE:

Upon review of Centra's response to CAC/Centra I-57 b), Centra noted the results were incorrectly presented net of contributions received. Please see below for an updated table with both the gross expenditures and contributions received.

ACTUAL ($ Thousands)	2012/13	2013/14	2014/15	2015/16	2016/17
Plant Relocation Program					
Gross Expenditures	1 063	1 321	1 342	1 379	1 946
Contributions	(408)	(343)	(93)	(489)	(835)
Total	**655**	**978**	**1 249**	**890**	**1 111**

REFERENCE:

CAC/CENTRA I-58a-b

PREAMBLE TO IR (IF ANY):

In the referenced IR, Centra provides information to support its decision to replace degraded steel service lines with plastic equivalents, noting that the installation of a new plastic service line is significantly more cost effective than a steel pipe leak repair. Centra also notes that the decision to use plastic pipes to replaces degraded steel services was not reflected in any technical standards.

QUESTION:

a) Please confirm that the $4,500 plastic replacement line installation cost estimate includes the cost of removing the existing (leaking or corroded) steel service line.
b) If Centra does not record the changes to the use of materials in an internal technical standard (as implied in the response to sub (b)), please explain whether and how Centra records and disseminates the information regarding decisions to add or amend field work practices and/or decisions to use new types of materials or equipment.

RATIONALE FOR QUESTION:

To ensure comparability of the two values provided, and understand the process for entrenching the changes to equipment and materials use.

RESPONSE:

a) Confirmed, the $4,500 plastic replacement line installation cost estimate includes the cost of removing the existing steel service line.

b) Centra records the changes to the use of materials in internal technical standards when new materials become deemed acceptable or required for use. When multiple materials are acceptable as defined by internal standards, Centra typically uses the least expensive material. While Centra does not have a specific standard on the service pipe material to be used when a service is replaced, Centra has many standards in place regarding the use of polyethylene piping materials for mains and services. Polyethylene piping materials have been in use in the Manitoba natural gas system since approximately 1970.

REFERENCE:

CAC/CENTRA I-59a

QUESTION:

Please provide an explanation as to why the Farm Taps Abandonment was the only program for which Centra contemplated the intervention options other than direct replacement.

RATIONALE FOR QUESTION:

To understand the evolution of Centra's approach to asset risk assessment over the past five years based on the Round 1 IR responses.

RESPONSE:

The Farm Tap Abandonments were the only group of Program Items within a Program that underwent a formal cost-benefit analysis. Many program items and overall programs contemplate intervention options other than direct replacement.

One example is pipeline insufficient cover remediation. For these projects several methods are reviewed and typically the lowest cost option is selected. The typical methods of remediation are direct replacement, lowering, concrete slab protection, or abandonment.

Another example is the overall Meter Compliance Program in which many of the meters within the program are refurbished and put back into service as opposed to being replaced.

In both of these cases the lowest cost options overall are selected and approved within the program item CIJ or overall program CIJ. While this is not a formal cost-benefit analysis the lowest overall cost option is typically selected.

REFERENCE:

CAC/CENTRA I-60a-c

PREAMBLE TO IR (IF ANY):

CAC's intent in asking the original IR was to gauge the degree to which the proposed investments may reflect a degree of management's discretion, as opposed to being investments required in the short-to-medium term as proposed. Having reviewed the Applicant's responses, CAC seeks to clarify certain statements.

QUESTION:

a) Please identify all information in the CIJ referenced in the response to sub (a) that speaks to the probability of the events that the program seeks to mitigate.
b) Please confirm whether the statement suggesting that the program would result in "minimal" O&A savings was based on an actual calculation, a general high-level assumption, or any other method of estimation.
c) Please estimate the value of asset risks mitigated across the applicable categories (using the most Risk Assessment methodology) if the program were to be executed as proposed over the five-year Plan Period.

RATIONALE FOR QUESTION:

To confirm the correctness of CAC's understanding of Centra's responses.

RESPONSE:

a) The CIJ referenced encompasses the entire measurement and regulation portfolio, providing an overview of scope, background and justification. The probability of events that the program seeks to mitigate is not calculated or presented.

b) The statement of minimal O&A savings is a high-level evaluation of the cost-benefit.

c) The value of mitigated risks if the proposed five year plan was executed was not calculated and is not easily quantified.

REFERENCE:

CAC/CENTRA I-62a

QUESTION:

Please confirm that the Risk Analysis work the outputs of which Centra included in the current iteration of the plan will not be discontinued in the favour of the Corporate Value Framework.

RATIONALE FOR QUESTION:

To seek clarification to Centra's answer in order to assess its implications.

RESPONSE:

Not confirmed. Centra plans to be consistent with corporate initiatives which include standardizing the use of the Corporate Value Framework. The current Risk Analysis results provided in the 2018-2023 Natural Gas Asset Management Capital Investment Plan will be discontinued.

REFERENCE:

CAC/CENTRA I-63a, I-81a-b

PREAMBLE TO IR (IF ANY):

In the first reference, Centra discusses its plans regarding the in-line pipeline inspection activities, along with its plans to capitalize all the associated expenditures. In the sub (a) of the second reference, Centra provides the accounting standard information on the basis of which it plans to capitalize the costs of meter testing work.

QUESTION:

a) Is Centra's rationale for capitalizing the costs of in-line inspections the same as the one indicated in I-81a in relation to the Meter Testing work? If the rationales differ, please outline the differences.
b) Over which timeline does Centra intend to depreciate the capitalized costs of in-line inspections?

RATIONALE FOR QUESTION:

To gain insights into Centra's plans for capitalizing of activities often treated as seen operating/maintenance by the utilities industry.

RESPONSE:

a) Centra's rationale for capitalizing the costs of in-line inspections ("ILI") is similar to the one indicated in the response to CAC/Centra I-81 a) in relation to meter testing work. The use of ILI supports Centra's internal standards for the inspection, defect assessment and remediation of its pipeline system and supports Centra's compliance with the external standard CSA Z662-15 Oil and Gas Pipeline Systems with regards to defect assessment and remediation. In Order 15/16, the PUB directed Centra to follow the requirements of CSA Z662-15 effective March 1, 2016 as the minimum standard for the design, construction, operation and maintenance of gas pipelines in Manitoba. Centra was directed to follow CSA Z662-15 by the PUB as part of Centra's requirement to comply with The Gas Pipe Line Act C.C.S.M. c. G50 which governs the standards for the design, construction, testing, operation and maintenance of natural gas pipelines in Manitoba.

b) As documented in the response to CAC/CENTRA I-10e, there are currently nine transmission pipeline systems that require inspections and the plan is to conduct an inspection of the pipelines every 5-10 years. As such, a five year depreciation period is proposed for this activity.

REFERENCE:

CAC/CENTRA I-81a-b

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Has Centra sought any outside expert opinions (e.g. audit / accounting firms) to validate its interpretation of the IAS 16, to Meter Testing work? If so, please provide all such external assessments, including drafts and final versions.

b) Please calculate the Net Present Value of ratepayer impact of the contemplated capitalization of Meter Testing activities using the following parameters:
   - a 10-year evaluation period;
   - use the current approved WACC as the discount rate;
   - use the avoided annual O&A costs as the ratepayer benefit cashflows;
   - use the incremental ROE earned from the capitalized meter testing activities as the cost cashflows (using the contemplated depreciation timeline for capitalized meter costs);
   - discuss any other assumptions made.

c) If Centra performed a similar calculation / analysis to that requested to it in sub (b), please provide the document(s) in which it is contained.

RATIONALE FOR QUESTION:

To explore the analytical work underlying the decision to capitalize the Meter Testing costs.

RESPONSE:

a) Given that Manitoba Hydro's auditors have not been concerned with Manitoba Hydro's capitalization of meter testing and exchange activities, as well as with the capitalization of Centra's meter testing and exchange activities for the preparation of the consolidated financial statements, Centra has not specifically sought any outside expert opinions to validate its interpretation of IAS 16.

b) The financial scenarios provided in the response to PUB/CENTRA II-7 parts b), c), and d) assume the accounting for meter sampling and testing either through the establishment of a regulated deferral or through the re-statement of Centra's PP&E balance, keeping the indicative rate increases unchanged from what was included in CGM18. The scenarios demonstrate the financial impacts of various amortization periods of the unamortized meter sampling and testing balance. Under each of the financial scenarios, Centra's equity ratio remained at or around the 30% equity target in each year of the forecast period. As such, the indicative annual rate increases were not required to be adjusted.

The following table provides the NPV of the indicative rate increases from CGM18 (November 30, 2018), which are consistent the rate increases in the scenarios provided in PUB/CENTRA II-7b, c and d. The table has been provided in the same format as the NPV analysis provided in the response to PUB/CENTRA I-62b which was filed as part of the 2019/20 Electric Rate Application.

In Millions of Dollars

	Nominal WACC	Discount Factor	Annual Rate Increases [1]	Annual Cumulative Rate Increases	Additional Domestic Revenue	Discounted Additional Domestic Revenue
2019	6.00%	1.000	0.00%	0.00%	0	$0
2020	6.00%	1.060	0.00%	0.00%	0	$0
2021	6.00%	1.124	2.25%	2.25%	6	$5
2022	6.00%	1.191	1.00%	3.27%	10	$9
2023	6.00%	1.262	1.00%	4.31%	14	$11
2024	6.00%	1.338	1.00%	5.35%	17	$13
2025	6.00%	1.419	1.00%	6.40%	21	$15
2026	6.00%	1.504	1.00%	7.47%	24	$16
2027	6.00%	1.594	1.00%	8.54%	28	$18
2028	6.00%	1.689	1.00%	9.63%	32	$19
NPV						**$105**

1. Rate increases are assumed to be effective August 1 for each forecast year

c) No similar calculation/analysis to that provided in the response to part (b) above has been performed previously.

REFERENCE:

CAC/CENTRA I-82a

PREAMBLE TO IR (IF ANY):

In the Capital investment justification for the CNG Filling Facility, the section related to impact on O&A costs contains no specific estimate values, but rather discusses the anticipated cost requirements verbally.

QUESTION:

a) Please comment on whether the absence of a numerical O&A impact estimate as in the CIJ in question, constitutes an appropriate / compliant manner of completing the CIJ documents as per Centra's current corporate policies.
b) Does Centra plan to require the quantification of O&A impact within CIJ? If quantification is currently required for certain types of projects and/or dollar value magnitudes, please provide the relevant thresholds.

RATIONALE FOR QUESTION:

To understand the manner of utilization of CIJ forms by Centra's planning / engineering staff on the basis of insights obtained from the original IR response.

RESPONSE:

a) The purpose of the "Impact on O&A Costs" section in the Capital Investment Justification ("CIJ") approval document is to discuss the impact to O&A costs as a result of constructing and implementing the investment and its related asset(s). The discussion would focus on incremental cost increases/savings anticipated following the investment. Items to be considered, but not limited to, would typically include:
   - the nature of the incremental cost or the saving (i.e. one-time versus annual)
   - EFT increases or reductions anticipated
   - a quantification of the cost or saving, if known

However, it is recognized that the future impacts to O&A may not be known and/or quantifiable at the time of project justification; conversely an investment may not have an incremental impact to O&A.

b) Centra requires an evaluation of the O&A impacts for all types of capital investments, while recognizing that not all investments will have an incremental impact on O&A. In cases where an impact is anticipated and can be reasonably estimated, a comprehensive summary and quantification of those impacts are to be included.

REFERENCE:

CAC/CENTRA I-85h

PREAMBLE TO IR (IF ANY):

In response to the referenced IR, Centra provides a 27-page table of incident history data in a chronological sequencing order.

QUESTION:

a) Please organize all incidents by Major Cause and Sub-Cause for each year. Please provide summary statistics including:
   i. listing the total number of events associated with each cause and each sub-cause over the total time period examined;
   ii. ranking them from most- to-least frequently occurring over the timeframe examined;
   iii. providing year-over-year trend analysis by Major Cause and Sub-Cause.

b) Does Centra track any information associated with impact of each of the events listed in the table on:
   - service continuity
   - remediation costs

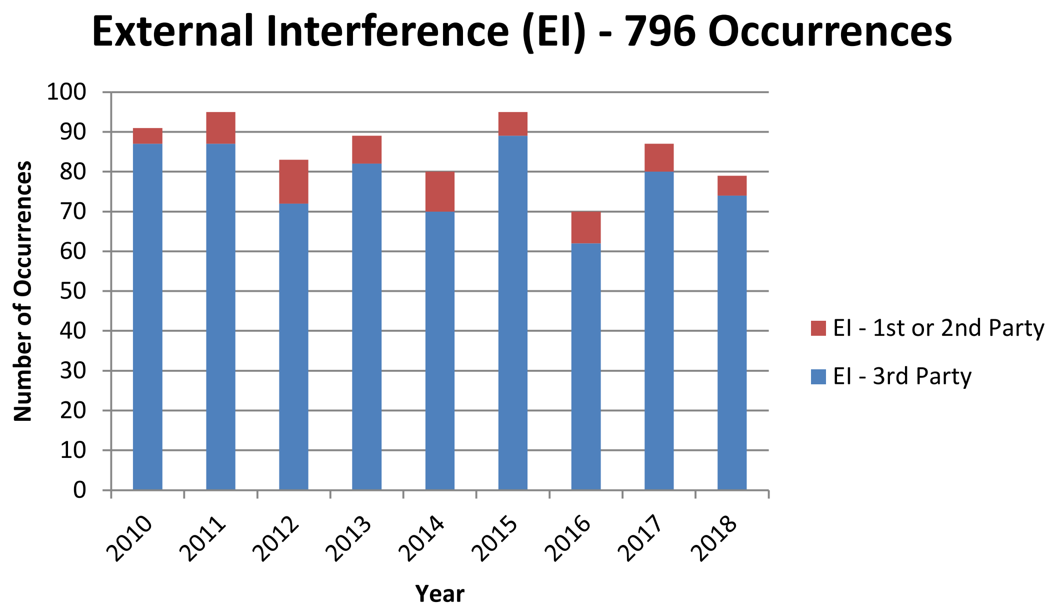
   i. If either or both types of impact quantification is available for all, or a subset of the list provided in the original IR, please provide them along with any supporting discussions to facilitate proper interpretation.
   ii. Please integrate the incident impact data into the organized cause code format requested in sub (a) and include the supporting summary statistics.

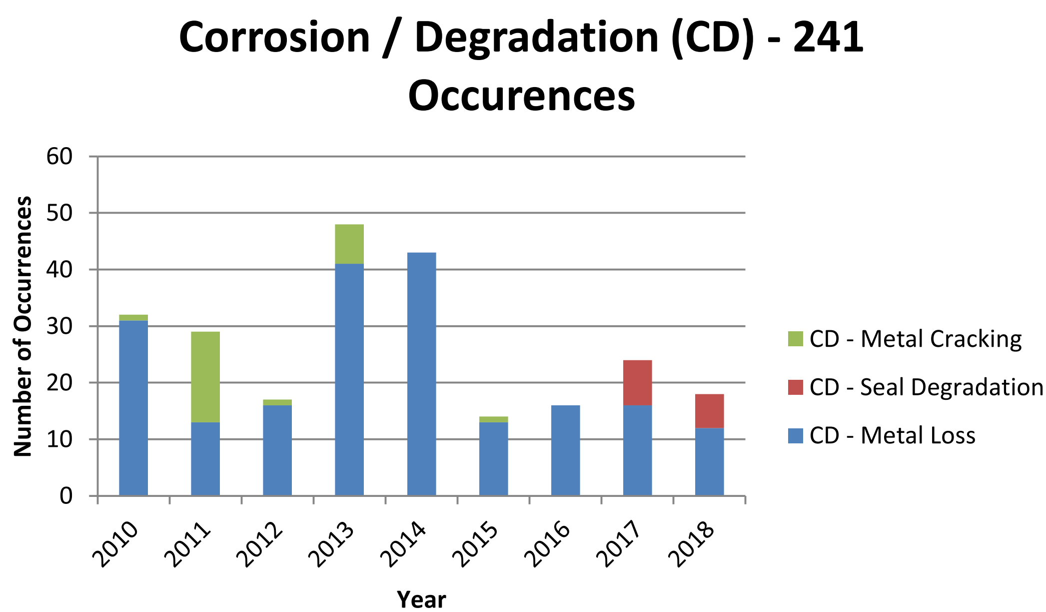
RATIONALE FOR QUESTION:

To gain a better understanding of Centra’s history of incidents.

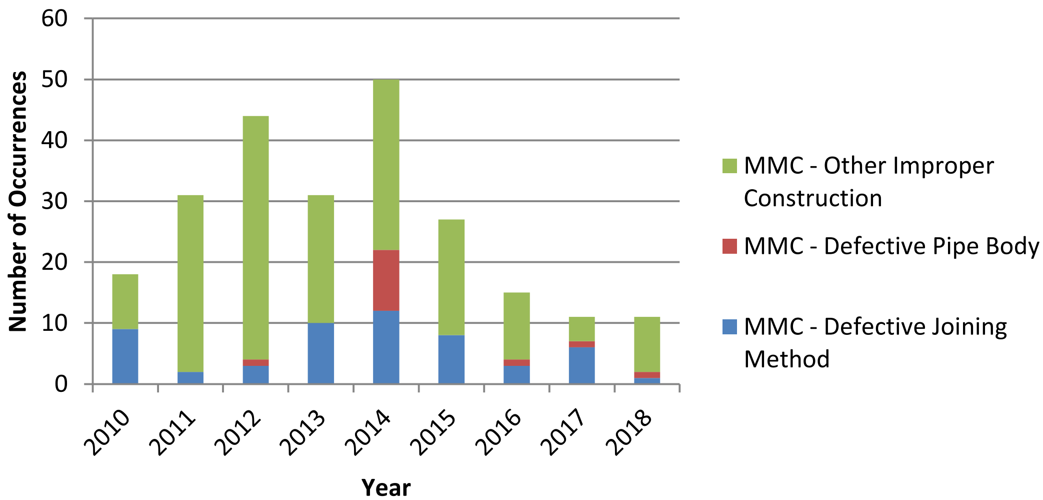
RESPONSE:

a) The following graphs show the occurrence of Centra's incidents by cause and sub-cause from 2010 to 2018. The graphs below are arranged from most frequent occurrence to least frequent by cause. Additionally, these graphs show year-over-year trends in incident occurrences by cause and sub-cause.

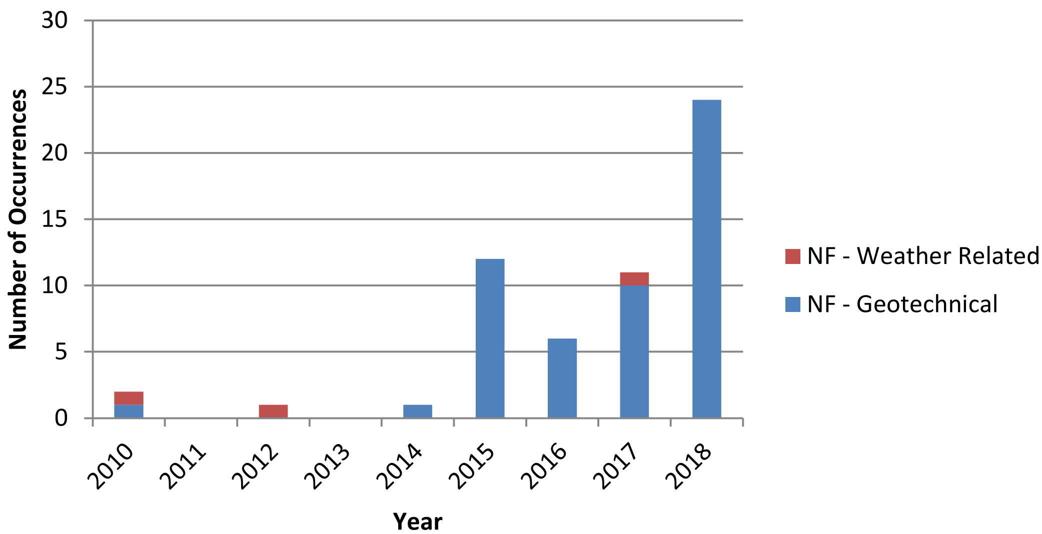


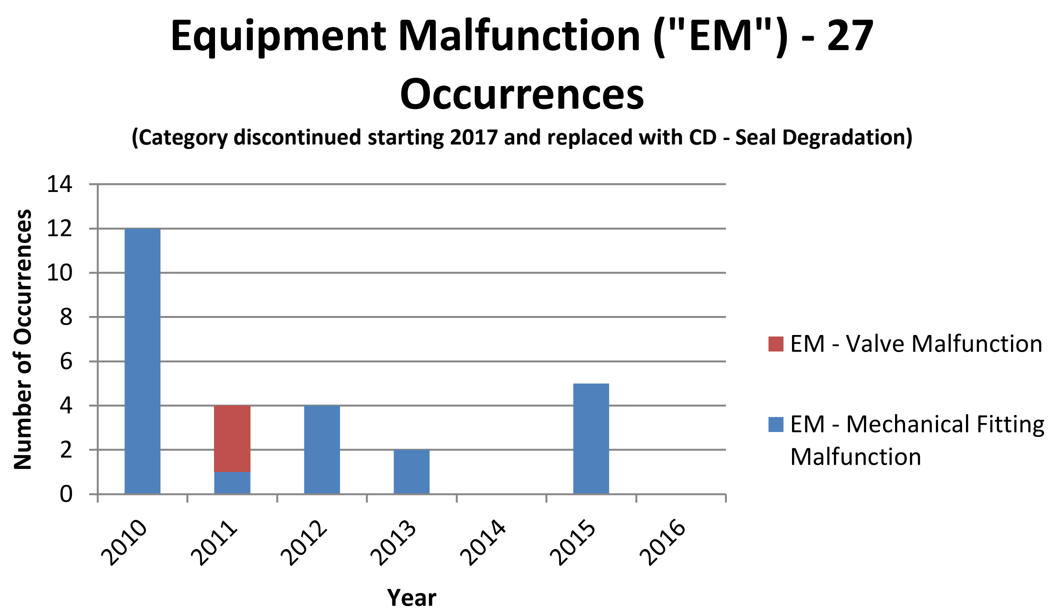


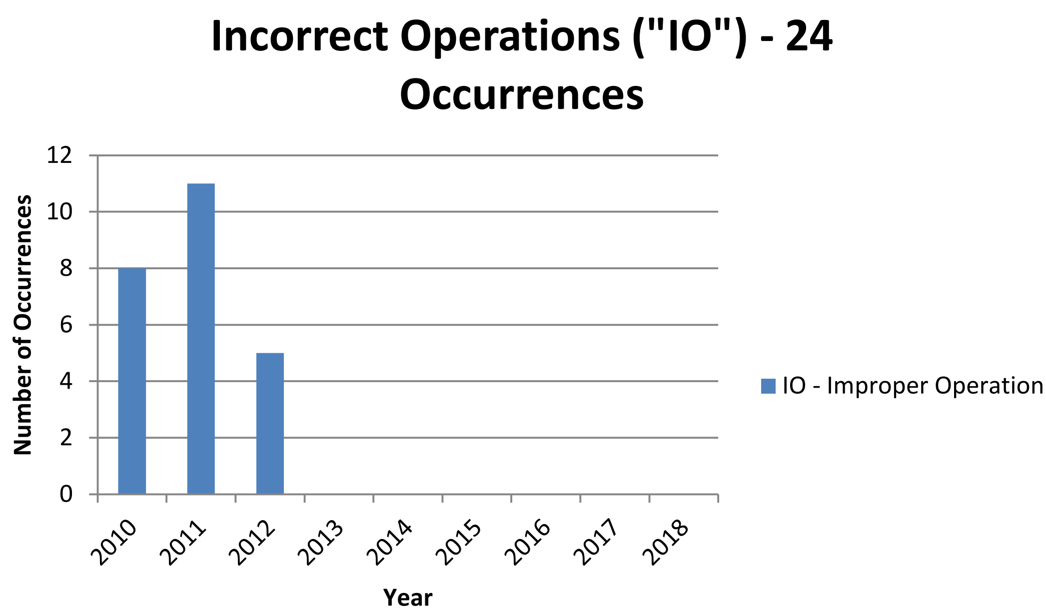
Material, Manufacturing & Construction Defects ("MMC") - 238 Occurrences

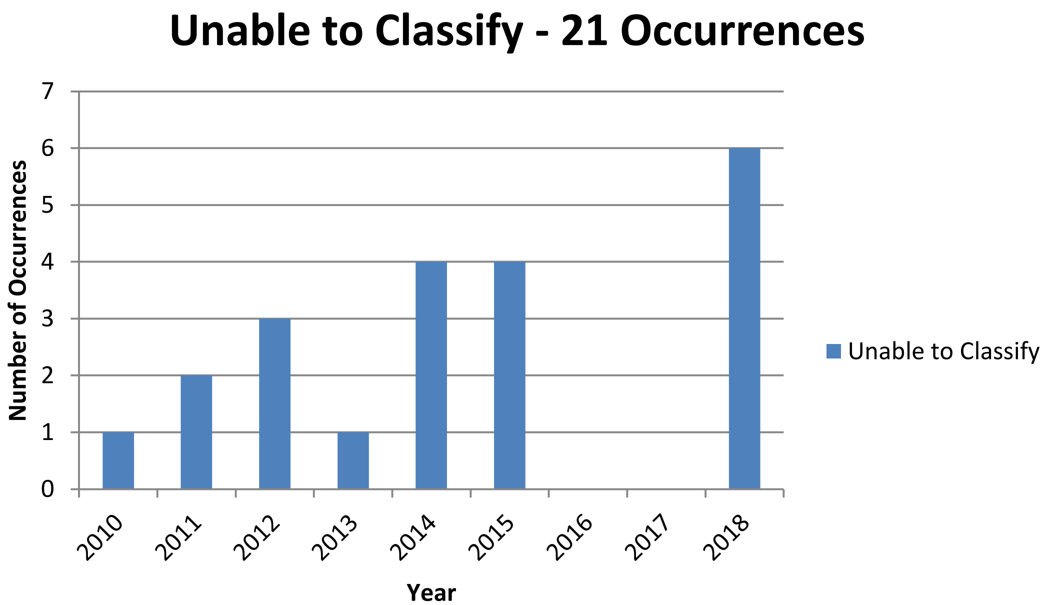


Natural Forces ("NF") - 57 Occurrences

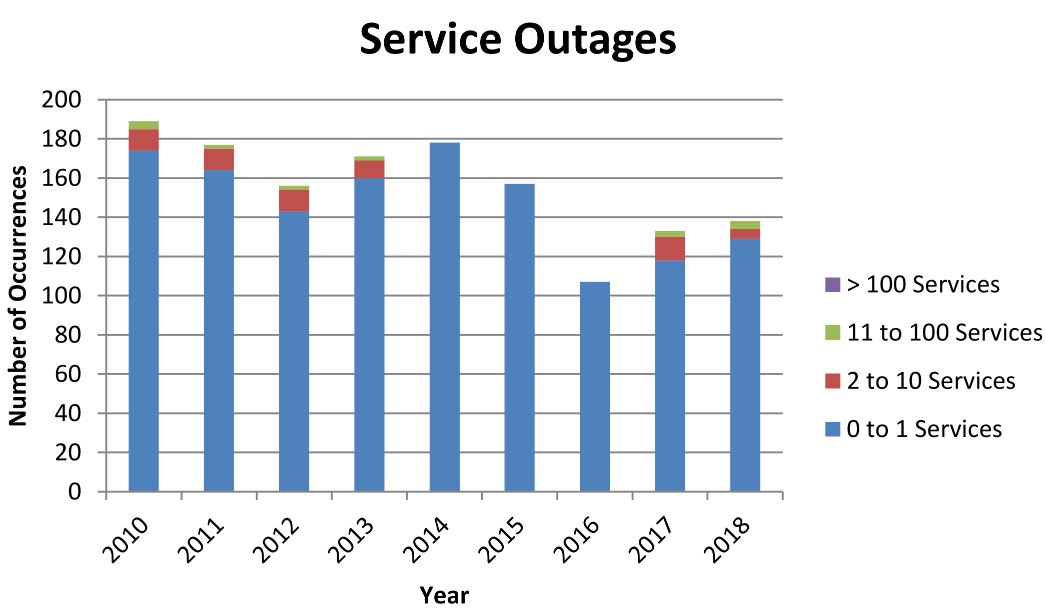



Equipment Malfunction ("EM") - 27 Occurrences
(Category discontinued starting 2017 and replaced with CD - Seal Degradation)
Number of Occurrences
0
2
4
6
8
10
12
14
2010
2011
2012
2013
2014
2015
2016
Year
EM - Valve Malfunction
EM - Mechanical Fitting Malfunction

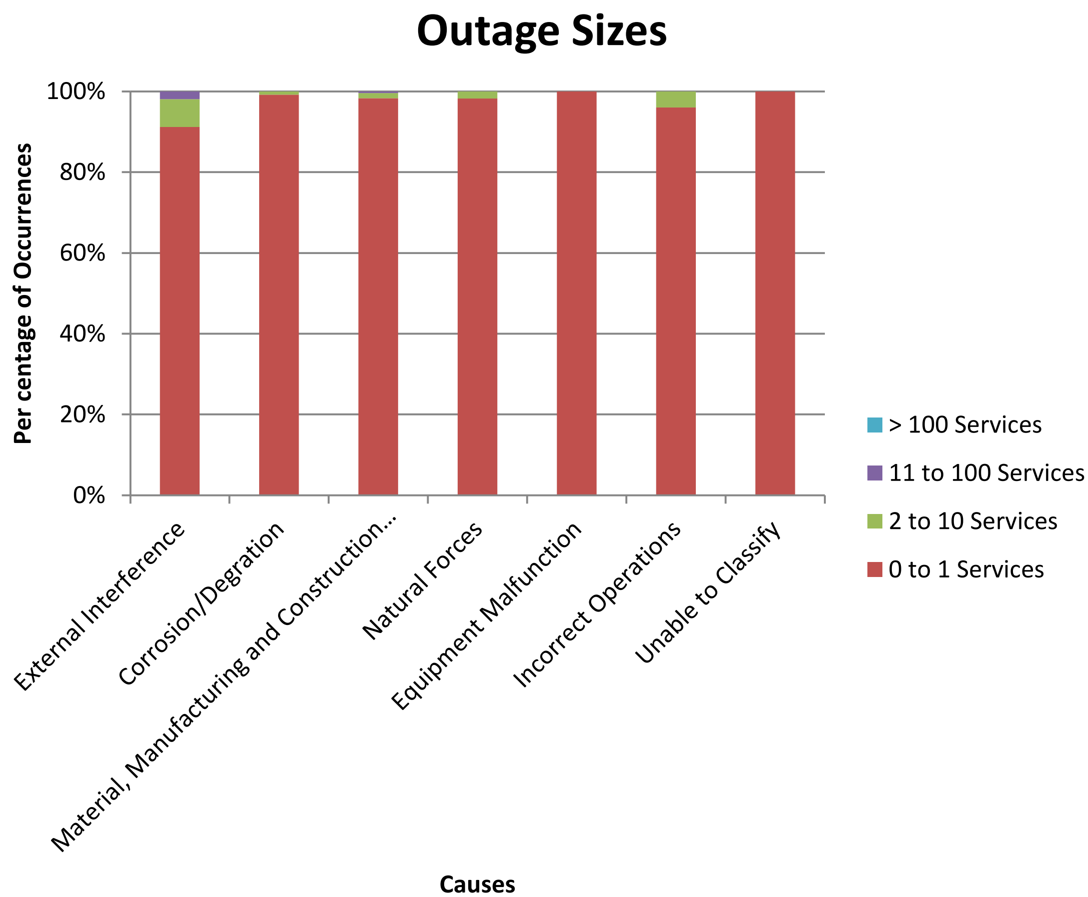

Incorrect Operations ("IO") - 24 Occurrences
Number of Occurrences
0
2
4
6
8
10
12
2010
2011
2012
2013
2014
2015
2016
2017
2018
Year
IO - Improper Operation



b) For service continuity, Centra has recorded the occurrence of natural gas customer outages caused by incidents. The size of outage is grouped into 4 categories. As seen below most incidents results in no or 1 service outage.



When service outage size is compared to the incident causes, incident data shows that external interference incidents are most likely to cause larger outages than other incident causes.



For remediation costs, Centra only records whether the direct repair cost was greater than $100k. This direct repair cost applies only to the remediation applicable to Centra's pipeline system. For all incidents between 2010 and 2018, one event exceeded the direct repair cost of $100k. The cause of this event was 3rd party external interference.