PUB #_____

Centra 2019/20 GRA
Board Counsel's Book of Documents

1.	O&A Expense and Methodology
2.	Accounting Treatment of Gas Meter Exchange Labour
3.	Capital Costs and Rate Base Additions
4.	DSM – Furnace Replacement Program
5.	Customer Equipment Problem Program
6.	Heating Value Margin Deferral Account
7.	Bill Mitigation
8.	Transportation Balancing Fees

1

REFERENCE:

Appendix 5.9 Figure 5.12

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a comparison of actual O&A vs 2013/14 approved O&A of $68,800 from 2013/14 to 2019/20.

RESPONSE:

The following table provides a comparison by program of the 2013/14 O&A approved forecast of $68,800 to the actual results from 2013/14 through 2017/18 and the forecast for 2018/19 and 2019/20. Centra has consistently maintained its O&A expenditures below the 2013/14 approved forecast of $68,800 through to 2019/20.

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

	CGAAP			IFRS				
	2013/14 Approved	**2013/14 Actual**	**2014/15 Actual**	**2015/16 Actual**	**2016/17 Actual**	**2017/18 Actual**	**2018/19 Forecast**	**2019/20 Test Year**
Customer Service & Corporate Relations								
Back/middle office services	$ 279	$ 233	$ 235	$ 177	$ 298	$ 277	$ 289	$ 294
Billing & collections	8,891	8,750	8,963	9,460	8,440	7,880	7,554	7,705
Customer & public relations	6,588	5,502	4,853	4,229	3,978	4,070	3,930	4,009
Customer information systems (Banner)	936	1,097	900	404	493	556	524	534
Customer inspections	7,349	7,164	7,296	7,064	7,301	7,488	7,011	7,151
Customer safety services	1,846	1,505	1,393	1,293	1,282	1,394	1,260	1,285
Dispatch	2,290	1,957	1,938	1,874	1,923	2,061	2,261	2,306
Energy supply, planning & support	1,990	2,232	2,358	2,420	2,682	2,517	2,813	2,869
Environment	412	495	781	450	391	261	391	399
Meter reading	2,045	1,969	1,947	1,922	1,949	1,832	1,960	2,511
Rate and regulatory affairs	1,665	1,555	1,125	1,221	964	846	925	944
	34,290	**32,458**	**31,789**	**30,514**	**29,701**	**29,183**	**28,918**	**30,008**
Operations and Maintenance								
Communication systems	161	164	221	124	124	124	133	135
Distribution maintenance	6,114	5,975	6,511	6,448	6,253	6,161	6,626	6,759
Load forecast	184	144	201	145	166	89	69	70
Metering	5,267	4,169	5,275	5,555	4,601	4,357	3,555	574
Plant failures & emergencies	92	1,114	254	190	327	271	297	303
Quality assessment	464	297	497	463	460	427	426	435
Station maintenance	4,950	4,429	4,965	5,121	5,162	5,120	5,271	5,376
System performance & reliability	1,721	2,149	2,565	1,955	2,528	2,716	2,464	2,513
	18,953	**18,439**	**20,490**	**20,001**	**19,621**	**19,266**	**18,841**	**16,165**
Organizational Support								
Corporate governance				2,726	2,555	2,236	2,116	2,157
Corporate infrastructure				5,263	4,593	4,778	4,418	4,581
Corporate services				2,535	2,260	2,203	1,972	2,010
Departmental support				5,182	5,947	5,787	5,754	5,872
Operational management				2,680	2,463	1,752	1,752	1,787
	18,501	**17,250**	**17,405**	**18,386**	**17,818**	**16,757**	**16,012**	**16,408**
Total Program Costs	**71,744**	**68,147**	**69,684**	**68,901**	**67,140**	**65,206**	**63,770**	**62,581**
Adjustments:								
Depreciation & taxes	(3,063)	(2,492)	(3,222)	(1,778)	(1,851)	(2,139)	(2,140)	(2,183)
Other	119	1,155	996	(516)	95	46	1,685	852
	(2,944)	**(1,337)**	**(2,226)**	**(2,294)**	**(1,756)**	**(2,093)**	**(455)**	**(1,331)**
Total Operating & Administrative	**$ 68,800**	**$ 66,810**	**$ 67,458**	**$ 66,607**	**$ 65,384**	**$ 63,113**	**$ 63,315**	**$ 61,250**

REFERENCE:

Application Tab 5, Figure 5.18, Supplement Appendix 5.13 Figure 5.18

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide details on restructuring costs from years 2016/17 through to 2019/20 including costs and benefits capitalized.

RESPONSE:

The restructuring expenditures from 2016/17 through to 2019/20 are primarily made up of voluntary departure plan payments and associated benefits ($3 million), as well as consulting expenditures related to the supply chain management initiative ($0.2 million). All costs have been expensed.

Staff approved under the VDP worked in all functions of the business impacting capital construction, as well as electric and gas operations and maintenance work; therefore, a reasonable allocation of these expenditures has been charged to Centra. As discussed in PUB/CENTRA I-28c, a new cost driver was introduced to allocate restructuring expenditures associated with the Voluntary Departure Program (VDP). These costs are not expected to continue past 2019/20 at which time this driver will no longer be required.

REFERENCE:

Appendix 5.9 Section 3.0; 2013-14 GRA PUB/Centra I-20(a-c)

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Provide a schedule that details Manitoba Hydro's overall OM&A expense, the amounts allocated or directly assigned to Centra and the percentage of the total allocated for each of the years since 2012/13 and through to 2019/20.

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

c) Please indicate whether any of the cost drivers have changed since the 2013/14 GRA and the rationale for the changes.

RESPONSE:

a) The following table details Manitoba Hydro's O&A expenditures by electric and gas operations and includes the percentage of the total allocated to Centra from 2012/13 through to 2019/20.

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

	CGAAP			IFRS				
	2012/13 Actual	**2013/14 Actual**	**2014/15 Actual**	**2015/16 Actual**	**2016/17 Actual**	**2017/18 Actual**	**2018/19 Forecast**	**2019/20 Test Year**
Electric O&A	$ 462,952	$ 480,717	$ 480,472	$ 542,714	$ 535,825	$ 516,859	$ 501,183	$ 511,100
Gas O&A	63,735	66,810	67,458	66,607	65,384	63,113	63,315	61,250
Total O&A	$ 526,687	$ 547,527	$ 547,930	$ 609,321	$ 601,209	$ 579,971	$ 564,499	$ 572,350
% Allocated to Centra	12%	12%	12%	11%	11%	11%	11%	11%

b) The following tables provide the amount of costs allocated directly and indirectly to Centra from 2012/13 to 2014/15 (CGAAP) and 2015/16 to 2019/20 (IFRS).

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

	CGAAP					
	2012/13 Actual		2013/14 Actual		2014/15 Actual	
	Direct	Indirect	Direct	Indirect	Direct	Indirect
Customer Service & Corporate Relations	$ 18,113	$ 13,048	$ 20,423	$ 12,035	$ 20,264	$ 11,525
Operations and Maintenance	16,579	266	18,251	188	20,157	333
Organizational Support	399	16,459	306	16,944	398	17,007
Total Program Costs	**$ 35,091**	**$ 29,773**	**$ 38,980**	**$ 29,167**	**$ 40,819**	**$ 28,865**

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

	IFRS									
	2015/16 Actual		2016/17 Actual		2017/18 Actual		2018/19 Forecast		2019/20 Test Year	
	Direct	Indirect	Direct	Indirect	Direct	Indirect	Direct	Indirect	Direct	Indirect
Customer Service & Corporate Relations	$ 19,739	$ 10,775	$ 19,300	$ 10,401	$ 18,702	$ 10,482	$ 19,250	$ 9,667	$ 20,147	$ 9,861
Operations and Maintenance	19,779	222	19,388	234	19,073	193	18,713	127	16,036	130
Organizational Support	868	17,518	798	17,019	770	15,987	430	15,582	439	15,969
Total Program Costs	**$ 40,386**	**$ 28,515**	**$ 39,486**	**$ 27,654**	**$ 38,544**	**$ 26,662**	**$ 38,394**	**$ 25,376**	**$ 36,621**	**$ 25,959**

The table below provides the cost drivers used for the allocation of indirect costs with examples of each.

Driver	Electric	Gas	Common Cost Examples	Rationale
Customers	67%	33%	Bill Insertion Operations	1
Customers	67%	33%	Banner Application	1
Total Assets	96%	4%	Executive Functions	2
Total Assets	96%	4%	Audit Costs - Common	2
Activity Charges	92%	8%	Corporate Safety Programs	3
Activity Charges	92%	8%	Human Resourses	3
Management Estimate	50%	50%	Line Locates	4
Management Estimate	45%	55%	Comprehensive general liability insurance	4

Rationale for the cost driver:

1. Customers - costs incurred are driven by the number customers.
2. Total assets - a general driver that represents the relative size of the electric and gas utility.
3. Activity charges - a general driver that represents the relative amount of activity charges by staff to each of the utilities.
4. Management Estimates - Where specific departments perform gas and electric functions simultaneously, the cost driver is based upon the relative estimate of time required of the task performed for each of the utilities. Management estimates represent many custom cost drivers that are determined by management, in coordination with their Financial Advisor, who will incorporate professional judgment and experience to determine when to use and how to calculate the management estimate cost driver.

c) A new cost driver was introduced in 2016/17 to allocate restructuring expenditures associated with the Voluntary Departure Program (VDP). The restructuring costs were not anticipated to impact the gas capital operations, so the driver was set to the gas portion of operating activities which is 6%. This driver is only used to allocate VDP restructuring costs which are accounted for in Other Expenses. These costs are not expected to continue past 2019/20 at which time this driver will no longer be required.

REFERENCE:

PUB/Centra I-18

PREAMBLE TO IR (IF ANY):

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

QUESTION:

a) Please provide an explanation for the following variances on O&A by cost element:
   - Consulting and professional fees
   - Office expenses
b) Please provide an update to the comparison for the 2018/19 annual versus forecast by cost element and program for the fourth quarter and explain all material variances.
c) Please provide an explanation for the following Q3 variances on O&A by program:
   - Customer and public relations
   - Customer safety services
   - Metering
   - System performance & reliability

RESPONSE:

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

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

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

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

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

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

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

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

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

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

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

REFERENCE:

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

QUESTION:

a) Please explain how Centra determined the total asset allocator was appropriate for allocation of savings related to the VDP.

b) Why did Centra not utilize the corporate activity charge ratio of 8% for allocating the labour savings related to VDP?

c) Please indicate how much of labour is allocated based on activity charges versus other allocators.

d) Please explain how the Corporation determined that the restructuring costs should be based on 6%. Please provide the determination of this allocation.

e) Please file the headcount analysis demonstrating the $92.6M in salary and benefit savings related to the VDP.

f) Please add an additional column to the schedule (d) indicating the number of staff that worked only on or primarily on natural gas specific work. Include additional columns for the wages and benefits related to those individuals.

RESPONSE:

a) and b):

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

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

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

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

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

CENTRA GAS MANITOBA INC.
RESTRUCTURING DRIVER
(in millions)

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

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

VOLUNTARY DEPARTURE PROGRAM
($ in millions)

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

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

REFERENCE:

Tab 5 – Section 5.2.4 Operating & Administrative Expense (pg 16 -20), and Appendix 5.9 – O&A Expense

PREAMBLE TO IR (IF ANY):

The PUB approved O&A expense from the 2013/14 Test Year was $68,800. Actual O&A expense and Other Expenses for 2017/18 was $65,441 for rate-setting purposes including net movement in regulatory deferrals (Appendix 5.12 (Update), Page 4, Figure 3, Lines 10 and 18).

Centra provides the following variance analysis of year over year changes in O&A expense in Tab 5, pages 19 and 20:

> **"2017/18 Actual vs. 2016/17 Actual (IFRS)**
> The decrease of $2.3 million is primarily due to…as well as reduced staffing levels and associated expenditures related to the Voluntary Departure Program ("VDP")…
> **2018/19 Forecast vs. 2017/18 Actual (IFRS)**
> A nominal increase of 0.3% or $0.2 million is forecast for 2018/19…The forecast reflects additional funds to assist management in the restructuring process…
> **2019/20 Forecast vs. 2018/19 Forecast (IFRS)**
> The decrease of $2.1 million is primarily due to the proposed capitalization of costs related to the sampling, testing, and exchange of natural gas meters partially offset by escalation and a proposed increase in fees paid to Manitoba Hydro Utility Services (MHUS) for meter reading costs.

QUESTION:

a) Further to the information requested in PUB/Centra I-24 of the current proceeding, please provide a comparison between the approved 2013/14 O&A expense of $68,800 (CGAAP) and 2017/18 actual O&A expense and Other expenses of $65,441 (for rate-setting purposes) and explain the key business drivers of the decrease of $3,359 on an overall basis, including the overall impacts of accounting changes from the transition to IFRS.

b) Further to the information requested in PUB/Centra I-30, please explain if Centra has conducted any overall review of the hours charged by program and costs that have been charged to it (in addition to the individual program cost variance analysis provided in Appendix 5.9) and made any overall conclusions with respect to the relatively consistent underspending to 2016/17 relative to the 2013/14 approved O&A expense. If yes, please provide the analysis. If not, please explain why.

c) Please provide a table similar to the response to Coalition/MH I-13 (b) and (c) from the Manitoba Hydro 2019/20 Rate application proceeding that summarizes the Centra O&A forecasts for 2018/19 and 2019/20 in two columns by (i) starting with Centra's 2017/18 actual O&A (ii) adding the impact of projected wage increases, merit & progression on labor costs (iii) adding the impact of escalation on non-labor & benefit costs (iv) deducting Centra's allocated portion of labor savings from the VDP (v) deducting Centra's allocated portion of sourcing savings from the Supply Chain initiative (vi) adding any contingency/provision for restructuring costs (vii) adding the increase in meter reading costs from MHUS (viii) adding/deducting the net amount of any other miscellaneous changes to O&A (ix) deducting the amount of meter exchange costs that are being capitalized in 2019/20 (x) resulting in 2018/19 and 2019/20 forecast O&A costs. Please include any assumptions that were made in developing the table similar to Coalition/MH I-13 (b) and (c).

d) Please provide a table similar to the response to Coalition/MH I-13 d from the Manitoba Hydro 2019/20 Rate Application proceeding that provides the cumulative labor savings from the VDP that are allocated to Centra for 2017/18, 2018/19 and 2019/20. Please provide the total VDP labor savings, the assumed percentage that is allocated to Centra with the rationale for the percentage allocation and the $ amounts that are allocated to Centra in the table.

e) Please provide a table similar to the response to Coalition/MH I-13 d from the Manitoba Hydro 2019/20 Rate Application proceeding that provides the cumulative sourcing savings from the Supply Chain Initiative that are allocated to Centra for 2017/18, 2018/19 and 2019/20. Please provide the total sourcing savings, the assumed percentage that is allocated to Centra with the rationale for the percentage allocation and the $ amounts that are allocated to Centra in the table.

f) Please provide a variance analysis and associated explanations between actual and forecast restructuring costs (charged to O&A) for the nine months to December 31,

2018. Please indicate if there are any restructuring costs forecast for Centra for the 2019/20 fiscal year.

g) Further to the information requested in PUB/Centra I-29 (b) for the current proceeding, please provide a table similar to the response to Coalition/MH I- 14 (j) from the Manitoba Hydro 2019/20 Rate Application that provides the Contracted Wage Settlements between January 1, 2014 and January 1, 2020 for Manitoba Hydro and explain which of the settlements impact the costs that Centra is allocated.

h) Please provide the escalation assumptions in CGM18 with respect to labor, benefits and non-labor costs for 2018/19 to 2027/28 as well as the corresponding $ increases for each year of that timeframe.

i) Please provide a breakdown of the Rate & Regulatory Affairs program costs listed on Figure 5.5, page 10 of Appendix 5.9 for 2015/16 actual to 2019/20 forecast. Please delineate between internal costs, external costs not related to specific regulatory proceedings and external costs related to specific regulatory proceedings (breaking out separately the forecast related to the 2019/20 GRA proceeding).

j) Please provide a breakdown of the Other line under Adjustments on Figure 5.5, page 10 of Appendix 5.9 for 2015/16 actual to 2019/20 Forecasts. Please describe the nature of the specific adjustments and any unallocated provisions or contingencies included in the Other Adjustment line.

k) Please provide a breakdown of the Restructuring costs (referred to in Note 12 on Page 12, lines 15 to 16) included in the Other Adjustment line of O&A on Figure 5.5, page 10 of Appendix 5.9 for 2015/16 actual to 2019/20 forecast. Please describe the nature of the specific initiatives that are being funded through this cost item and the percentage and rationale for the percentage allocated to Centra.

l) Further to the information requested in PUB/Centra I-25 of the current proceeding, requesting details of Corporate Restructuring costs included in Other Expenses, please provide the percentage and rationale for the percentage allocated to Centra.

m) Further to the information requested in PUB/Centra I-19 (c) in this proceeding, please provide the total number and costs of positions/EFT’s that have been refilled since the previous incumbents have taken the VDP.

RATIONALE FOR QUESTION:

To understand the key drivers for the changes in Centra's O&A costs since the 2013/14 GRA for rate-setting purposes.

RESPONSE:

a) The following table provides a breakdown of the $65,441 referenced in the question:

Appendix 5.12 Figure 3 *(in thousands of dollars)*	2017/18 Actual
Operating & Administrative (Rate Setting)	$62,413
Other Expenses (Rate Setting):	
Corporate Restructuring Costs	3,006
Miscellaneous	22
Total O&A and Other (Rate Setting)	$65,441

Please refer to PUB/Centra I-7 Figure 5 for an analysis of actual 2017/18 results ($62,413K) in comparison to the 2013/14 forecast ($68,800K) approved by the PUB for Operating & Administrative expenses.

Corporate Restructuring costs of $3,006K are one-time costs associated with the Voluntary Departure Program ("VDP") and management restructuring. These costs are not expected to recur; therefore it would not be an appropriate to include these costs in O&A expenses required to operate the business.

Miscellaneous costs of $22K are related to business initiative revenue which is inherently different than O&A expenses required to operate the business.

b) Centra reviews actual results to approved corporate forecasts as part of its financial controls and governance functions. The table below provides a summary of Centra's O&A forecast and actual performance from 2013/14 through 2016/17. Detailed explanations by program can be found in Section 6 of Appendix 5.9.

CENTRA GAS MANITOBA INC.
O&A PERFORMANCE
($000'S)

	2013/14	2014/15	2015/16	2016/17
Forecast	$ 68,800	$ 67,829	$ 66,691	$ 67,818
Actual	66,810	67,458	66,607	65,384
Difference	$ 1,990	$ 371	$ 84	$ 2,434

c) Centra's operations are integrated within the organization structure of Manitoba Hydro with costs being allocated to Centra through the Integrated Cost Allocation Methodology ("ICAM"), which is discussed in greater detail in Appendix 5.10 - Manitoba Hydro ICAM Technical Conference and in response to PUB/Centra I-33 a). Centra does not have employees, as such employee time is allocated to Centra through an activity charge (activity rate x hours worked) or through a cost driver for common or governance functions. Activity charges represent close to 70% of the overall allocations to Centra, as per PUB/Centra I-27a). The change in activity charges can be impacted by wage settlements, other activity rate cost components, sick and vacation time, variability of work requirements, as well as other factors. Given the method under which costs are allocated, Centra cannot isolate the impact of general wage increases, merit, etc. on O&A and is unable to provide a table comparison as requested.

d) The following table provides an estimate of cumulative labour savings from the VDP allocated to Centra from 2017/18 through 2019/20. The allocation is assumed to be 4%, equivalent to the Total Assets driver, which is representative of the relative size of the electric and gas utility.

CENTRA GAS MANITOBA INC.
ESTIMATED VOLUNTARY DEPARTURE PROGRAM SAVINGS
(in millions of dollars)

	Total Employee Departures - Consolidated	Centra O&A Savings 2017/18	Centra O&A Savings 2018/19	Centra O&A Savings 2019/20
2017/18	795	$ 0.8	$ 2.2	$ 2.2
2018/19	26	-	0.0	0.1
2019/20	-	-	-	-
TOTAL	821	$ 0.8	$ 2.2	$ 2.3

e) The following table provides an estimate of cumulative sourcing savings from the Supply Chain initiative allocated to Centra from 2017/18 through 2019/20. The allocation is assumed to be 4%, equivalent to the Total Assets driver, which is representative of the relative size of the electric and gas utility.

CENTRA GAS MANITOBA INC.
ESTIMATED SOURCING SAVINGS - SUPPLY CHAIN
(in millions of dollars)

	Total Sourcing Savings	O&A Component Of Sourcing Savings (30%)	Centra O&A Savings 2017/18	Centra O&A Savings 2018/19	Centra O&A Savings 2019/20
2017/18	$ 6.9	$ 2.1	$ 0.1	$ 0.1	$ 0.1
2018/19	9.5	2.8	-	0.1	0.1
2019/20	14.9	4.5	-	-	0.2
TOTAL	$ 31.3	$ 9.4	$ 0.1	$ 0.2	$ 0.4

f) For the nine months ended December 31, 2018 there were no restructuring costs recorded in O&A and there are no restructuring costs forecast in 2019/20.

g) The table in PUB/Centra I-29 b) contains the Contracted Wage Settlements between January 1, 2014 and January 1, 2020 for Manitoba Hydro.

Manitoba Hydro's electric and natural gas lines of business are fully integrated with all staff employed by Manitoba Hydro. As there are no Centra employees, any employee that works on Centra programs as well as common costs between the electric and gas lines of business would impact Centra's costs. As such, all wages settlement agreements in place could have an impact on the costs that are allocated to Centra.

h) The CGM18 escalation assumption for the O&A forecast was 2% per year from 2018/19 to 2027/28. The forecasted O&A expense as well as the year over year increase/(decrease) are shown in the table below. The 3% reduction in the 2019/20 Test Year reflects the proposal to capitalize meter compliance expenses.

CENTRA GAS MANITOBA INC.
OPERATING & ADMIN COSTS
(in millions)

	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
Operating & Admin Costs	$63	61	62	63	64	65	66	68	69	70
Year over Year										
Increase/(Decrease)		(2)	1	1	1	1	1	1	1	1
% Increase/(Decrease)		-3%	2%	2%	2%	2%	2%	2%	2%	2%

i) The table below provides a breakdown of the Rates & Regulatory Affairs program as shown on Figure 5.5, page 10 of Appendix 5.9 from 2015/16 through to 2019/20.

CENTRA GAS MANITOBA INC.
RATE & REGULATORY AFFAIRS PROGRAM COSTS
($000s)

	2015/16 Actual	2016/17 Actual	2017/18 Actual	2018/19 Forecast	2019/20 Test Year
Internal Costs	752	515	360	478	487
External Costs - Non Proceeding Related *	469	449	486	448	457
External Costs - Proceeding Related **	-	-	-	-	-
Total Costs	**1,221**	**964**	**846**	**925**	**944**

* Non-Proceeding Related costs include PUB monthly fees & advisor fees

**External Proceeding Related costs are capitalized and are therefore not included as part of the O&A program for Rates & Regulatory Affairs

Please refer to CAC/Centra I-10 h) for the forecast costs related to the 2019/20 General Rate Application.

j) Please refer to the corresponding items listed below which are shown in the table on page 2 of PUB/Centra I-38 as the component breakdown of "Other" in Adjustments on Figure 5.5, page 10 of Appendix 5.9 for the years 2015/16 through 2019/20:
- Benefits not allocated to programs;
- Cost recoveries; and
- Contingency forecast.

k) The explanation of the increase in "Other" provided on page 10 of Appendix 5.9 is referring primarily to funds held in the 2018/19 forecast year to assist management in the restructuring process. Specific initiatives were not identified for these funds.

l) Please refer to PUB/Centra I-28 c) which provides the percentage and rationale for the allocation of costs to Centra related to Corporate Restructuring.

m) As outlined in the response to PUB/Centra I-19 c), Manitoba Hydro's electric and natural gas lines of business are fully integrated and all employees are employed by Manitoba Hydro. Centra does not have employees and as such is unable to respond to this request.

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)**

In summary, after the appropriate rate-setting adjustments to properly attribute the cumulative gas meter exchange profit adjustment to Centra, its projected financial reserves are $96 million, and the projected Equity ratio is 32% in the 2019/20 Test Year. This level of financial reserves is the higher under MH's ownership.

6.0 It is Recommended that Centra's 2019/20 Non-Gas Revenue Requirement be Adjusted Downward by $5 million for Rate-Setting Purposes

In its application, Centra indicates that it is not applying for a general rate increase for 2019/20 related to non-gas costs and that based on the revenues currently being generated by existing rates, it expects to generate a net income (contribution to financial reserves) of approximately $2.9 million in the 2019/20 Test Year (within the PUB's previously approved level of net income of $3 million).

This section of the Evidence reviews various elements of the 2019/20 non-gas revenue requirement (O&A Expense and Property Tax Expense) where there are issues related to the reliability of Centra's forecasts for rate-setting purposes and it is ultimately recommended that the PUB should approve downward rate-setting adjustments of $5 million related to Centra's 2019/20 O&A expense targets. The $5 million reduction is equivalent to an overall rate reduction of approximately 1.6% based on current revenues of $308 million, including gas costs. It is also recommended that the PUB obtain further information on the impacts of the 2018 re-assessment before approving Centra's 2019/20 property taxes into rates.

This section also recommends that the PUB direct that additional information and analysis be provided at future Centra GRA's with respect to the integrated cost allocation methodology, debt management strategies and the application of debt policy guidelines and that the PUB provide further clarification, directives or recommendations with respect to the disposition or use of the $17 million of excess Furnace Replacement Program funding collected from SGS customers since 2007/08.

6.1 Centra's Application Indicates that at the Projected Net Income of $2.9 million there is No Non-Gas Revenue Requirement Increase Required for 2019/20

In Tab 2 of Centra application, it indicates that it is not applying for a general rate increase for 2019/20 related to non-gas costs. Centra is also requesting approval to discontinue funding the Furnace Replacement Program (FRP) and to remove the associate costs from the rates of SCG customers.

In information request CAC/Centra II-124 (b), CAC requested Centra to reconcile different figures that were provided between the application and information requests with respect to the while the remaining 15% are allocated using other allocation processes. As noted above, in the response to CAC/Centra I-12 (c), Centra indicated that activity charges represent close to 70% of the overall allocations to Centra. Also, based on a review of the responses to PUB/Centra II-23 (a) to (f) it appears that there is only a vary small amount ($1.3 million in 2019/20) of costs allocated to Centra using the corporate asset driver that relate to corporate governance, corporate services and public relations. The other cost drivers noted in this information request are allocating costs to Centra in a proportion that significantly exceed the 4% corporate asset driver (Number of customers is 33%, Activity charges is 8%, Management Estimates is 24%), with 4% being the lowest allocation to Centra (Corporate Assets driver).

Based on this analysis and given the broad nature of the VDP/supply chain savings (which are not limited to corporate governance programs or activities), it is concluded that the Corporate Asset cost driver (4%) is not the appropriate cost driver to use to allocate the savings to Centra. On the face of it, it would be expected that the allocation of these savings to Centra would be much higher given Centra's own evidence at this proceeding that gas operations are allocated about 11% of total O&A costs and Activity charges (8% allocated to Centra) represent about 70% of the overall allocations of O&A costs to Centra.

It is not clear from the record of this proceeding, why Centra believes that a 4% allocation of VDP/supply chain savings to gas operations is appropriate. The causal relationship between the broadly based VDP/supply chain savings and the relative amount of corporate assets between MH and Centra appears to be weak.

The information in this proceeding indicates that an allocation of at least 8% of the VDP/supply chain savings would be more reasonable given the broad nature of the underlying savings and the better causal relationship between these savings and the relative amounts of activity charges between MH and Centra.

Using the Company's estimate of $2.7 million of savings based on a 4% allocation, a more appropriate allocation of 8% of the savings to Centra for rate-setting purposes would be estimated at $5.4 million ($2.7 million * 8% / 4%) or double the savings that have been allocated to Centra. As such, an appropriate downward adjustment to Centra's O&A target for 2019/20 would be quantified at $2.7 million ($5.4 million - $2.7 million) of additional savings.

Escalation Assumptions for Centra

As note in Section 6.2 of the Evidence, in the response to CAC/Centra I-12 (c), Centra stated that due to the method that is used to allocate costs to gas operations, it was unable to isolate the dollar impact of escalation factors such as general wage increases and merit for 2018/19 and 2019/20.

In the response to CAC/Centra I-12 (h), Centra indicated that the CGM18 escalation assumption for the O&A forecast was 2% per year from 2018/19 to 2027/28, which at O&A levels around the $61 million level would result in annual escalation in the order of $1.2 million on an annual basis.

At a rate of 2% escalation per annum, the cumulative impact of around $2.4 million from 2018/19 to 2019/20 would offset about 89% of the VDP and supply chain savings ($2.7 million) allocated to Centra, in just two fiscal years.

While there are other impacts on the O&A forecasts, (such as a decrease in meter program activities as a result of lower requirements to meet Measurement Canada standards), this high-level calculation is confirmed by the fact that 2019/20 O&A would be at the level of $64 million ($61 + $3) absent the accounting change to capitalize gas meter exchange labour which is only slightly down from the $65 million pre-VDP O&A levels in 2016/17.

Even at the recommended adjusted level of savings allocated to Centra of $5.4 million calculated above, annual escalation of $1.2 million would totally erode the savings in approximately 4 to 5 years ($5.4/$1.2 = 4.5 years).

Centra confirmed in the response to CAC/Centra II-133 (g) that it did not explicitly incorporate a productivity factor in establishing its O&A targets for 2018/19 and 2019/20.

As was the case in the MH 2019/20 Rate Application proceeding, Centra has not supported the 2% escalation factor with any evidence, it is simply the return to a previous budgeting practice that MH used before 2013.

The return to a 2% escalation factor represents a passive approach to cost control. Given the rate pressures that Centra is facing (reviewed in Section 8.0), more active cost control is required to manage the rate increases projected in the 10-year forecast and preserve the savings from the VDP and supply chair initiative for a longer period of time.

Consistent with the PUB findings in Order 69/19 and recognizing that gas operations O&A is an allocation from the larger consolidated MH operations, it is recommended that the PUB utilize a 1% escalation factor for Centra for rate-setting purposes in 2018/19 and 2019/20. The 1% escalation factor was used by MH in its forecasts between MH13 and MH15.

This recommendation is also consistent with the rate-setting policy signal being provided to MH in Orders 59/18 and 69/19 that it must prudently and actively control costs to the full extent possible before it seeks rate increases from customers and recognizes that Centra is not a stand-alone entity, but rather, its O&A costs are allocated from MH consolidated O&A costs. It is also consistent with the current provincial governments approach to managing costs in the public sector in Manitoba.

This recommendation would reduce annual escalation from $1.2 million to $0.6 million. This would result in cumulative escalation for the two test years of $1.2 million or a $1.2 million downward rate-setting adjustment from the cumulative $2.4 million inherent in the Centra O&A targets.

The adjusted $1.2 million cumulative escalation for 2018/19 and 2019/20 would represent about 22% ($1.2/$5.4) of the recommended $5.4 million savings allocation to Centra. The combination of the two recommendations to increase the VDP/supply chain savings to Centra to $5.4 million and reduce the annual escalation to 1% or $0.6 million, would have the impact of preserving the benefits of these savings for Centra's customers to 9 years ($5.4/$0.6 = 9 years).

Unallocated Contingencies for Centra

In responses to information requests CAC/Centra I-12 (f) and CAC/Centra II-133 (f), Centra confirmed that:

- The contingency forecast of $1.887 million (PUB/Centra I-38) for 2018/19 was for funds held to assist management in the restructuring process;
- For the nine-months ended December 31, 2018 there were no restructuring costs and there were no restructuring costs forecast in 2019/20; and
- The contingency forecast of $1.059 million (PUB/Centra I-38) for 2019/20 represents the difference between the target and the detailed budgets or a reserve for cost increases and program changes that have not yet been incorporated into detailed plans.

Consistent with the issues that were noted in the MH 2019/20 Rate Application, these contingency amounts appear to be plugs to make the detailed budgets match the previously developed targets from CGM16 and do not have any planned expenditures associated with them. As such, they have not been justified for rate-setting purposes.

It is recommended that the $1.059 million contingency for 2019/20 be adjusted for rate-setting purposes by making a corresponding downward reduction to approved O&A expenses for 2019/20.

Total Recommended Reductions to 2019/20 O&A for Rate-Setting Purposes

Based on the record of this proceeding and considering the foregoing analysis, it is recommended that the PUB to make the following adjustments to Centra's 2019/20 O&A target for rate-setting purposes:

1. Adjust the allocation of the VDP and supply chain savings to Centra upward by $2.7 million for a total of $5.4 million to 2019/20 based on an 8% allocation, which would result in a downward adjustment to O&A of $2.7 million;
2. Adjust the escalation assumptions in the 2018/19 and 2019/20 O&A targets to 1% to reflect the assumption of a productivity factor and be consistent with Order 69/19. This

would reduce escalation from $1.2 million in each fiscal year to $0.6 million, with a cumulative downward adjustment to 2019/20 O&A of $1.2 million; and

3. Adjust the 2019/20 O&A target for the unallocated general contingency of $1.1 million as this contingency has no planned expenditures and has not been justified for rate-setting purposes.

The recommended adjustment for 2019/20 for rate-setting purposes is a total of $5.0 million ($2.7+$1.2+$1.1) which would reduce the 2019/20 O&A target to $56.3 million ($61.3 - $5.0) from the $61.3 million requested by Centra in its application. The $5 million reduction is equivalent to an overall rate reduction of approximately 1.6% based on current revenues of $308 million, including gas costs.

Figure 9 provides a high-level illustrative calculation of the cumulative impacts of the recommended rate-setting adjustments on Centra's O&A forecast for the period to the end of CGM18 (2027/28):

Figure 9 - Impacts to O&A Forecast of Recommended Rate-Setting Adjustments

	2020	2021	2022	2023	2024	2025	2026	2027	2028
O&A @ 2% Esclation	61.3	62.5	63.8	65.1	66.4	67.7	69.1	70.5	71.9
O&A @ 1% Escalation	56.3	56.9	57.5	58.1	58.7	59.3	59.9	60.5	61.1
(including rate-settting adjustments)									
Decrease in O&A Forecast	**(5.0)**	**(5.6)**	**(6.3)**	**(7.0)**	**(7.7)**	**(8.4)**	**(9.2)**	**(10.0)**	**(10.8)**

The key observations from Figure 9 are as follows:

1. Figure 9 uses Centra's 2019/20 O&A forecast of $61.3 million as the starting point and escalates this amount at 2% in the top row to illustrate the O&A trajectory to 2027/28. In the second row, the 2019/20 O&A net of the recommended $5.0 million of rate-setting adjustments of $56.3 million is escalated at the 1% recommended out to 2027/28. The third row is the decrease to O&A targets as a result of the rate-setting adjustments and a 1% escalation factor;
2. Based on the total O&A rate-setting adjustments for 2019/20 and a 1% escalation factor, total O&A would grow to $58 million by 2022/23, a reduction of $7 million from trajectory

CENTRA GAS 2019/20 GENERAL RATE APPLICATION

INTERVENER EVIDENCE INFORMATION REQUESTS

CAC (D. RAINKIE, K. DERKSEN)

JULY 5, 2019

PUB/CAC(Rainkie)-12 Reference**:** Rainkie-Derksen Evidence p.39 Line 23-26

Request:

Given that all O&A is assigned through allocators, please provide how Mr. Rainkie proposes ensuring 1% escalation in O&A costs. (i.e. the constraint put on the amount of costs allocated through ICAM to Centra being restricted to 1% of growth)

Response:

In the event that MH is able to manage its O&A costs within the 1% escalation factor that the PUB found was acceptable for rate-setting purposes on Page 24 of Order 69/19, then there should be a natural flow-through of this level of escalation in the O&A costs that are allocated to Centra through the ICAM. In this case, there would be no requirement for a discrete rate-setting adjustment.

In the event that MH is unable to manage its O&A cost within the 1% escalation factor, then a discrete adjustment to the O&A costs that are allocated to Centra through the ICAM would have to be made for rate-setting purposes. This adjustment could be made in a manner that is consistent with the calculations provided on pages 47 to 49 of our Evidence, by considering the level (percentage) of escalation inherent in the MH consolidated O&A forecast and making a corresponding adjustment down to the 1% escalation level, based on the total O&A costs allocated to Centra.

to allocate the Heating Value Deferral Account on a volumetric basis, based on the existing PUB-approved Cost of Service Study, and consistent with the original Application and Supplement, and recognizes that alternative dispositions of the Heating Value Deferral Account will be discussed at the oral evidentiary portion of the hearing to be held in August.

Figure 3.4: Summary of Gas Year Deferral Balances by Rate Class

PGVA's by Rate Class	Total	SGS	LGS	HVF	Mainline	Interr.	SC	PS
2019/20 Rider - 2015/16 GY	6,033,724	3,024,698	2,451,091	465,287	-38,323	-97,972	[redacted]	
2019/20 Rider - 2016/17 GY	2,536,082	1,498,755	1,185,818	-47,868	-92,885	-95,806		
2019/20 Rider - 2017/18 GY	-16,693,758	-8,263,939	-5,970,447	-2,379,554	-88,997	-286,131		
2019/20 Rider - 2018/19 GY	-13,213,324	-6,524,939	-4,347,969	-2,394,342	13,384	-217,375		
Total	-21,337,276	-10,265,424	-6,681,507	-4,356,478	-206,821	-697,284		

2d, 1e

3.2 Updated Detailed O&A Budgets

Although the total non-gas costs remain unchanged in this filing, the changes to the program costs in Operating & Administrative expenses have resulted in changes to allocation of these costs between classes. Figure 3.5 below provides a summary of the allocation of non-gas costs to various customer classes compared to Mar 22, 2019 filing.

Figure 3.5: Comparison of Non-Gas Costs by Customer Class ($000s)

	2019/20 TY March 22, 2019 Supplement	2019/20 TY July 24, 2019 Pre-Hearing Update	Increase/ (Decrease)
SGS	102,633	102,604	(29)
LGS	32,456	32,286	(170)
High Volume Firm	6,824	6,889	65
Co-op	8	8	(0)
Mainline	2,058	2,052	(6)
Special Contract	2,247	2,278	32
Power Stations	158	198	40
Interruptible	770	779	9
Primary Gas	[redacted]		
Supplemental Firm			
Supplemental Interrupt ble			
Fixed Rate Primary Gas	21	14	(8)
Total Non-Gas Costs of Service	148,519	148,519	(0)

1e

The increase in O&A costs allocated to HVF, SC, PS and INT classes is the result of the increase in program costs such as Customer Inspections, Environment, Distribution

Maintenance and System Performance and Reliability, which are allocated to customer classes in proportion to transmission and distribution mains and distribution service plant. The decrease in O&A costs allocated to SGS and LGS classes resulted from the decrease in program costs such as Dispatch, Billing and Collections and Other that these classes have relatively higher cost responsibility for.

Explanations for programs with costs that changed significantly compared to the information filed as part of the March 22nd Supplement are provided below.

Further, the allocated non-gas costs to be included in the Primary Gas base rate will also slightly increase as a result of this update. Centra is requesting approval of a new updated Primary Gas Overhead Rate (non-gas component) of $0.98/10^3m^3 (Schedule 10.1.2, lines 47 and 49) compared to $0.91/10^3m^3 from March 22 Update Filing.

Centra has also updated its Fixed Rate Primary Gas Service ("FRPGS") Program Cost Rate ("PCR"). The revised PCR is $24.18/10^3m^3 (Schedule 10.1.2, line 49), which is lower than the $37.67/10^3m^3 included in March 22, 2019 filing and lower than the 31.37/10^3m^3 currently approved by the PUB. The decrease compared to the March filing results from a further reduction in program administration costs forecasted for this service for the 2019/20 test year.

The non-gas cost components within the Supplemental Gas rates have also been updated. The Firm Supplemental gas overhead component is proposed to be $1.54/10^3m^3 and the Interruptible Supplemental gas overhead component is proposed to be $1.55/10^3m^3. Figure 3.6 provides the calculation of overhead rates for Supplemental Gas.

Figure 3.6: Calculation of Supplemental Gas Overhead Rate

	2019/20 March 22, 2019 Supplement	2019/20 July 24, 2019 Pre-Hearing Update	
Firm Supplemental OH rate			
Non-gas allocated ($)	[redacted]		1d, 1e
Volumes (10^3m^3)			
Rate/10^3m^3	1.60	1.54	
rate/m^3	0.0016	0.0015	
INT Supplemental OH rate			
Non-gas allocated ($)	[redacted]		1d, 1e
Volumes (10^3m^3)			
Rate/10^3m^3	1.59	1.55	
rate/m^3	0.0016	0.0015	

Centra's overall O&A Expense target for 2019/20 remains unchanged at $61.2 million, consistent with the original Application and the Supplement to the Application filed on March 22, 2019. Figure 3.7 below provides the recently finalized detailed O&A budget by program for 2019/20 along with a comparison to the O&A by program filed in the original Application.

Figure 3.7: Detailed O&A Budget by Program for 2019/20

CENTRA GAS MANITOBA INC.
2019/20 O&A PROGRAM COMPARISON

	2019/20 Approved Budget	2019/20 Test Year Submitted	Change	Notes
Customer Service & Corporate Relations				
Back/middle office services	290	294	(5)	
Billing & collections	7 306	7 705	(399)	1
Customer & public relations	3 959	4 009	(49)	
Customer information systems (banner)	627	534	93	
Customer inspections	8 184	7 151	1 033	2
Customer safety services	1 533	1 285	248	
Dispatch	1 920	2 306	(386)	3
Energy supply, planning & support	2 721	2 869	(149)	
Environment	948	399	549	4
Meter reading	2 497	2 511	(14)	
Rate and regulatory affairs	1 304	944	360	5
Total Customer & public relations	31 288	30 008	1 280	
Operations and Maintenance				
Communication systems	133	135	(2)	
Distribution maintenance	7 005	6 759	247	
Load forecast	107	70	37	
Metering	361	574	(213)	
Plant failures & emergencies	232	303	(71)	
Quality assessment	448	435	13	
Station maintenance	5 106	5 376	(271)	
System performance & reliability	2 662	2 513	149	
Total Operations and Maintenance	16 055	16 165	(110)	
Organizational Support				
Corporate governance	2 297	2 157	141	
Corporate infrastructure	4 591	4 581	10	
Corporate services	2 116	2 010	105	
Departmental support	6 174	5 872	302	6
Operational management	1 638	1 787	(149)	
Total Organizational Support	16 816	16 408	408	
Corporate Allocation & Adjustment				
Depreciation & Taxes	(2 212)	(2 183)	(29)	
Other	(697)	852	(1 549)	7
	(2 909)	(1 331)	(1 579)	
Operating & Adminstrative Expenses	**61 250**	**61 250**	**(0)**	

Explanations have been provided for programs with a significant change.

1. The decrease in the **Billing and Collections program** is primarily due to a reduction of hours required as a result of the discontinuance of accepting bill

payments at all customer service centres.

2. The increase in the **Customer Inspections Program** is primarily due to changes in the activity rates to reflect the current mix of supervisory and technical staff required to support the program as well as a refinement of the hours to align with current and projected averages in customer requested programs such as line locates and equipment inspections.
3. The decrease in the **Dispatch Program** reflects lower staffing levels for the planning and scheduling function as well as reduced activity rates primarily as a result of organizational changes following the VDP.
4. The increase in the **Environment Program** is primarily related to additional environmental investigations required at 35 Sutherland.
5. The increase in the **Rates and Regulatory Affairs Program** reflects an increase in internal labour hours required to support the 2019/20 Gas General Rate Application.
6. The increase in the **Departmental Support Program** is due to the refinement of training and support cost estimates to reflect historical and known requirements.
7. The decrease in **Other** is due to an update of the contingency to align the detailed budget with the approved O&A target. Centra is currently reflecting a negative contingency of $600K which will be managed over the 2019/20 fiscal year to meet the approved target.

3.3 Updated Power Station Coincident Peak Day Forecast

With this update Centra has updated the methodology for calculating the coincident system peak day forecast of the power stations. Historically, the methodology which has been utilized for all rate classes, is to average the peak day contribution by rate class over the previous three years of history to be applied to the forecast. For the power station class the peak day contribution of each customer was independently calculated. Unlike prior forecasts, in the 2018 forecast only one of these customers was contributing to the peak day. The power station customers consume natural gas differently than other customer classes and may not draw from the system during the coincident peak day during the three previous years of history. For this update, the power station class coincident peak day has been calculated using the system coincident peak day contribution over the previous ten *strategy/approach to managing the aggregate of variable rate debt and targeting the appropriate or optimal positioning in the 15% to 25% policy guideline".*

The growth in the short-term debt balance typically peaks in November/ December in each of the forecast years. This growth is both a result of seasonal working capital requirements and capital expenditures. To be clear, the reduction in the short-term debt balance at March 31 in each forecast year is largely due to the forecast issuance of capital-related long term debt in March of each fiscal year. Generally, approximately $20 - $30 million is kept in the short term facility year round for working capital purposes. In November/December, at the peak of the seasonal requirements, approximately $20 million in additional short term debt is projected for working capital purposes in CGM18. There is interest rate risk associated with these seasonal working capital amounts. An increase in variable interest rates will increase finance expense regardless of whether the short term debt is outstanding all year or for a portion of the year. Centra believes that it is appropriate to consider all short term debt balances subject to interest rate risk in considering the impact on the rolling averages of variable rate debt outstanding throughout the year. However, as Centra applies the interest rate risk policy and guidelines to the debt portfolio at March 31 of each year, the seasonal working capital requirements are not included in the compliance calculations.

5.0 <u>REVENUE REQUIREMENT</u>

5.1 Operating & Administrative Expenses

Page 49 of Mr. Rainkie's evidence recommends that the PUB reduce Centra's Operating & Administrative (O&A) 2019/20 target for rate setting purposes by $5 million to reflect an adjustment for the allocation of Voluntary Departure Program ("VDP") and supply chain savings of $2.7 million, a decrease in the escalation assumption to 1% for both 2018/19 and 2019/20 for a cumulative reduction of $1.2 million, and the removal of a contingency of $1.1 million. In addition, on page 45 Mr. Rainkie makes the assumption that the 2019/20 O&A target was set prior to the VDP transition and is outdated.

Mr. Rainkie's assumption that the 2019/20 O&A target of $61.25 million is outdated is incorrect. Centra reviews its O&A target on an annual basis as part of the development of the annual budget. The corporation considers the upcoming business requirements and the level of resourcing required when confirming or establishing the annual targets. In the fall of 2018, the target of $61.25 million was revalidated with the only significant change identified being the additional meter reading expenditures from

MHUS of $524K (discussed on page 3 of Appendix 5.9). It was determined that these additional expenditures could be managed within the target of $61.25 million given the trend of lower program costs primarily due to the impacts of the VDP.

Mr. Rainkie's recommendation to reduce the O&A target for rate setting purposes completely ignores the reality that Centra actually operates within. Mr. Rainkie's recommendation means an **overall reduction of 8%** to the programs and services provided by Centra to its customers. In his evidence, Mr. Rainkie makes no mention as to which programs/services should be reduced or the corresponding impact to customers of any such reduction. As discussed by Mr. Rainkie on page 47, the majority of the O&A costs are activity charges and as such, a reduction of 8% would result in fewer resources allocating their time to the gas operations. A $5 million reduction achieved through lower activity charges would result in a reduction of approximately 59 000 straight time hours or 12% of the approximate 500,000 hours forecast for 2019/20. This would equate to a reduction of approximately 40 staff and in addition, would have an offsetting cost (workforce adjustment) impact to Centra in 2019/20.

A reduction of this magnitude also appears to be contrary to the statement made by Mr. Rainkie on page 26: "*There will always be expectations of on-going active cost control by a publicly owned regulated monopoly like Centra, but it cannot be assumed that a broad-based VDP will occur again the near future.*" An 8% reduction in O&A costs as suggested by Mr. Rainkie is well beyond active cost control and as noted above would have significant staffing and corresponding service level implications, especially so given the recent VDP.

The following provides additional comments with respect to the individual recommendations made on pages 49 and 50 by Mr. Rainkie:

1. Allocation of VDP and Supply Chain savings of 8% rather than the 4% used by Centra

   Contrary to Mr. Rainkie's comments on page 47, the 4% allocation is appropriate. The 4% is a general driver that represents the relative size of the electric and gas utility. The VDP was a corporate wide offering to all Manitoba Hydro staff, regardless of their age, jurisdiction, years of service, etc. The 8% allocation suggested by Mr. Rainkie represents labour costs that are directly charged to Centra through the timecard process and does not include labour costs applied through other allocators such as overhead and system postings. For example, the labour costs of staff in the Accounts Payable function are allocated to Centra through overhead. As such, without knowing the full impact of the VDP, it was deemed that a general driver based upon the size of each utility (4% Gas; 96% Electric) was the most appropriate allocator for the savings associated with the VDP. The 4% general allocator is also appropriate for supply chain savings given the savings impact all aspects of the business across both electric and gas segments.

In addition, at the 2019/20 Electric Rate Application Mr. Rainkie did not express any concerns with the allocation of savings of 96% to Manitoba Hydro. A higher level of savings allocated to Centra would require a lower level of savings to be allocated to Manitoba Hydro; the two are not mutually exclusive.

2. Adjust the escalation assumptions in 2018/19 and 2019/20 to 1%

A 1% escalation factor had initially been assumed in CGM15 as a cost control mechanism. At the time, the 1% escalation factor was to be achieved through reductions of staff primarily through attrition over the period 2015/16 through to 2021/22 with a return to inflationary increases in 2022/23. In late 2016, Manitoba Hydro made a decision to advance the staffing reductions through the VDP, thus advancing the O&A savings. As shown in the table below, the impact to Centra was a reduction of O&A expenditures by $2 million and $5 million in 2016/17 and 2017/18 respectively.

CENTRA GAS MANITOBA INC.
O&A ACTUAL PERFORMANCE TO CGM 15
(in millions)

	2015/16	2016/17	2017/18
CGM15	67	68	69
Actuals	67	65	63
(Decrease) from CGM15	**(0)**	**(2)**	**(5)**

As highlighted in the table below, as well as in the response to CAC/MH II-133 g), the decision to advance the staff reductions has resulted in further O&A savings for Centra in CGM18 of approximately $9 million per year beginning 2019/20 as compared to the CGM15 plan.

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

	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)**

Given ongoing cost pressures associated with wage settlements, increases in costs for material & maintenance services and higher vehicle fuel costs, a 1% escalation factor cannot be achieved without further reductions to the hours charged to Centra programs and ultimately reduced staffing levels for Manitoba Hydro. Mr. Rainkie's recommendation on page 48 to apply a 1% escalation factor results in Centra's O&A target being reduced by $1.2 million in 2019/20 and would equate to a further reduction of approximately 14,200 hours. Combined with the reductions already in place, further reductions may increase the risk associated with public and employee safety, system reliability and Centra's ability to provide reasonable levels of customer service.

In Mr. Rainkie's response to PUB/CAC(Rainkie-12) he states: "*In the event that MH is unable to manage its O&A cost within the 1% escalation factor, then a discrete adjustment to the O&A costs that are allocated to Centra through the ICAM would have to be made for rate-setting purposes*." Mr. Rainkie's response does not properly account for the fact that an adjustment for rate setting purposes would prevent Centra from recovering its actual O&A costs through rates charged to customers. If this concept continues to be applied into the future, it could result in net losses or additional debt to fund the expenditures.

3. Reduce the O&A target to remove the positive contingency of $1.059 million

The use of a contingency is appropriate and a necessary part of the budgeting process. Its purpose is to capture differences between a high level target established by Executive and the detailed budget requirements of individual programs identified prior to the start of the fiscal year. Over the course of the year, the requirements as identified in the budget may change as a result of customer requirements, circumstances, and business priorities. Although the details within O&A programs may change, Centra is committed to managing within its approved target.

On July 24th, Centra filed its updated detailed O&A budget for the 2019/20 fiscal year. Centra's overall O&A target for 2019/20 remains unchanged at $61.2 million, consistent with the original Application and the Supplement to the Application filed on March 22, 2019. The detailed budget submitted on July 24th reflects current requirements for each program including internal labour, materials, external contractors and other cost components. This has resulted in Centra reflecting a negative contingency of approximately $600K which will be managed over the 2019/20 fiscal year to meet the approved target. The current budget reflects changes in various programs with the most notable increases in the customer inspection and environment programs.

It would also seem logical that considering Mr. Rainkie's suggestion that a positive contingency should result in a decrease to the O&A target, a negative contingency should be treated in a similar manner and could result in an increase to the O&A target for rate setting purposes if the planned program expenditures are justified. Just as Centra rejects the idea that a positive contingency should result in an O&A decrease, Centra does not believe that a negative contingency should result in an O&A increase. Rather in both cases, management's role is to manage to the target that has been established.

5.2 Cumulative Profit Adjustment for Meter Exchange Activities

Page 35 of Mr. Rainkie's evidence includes the following recommendation: "*…that the PUB direct Centra to include the cumulative profit adjustment of $15.3 million related to the capitalization of Gas meter exchange labour from 2014/15 to 2018/19 to be part of the financial reserves for rate setting purposes.*"

Centra does not agree with Mr. Rainkie's recommendation as the costs associated with the meter exchange program have already been included in revenue requirement and as a result have been recovered through the rates charged to customers through to 2018/19.

It is not clear if Mr. Rainkie is suggesting a further rate reduction in 2019/20 in recognition of higher retained earnings. If so, then rates would subsequently need to be increased and rate payers charged for the same cost through the future amortization of a regulatory asset, recorded through net movement and recovered in revenue requirement. Alternatively, if Mr. Rainkie is suggesting lower future rate

2

REFERENCE:

Appendix 3.4 pg. 14 Figures 6 and 7; Manitoba Hydro 2017/18 & 2018/19 GRA PUB/MH I-1a-f

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Provide the net movement in regulatory deferral accounts breakdown in support of the IFF showing all values for the 10 year forecast with similar detail as noted in PUB/MH I-1a-f from the Manitoba Hydro 2017/18 & 2018/19 GRA, providing details of both opening and closing balances, total net movement in regulatory deferral balances, and year over year change in dollars and percentage.
b) Please restate CGM18 if required to reconcile with the regulatory deferral accounts noted in Figure 6 and 7.

RESPONSE:

a) Please see the following schedule for the continuity of the regulatory deferral accounts for CGM18 as well as for the Supplement to the 2019/20 General Rate Application filed on March 22, 2019.

Centra Gas Manitoba Inc. 2019/20 General Rate Application
PUB/CENTRA I-5

CGM 18 Changes in Regulatory Deferral Accounts - Net Movement Account
(in Thousands of Dollars)

	2019	2020	2021	2022	2023
Opening Balance - Regulatory Deferral Accounts					
Demand Side Management Programs	55,181	54,458	55,318	56,159	57,072
Deferred Income Taxes Carrying Costs	19,846	18,042	16,238	14,434	12,630
Site Restoration	2,079	1,765	1,452	1,168	948
Regulatory Costs	1,068	2,666	2,962	3,170	2,873
Loss on Disposal of Assets	10,962	12,730	14,159	15,571	16,965
Change in Depreciation Method (ELG vs. ASL)	8,732	11,107	13,496	15,937	18,462
Impact of 2014 Depreciation Study	(3,698)	(4,718)	(4,579)	(4,441)	(4,302)
Change in Depreciation Rate - Meters	1,430	1,929	1,833	1,736	1,640
Deferred Ineligible Overhead	2,728	3,335	3,922	4,488	5,034
PGVA	(15,029)	(7,246)	-	-	-
DSM Deferral Debit Balance	8,200	-	-	-	-
DSM Deferral Credit Balance	(8,200)	-	-	-	-
Total Regulatory Deferrals	83,300	94,069	104,800	108,223	111,320
Additions to Regulatory Deferral Accounts					
Demand Side Management Programs	9,367	10,806	10,773	10,870	10,416
Deferred Income Taxes Carrying Costs	1,535	1,389	1,242	1,096	950
Site Restoration	-	-	-	-	-
Regulatory Costs	2,233	1,811	2,554	1,137	1,439
Loss on Disposal of Assets	1,768	1,803	1,839	1,876	1,913
Change in Depreciation Method (ELG vs. ASL)	2,375	2,389	2,441	2,525	2,611
Impact of 2014 Depreciation Study	(1,020)	-	-	-	-
Change in Depreciation Rate - Meters	499	-	-	-	-
Deferred Ineligible Overhead	700	700	700	700	700
PGVA (inflows include carrying costs)	166,482	165,660	165,928	166,019	165,249
DSM Deferral Debit Balance	(8,200)	-	-	-	-
DSM Deferral Credit Balance	8,200	-	-	-	-
Total Additions	183,938	184,557	185,477	184,222	183,278
Amortization of Regulatory Deferral Accounts					
Demand Side Management Programs	(10,090)	(9,946)	(9,932)	(9,957)	(10,014)
Deferred Income Taxes Carrying Costs	(3,339)	(3,193)	(3,047)	(2,900)	(2,754)
Site Restoration	(314)	(314)	(283)	(220)	(163)
Regulatory Costs	(635)	(1,515)	(2,345)	(1,434)	(1,912)
Loss on Disposal of Assets	-	(374)	(427)	(482)	(537)
Change in Depreciation Method (ELG vs. ASL)	-	-	-	-	-
Impact of 2014 Depreciation Study	-	139	139	139	139
Change in Depreciation Rate - Meters	-	(96)	(96)	(96)	(96)
Deferred Ineligible Overhead	(93)	(113)	(134)	(154)	(175)
PGVA (WACOG incl. adjustment and amortization)	(158,699)	(158,414)	(165,928)	(166,019)	(165,249)
DSM Deferral Debit Balance	-	-	-	-	-
DSM Deferral Credit Balance	-	-	-	-	-
Total Amortization	(173,169)	(173,826)	(182,054)	(181,125)	(180,762)
Closing Balance - Regulatory Deferral Accounts					
Demand Side Management Programs	54,458	55,318	56,159	57,072	57,474
Deferred Income Taxes Carrying Costs	18,042	16,238	14,434	12,630	10,825
Site Restoration	1,765	1,452	1,168	948	785
Regulatory Costs	2,666	2,962	3,170	2,873	2,399
Loss on Disposal of Assets	12,730	14,159	15,571	16,965	18,342
Change in Depreciation Method (ELG vs. ASL)	11,107	13,496	15,937	18,462	21,072
Impact of 2014 Depreciation Study	(4,718)	(4,579)	(4,441)	(4,302)	(4,163)
Change in Depreciation Rate - Meters	1,929	1,833	1,736	1,640	1,543
Deferred Ineligible Overhead	3,335	3,922	4,488	5,034	5,559
PGVA	(7,246)	-	-	-	-
DSM Deferral Debit Balance	-	-	-	-	-
DSM Deferral Credit Balance	-	-	-	-	-
Total Ending Balance	94,069	104,800	108,223	111,320	113,836
Net Movement in Regulatory Deferral Balances	**10,769**	**10,731**	**3,423**	**3,098**	**2,516**
Year over Year $ change		(38)	(7,308)	(325)	(582)
Year over Year % change		0%	-68%	-10%	-19%

CGM 18 Changes in Regulatory Deferral Accounts - Net Movement Account
(in Thousands of Dollars)

	2024	2025	2026	2027	2028
Opening Balance - Regulatory Deferral Accounts					
Demand Side Management Programs	57,474	57,880	57,935	58,033	57,826
Deferred Income Taxes Carrying Costs	10,825	9,021	7,217	5,413	3,608
Site Restoration	785	622	479	339	230
Regulatory Costs	2,399	2,249	1,862	1,786	1,639
Loss on Disposal of Assets	18,342	19,700	21,040	22,362	23,664
Change in Depreciation Method (ELG vs. ASL)	21,072	23,780	26,584	29,485	32,487
Impact of 2014 Depreciation Study	(4,163)	(4,024)	(3,886)	(3,747)	(3,608)
Change in Depreciation Rate - Meters	1,543	1,447	1,350	1,254	1,157
Deferred Ineligible Overhead	5,559	6,063	6,547	7,010	7,453
PGVA	-	-	-	-	-
DSM Deferral Debit Balance	-	-	-	-	-
DSM Deferral Credit Balance	-	-	-	-	-
Total Regulatory Deferrals	113,836	116,737	119,128	121,936	124,456
Additions to Regulatory Deferral Accounts					
Demand Side Management Programs	10,553	10,445	10,589	10,345	9,497
Deferred Income Taxes Carrying Costs	804	658	512	366	219
Site Restoration	-	-	-	-	-
Regulatory Costs	1,137	1,439	1,137	1,439	1,137
Loss on Disposal of Assets	1,952	1,991	2,030	2,071	2,113
Change in Depreciation Method (ELG vs. ASL)	2,708	2,804	2,901	3,002	3,106
Impact of 2014 Depreciation Study	-	-	-	-	-
Change in Depreciation Rate - Meters	-	-	-	-	-
Deferred Ineligible Overhead	700	700	700	700	700
PGVA (inflows include carrying costs)	164,508	163,818	163,142	162,464	162,713
DSM Deferral Debit Balance	-	-	-	-	-
DSM Deferral Credit Balance	-	-	-	-	-
Total Additions	182,361	181,854	181,011	180,386	179,485
Amortization of Regulatory Deferral Accounts					
Demand Side Management Programs	(10,147)	(10,390)	(10,490)	(10,552)	(10,516)
Deferred Income Taxes Carrying Costs	(2,608)	(2,462)	(2,316)	(2,170)	(2,024)
Site Restoration	(163)	(144)	(139)	(109)	(109)
Regulatory Costs	(1,287)	(1,826)	(1,212)	(1,586)	(989)
Loss on Disposal of Assets	(593)	(650)	(709)	(769)	(830)
Change in Depreciation Method (ELG vs. ASL)	-	-	-	-	-
Impact of 2014 Depreciation Study	139	139	139	139	139
Change in Depreciation Rate - Meters	(96)	(96)	(96)	(96)	(96)
Deferred Ineligible Overhead	(196)	(216)	(237)	(257)	(278)
PGVA (WACOG incl. adjustment and amortization)	(164,508)	(163,818)	(163,142)	(162,464)	(162,713)
DSM Deferral Debit Balance	-	-	-	-	-
DSM Deferral Credit Balance	-	-	-	-	-
Total Amortization	(179,460)	(179,464)	(178,202)	(177,866)	(177,416)
Closing Balance - Regulatory Deferral Accounts					
Demand Side Management Programs	57,880	57,935	58,033	57,826	56,807
Deferred Income Taxes Carrying Costs	9,021	7,217	5,413	3,608	1,804
Site Restoration	622	479	339	230	121
Regulatory Costs	2,249	1,862	1,786	1,639	1,786
Loss on Disposal of Assets	19,700	21,040	22,362	23,664	24,947
Change in Depreciation Method (ELG vs. ASL)	23,780	26,584	29,485	32,487	35,593
Impact of 2014 Depreciation Study	(4,024)	(3,886)	(3,747)	(3,608)	(3,469)
Change in Depreciation Rate - Meters	1,447	1,350	1,254	1,157	1,061
Deferred Ineligible Overhead	6,063	6,547	7,010	7,453	7,875
PGVA	-	-	-	-	-
DSM Deferral Debit Balance	-	-	-	-	-
DSM Deferral Credit Balance	-	-	-	-	-
Total Ending Balance	116,737	119,128	121,936	124,456	126,525
Net Movement in Regulatory Deferral Balances	**2,901**	**2,390**	**2,808**	**2,520**	**2,069**
Year over Year $ change	386	(511)	418	(288)	(452)
Year over Year % change	15%	-18%	17%	-10%	-18%

Supplement to the 2019/20 GRA Changes in Regulatory Deferral Accounts - Net Movement Account
(in Thousands of Dollars)

	Outlook 2019	Approved Budget 2020
Opening Balance - Regulatory Deferral Accounts		
Demand Side Management Programs	55,181	54,458
Deferred Income Taxes Carrying Costs	19,846	18,042
Site Restoration	2,079	1,765
Regulatory Costs	1,068	2,325
Loss on Disposal of Assets	10,962	12,730
Change in Depreciation Method (ELG vs. ASL)	8,732	11,107
Impact of 2014 Depreciation Study	(3,698)	(4,718)
Change in Depreciation Rate - Meters	1,430	1,929
Deferred Ineligible Overhead	2,728	3,335
PGVA	(15,029)	(21,757)
DSM Deferral Debit Balance	8,200	-
DSM Deferral Credit Balance	(8,200)	-
Total Regulatory Deferrals	83,300	79,217
Additions to Regulatory Deferral Accounts		
Demand Side Management Programs	9,367	8,483
Deferred Income Taxes Carrying Costs	1,535	1,389
Site Restoration	-	-
Regulatory Costs	1,885	2,145
Loss on Disposal of Assets	1,768	1,803
Change in Depreciation Method (ELG vs. ASL)	2,375	2,389
Impact of 2014 Depreciation Study	(1,020)	-
Change in Depreciation Rate - Meters	499	-
Deferred Ineligible Overhead	700	700
PGVA	186,324	187,698
DSM Deferral Debit Balance	(8,200)	-
DSM Deferral Credit Balance	8,200	-
Total Additions	203,433	204,606
Amortization of Regulatory Deferral Accounts		
Demand Side Management Programs	(10,090)	(9,946)
Deferred Income Taxes Carrying Costs	(3,339)	(3,193)
Site Restoration	(314)	(314)
Regulatory Costs	(629)	(1,493)
Loss on Disposal of Assets	-	(374)
Change in Depreciation Method (ELG vs. ASL)	-	-
Impact of 2014 Depreciation Study	-	139
Change in Depreciation Rate - Meters	-	(96)
Deferred Ineligible Overhead	(93)	(113)
PGVA	(193,053)	(173,667)
DSM Deferral Debit Balance	-	-
DSM Deferral Credit Balance	-	-
Total Amortization	(207,516)	(189,057)
Closing Balance - Regulatory Deferral Accounts		
Demand Side Management Programs	54,458	52,996
Deferred Income Taxes Carrying Costs	18,042	16,238
Site Restoration	1,765	1,452
Regulatory Costs	2,325	2,977
Loss on Disposal of Assets	12,730	14,159
Change in Depreciation Method (ELG vs. ASL)	11,107	13,496
Impact of 2014 Depreciation Study	(4,718)	(4,579)
Change in Depreciation Rate - Meters	1,929	1,833
Deferred Ineligible Overhead	3,335	3,922
PGVA	(21,757)	(7,726)
DSM Deferral Debit Balance	-	-
DSM Deferral Credit Balance	-	-
Total Ending Balance	79,217	94,766
Net Movement in Regulatory Deferral Balances	**(4,083)**	**15,549**
Year over Year $ change		19,632
Year over Year % change		-481%

b) Please see the following CGM18 restated financial statements and Supplement to the 2019/20 General Rate Application in a format consistent with the inclusion of PGVA balances in the Net Movement Account:

GAS OPERATIONS (CGM18)
PROJECTED OPERATING STATEMENT
CGM18 - Restated for PGVA and Net Movement
(In Millions of Dollars)

For the year ended March 31	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
REVENUES										
Domestic Revenue										
Cost of Gas	159	158	166	166	165	165	164	163	162	163
Non-Gas Costs *	152	150	150	151	151	151	151	152	152	151
Furnace Replacement Program Funding	(4)	(1)	-	-	-	-	-	-	-	-
Late Payment Charges and Broker Revenue	1	1	1	1	1	1	1	1	1	1
	308	308	316	317	317	316	316	315	315	315
additional revenue requirement***	-	-	6	10	14	17	21	24	28	32
	308	308	323	328	331	334	337	340	343	346
Weighted Average Cost of Gas Sold **	167	166	166	166	165	165	164	163	162	163
Gross Margin	141	142	157	162	165	169	173	177	181	184
Other	2	2	2	2	2	2	2	2	2	2
	143	144	158	163	167	171	175	179	183	186
EXPENSES										
Operating and Administrative	63	61	62	63	64	65	66	68	69	70
Finance Expense	22	23	25	26	27	29	30	30	32	33
Depreciation and Amortization	24	25	27	28	29	31	31	32	33	34
Capital and Other Taxes	17	17	18	18	19	19	20	20	21	21
Other Expenses	12	13	13	12	12	12	12	12	12	11
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
	150	152	157	160	163	167	171	174	178	181
Net Income before Net Movement in Regulatory Deferral Accounts	(8)	(8)	1	4	4	4	4	5	4	5
Net Movement in Regulatory Deferral Accounts**	11	11	3	3	3	3	2	3	3	2
Net Income	**3**	**2**	**5**	**7**	**7**	**7**	**7**	**8**	**7**	**7**

* The Non-Gas Costs reflect the proposed discontinuance of FRP funding and removal of associated costs from rates for the SGS class, effective Aug 1, 2019
** WACOG has been restated to match purchased cost of gas and Net Movement has been restated to include the PGVA balance.
***Additional Revenue Requirement

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Percent Increase	0.00%	0.00%	2.25%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
Cumulative Percent Increase	0.00%	0.00%	2.25%	3.27%	4.31%	5.35%	6.40%	7.47%	8.54%	9.63%

GAS OPERATIONS
SUPPLEMENT TO THE 2019/20 GRA
PROJECTED OPERATING STATEMENT
Restated for PGVA and Net Movement
(In Millions of Dollars)

For the year ended March 31	Outlook 2019	Approved Budget 2020
REVENUES		
Domestic Revenue		
Cost of Gas	193	174
Non-Gas Costs *	153	149
Furnace Replacement Program Funding	(4)	(1)
Late Payment Charges and Broker Revenue	1	1
	343	323
additional revenue requirement***	-	-
	343	323
Weighted Average Cost of Gas Sold **	187	188
Gross Margin	156	135
Other	2	2
	158	136
EXPENSES		
Operating and Administrative	63	61
Finance Expense	22	23
Depreciation and Amortization	24	25
Capital and Other Taxes	17	17
Other Expenses	12	11
Corporate Allocation	12	12
	150	149
Net Income before Net Movement in Regulatory Deferral Accounts	9	(13)
Net Movement in Regulatory Deferral **	(4)	16
Net Income	**4**	**3**

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

** WACOG has been restated to match purchased cost of gas and Net Movement has been restated to include the PGVA balance.

***Additional Revenue Requirement		
Percent Increase	0.00%	0.00%
Cumulative Percent Increase	0.00%	0.00%

REFERENCE:

Appendix 5.9

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please explain how each of Manitoba Hydro and Centra accounted for meter sampling, testing and exchange activities for gas and electric operations for financial reporting purposes in each of the years since the adoption of IFRS.
b) Please provide details of total meter costs incurred related to meter sampling, testing and exchanges for each of the years 2012/13 through 2017/18 and that forecast for 2018/19 and 2019/20.
c) Please provide detail of field labour for replacement and installation of meters including the cost of testing. Please indicate where these costs were expensed in Centra's OM&A costs for each year 2013/14 through 2019/20.
d) Please indicate the amortization period for meter replacement costs and indicate the impact related to meter replacement costs for each year from 2014/15 onward (i.e. costs, impact to retained earnings, accounting adjustments, etc.).

RESPONSE:

a) The following table provides a summary of the accounting treatment for each of Manitoba Hydro and Centra for meter sampling, testing and exchange activities for financial reporting purposes since the adoption of IFRS:

	2016		**2017**		**2018**		**2019**		**2020 proposed**	
	Manitoba Hydro	**Centra Gas**	**Manitoba Hydro**	**Centra Gas**	**Manitoba Hydro**	**Centra Gas**	**Manitoba Hydro**	**Centra Gas**	**Manitoba Hydro**	**Centra Gas**
Meter sampling	capitalized	expensed	capitalized	expensed	capitalized	expensed	capitalized	expensed	capitalized	capitalized
Meter testing	capitalized	expensed	capitalized	expensed	capitalized	expensed	capitalized	expensed	capitalized	capitalized
Meter exchange	capitalized	expensed	capitalized	expensed	capitalized	expensed	capitalized	expensed	capitalized	capitalized

b) and c)

The table below provides details of the meter exchange program including labour and materials for 2012/13 through 2019/20. These costs were charged to the "metering" program in the Operations and Maintenance program of Centra's Operating & Administrative (O&A) expense as shown in Appendix 5.9 until 2018/19. Centra has proposed capitalization of these costs for 2019/20.

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

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

* Refer to PUB/Centra 1-31 a-b for a summary of labour overhead rates

d) For the Test Year and beyond, Centra is proposing a 10 year amortization period used for meter sampling, testing and exchange activities.

For the years prior to the Test Year, meter sampling, testing and exchange activities for Centra Gas are recorded as a charge to O&A on Centra's financial statements. The annual impact to Centra's O&A is shown above. As the amounts are expensed each year prior to the test year, there is a corresponding impact to net income and retained earnings for each year.

The capitalization and amortization of the meter exchange program relating to Centra is only applicable for the preparation of the consolidated financial statements of Manitoba Hydro so as to comply with the IFRS requirement to harmonize the accounting policies of a parent company with its subsidiaries. There is no impact to Centra's financial statements for this consolidation entry.

REFERENCE:

Appendix 3.1 pg. 3; Appendix 5.6; 2013/14 GRA Appendix 4.2 pg. 45

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Refile the Projected Cash Flow Statement presented using the Direct Method on a consistent basis with the presentation in Appendix 4.2 pg. 45 (2013/14 GRA).
b) Please refile the Statement of Cash Flows from the most recent financial statements at March 31, 2018 under the Direct Method so as to be consistent and comparable to prior years.
c) For both (a) and (b), please file cash flows under both the indirect and direct method of cash flow presentation showing capitalized interest as it was in prior years before March 31, 2018 (as an investing activity as opposed to an operating activity).
d) Provide the rationale for classifying capitalized interest as an operating activity in the Cash Flow Statement as referenced in Note 3(n) of the March 31, 2018 financial statements of Centra Gas Manitoba Inc.

RESPONSE:

a) The cash flow statements using the direct method for Appendix 3.1 and Appendix 3.6 have been provided below.

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

For the year ended March 31	Current Outlook 2019	Approved Budget 2020
OPERATING ACTIVITIES		
Cash Receipts from Customers	376	351
Cash Paid to Suppliers and Employees	(293)	(294)
Interest Paid	(33)	(34)
Cash Provided by Operating Activities	50	23
FINANCING ACTIVITIES		
Proceeds from Long-Term Debt	20	50
Retirement of Long-Term Debt	-	(20)
Cash Provided by Financing Activities	20	30
INVESTING ACTIVITIES		
Additions to Capital Assets	(42)	(47)
Additions to Intangible Assets	(1)	(0)
Additions to Regulatory Deferral Balances	(14)	(13)
Contributions Received	3	3
Cash Used for Investing Activities	(54)	(58)
Net Increase (Decrease) in Cash	16	(5)
Cash at Beginning of Year	(44)	(28)
Cash at End of Year	(28)	(33)

GAS OPERATIONS (CGM18)
PROJECTED DIRECT CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
OPERATING ACTIVITIES								
Cash Receipts from Customers	349	354	358	361	364	368	371	375
Cash Paid to Suppliers and Employees	(290)	(275)	(275)	(276)	(277)	(279)	(279)	(281)
Interest Paid	(37)	(38)	(39)	(41)	(42)	(43)	(44)	(45)
Cash Provided by Operating Activities	22	42	43	44	45	46	48	49
FINANCING ACTIVITIES								
Proceeds from Long-Term Debt	40	10	40	30	10	60	10	20
Retirement of Long-Term Debt	-	-	(20)	(10)	-	(35)	-	(10)
Cash Provided by Financing Activities	40	10	20	20	10	25	10	10
INVESTING ACTIVITIES								
Additions to Capital Assets	(45)	(46)	(47)	(48)	(49)	(50)	(51)	(52)
Additions to Intangible Assets	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Additions to Regulatory Deferral Balances	(16)	(15)	(14)	(14)	(15)	(14)	(15)	(13)
Contributions Received	3	3	3	2	2	3	3	3
Cash Used for Investing Activities	(59)	(58)	(59)	(61)	(62)	(62)	(64)	(63)
Net Increase (Decrease) in Cash	3	(7)	4	3	(7)	9	(5)	(4)
Cash at Beginning of Year	(33)	(30)	(36)	(33)	(29)	(36)	(27)	(32)
Cash at End of Year	(30)	(36)	(33)	(29)	(36)	(27)	(32)	(36)

b) The cash flow statement using the direct method for March 31, 2018 is provided below.

GAS OPERATIONS
DIRECT METHOD CASH FLOW STATEMENT
FOR THE YEAR ENDED MARCH 31
(In Thousands of Dollars)

	ACTUAL RESULTS 2018
Operating Activities	
Cash receipts from customers	$334
Cash paid to suppliers and employees	(273)
Interest paid	(33)
Cash provided by (used for) operating activities	29
Investing Activities	
Additions to property, plant and equipment	(35)
Additions to regulatory deferral balances	(12)
Contributions received	1
Additions to intangible assets	(4)
Cash used for investing activities	(50)
Financing Activities	
Long term advances from parent	10
Cash provided by financing activities	10
Net decrease in cash	(11)
Cash at Beginning of Year	(33)
Cash at End of Year	**($44)**

c) As noted in Appendix 5.13 of the Supplement to Centra's 2019/20 General Rate Application, Figure 5.12, line 13 shows capitalized interest for the 2017/18 actual results, 2018/19 Current Outlook and 2019/20 Approved Budget are all less than a million dollars. As such, the classification of capitalized interest as either an investing activity or an operating activity is not material and does not impact the presentation of cash flows.

d) The decision to reclassify capitalized interest to operating activities from investing activities was to provide readers of the financial statements with the total interest paid by Centra regardless of whether expensed or capitalized. The reclassification was accepted by Manitoba Hydro's external auditors in their review of the 2017/18 financial statements.

REFERENCE:

Tab 3 – Section 3.1.4 Capitalization of Expenditure for Meter Sampling/Exchanges (pg 4), Appendix 3.1 – CGM18, Appendix 5.9, Page 4 – O&A Expense, Appendix 5.14, Page 4 _ MHEB Third Quarter Report – 2018/19, PUB/Centra I-11 (a) current proceeding

PREAMBLE TO IR (IF ANY):

On Page 4 of Appendix 5.9, Lines 3 to 11, Centra states that it is proposing to capitalize the expenditures associated with meter sampling, testing and exchange activities effective for the 2019/20 fiscal year in an effort to harmonize the accounting for these types of costs between the gas and electric lines of business. Previously, these costs were charged to O&A expense for Centra. This accounting change results in a reduction of O&A expenses of approximately $3 million on an annual basis.

On Page 4 of 10 – of Appendix 5.14, the Manitoba Hydro third quarter report for the nine months ended December 31, 2018, under the Other Segment it states "The other segment includes Manitoba Hydro International Ltd., Manitoba Hydro Utility Services, Minell Pipelines Ltd. And Teshmont Holdings Ltd…There is also a $2 million profit impact in adjustments and eliminations as a result of the requirement to harmonize accounting policies between electric and natural gas operations related to the gas meter exchange program."

QUESTION:

a) Please explain why the profit adjustment related to harmonizing the gas meter exchange program accounting treatment with electric operations is recorded in the Other Segment of Manitoba Hydro's consolidated financial statements versus the Gas Segment.
b) Please provide a schedule of actual and forecast profit adjustments to the Other Segment related to the gas meter exchange program for each fiscal year since the implementation of IFRS effective for the 2014/15 fiscal year to the 2018/19 fiscal year and quantify the cumulative profit adjustment to the end of the 2018/19 fiscal year.

c) Please confirm that gas customers have been funding the costs of the gas meter exchange program through rates between 2014/15 and 2018/19 given that these costs were included in the 2013/14 approved revenue requirement as an O&A expense. If Centra is unable to confirm this fact, then please explain Centra's views on what amount has been included in the rates paid by customers with respect to the gas meter exchange program between 2014/15 and 2018/19.

d) Please explain why Centra is not proposing to transfer the cumulative profit adjustments for 2014/15 to 2018/19 (quantified in part (b)) related to the gas meter exchange program from the Other Segment to the Gas Segment effective April 1, 2019, for the benefit of gas customers. Please explain the relationship between profit adjustments related to the gas meter exchange program and the Other Financial Reporting segment of Manitoba Hydro's consolidated operations.

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.

RATIONALE FOR QUESTION:

To understand the financial impact and appropriate rate-setting treatment for the gas meter exchange program profit adjustment between 2014/15 and 2018/19.

RESPONSE:

a) For clarification purposes, the profit adjustment related to harmonization of accounting policies is recorded in the Eliminations column as shown on page 9 of 10 of Appendix

5.14. It is included in the narrative discussion under the Other Segment heading for simplicity purposes only.

Centra's stand-alone financial statements records the costs associated with the meter exchange program as an operating expense. These costs are included in O&A and are appropriately recovered from customers through rates as a period expense.

Manitoba Hydro's electric segment includes these costs as a capital expenditure and records the costs in Property, Plant & Equipment. The depreciation of this asset is included in customer rates as a period expense.

On consolidation, these accounting policies must be harmonized and it was determined that the costs should be recorded as capital expenditures/Property Plant & Equipment and depreciated over the life of the program (10 years). To accomplish the harmonization, an elimination entry is performed to reclassify the Gas Segment meter exchange costs from O&A to Property Plant & Equipment. This entry is included in the Eliminations column, thereby increasing the net income of the Eliminations column. The associated depreciation expense of this asset is also recorded in the Eliminations column. Over the life of the asset recorded in the Eliminations column, the depreciation will equal the original reduction to O&A that created the income in the Eliminations column.

A simple example is provided below. The example assumes the meter exchange program costs are $10 and the program has a one-year duration. There are no other revenues or expenses during the year.

Meter Exchange Program

Year 1

	Electric Segment	Gas Segment	Other Segment	Eliminations	Consolidated Results
O&A	-	10	-	(10)	-
Net income	-	(10)	-	10	-
PP&E	-	-	-	10	10

Year 2 - 11 annual entry

	Electric Segment	Gas Segment	Other Segment	Eliminations	Consolidated Results
Depr exp	-	-	-	1	1
Net loss	-	-	-	(1)	(1)

As demonstrated in the above example, the net income or "profit impact" must remain in the Eliminations column to offset the depreciation expense that will be recorded in future years. Neither the future depreciation related to the program nor the net income generated from the harmonization of accounting policies are charged to gas operations.

b) The following schedule provides the income statement and the balance sheet balances related to the meter exchange program that are included in the Eliminations column of the consolidated entity.

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

c) Confirmed.

d) Please see the response to a) above.

e) and f)

As per the responses to parts a) and b) above, Centra records the costs associated with the meter exchange program as an O&A expense and these costs have been appropriately recovered from customers through rates as a period expense. It is only upon consolidation with its parent where the accounting policies were harmonized and therefore the costs associated with the meter exchange program were recorded as capital expenditures. As such, Centra is unsure of how these costs could be retro-actively 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 is unable to provide the financial scenario requested.

The following table contains information related to the operating results, assets, liabilities, contributions in aid of construction and retained earnings by segment:

	Electricity		Gas		Corporate		Total	
	2015	2014	2015	2014	2015	2014	2015	2014
				millions of dollars				
Revenues[1]	1,892	1,897	154	163	-	-	2,046	2,060
Expenses								
Operating and administrative	492	491	67	67	-	-	559	558
Finance expense	492	435	16	16	19	19	527	470
Depreciation and amortization	405	412	29	28	2	2	436	442
Water rentals and assessments	125	125	-	-	-	-	125	125
Fuel and power purchased	145	160	-	-	-	-	145	160
Capital and other taxes	100	97	20	20	-	-	120	117
Other expenses	31	36	-	-	-	-	31	36
Corporate allocation	9	9	12	12	(21)	(21)	-	-
	1,799	1,765	144	143	-	-	1,943	1,908
Net income before non-controlling interest	93	132	10	20	-	-	103	152
Net loss attributable to non-controlling interest	11	22	-	-	-	-	11	22
Net income	104	154	10	20	-	-	114	174
Total assets	16,905	14,950	689	689	-	-	17,594	15,639
Total liabilities	13,910	11,909	454	464	-	-	14,364	12,373
Contributions in aid of construction	399	339	42	42	-	-	441	381
Retained earnings	2,758	2,654	72	62	-	-	2,830	2,716

[1]Revenues are stated net of cost of gas sold of $274 million (2014 - $252 million).

NOTE 27 COMPARATIVE FIGURES

Where appropriate, comparative figures for 2014 have been reclassified in order to conform to the presentation adopted in 2015.

(in millions of Canadian dollars)

Segmented results

Results by operating segment for the years ended March 31, 2016 and 2015 are shown below. Intersegment eliminations are presented to reconcile segment results to the corporation's consolidated totals. Eliminations have been made for intersegment transactions and balances.

	Electric operations		Natural gas operations		All other segments		Eliminations		Total	
	2016	2015	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015
Revenues										
External revenue	**1 845**	1 838	**355**	428	**58**	50	**-**	-	**2 258**	2 316
Intersegment revenue	**-**	-	**1**	1	**9**	8	**(10)**	(9)	**-**	-
	1845	1 838	**356**	429	**67**	58	**(10)**	(9)	**2 258**	2 316
Expenses										
Cost of gas sold	**-**	-	**181**	266	**-**	-	**-**	-	**181**	266
Finance expense	**582**	515	**20**	19	**-**	(2)	**18**	19	**620**	551
Operating and administrative	**543**	538	**67**	70	**16**	17	**(12)**	(11)	**614**	614
Depreciation and amortization	**367**	352	**23**	22	**1**	2	**3**	2	**394**	378
Water rentals and assessments	**126**	125	**-**	-	**-**	-	**-**	-	**126**	125
Fuel and power purchased	**117**	129	**-**	-	**-**	-	**-**	-	**117**	129
Capital and other taxes	**107**	100	**16**	16	**-**	(1)	**-**	-	**123**	115
Other expenses	**65**	37	**10**	10	**42**	33	**(3)**	(3)	**114**	77
Finance income	**(22)**	(26)	**-**	-	**(1)**	-	**-**	-	**(23)**	(26)
Corporate allocation	**8**	9	**12**	12	**-**	-	**(20)**	(21)	**-**	-
	1 893	1 779	**329**	415	**58**	49	**(14)**	(14)	**2 266**	2 229
Net income (loss) before net movement in regulatory deferral balances	**(48)**	59	**27**	14	**9**	9	**4**	5	**(8)**	87
Net movement in regulatory deferral balances	**75**	41	**(28)**	(3)	**-**	-	**-**	-	**47**	38
Net Income (Loss)	**27**	100	**(1)**	11	**9**	9	**4**	5	**39**	125
Net income (loss) attributable to:										
Manitoba Hydro	**37**	111	**(1)**	11	**9**	9	**4**	5	**49**	136
Non-controlling interests	(10)	(11)	-	-	-	-	-	-	(10)	(11)
	27	100	**(1)**	11	**9**	9	**4**	5	**39**	125

(in millions of Canadian dollars)

	Electric operations		Natural gas operations		Other segment		Eliminations		Total	
	2018	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017
Revenues										
External revenue	**1 931**	1 927	**345**	344	**54**	56	**-**	-	**2 330**	2 327
Intersegment revenue	**-**	-	**1**	1	**10**	9	**(11)**	(10)	**-**	-
	1 931	1 927	**346**	345	**64**	65	**(11)**	(10)	**2 330**	2 327
Expenses										
Finance expense	**601**	608	**21**	19	**1**	-	**18**	18	**641**	645
Operating and administrative	**517**	536	**63**	65	**17**	17	**(11)**	**(10)**	**586**	608
Depreciation and amortization	**402**	375	**24**	23	**1**	2	**3**	2	**430**	402
Cost of gas sold	**-**	-	**196**	183	**-**	-	**-**	-	**196**	183
Water rentals and assessments	**126**	131	**-**	-	**-**	-	**-**	-	**126**	131
Fuel and power purchased	**130**	132	**-**	-	**-**	-	**-**	-	**130**	132
Capital and other taxes	**130**	119	**16**	16	**-**	-	**-**	-	**146**	135
Other expenses	**502**	60	**14**	12	**35**	35	**(3)**	(3)	**548**	104
Finance income	**(23)**	(17)	**-**	-	**-**	-	**-**	-	**(23)**	(17)
Corporate allocation	**8**	8	**12**	12	**-**	-	**(20)**	(20)	**-**	-
	2 393	1 952	**346**	330	**54**	54	**(13)**	(13)	**2 780**	2 323
Net income (loss) before net movement in regulatory deferral balances	**(462)**	(25)	**-**	15	**10**	11	**2**	3	**(450)**	4
Net movement in regulatory deferral balances	**472**	66	**7**	(11)	**-**	-	**-**	-	**479**	55
Net Income	**10**	41	**7**	4	**10**	11	**2**	3	**29**	59
Net income (loss) attributable to:										
Manitoba Hydro	**18**	53	**7**	4	**10**	11	**2**	3	**37**	71
Non-controlling interests	(8)	(12)	-	-	-	-	-	-	(8)	(12)
	10	41	**7**	4	**10**	11	**2**	3	**29**	59

REFERENCE:

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

PREAMBLE TO IR (IF ANY):

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

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

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

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

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

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

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

QUESTION:

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

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

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

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

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

RESPONSE:

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

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

b) through e)

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

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

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

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

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

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

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

Part b)

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

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

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

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

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

Part b)

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

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

Part b)

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

For the year ended March 31

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

Part b)

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

For the year ended March 31

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

Part b)

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

For the year ended March 31

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

* Includes amortization of deferred income tax

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

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

Part c) i

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

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

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

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

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

Part c) i

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

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

Part c) i

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

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

Part c) i

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

For the year ended March 31

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

Part c) i

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

For the year ended March 31

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

* Includes amortization of deferred income tax

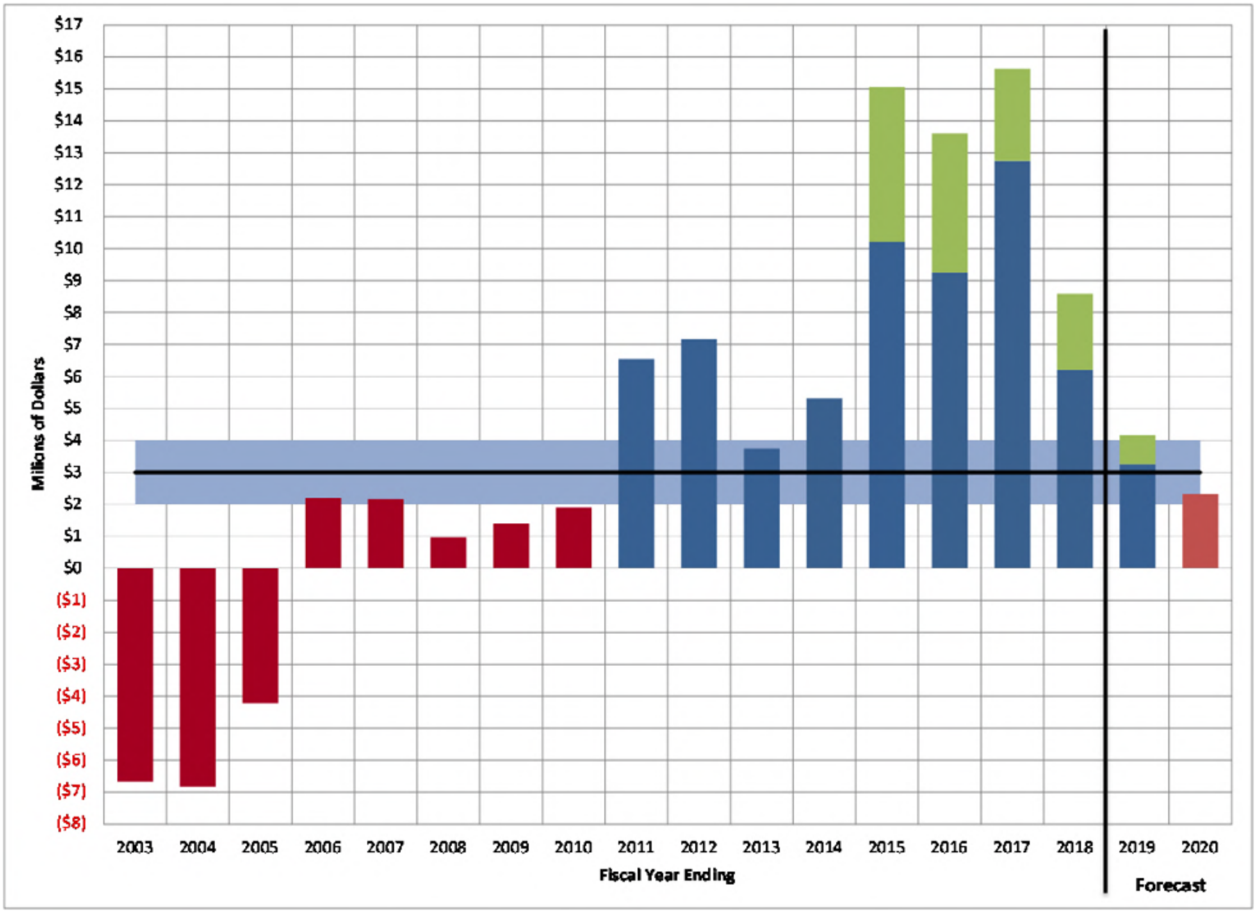
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
CAPITAL COVERAGE										
Internally Generated Funds	27.389	27.803	21.883	41.529	43.240	43.998	45.269	46.397	48.372	48.890
Capitalized Interest*	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	27.560	28.040	22.134	41.661	43.275	44.033	45.305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

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

part c) ii

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

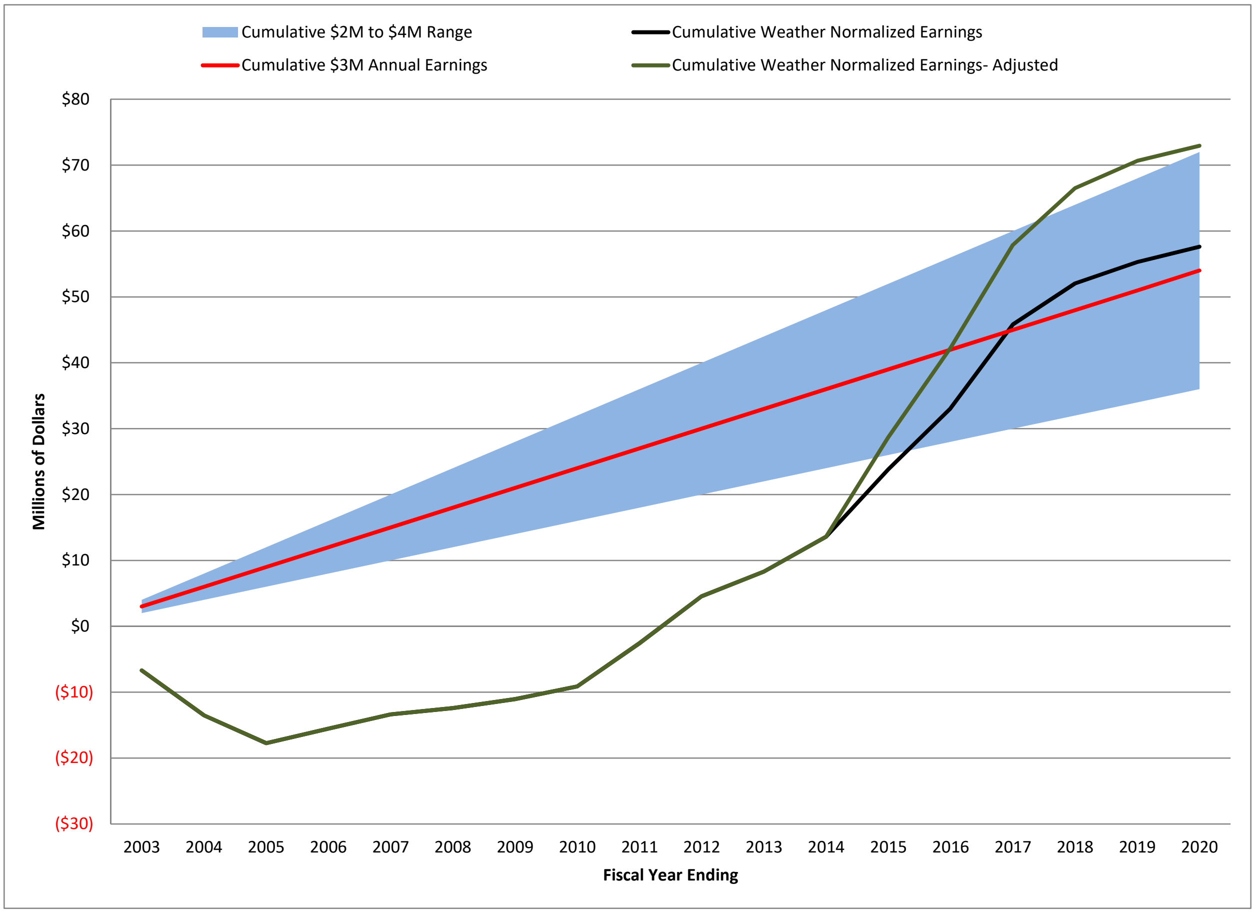
Figure 3.3: Centra's Weather-Normalized Net Income – Restated



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

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

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



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

Part d) i

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

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

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

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

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

Part d) i

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

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

Part d) i

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

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

Part d) i

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

For the year ended March 31

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

Part d) i

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

For the year ended March 31	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
INTEREST COVERAGE										
Net Income	3.267	(0.812)	1.454	3.816	3.668	3.693	6.497	7.567	6.760	6.800
Finance Expense	20.502	22.230	23.946	25.316	26.223	27.722	28.945	29.827	31.555	32.409
Capitalized Interest	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	23.941	21.655	25.651	29.263	29.926	31.450	35.478	37.431	38.353	39.247
Finance Expense	20.502	22.230	23.946	25.316	26.223	27.722	28.945	29.827	31.555	32.409
Capitalized Interest	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	20.674	22.467	24.197	25.448	26.257	27.757	28.981	29.864	31.593	32.447
Interest Coverage	**1.16**	**0.96**	**1.06**	**1.15**	**1.14**	**1.13**	**1.22**	**1.25**	**1.21**	**1.21**
Add: Depreciation and Amortization *	34.899	39.762	41.609	41.880	43.467	43.998	42.096	42.256	43.428	43.831
Total EBITDA	58.840	61.418	67.260	71.143	73.393	75.448	77.574	79.686	81.781	83.078
EBITDA Interest Coverage	**2.85**	**2.73**	**2.78**	**2.80**	**2.80**	**2.72**	**2.68**	**2.67**	**2.59**	**2.56**

* Includes amortization of deferred income tax

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

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

Part d) ii

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

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

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

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

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

Part d) ii

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

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

Part d) ii

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

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

Part d) ii

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

For the year ended March 31	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
PUB APPROVED DEBT TO EQUITY RATIO										
Average Long-Term Debt	389.903	424.903	459.903	484.903	499.903	519.903	534.903	552.403	569.903	584.952
Average Due to Parent	37.384	31.707	31.148	33.108	34.667	31.181	32.917	31.774	29.899	29.693
Average Debt	**427.287**	**456.610**	**491.051**	**518.011**	**534.570**	**551.084**	**567.820**	**584.177**	**599.802**	**614.645**
Average Share Capital	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250
Average Retained Earnings	77.225	86.887	96.402	100.551	105.799	110.977	116.033	121.498	127.102	132.328
Average Equity	**198.474**	**208.137**	**217.651**	**221.801**	**227.049**	**232.226**	**237.283**	**242.748**	**248.351**	**253.578**
Average Debt	427.287	456.610	491.051	518.011	534.570	551.084	567.820	584.177	599.802	614.645
Average Equity	198.474	208.137	217.651	221.801	227.049	232.226	237.283	242.748	248.351	253.578
Average Debt and Equity	625.761	664.747	708.702	739.812	761.619	783.310	805.102	826.925	848.153	868.223
PUB Approved Equity Ratio	**31.72%**	**31.31%**	**30.71%**	**29.98%**	**29.81%**	**29.65%**	**29.47%**	**29.36%**	**29.28%**	**29.21%**

Part d) ii

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

For the year ended March 31

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

* Includes amortization of deferred income tax

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

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

Part e) i

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

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

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

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

***__Additional Revenue Requirement__										
Percent Increase	0.00%	0.00%	2.81%	0.01%	1.30%	0.93%	0.07%	0.95%	1.31%	1.02%
Cumulative Percent Increase	0.00%	0.00%	2.81%	2.82%	4.16%	5.13%	5.20%	6.20%	7.59%	8.69%
Equity Ratio (PUB Approved Methodology)	32%	31%	31%	30%	29%	29%	29%	28%	28%	27%

Part e) i

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

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

Part e) i

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

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

Part e) i

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

For the year ended March 31

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

Part e) i

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

For the year ended March 31

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

* Includes amortization of deferred income tax

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

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

Part e) ii

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

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

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

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

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

Part e) ii

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

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

Part e) ii

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

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

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

For the year ended March 31

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

Part e) ii

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

For the year ended March 31

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

* Includes amortization of deferred income tax

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

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

REFERENCE:

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

QUESTION:

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

RESPONSE:

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

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

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

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

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

CENTRA GAS ACCOUNTING CHANGES - 2013/14 GENERAL RATE APPLICATION

(In Millions of Dollars)

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

CENTRA GAS ACCOUNTING CHANGES - 2013/14 GENERAL RATE APPLICATION
(In Millions of Dollars)

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

CENTRA GAS ACCOUNTING CHANGES - 2013/14 GENERAL RATE APPLICATION

(In Millions of Dollars)

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

REFERENCE:

PUB/Centra I-15

QUESTION:

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

RESPONSE:

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

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

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

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

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

> "…The **Board will direct Centra to file** an **International Financial Reporting Standards status update** at the **next General Rate Application**. **Until such time**, the Board expects **Centra not** to **make any further accounting changes** for **rate-setting purposes**. With respect to **meter exchange costs**, the **Board will not direct a change in accounting policy at this time**. The **Board will expect Centra** to **put forward a proposal** on harmonizing this accounting policy with Manitoba Hydro **in its IFRS status update report** directed in this Order." (Emphasis added)

> "The Board notes that given the direction in the Regulatory Deferral Accounts exposure draft, Centra may not have to write of its rate-regulated assets. The **Board will expect Centra to keep the Board apprised on developments on this issue** as they evolve and the **implications on ratepayers**. The Board understands the underpinning for accounting policy changes related to rate-regulated assets and depreciation rates depend on the outcome of this issue. **Centra is not to make any further accounting changes** related to **International Financial Reporting Standards without seeking the Board's approval**…" (Emphasis added)

In Order 85/13, the PUB provided the following directive to Centra with respect to IFRS on page 7 as follows:

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

Gas Meter Exchange Accounting Policy – 2019/20 GRA

In the 2019/20 GRA filing, pages 6 to 7 of Tab 13, Centra indicated that in response to the above noted PUB directive, MH filed an IFRS Status Update Report with the PUB as Appendix 5.4 of the MH 2014/15 & 2015/16 Electric GRA.

Centra also noted that it filed a letter dated March 10, 2016 seeking the PUB's confirmation of its proposed accounting treatment of certain matters related to gas operations and that on April 4, 2016 the PUB informed Centra that it intended to make a final ruling on the proposed accounting changes at the next Gas GRA. Centra also indicated that with the filing of information in the 2019/20 GRA related to the transition to IFRS and proposed accounting changes, it is seeking confirmation from the PUB that the directive is now closed.

The IFRS status report that was provided with the MH 2014/15 & 2015/16 GRA, contains a very short paragraph on harmonization of accounting policies at page 49 and does disclose that the capitalization of gas meter exchange costs was expected to increase consolidated net income by approximately $5 million in 2015/16. This report did not address the portion of the PUB directive to provide rate-setting options for Centra to the PUB.

In its March 10, 2016 letter to the PUB (provided in Attachment 1 of the response to CAC/Centra I-16 (a)), Centra indicated that on transition to IFRS it intended to harmonize the accounting treatment for gas meter exchange labour with that of electric operations, which is to capitalize these costs. Centra also indicated that:

> "**Centra intends** to **apply this change in policy on a prospective basis** commencing in the **2015/16 fiscal year** (with **restatement of the 2014/15 fiscal year** for comparative reporting purposes) and is **requesting the PUB's confirmation** that **this approach** is **appropriate** for **rate-setting purposes**."

In the PUB's response letter of April 4, 2016, it stated that:

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

In section 5.3 of Tab 5 and Appendix 3.4 of the 2019/20 GRA filing, Centra provided an overview of its transition to IFRS and associated accounting changes, including new regulatory deferral accounts and amortization periods for these accounts for which Centra is seeking PUB endorsement as part of this application.

Appendix 3.4 contains a lengthy list of new regulatory deferral accounts that Centra established on the transition to IFRS effective April 1, 2014 (2014/15 fiscal year which with the restatement is the effective year of transition to IFRS) for which it is now requesting endorsement from the PUB for rate-setting purposes. In Appendix 5.9, Centra indicates that it is commencing the capitalization of gas meter exchange labour costs for Centra for financial reporting and rate-setting purposes beginning in the 2019/20 Test Year.

Appendix 3.4 and Appendix 5.9 of the 2019/20 GRA filing are silent with respect to the impacts of capitalization of gas meter exchange labour costs for financial reporting and rate-setting purposes for the five-year period from the effective date of transition to IFRS, in the 2014/15 fiscal year to the 2018/19 fiscal year. This material is also silent with respect to any options that the PUB has with respect to the rate-setting treatment of these impacts for that five-year period.

Recommended Rate-Setting Treatment for Gas Meter Exchange Labour - Cumulative Profit Adjustment

In the response to CAC/Centra I-6 (a), Centra clarified that the profit adjustment related to the harmonization of the accounting policy of meter exchange costs (profit adjustment) has been recorded in the Eliminations column of MH's consolidated financial statements since that transition to IFRS, effective in the 2014/15 fiscal year. The profit adjustment in the Eliminations Column is made up of the lower O&A costs as a result of the capitalization of these costs and is partly offset by the depreciation of the capitalized costs with the net impact being an increase in MH's consolidated net income (and retained earnings) each year since 2014/15.

For the five-year period between 2014/15 and 2018/19, the cumulative net impact on MH's consolidated income statement and balance sheet can be summarized as follows (from the response to CAC/Centra I-6 (b)):

- Consolidated Balance Sheet: increase in Property, Plant & Equipment of $21.2 million offset by $5.9 million of Accumulated Depreciation – for Net Plant of $15.3 million; and
- Consolidated Income Statement: reduction of O&A expense of $21.2 million offset by $5.9 million of Depreciation Expense – for a Net Profit/Retained Earnings increase of $15.3 million.

The cumulative impact of this profit adjustment of $15.3 million has currently been recorded in the Eliminations column of MH's consolidated financial statements and has not been attributed to Gas operations for purposes of evaluating the sufficiency of Centra's financial reserves (retained earnings) for rate-setting purposes.

In the response to CAC/Centra I-6 (c), Centra confirmed that Gas customers have been funding the costs of the gas meter exchange program in rates between 2014/15 and 2018/19 given that these costs were included in the 2013/14 revenue requirement, as an approved O&A expense.

When requested in information request CAC/Centra I-6 (d), to explain why it was not proposing to transfer the cumulative profit adjustment for this five-year period to the Gas operations effective April 1, 2019, so that Gas customers who have paid for the meter exchange costs in gas rates could benefit from this profit adjustment, Centra did not provide a rationale and simply referred back to the response to part (a) of this information request which outlines the accounting treatment for the last five-year period.

The key observations from a rate-setting perspective based on the forgoing information are as follows:

1. Centra has captured the impact of a number of accounting changes related to the transition to IFRS in deferral accounts between the 2014/15 and 2018/19 period for review and disposition for rate-setting purposes at the 2019/20 GRA;

2. Most of these IFRS accounting changes would have resulted in a reduction in Centra's net income/increase in expenses if not captured in deferral accounts for rate-setting purposes. These increased expenses were not built into Centra's rates that were approved in 2013/14;
3. The change in the gas meter exchange accounting treatment has the impact of increasing net income/reducing expenses and the associated revenue requirements. However, Centra's customers have been paying rates that were set back in 2013/14 that include the higher level of costs associated with meter exchange cost being expensed in O&A;
4. It was clearly the intent of Centra back in 2016 to credit customers with the favourable reduction in O&A expenses related to the harmonization/capitalization of the gas meter exchange costs for rate-setting purposes, as evidenced by its request to the PUB in its March 10, 2016 letter to confirm that this change was appropriate for rate-setting purposes;
5. It appears that the PUB did not want to make decisions on the impacts of IFRS accounting changes for rate-setting purposes on an interim basis and outside of a comprehensive GRA, that was at the time of the writing of its April 4, 2016 reply to Centra's letter, expected to occur early in 2017;
6. The recording of the profit adjustment related to gas meter exchange costs in the Eliminations column of MH's consolidated financial statements can be viewed as an interim measure to record the impacts for financial reporting purposes until the comprehensive review for rate-setting purposes occurred at the current GRA. This is no different in substance than the recording of other IFRS adjustments in deferral accounts pending endorsement/approval by the PUB for rate-setting purposes; and
7. The current 2019/20 GRA is the first GRA since the implementation of IFRS for Centra and as such is the expected regulatory proceeding to determine the appropriate rate-setting treatment of all IFRS accounting changes for Centra, including the gas meter exchange cumulative profit adjustment.

It is recommended that the PUB direct Centra to include the cumulative profit adjustment of $15.3 Million related to the capitalization of Gas meter exchange labour from 2014/15 to 2018/19 to be part of the financial reserves for rate-setting purposes. It is also appropriate to include the plant, accumulated depreciation and depreciation expense for rate-setting purposes.

It is fair that customers receive both the costs and benefits associated with all of the IFRS accounting changes including the gas meter exchange accounting change. Gas customers have continued to fund gas meter exchange costs between 2014/15 and 2018/19 (in the rates that were approved in the 2013/14 GRA) and as such should enjoy the associated benefit of the cumulative profit adjustment in the consideration of financial reserves for rate-setting purposes.

MH's business is a largely regulated electric and gas operations with a few smaller unregulated subsidiaries. As a public and regulated entity, it is reasonable that all of MH's consolidated

CENTRA GAS 2019/20 GENERAL RATE APPLICATION

INTERVENER EVIDENCE INFORMATION REQUESTS

CAC (D. RAINKIE, K. DERKSEN)

JULY 5, 2019

PUB/CAC(Rainkie)-11 Reference**:** Rainkie-Derksen Evidence Section 5.4 p.35

Preamble:

"It is recommended that the PUB direct Centra to include the cumulative profit adjustment of $15.3 million related to the capitalization of Gas meter exchange labour from 2014/15 to 2018/19 to be part of the financial reserves for rate-setting purposes. It is also appropriate to include the plant, accumulated depreciation and depreciation expense for rate-setting purposes. It is fair that customers receive both the costs and benefits associated with all of the IFRS accounting changes including the gas meter exchange accounting change. Gas customers have continued to fund gas meter exchange costs between 2014/15 and 2018/19 (in the rates that were approved in the 2013/14 GRA) and as such should enjoy the associated benefit of the cumulative profit adjustment in the consideration of financial reserves for rate-setting purposes."

Request:

a) Please indicate whether there are any obstacles under IFRS from including in the Centra financial statements and financial reporting the cumulative impacts of the gas meter exchange accounting policy change to allow for "one-set of books" for financial reporting and rate setting purposes.

b) If the cumulative profit adjustment related to the gas meter exchange accounting policy change were set up as a regulatory deferral account, what period of time would Mr. Rainkie suggest be used to amortize the balance of such an account.

c) If the preferred options were not possible, and the cumulative adjustment for the gas meter exchange accounting policy change remained only on Manitoba Hydro's consolidated financial statements, please describe what form and content of regulatory financial reporting would be required to allow the PUB to consider the amount in its regulatory proceedings for rate setting purposes.

Response:

a) The recommendations provided in Section 5.4 of the Evidence where made from the perspective of rate-setting and not based upon an analysis of IFRS standards for financial reporting purposes. CAC did not retain Mr. Rainkie and Ms. Derksen to provide a professional opinion on whether or not it is possible to transfer the cumulative profit adjustment from the Eliminations column of MH's consolidated financial statements to Centra's financial statements under IFRS. This transfer is a financial reporting issue that would have to be discussed and decided between Centra and its external auditors.

However, it is noted that Centra's intent (as expressed in its letter to the PUB on March 10, 2016) was to record this accounting policy change in its own financial statements commencing in 2015/16 with restatement to the 2014/15 fiscal year and it was the PUB's direction (in its response letter of April 4, 2016) that each of the accounting policy changes would be examined for rate-setting purposes at the next gas GRA. The recording of the cumulative profit adjustment in the Eliminations column of MH's consolidated financial statements is partly a function of the requirement to harmonize accounting treatment between MH and Centra but is also partly a result of the PUB not accepting accounting policy changes in Centra's financial statements on an interim basis for rate-setting purposes before an appropriate review at a GRA.

Therefore, the original accounting treatment (Elimination column) resulted in part from direction from the PUB and it would be reasonable for Centra and its external auditors to anticipate that the original accounting treatment would be reviewed and the possibility that it would be adjusted for rate-setting purposes by the PUB in the current GRA. As such, this is a pre-existing situation caused in part by a PUB regulatory directive and it would be expected that Centra and its external auditors would carefully consider subsequent PUB directives from the current GRA in terms of the appropriate financial accounting treatment on a go-forward basis.

b) The principle behind the recommendation that Centra include the cumulative profit adjustment to be part of financial reserves for rate-setting purposes is that the financial position and financial outlook be the same as if this accounting policy change had been directly recorded in Centra's financial statements commencing in 2014/15. Accordingly, it is suggested that an amortization period would be directed by the PUB that closely matches the depreciation rate associated with the capitalization of the gas meter exchange labor, which is understood to be 10 years.

c) If the "preferred options are not possible", is understood as meaning that Centra is unable to (1) directly record the cumulative retained earnings, property, plant and equipment (PP&E) and accumulated depreciation or (2) directly record a regulatory asset and a corresponding increase in retained earnings - in its own financial statements (in these situations the cumulative profit adjustment would remain in the Eliminations column of MH's consolidated financial statements).

In the situation where the preferred options are not possible, it is recommended that Centra include the cumulative impacts of the profit adjustment (retained earnings, PP&E and accumulated depreciation) in all of the schedules of the GRA minimum filing requirements to form part of the revenue requirement calculations for rate-setting purposes as well as the associated cost allocation study for developing rate proposals. In addition, it is recommended that Centra prepare and file an alternate Gas IFF financial scenario that includes the cumulative impacts of the profit adjustment as part of the GRA filing and that Centra would explain in its GRA filing how it has considered this alternate financial scenario in making its proposals for rate changes.

PUB/CAC(Rainkie)-12 Reference**:** Rainkie-Derksen Evidence p.39 Line 23-26

Request:

Given that all O&A is assigned through allocators, please provide how Mr. Rainkie proposes ensuring 1% escalation in O&A costs. (i.e. the constraint put on the amount of costs allocated through ICAM to Centra being restricted to 1% of growth)

Response:

In the event that MH is able to manage its O&A costs within the 1% escalation factor that the PUB found was acceptable for rate-setting purposes on Page 24 of Order 69/19, then there should be a natural flow-through of this level of escalation in the O&A costs that are allocated to Centra through the ICAM. In this case, there would be no requirement for a discrete rate-setting adjustment.

In the event that MH is unable to manage its O&A cost within the 1% escalation factor, then a discrete adjustment to the O&A costs that are allocated to Centra through the ICAM would have to be made for rate-setting purposes. This adjustment could be made in a manner that is consistent with the calculations provided on pages 47 to 49 of our Evidence, by considering the level (percentage) of escalation inherent in the MH consolidated O&A forecast and making a corresponding adjustment down to the 1% escalation level, based on the total O&A costs allocated to Centra.

CENTRA GAS 2019/20 GENERAL RATE APPLICATION

INTERVENER EVIDENCE INFORMATION REQUESTS

CAC (D. RAINKIE, K. DERKSEN)

JULY 5, 2019

PUB/CAC(Rainkie)-13 Reference: Rainkie-Derksen Evidence p. 52-53

Preamble:

Based on the referenced analysis there are no recommendations for rate-setting adjustments as a result of the information on the record associated with the ICAM, with the exception of the issues and recommendations noted in Section 6.3 with respect to O&A. However, there are a number of recommendations with respect to the ICAM review for future Centra GRA's:

1. The PUB should direct Centra to develop a comprehensive ICAM report that can be used to support the allocation of consolidated operating costs and shared costs between Centra and MH, at future gas and electric rate-setting proceedings. This report would document the overall consolidated costs that are allocated to MH and Centra, the detailed basis for costs drivers used, discuss emerging issues and alternative cost drivers considered, with any resulting recommendations for changes to the PUB for rate-setting purposes;

2. The initial ICAM report could be reviewed through a collaborative process of workshops/technical conferences that occur before the next MH or Centra GRA, including PUB staff and advisors and intervenor representatives, with the goal of obtain sufficient information and assurance that the ICAM is an appropriate methodology for a fair allocation of O&A and shared costs;

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INTERVENER EVIDENCE INFORMATION REQUESTS

CAC (D. RAINKIE, K. DERKSEN)

JULY 5, 2019

3. Once the initial ICAM report is accepted as satisfying the intent of the PUB directive, this report should be maintained on an annual basis (much like a Cost of Service Study) and filed with each Centra and MH GRA to support the allocation of O&A and common costs; and

4. If for any reason, Centra is unwilling or unable to develop the ICAM report and continue to pursue this issue through a collaborative process, then the PUB should proceed to once again direct Centra to file a terms of reference for an independent external review, including circulation to intervenors for comments.

Request:

a) Please provide Mr. Rainkie's view on the cost versus the benefit of an external review of the ICAM versus the proposed internal comprehensive ICAM report and process.

b) If an external report were undertaken, would there still be a need for an annual ICAM process as proposed by Mr. Rainkie? Please explain.

Response:

a) As noted on the bottom of page 52 and top of page 53 of the Evidence, the overall benefit of an external review of the ICAM would be a more comprehensive review as an external consultant would have greater direct access to MH/Centra's records, staff and systems as well as the ability to perform detailed testing of allocations and systems in order to express an opinion on the reasonableness of the methodology. As such, an external review is expected to provide a higher level of assurance to the PUB and interested parties that the ICAM is appropriate and reliable for rate-setting purposes.

An external review is expected to cost more as a result of the upfront consulting cost, additional Centra internal costs to facilitate the engagement as well as the cost of the subsequent regulatory review by the PUB and interested parties at a GRA proceeding.

The collaborative review proposed on page 53 of the Evidence is viewed as a practical but effective compromise. It is expected that an appropriate (albeit lower) level of assurance for rate-setting purposes could be obtained through this form of a review, at a lower overall cost than an external review. The added benefit could be a greater understanding of the ICAM by the PUB, its advisors and interested parties by participating in a collaborative review versus relying on an external review with subsequent testing at a GRA.

b) Yes, the need for an annual ICAM report would still be required if an external review was undertaken. The purpose of an initial external review (or collaborative review process amongst Centra, PUB and interested parties) would be to obtain the assurance with respect to the appropriate functioning of the ICAM for rate-setting purposes.

The purpose of annual ICAM report would be to ensure the on-going appropriateness of the ICAM for rate-setting purposes and would support the annual allocation of O&A and common costs between MH and Centra at electric and gas GRA proceedings. After the initial review of the ICAM report, the subsequent reports would become part of the basic minimum filing requirements with the expectation that the amount of review dedicated to the ICAM report on an annual basis would significantly diminish, until and unless there were significant changes to the ICAM proposed by MH or Centra.

CENTRA GAS 2019/20 GENERAL RATE APPLICATION

INTERVENER EVIDENCE INFORMATION REQUESTS

CAC (D. RAINKIE, K. DERKSEN)

JULY 5, 2019

PUB/CAC(Rainkie)-14 Reference: Rainkie-Derksen Evidence – Section 7.2 p. 63-64; p. 91-92 Appendix 14-1 Attachment

Preamble:

While the limited information on risk assessment/quantification in the information requests is directionally better than the information in the application, the overall assessment is that it is incomplete and does not provide sufficient information for a comprehensive review of the appropriate level of financial reserves for rate-setting purposes.

It is recommended that PUB direct the consideration of the establishment of a Minimum Retained Earnings Test for future Centra GRA's for rate-setting purposes, based on a comprehensive assessment of risk and required reserve levels. The approach that is recommended is to use the principles and analysis that are developed for MH and apply and adapt that to Centra's circumstances, as necessary. This would include the development of an Uncertainty Analysis model for Centra that would be used as a quantitative tool to guide the consideration of the appropriate level of financial reserves for gas operations, for rate-setting purposes.

Request:

Please discuss what risks the uncertainty analysis for Centra should model.

Response:

Given that the MH Corporate Risk Management Report is focused mainly on its electric operations, an initial step towards the uncertainty analysis for Centra would be the development of a comprehensive risk assessment/analysis by Centra's management that was specifically focused on the most adverse risks facing natural gas operations and their probability of occurrence. The uncertainty analysis would model a combination of the most plausible adverse risk scenarios that are faced by Centra, as well as potential management and regulatory responses, in order to assess the ability of the expected financial reserves to withstand these adverse scenarios while continuing to promote a high degree of rate stability for customers. Examples of risks on the record of this proceeding that may be modelled in the uncertainty analysis include weather, interest rates, customer growth, variations in BOC, O&A and DSM spending, catastrophic system failure and infrastructure risks.

In addition to the uncertainty analysis, the PUB would also likely want to provide rate-setting direction on those natural gas risks that should be built into on-going rate changes, those risks that would be protected by financial reserves and those risks that the PUB would be prepared to deal with through future regulatory response (rate increases when the emergent risks are actually facing Centra rather than being built up in financial reserves through rate increases in advance of occurrence in those risks). For example, In Orders 59/18 and 69/19 related to electricity operations, the PUB found that key risks such as interest rate and export price risks should be built into rates when those risks materialise and not through building up of retained earnings and that drought risk should be managed through a combination of retained earnings and regulatory action when drought is actually facing MH. Similar direction from the PUB would be beneficial in developing an uncertainty analysis and minimum retained earnings test for natural gas operations.

On July 24th, Centra filed its updated detailed O&A budget for the 2019/20 fiscal year. Centra's overall O&A target for 2019/20 remains unchanged at $61.2 million, consistent with the original Application and the Supplement to the Application filed on March 22, 2019. The detailed budget submitted on July 24th reflects current requirements for each program including internal labour, materials, external contractors and other cost components. This has resulted in Centra reflecting a negative contingency of approximately $600K which will be managed over the 2019/20 fiscal year to meet the approved target. The current budget reflects changes in various programs with the most notable increases in the customer inspection and environment programs.

It would also seem logical that considering Mr. Rainkie's suggestion that a positive contingency should result in a decrease to the O&A target, a negative contingency should be treated in a similar manner and could result in an increase to the O&A target for rate setting purposes if the planned program expenditures are justified. Just as Centra rejects the idea that a positive contingency should result in an O&A decrease, Centra does not believe that a negative contingency should result in an O&A increase. Rather in both cases, management's role is to manage to the target that has been established.

5.2 Cumulative Profit Adjustment for Meter Exchange Activities

Page 35 of Mr. Rainkie's evidence includes the following recommendation: "*…that the PUB direct Centra to include the cumulative profit adjustment of $15.3 million related to the capitalization of Gas meter exchange labour from 2014/15 to 2018/19 to be part of the financial reserves for rate setting purposes.*"

Centra does not agree with Mr. Rainkie's recommendation as the costs associated with the meter exchange program have already been included in revenue requirement and as a result have been recovered through the rates charged to customers through to 2018/19.

It is not clear if Mr. Rainkie is suggesting a further rate reduction in 2019/20 in recognition of higher retained earnings. If so, then rates would subsequently need to be increased and rate payers charged for the same cost through the future amortization of a regulatory asset, recorded through net movement and recovered in revenue requirement. Alternatively, if Mr. Rainkie is suggesting lower future rate increases, Centra may incur losses as the full revenue requirement would not be recovered through rates. The recommendation by Mr. Rainkie adds unnecessary complexity and confusion for all parties including its customers and the readers of Centra's financial statements.

Centra is requesting the PUB's endorsement for the capitalization of the meter exchange costs on a go forward basis effective April 1, 2019. It is noted that beginning in 2019/20 the cumulative adjustment balance (i.e. $15.3 million) on the consolidated books of Manitoba Hydro will naturally unwind as it assumed to be amortized over a 10 year period aligned with the life of the asset.

5.3 Accounting Treatment for Meter Verification and In-Line Inspection costs

METSCO states Centra is capitalizing the cost of inline inspections and meter verifications due to inability to manage O&A costs.

METSCO states on page 43 the following:

"*We were, however, interested to understand the managerial reasons that drove Centra to make this decision at this juncture.";* and

"While we suspect that the decision to capitalize these two types of expenditure categories were driven by the Applicant's inability to effectively manage its O&A expenditures…"

Centra disagrees with METSCO's statement that decisions with respect to the accounting treatment of expenditures (i.e. capital vs expense) are managerial decisions. Management is responsible to identify the work requirements and the execution of the work (e.g. internal labour vs contracted services). Decisions to capitalize or expense are driven by accounting standards and are the responsibility of the corporation's financial division, along with its external auditors. The response to CAC/Centra I-81a provides a discussion on the accounting considerations for capitalization of meter testing costs.

3

REFERENCE:

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

QUESTION:

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

RESPONSE:

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

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

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

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

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

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

3 COST SUMMARY

The five year projected capital cost requirements are summarized below. Costs are shown as "Programs" and "Projects" with programs generally representing multiple, lower cost expenditures on similar ongoing work such as the installation of new services or replacement of natural gas meters.

Projects are typically higher cost, with a nominal threshold of $1 million. Individual work items with a cost below $1 million can also be included as projects if they are a unique scope of work where designation as a project assists in tracking of the work or providing visibility to the project.

Projects are generally identified and well developed for a two year period. While it is known that projects will continue to be done in year's three to five, these have not been fully scoped or developed and a "Planning Item" is shown to reflect the continued requirement for funding as outlined in Section 5.13.

(Note: The Capital Expenditure Forecast (CEF) process to establish approved capital expenditures is performed with a different timeline than the preparation of this work. While the costs shown are representative, with ongoing efforts to provide the most accurate capital costs, the approved CEF numbers are the official capital costs and may differ from the values shown here.)

PROGRAMS	2018–19	2019–20	2020–21	2021–22	2022–23
New Business	$14,500 K	$14,800 K	$15,100 K	$15,400 K	$15,700 K
System Betterment – Relocations	$1,640 K	$1,040 K	$1,060 K	$1,080 K	$1,100 K
System Betterment – Integrity	$4,800 K	$4,890 K	$4,990 K	$5,090 K	$5,190 K
System Betterment – Capacity & Other	$990 K	$1,240 K	$1,260 K	$1,290 K	$1,320 K
System Betterment – Measurement & Regulator Stations	$3,040 K	$3,100 K	$3,160 K	$3,230 K	$3,290 K
Meter Compliance Program	$2,510 K	$6,700 K	$6,834 K	$6,970 K	$7,110 K
Customer Service Operations – Capital	$1,220 K	$1,240 K	$1,260 K	$1,290 K	$1,320 K
Gas Apparatus Maintenance & Control	$660 K	$670 K	$680 K	$700 K	$710 K
Corrosion Control	$370 K	$370 K	$380 K	$380 K	$390 K
Programs Subtotal	**$29,730 K**	**$34,050 K**	**$34,724 K**	**$35,430 K**	**$36,130 K**
PROJECTS	**2018–19**	**2019–20**	**2020–21**	**2021–22**	**2022–23**
Winnipeg Waverley West MP – Phase 2	$880 K	$1,990 K	$550 K	$0 K	$0 K
Steinbach TP Upgrade	$430 K	$1,430 K	$1,920 K	$330 K	$0 K
St. Andrew's Distribution Upgrade	$1,240 K	$0 K	$0 K	$0 K	$0 K
In-Line Inspection Program	$2,550 K	$1,640 K	$1,710 K	$520 K	TBD*
Cathodic Rectifier Remote Monitoring Devices	$490 K	$0 K	$0 K	$0 K	$0 K
GS-123 Brandon Primary Gate Station Upgrades	$1,900 K	$1220 K	$0 K	$0 K	$0 K
Portage la Prairie TP Main – Secure Gas Supply	$70 K	$450 K	$100 K	$960 K	$0 K
Distribution System Monitoring	$1,230 K	$670 K	$0 K	$0 K	$0 K
St. Pierre TP Upgrade	$360 K	$0 K	$0 K	$0 K	$0 K

COST SUMMARY (CONTINUED)

PROJECTS (continued)	2018–19	2019–20	2020–21	2021–22	2022–23
Red River TP Pipeline Replacement	$260 K	$1,340 K	$0 K	$0 K	$0 K
Addressing Encroachment on Pipelines	$100 K	$0 K	$0 K	$0 K	$0 K
Planning Item	$0 K	$1,650 K	$3,550 K	$6,000 K	$8,000 K
Projects Subtotal	**$9,510 K**	**$10,390 K**	**$7,830 K**	**$7,810 K**	**$8,000 K**
TOTAL COSTS	**$39,240 K**	**$44,440 K**	**$42,554 K**	**$43,240 K**	**$44,130 K**
Target Adjustment**	$(3,924) K	$(4,444) K	$(4,255) K	$(4,324) K	$(4,413) K
NET TOTAL COSTS	**$35,316 K**	**$39,996 K**	**$38,299 K**	**$38,916 K**	**$39,717 K**

*Future project scope and dollars are to be determined and are currently estimated and shown under "Planning Item" as summarized in Section 5.13.

**The Target Adjustment reduces forecasted capital spending to Corporate approved capital targets to account for year to year variations in the roll up of program spending and recognition that external factors (contractor availability, procurement of property and external approvals) can affect project delivery and total spending.

REFERENCE:

Appendix 4.1 p. 1

PREAMBLE TO IR (IF ANY):

QUESTION:

For each year since 2012/13, provide the forecast total capital expenditures (excluding DSM) from the prior year CEF and compare to the actual total capital expenditures. For example, provide the actual spending for 2012/13 and compare with the forecast spending for 2012/13 from CEF11, compare actual spending for 2013/14 with the forecast from CEF12, etc. Explain any material variances.

RESPONSE:

The following table provides a comparison of Business Operations Capital approved targets (excluding DSM) compared to the actual capital expenditures for each year from 2012/13 to 2017/18, based upon the approved CEF for each relevant year.

CENTRA GAS MANITOBA INC.
BUSINESS OPERATIONS CAPITAL PERFORMANCE
($ Millions)

($ Millions)	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**
CEF12	26.9					
CEF13		40.6				
CEF14			38.3			
CEF15				54.0		
CEF16					50.8	31.0
ACTUAL	29.8	32.6	27.3	40.4	54.4	32.9
VARIANCE	**(2.9)**	**8.0**	**11.0**	**13.6**	**(3.6)**	**(1.8)**

Explanations have been provided for the variances.

2012/13 –The over expenditure was primarily due to higher than planned requests for new business from rural colonies as a result of impending legislation banning the use of coal.

2013/14 – The under expenditure was primarily due to:

- Gas SCADA Replacement project due to lower than anticipated vendor costs for application software, contract services and travel, as well as planned building upgrades that were not required;
- Morris Natural Gas Transmission Network Upgrade and St. Francois Xavier Transmission Line projects due to lower material and contractor costs than planned; and
- Less service line retirements and gas meter purchases.

2014/15 –The under expenditure was primarily due to lower customer service related infrastructure additions and system improvements, as well as the deferral of Winnipeg Northwest Upgrade Phase 1 construction to the following fiscal year.

2015/16 – The under expenditure was primarily due to:

- The assumption that the capitalization of meter sampling, testing and exchange activities would commence in 2015/16; however, since Centra had not yet received PUB approval metering costs continued to be expensed;
- Winnipeg North West Phase 2 incurred lower than anticipated contractor costs due to a reduced workload in Western Canada which resulted in significant out-of-Province contractor interest in the work, yielding significant project savings. In addition, lower than anticipated costs for environmental licenses and property requirements as existing easements and right-of-ways were used rather than acquiring new easements and right-of-ways as originally planned; and
- Compressed Natural Gas Trailer Filling Station under expenditures due to consultant design delays which deferred the tendering process for materials.

2016/17 – The over expenditure was primarily due to:

- Winnipeg North West Phase 2 project incurred additional expenses (such as replacement of damaged pipe, use of specialized field applied abrasion resistant coatings, specialized drill bits, etc.) due to worse than anticipated rocky conditions encountered during horizontal directional drilling resulting in damage to the pipe and coating. In addition, extra time for drilling was required, all of which resulted in overall project delays resulting in higher inspection and internal costs.
- Unplanned construction of approximately 3.0 km of new 8” main to provide natural gas service to a new industrial facility; physical constraints within the road right of way required an extensive section of the main to be installed under the road surface which resulted in high restoration costs.

2017/18 – The over expenditure was primarily due to:

- Compressed Natural Gas Trailer Filing Station incurred higher contracted costs than originally anticipated as well as increased costs due to winter construction and project delays.

CAPITAL EXPENDITURE & DEMAND SIDE MANAGEMENT FORECAST (CEF18)

NATURAL GAS CAPITAL EXPENDITURE & DEMAND SIDE MANAGEMENT FORECAST (CEF18)

(in millions of dollars)

	Total Project Cost	2019	2020	2021	2022	2023	2019-2023 5 Year Total	2019-2028 10 Year Total
Business Operations Capital								
Distribution System & Corporate Infrastructure								
Programs								
Capacity & Growth	NA	15.7	18.5	18.9	19.2	19.6	91.9	196.0
Sustainment	NA	14.1	15.6	16.0	16.3	16.6	78.6	166.7
Projects								
Capacity & Growth	10.3	1.7	3.4	2.5	0.3	0.0	7.9	7.9
Sustainment	19.2	7.8	5.3	1.8	1.5	0.0	16.5	16.5
Distribution System & Corporate Infrastructure Subtotal		**39.3**	**42.9**	**39.1**	**37.3**	**36.2**	**194.8**	**387.0**
Target Variance	NA	(3.9)	(2.8)	(0.7)	1.7	3.6	(2.2)	16.9
Business Operations Capital Total		**35.4**	**40.1**	**38.4**	**39.0**	**39.8**	**192.7**	**403.9**
Demand Side Management	NA	9.4	10.8	10.8	10.9	10.4	52.2	103.7
NATURAL GAS CAPITAL & DSM FORECAST TOTAL		**44.8**	**50.9**	**49.2**	**49.9**	**50.2**	**244.9**	**507.6**

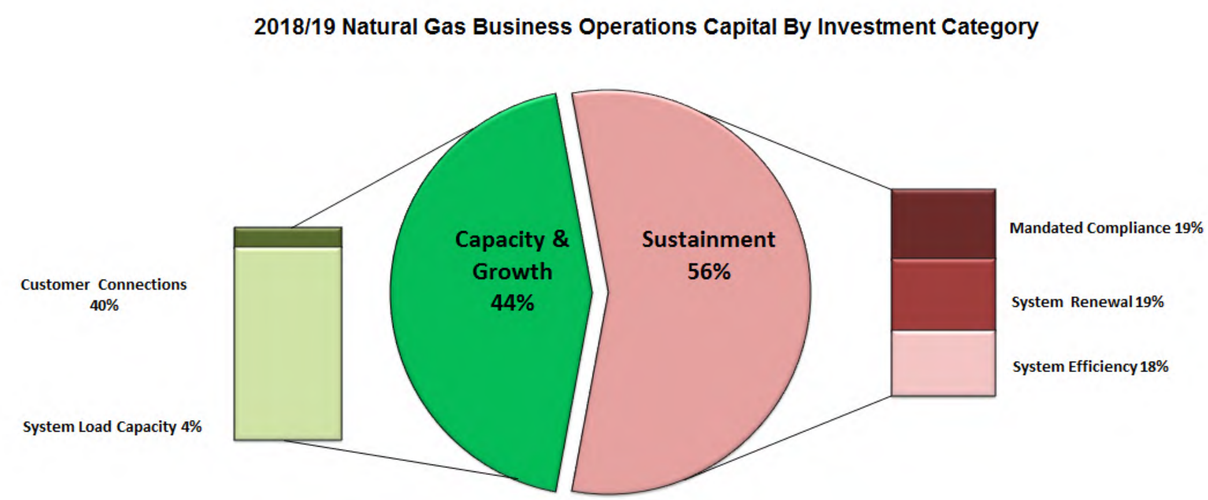
Capital Expenditure & Demand Side Management Forecast (CEF18)

Business Operations Capital – Natural Gas

Distribution System & Corporate Infrastructure

The Manitoba Hydro natural gas distribution system consists of approximately 17 000 km of pipelines, 400 pressure regulating stations and 270 000 services to deliver natural gas service to residential, commercial and industrial customers.

The natural gas distribution system capital expenditure forecast for 2018/19 is comprised entirely of capacity & growth and sustainment projects and programs to address customer connection requirements as well as system upgrades reflecting those as a result of compliance, renewal and efficiency requirements as shown in the graph that follows.



Investment category and cashflow details for natural gas projects with a total project forecast between
$1 million and $15 million can be found in Appendix II – Projects Greater than $1 Million and Less than
$15 Million.

There are no distribution system or corporate infrastructure projects with a total project forecast greater than $50 million.

Capital Expenditure & Demand Side Management Forecast (CEF18)

Natural Gas Demand Side Management (DSM)

CEF18 includes demand side management investments for both Electric and Natural Gas operations designed to manage the demand for energy. These expenditures relate to programs that provide education, incentives and expertise to achieve energy savings in an effort to offset growing demand.

Demand Side Management ($ Millions)	2019	2020	2021	2022	2023	2019-2023 5 Year Total	2019-2028 10 Year Total
Natural Gas Programs	9.4	10.8	10.8	10.9	10.4	52.2	103.7

	Total	2019	2020	2021	2022	2023	2024-28
Previously Approved	NA	$ 11.7	$ 10.8	$ 10.8	$ 10.9	$ 10.4	$ 51.4
Increase (Decrease)		(2.3)	-	-	-	-	$ -
Revised Forecast	NA	$ 9.4	$ 10.8	$ 10.8	$ 10.9	$ 10.4	$ 51.4

The reduction of the 2018/19 forecast as compared to CEF16 is primarily due to a change in the mix of programs and updates to customer activity projections for the Load Displacement program.

Capital Expenditure & Demand Side Management Forecast (CEF18)

Projects greater than $1 million.

Project Details ($ Millions)	Project Status	Total Project Cost	2019	2020	2021	2022 to 2028
Natural Gas Distribution System & Corporate Infrastructure						
Capacity & Growth						
System Load Capacity						
St-Pierre Transmission Pipeline Upgrade	Executing Project	2.4	0.4	-	-	-
Steinbach Natural Gas System Upgrade	New Project	4.1	0.4	1.4	1.9	0.3
Waverley West Upgrade	New Project	3.5	0.9	2.0	0.5	-
System Load Capacity Total			**1.7**	**3.4**	**2.5**	**0.3**
Capacity & Growth Total			**1.7**	**3.4**	**2.5**	**0.3**
Sustainment						
System Renewal						
Brandon Primary Generating Station Re-Construction	Executing Project	3.9	1.9	1.2	-	-
System Renewal Total			**1.9**	**1.2**	**-**	**-**
Mandated Compliance						
Medium Pressure Monitoring System Replacement	Executing Project	2.1	1.2	0.7	-	-
Winnipeg Natural Gas Transmission Easement Widening	Executing Project	1.6	0.1	-	-	-
Mandated Compliance Total			**1.3**	**0.7**	**-**	**-**
System Efficiency						
Natural Gas Transmission Pipeline System In-Line Inspection	New Project	6.5	2.5	1.6	1.7	0.5
Letellier-Red River Transmission Upgrade	New Project	1.6	0.3	1.3	-	-
Provision of Secure Gas Supply-Portage	New Project	1.6	0.1	0.4	0.1	1.0
St. Andrews Distribution System Upgrade	New Project	1.3	1.2	-	-	-
System Efficiency Total			**4.1**	**3.4**	**1.8**	**1.5**
Sustainment Total			**7.3**	**5.3**	**1.8**	**1.5**
Natural Gas Distribution System & Corporate Infrastructure Total			**9.0**	**8.7**	**4.3**	**1.8**

REFERENCE:

Tab 4 p. 7 and 21 of 22, Tab 14 Attachment 1

PREAMBLE TO IR (IF ANY):

QUESTION:

Explain whether Centra determines its asset investment levels in order to reduce risk to the acceptable level of corporate risk tolerance (e.g. Tab 14 Attachment 1), or whether Centra uses its risk assessment process to prioritize projects or programs. If the latter, explain whether Centra potentially invests too little (insufficient mitigation of risks to reach corporate risk tolerance levels) or too much (risks mitigated beyond what is needed to meet corporate risk tolerance levels).

RESPONSE:

Centra is transitioning to the application of the C55 Corporate Value Framework to assist in prioritizing projects and program expenditures. This process is not fully implemented at this time. The current capital planning process combines the requirements of programs and projects to establish a total annual capital requirement. As described in the response to PUB/Centra I-67, much of the program spending is to meet non-discretionary requirements such as new customer attachment and regulatory compliance. The program spending was 76% of the 2018/19 budget, with similar or higher percentages expected for the fiscal years 2019/20 through to 2022/23. There is limited opportunity to prioritize spending on programs that reflect a significant portion of the annual capital. At this time projects are identified by subject matter experts to respond to identified issues and risks. Reports and capital investment documents are prepared and reviewed and proceed to implementation if approved.

REFERENCE:

Tab 4 p. Figure 4.1; Appendix 4.1 p. 1 of 17

PREAMBLE TO IR (IF ANY):

QUESTION:

Refile the table on page 1 of CEF18 (Appendix 4.1 page 1) in order to show the Level 1 and Level 2 investment categories, similar to Tab 4 Figure 4.1 but with the CEF18 yearly expenditures. In addition, also provide the sub-component line items related to Target Variance and Demand Side Management expenditures.

RESPONSE:

The following table provides Level 1 and Level 2 investment categories of Business Operations Capital expenditures.

NATURAL GAS CAPITAL EXPENDITURE & DEMAND SIDE MANAGEMENT FORECAST (CEF18)
(in millions of dollars)

	Total Project Cost	2019	2020	2021	2022	2023	2019-2023 5 Year Total	2019-2028 10 Year Total
Business Operations Capital								
Distribution System & Corporate Infrastructure								
Programs								
Capacity & Growth								
Customer Connections	NA	15.7	18.5	18.9	19.2	19.6	91.9	196.0
		15.7	**18.5**	**18.9**	**19.2**	**19.6**	**91.9**	**196.0**
Sustainment								
Mandated Compliance	NA	6.1	7.3	7.5	7.6	7.8	36.3	77.5
System Renewal	NA	5.7	5.8	6.0	6.1	6.2	29.8	62.7
System Efficiency	NA	2.3	2.5	2.5	2.6	2.6	12.5	26.5
		14.1	**15.6**	**16.0**	**16.3**	**16.6**	**78.6**	**166.7**
Projects								
Capacity & Growth								
System Load Capacity	10.3	1.7	3.4	2.5	0.3	-	7.9	7.9
		1.7	**3.4**	**2.5**	**0.3**	**-**	**7.9**	**7.9**
Sustainment								
System Efficiency	11.5	4.6	3.4	1.8	1.5	-	11.3	11.3
System Renewal	3.9	1.9	1.2	-	-	-	3.1	3.1
Mandated Compliance	3.8	1.3	0.7	-	-	-	2.0	2.0
		7.8	**5.3**	**1.8**	**1.5**	**-**	**16.5**	**16.5**
Distribution System & Corporate Infrastructure Subtotal		**39.3**	**42.9**	**39.1**	**37.3**	**36.2**	**194.8**	**387.0**
Target Variance	NA	**(3.9)**	**(2.8)**	**(0.7)**	**1.7**	**3.6**	**(2.2)**	**16.9**
Business Operations Capital Total		**35.4**	**40.1**	**38.4**	**39.0**	**39.8**	**192.7**	**403.9**

REFERENCE:

Tab 4 p. 7 and 21 of 22, Tab 14 Attachment 1; Appendix 4.1 p. 1

PREAMBLE TO IR (IF ANY):

QUESTION:

d) Explain how Centra developed its sustainment budget of $183 million (as shown in Appendix 4.1 at page 1 of 17) and explain how Centra determined that $183 million is the optimum amount.

e) Please provide a comparison of the Appendix 4.1 pg. 7 CEF16 sustainment budget and the CEF18 sustainment budget. Please also explain why the budget has changed from $154 million to $183 million.

RESPONSE:

d) The 10 year CEF18 Business Operations Capital ("BOC") forecast for Centra totals $403.9 million. The BOC forecast is established annually, within the capital planning cycle and portfolio plans for projects and programs are developed for the coming year and forecasts of investment requirements are updated for the years beyond. Of that forecast, $183.2 million ($166.7 in programs and $16.5 million in projects) is displayed with the 'Sustainment' investment category. As discussed in Appendix 4.2, Centra, in conjunction with Manitoba Hydro, developed and incorporated the use of investment categories as part of the Capital Asset Management framework as a means to provide stakeholders with a better understanding of the *primary driver* of an investment. Forecasts are not established by investment category; the 10 year forecast with the primary driver of 'Sustainment' is comprised of approved projects and programs over the same time frame.

e) The table below provides a comparison of the forecast, with the primary driver of 'Sustainment', for CEF16 and CEF18, noting that the ten-year forecast for CEF16 covers 2018/19 to 2027/28, whereas CEF18 covers 2019/20 to 2028/29.

SUSTAINMENT ($ Millions)	CEF18 2019-2028 10 Year Total	CEF16 2018-2027 10 Year Total	CEF18 Less CEF16
CEF18 Less CEF16			
Mandated Compliance	80	83	(3)
System Renewal	66	51	15
System Efficiency	38	20	18
TOTAL	**183**	**154**	**29**

As noted in part d) above, investment categories are intended to provide the reader with the primary driver of the investment and were not intended to represent approved budgets for which targets are established.

The assessment of investment requirements is an ongoing process in which project and program forecasts and plans are updated to reflect new information as it becomes available. The timing of investment is a complex risk decision with significant potential operational and cost consequences and is completed as part of the annual capital planning process, based on the best information available at the time. Adjustments are made as new information becomes available.

Critical Asset Groups		Typical Asset Condition Score Characteristics		
		Acceptable	**Fair/Poor**	**Critical**
Stations and Control Points	Stations	· No heaving, no corrosion pitting, · Up to date equipment	· Some heaving occurring, more than superficial corrosion occurring. · Older equipment with replacement parts still available.	· Settling or heaving of pipe is quite noticeable · Corrosion pitting · There are no replacement parts available for equipment
	Steel Valves	· No abnormal condition present	· Valve is operating but has an abnormal condition that will lead to failure	· Valve is inoperable and will need to be worked on or replaced
Pipelines	Transmis-sion Pressure	· New and some older Pipe · Good cathodic protection history · Good below grade leak history	· Older Pipe · Possibility of cathodic protection time below target · Possibility of below grade leaks due to degradation defects	· Vintage Pipe · History of cathodic protection time below target · Presence of below grade leaks due to degradation defects
	High and Medium Pressure	· New and some older pipe · Good cathodic protection history · Good below grade leak history	· Older Pipe · Prevalence of cathodic protection time below target · >1.5 below grade leaks due to degradation defects per kilometer.	· Vintage Pipe · Prevalence of cathodic protection time below target · >4.6 below grade leaks due to degradation defects per kilometer.
Services		· Riser coating has no holidays · Valve turns smoothly, is insulated. · No stress on meter set. · Regulator provides required pressure.	· Riser coating has signs of fading, peeling or cracking. · Valve requires greasing. · Regulator is older than 25 years or may vary slightly in pressure point. · Piping is not at current standard designed to prevent strain.	· Riser is delaminated and exhibits corrosion flaking or strain. · Valve is damaged (ears are broken) or seized. · Regulator is continually leaking or does not provide set pressure. · Piping shows severe signs of strain.

Table 5: Natural Gas Asset Health Index

Figures 1 and 2 represent the percentage of each asset rated acceptable, fair/poor and critical as per the asset health index categories in Table 5. The majority of natural gas assets are currently in acceptable condition, with the exception of services which are primarily in fair/poor condition as shown in Figure 1 below. The 20 year forecast of asset health shows in Figure 2 that asset health of condition acceptable will decline on average. Note that the due to the below grade nature of pipelines, the asset health of pipelines is the most uncertain relative to other assets.

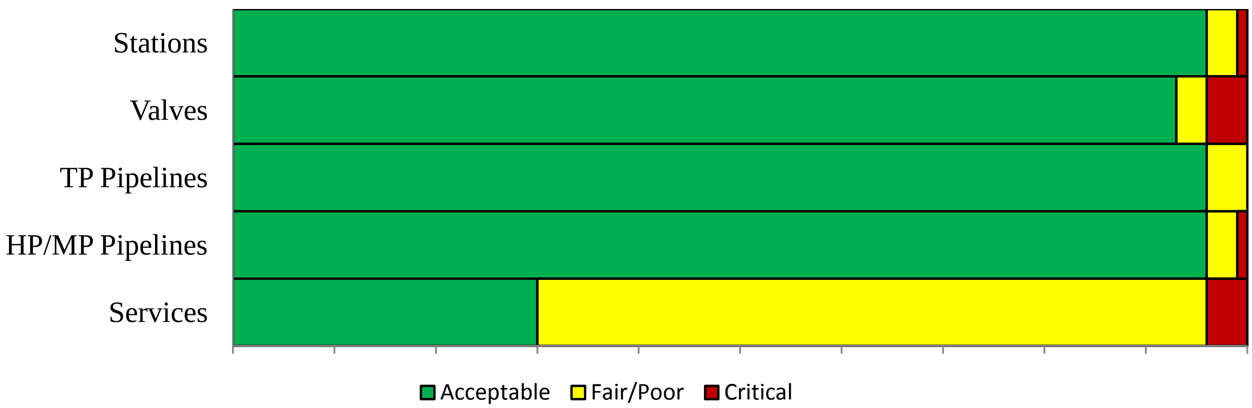


Figure 1: Current Asset Health "Soccer Field" [5]

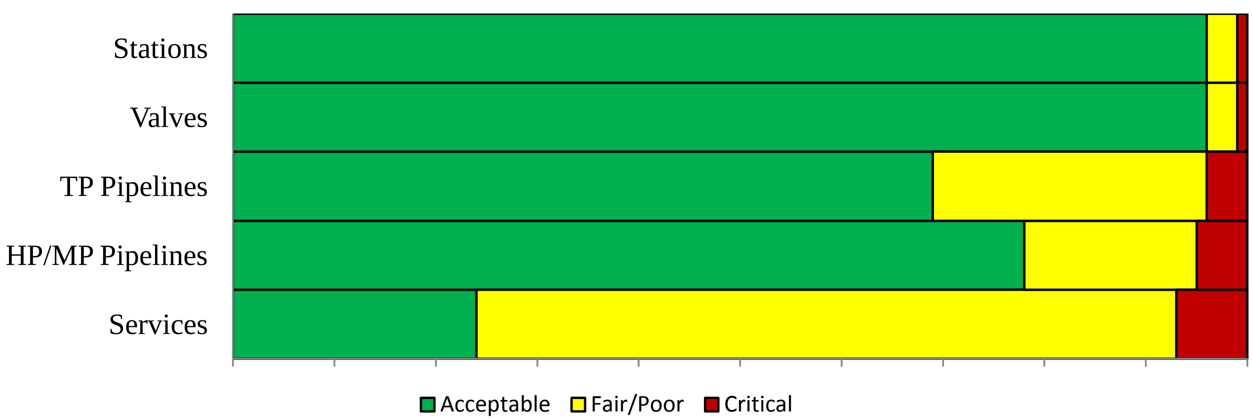


Figure 2: 20 Year Forecast Asset Health "Soccer Field"

[5] Note that the due to the below grade nature of pipelines, the asset health of pipelines is the most uncertain relative to other assets.

5.2 STEINBACH UPGRADE

JUSTIFICATION

The City of Steinbach has experienced strong residential and commercial growth and continues to grow at a higher rate than other parts of Manitoba. Steinbach continues to attract major industries and retailers which further drive the city's residential growth; this growth has a related increase in gas load.

Steinbach is the third-largest city in Manitoba, and is the largest city in Manitoba not having a secondary gas supply. The proposed upgrade will increase the available supply to the community while providing a secondary supply. This secondary supply will reduce or eliminate the possibility of an outage in the community.

RECOMMENDATION

Install a new gas supply to feed the City of Steinbach.

Install a new 6 NPS steel transmission pressure (TP) pipeline from the existing Hanover transmission line located southwest of Steinbach (9.9 km), to a new Steinbach pressure regulating station with distribution mains (5.1 km of 8 NPS) connecting to the existing gas distribution system.

STEINBACH UPGRADE				
ANNUAL BUDGET				
2018–19	2019–20	2020–21	2021–22	2022–23
$430 K	$1,430 K	$1,920 K	$330 K	$0 K

RISK ANALYSIS					
Consequence	High	Likelihood	Almost Certain	Risk Rating	9A

FIGURE 32 – STEINBACH TP UPGRADE

5.7 PORTAGE LA PRAIRIE TP MAIN – SECURE GAS SUPPLY

JUSTIFICATION

The City of Portage la Prairie is the fourth-largest city in Manitoba supplied with natural gas. The system was constructed as a single feed system and it is vulnerable to a single failure or damage that could potentially result in an outage for all downstream customers. Major portions of the pipeline were installed in 1957 and 1962. While there are no known pipeline integrity concerns, the pipeline system has not been assessed for corrosion and would be susceptible to corrosion mechanisms observed on other Manitoba Hydro pipelines.

The number of customers in the community and associated gas supply requirements exceeds the supply abilities of an alternate trucked-in gas supply. The proposed modifications maintains the use of the existing assets while providing valves and a second river crossing that will permit a single transmission pipeline damage or failure to be isolated while maintaining gas supply to the customers.

RECOMMENDATION

Provide pipeline modifications and additions to reduce the number of customers that may lose gas service in the event of a pipeline damage or failure. In 2019, add pipeline isolation valves on the parallel 114.3 mm transmission pipelines and on the 168.3 mm transmission pipeline at GS-182. In 2021, install a second 168.3 mm transmission pressure river crossing of the Assiniboine River with associated valves.

PORTAGE LA PRAIRIE TRANSMISSION PRESSURE MAIN – SECURE GAS SUPPLY				
ANNUAL BUDGET				
2018–19	2019–20	2020–21	2021–22	2022–23
$70 K	$450 K	$100 K	$960 K	$0 K

RISK ANALYSIS					
Consequence	High	Likelihood	Rare	Risk Rating	8A

FIGURE 38 – PROPOSED SECOND ASSINIBOINE RIVER CROSSING

5.10

RED RIVER AT LETELLIER TP PIPELINE REPLACEMENT

JUSTIFICATION

Currently, there are two NPS 4 transmission pressure (TP) pipelines crossing under the Red River between Letellier and Dominion City. The area of the crossings is known to be geotechnically unstable and Manitoba Hydro has previously had to repair a pipeline leak on a fitting damaged due to slope movement.

If further bank failures occur, it is possible that one or both pipeline crossings may become inoperable. This would compromise Manitoba Hydro's ability to operate the Southwest Transmission Loop.

In 2009, Manitoba Infrastructure replaced a bridge in the area due to concerns over geotechnical instabilities. They have also completed bank stabilization in the vicinity, though not close enough to the pipelines to currently benefit Manitoba Hydro.

RECOMMENDATION

- Install new transmission pipeline crossings below predicted slope failures or at a location that has had bank stabilization performed by Manitoba Infrastructure.
- Take the opportunity to examine the feasibility of installing control valves to independently operate the river crossings.

RED RIVER TRANSMISSION PRESSURE PIPELINE REPLACEMENT				
ANNUAL BUDGET				
2018–19	2019–20	2020–21	2021–22	2022–23
$260 K	$1,340 K	$0 K	$0 K	$0 K

RISK ANALYSIS					
Consequence	High	Likelihood	Possible	Risk Rating	8A

FIGURE 43 – HORIZONTAL DIRECTIONAL DRILLING

APPENDIX A

RISK ASSESSMENT METHODOLOGY

This report uses the Marketing and Customer Service six-step methodology to identify and manage the risks associated with a natural gas system. The Risk Rating Criteria, Likelihood Criteria and Risk Map are shown below.

TABLE A-1 RISK RATING CRITERIA

CONSEQUENCE	MEASURE	RATING
Financial	Net Income / capital investment	**Low** – $0–$50 Million
		Medium – $51–$150 Million
		High – >$150 Million
System Reliability	Domestic Customers	**Low** – Outage affecting 50 customers for 4 hours. Not life threatening.
		Medium – Outage affecting 500 customers for up to 24 hours. Have ability to serve critical loads. Not life threatening (critical loads served).
		High – Do not have capacity to serve Manitoba load for extended period of time. Life threatening. Loss of public confidence.
	MW Generation or Interconnection capacity	**Low** – NERC level 1, in compliance with industry reliability standards.
		Medium – Loss of 2000 MW. NERC level 2 – load management procedures in effect. In compliance with industry reliability standards.
		High – Loss of >2000 MW. NERC level 3 – firm load interruption imminent or in progress; and/or non compliance with industry reliability standards.
Safety, Employee and Public	High risk accidents, severity rate, frequency rate and public contacts	**Low** – Minor injuries, in compliance with laws and standards.
		Medium – Disabling injuries, in compliance with laws and industry standards.
		High – Severe injuries and fatalities and/or non compliance with legislation and industry standards resulting in imprisonment for MH management, significant fines and loss of public trust.
Environment	Environmental Impact – air emissions, water management, spills, land and habitat disturbances, etc.	**Low** – Minor impact to environment in compliance with stakeholder expectations and laws and regulations. Ability to obtain/renew environmental licensing and operating approvals.
		Medium – Local and contained damage to environment. In compliance with stakeholder expectations and laws and regulations. Ability to obtain/renew environmental licensing operating approvals.
		High – Severe widespread and uncontained damage to environment and/or non-compliance with stakeholder expectations, laws and regulations resulting in imprisonment for Manitoba Hydro management, significant fines, loss of public trust and long term operating restrictions.

RISK ASSESSMENT METHODOLOGY (CONTINUED)

TABLE A-1 RISK RATING CRITERIA (CONTINUED)

CONSEQUENCE	MEASURE	RATING
Customer Value	Customer perception of service with regard to retail electricity rates	**Low** – No rate increase
		Medium – Annual increase of <10%
		High – Annual increase >10%
	Customer perception of service with regard to reliability and quality service	**Low** – Restoration service within 4 hours, no threat to public safety, <1.3 outages/customer/year, provision of energy related services.
		Medium – Restoration service within 24 hours with no threat to public safety. 2 outages/customer/year.
		High – Outage for extended period of time. Life threatening. Loss of public confidence.
	Customer perception of service with regard to reputation	**Low** – Local media coverage with negligible impact on stakeholders.
		Medium – A highly visible event attracting national media coverage or environmental concern; and/or a moderate negative impact on stakeholders.
		High – A highly visible event attracting international media coverage or environmental concern; and/or a significant negative impact on stakeholders such as breach of privacy, contractual obligation or environmental stewardship.

TABLE A-2 LIKELIHOOD CRITERIA

DESCRIPTOR	QUALIFIER	QUANTIFIER
Almost Certain	The event will occur on an annual basis	Once a year or more frequently
Likely	The event has occurred several times or more in a decade	Once every 3 years
Possible	The event might occur once in a decade	Once every 10 years
Unlikely	The event does occur somewhere from time to time	Once every 30 years
Rare	Have heard of something like this occurring elsewhere	Once every 100 years
Very Rare	Have never heard of this happening	Once every 1000 years

RISK ASSESSMENT METHODOLOGY (CONTINUED)

FIGURE A-1 RISK MAP

Risk Map

Consequence						
High	6B	6A	8B	8A	9B	9A
Medium	3B	3A	5B	5A	7B	7A
Low	1B	1A	2B	2A	4B	4A
	Very Rare (1 in 1000 yrs)	**Rare** (1 in 100 yrs)	**Unlikely** (1 in 30 yrs)	**Possible** (1 in 10 yrs)	**Likely** (1 in 3 yrs)	**Almost Certain** (Yearly or more)
	Likelihood					

Each project can be plotted on the Risk Map according to their associated risk rating. The Risk Map is colour-coded with red, yellow and green segments. According to the Risk Management Process the coloured segments imply the following level of consideration:

Red: The risk has become critical to business operations and requires day to day senior management attention. If not resolved quickly, it could have catastrophic impacts on the organization.

Yellow: There are or appears to be some emerging issues that need to be closely monitored and addressed. Additional action is required to bring the risk back to the established tolerance. Management has time to respond in an orderly manner.

Green: No additional action required at this time as the risk is under control and is not subject to significant change.

REFERENCE:

Appendix 4.3 pp. 40 to 57 and 60, 61 of 64

PREAMBLE TO IR (IF ANY):

QUESTION:

a) For each project included in Section 5 of Appendix 4.3:
   i. List the specific risk analysis consequence and measure from Table A1 (Appendix 4.3 page 61) that is applicable and explain why that consequence rating applies.
   ii. Provide the justification for the likelihood rating.

b) Clarify whether the risk analysis results for the projects in (a) represent the consequence and likelihood that generate the highest risk score, or whether the risk analysis results show the highest consequence and highest likelihood applicable to the project, even if the highest consequence may not be associated with the highest likelihood.

RESPONSE:

a) 5.1 Winnipeg Waverley West MP – Phase 2
   i. System Reliability High – This is a capacity driven project that directly supports new customer additions in an area of the City of Winnipeg that is developing at a faster rate than originally anticipated.
   ii. Almost Certain – The existing system has a fixed capacity and once it is reached it will not be possible to connect new customers.

   5.2 Steinbach Upgrade
   i. System Reliability High – This is a capacity driven project that directly supports new customer additions in Steinbach which is experiencing load growth at a higher rate than other areas of Manitoba.

      Customer Value High – This is also a resiliency project as it provides a second feed into Steinbach. A single gas supply leaves the community vulnerable to a single damage or line failure that could result in a large scale outage.

ii. Almost Certain – The existing system has a fixed capacity and once it is reached it will not be possible to connect new customers. In addition, remaining at one supply feed into Steinbach keeps the risk of an outage for an extended period of time

5.3 St. Andrew's Distribution Upgrade

i. System Reliability High– This is a capacity driven project that directly supports new customer additions. Large customer loads added in this area utilized the available capacity and established the requirement for the upgrade.

ii. Almost Certain – The existing system has a fixed capacity and once it is reached it will not be possible to connect new customers.

   - Note: The risk analysis for this project is incorrectly shown on page 43 of Appendix 4.3. The response is based on the corrected information of Consequence High, Likelihood Almost Certain and Risk Rating of 9A.

5.4 In-Line Inspection Projects

i. Safety, Employee and Public High – A failure of a transmission pressure pipeline could result in an immediate severe injury or fatality or indirect injuries and fatalities due to an extended natural gas outage.

   Customer Value High – The in-line inspection projects will assist in the provision of a reliable pipeline system. A transmission pressure pipeline failure could result in a large outage for an extended period of time. Customers rely on a reliable supply of natural gas for heating and commercial requirements. Information on the asset condition will also be used to assist in determining the timing for pipeline replacements.

ii. Unlikely/Rare – It is unlikely or rare for a transmission pipeline failure to occur. There are pipelines in the Centra systems that are over 60 years old. In the absence of condition information, the likelihood of failure would be considered to be increasing while the consequence always remains high.

5.5 Cathodic Rectifier Remote Monitoring Devices

i. System Reliability Medium – The objective of this project is to increase the reliability of the natural gas pipeline cathodic protection systems and improve operational efficiency through the automation of monitoring and measurement of cathodic reads.

ii. Possible – personnel will not need to travel long distances to each of the 92 cathodic rectifiers and nearly 300 checkpoints to collect the operational information. By reducing monitoring workload, it will allow the Customer Service Centres ("CSCs") around the province to redeploy staff to perform other critical work. As a result of this capital investment, the cathodic protection operating costs will be reduced. These savings will be accrued to the cathodic protection budgets of the different CSCs around the province.

5.6 GS-123 Brandon Primary Gate Station Upgrades

i. Customer Value High – This is a reliability driven project that ensures the sole gas feed to the Brandon gas distribution system continues to operate securely and safely.

ii. Possible – There have been several building and meter failures at this station within the past 10 years. To date these failures have been addressed with quick field response and interim mitigations to prevent service interruption. The station upgrades have been prioritized for capital investment considering the consequences of service interruption at this critical, upstream location feeding the network.

5.7 Portage La Prairie TP Main - Secure Gas Supply

i. Customer Value High – The river crossing for the existing transmission pressure pipeline supplying Portage La Prairie crosses in an area now known to have geotechnical instabilities. A failure would result in an outage for an extended period of time for Portage La Prairie. Two parallel pipelines supplying the river crossing do not have valves that permit independent operation of the pipelines. The addition of valves will increase system resiliency.

ii. Rare – Geotechnical monitoring of the river crossing is being performed at this time due to identified movement. The likelihood may be revised upward based on the results of this monitoring.

5.8 Distribution System Monitoring

i. Customer Value Medium – The distribution system monitoring system will provide actual system operation data that can be used to validate the system hydraulic modeling that is performed. This validation of the hydraulic model is important to provide confidence that the medium pressure distribution system is adequate to meet peak customer supply requirements and to better define when capacity driven pipeline projects are needed. The value to the customer is provided through a system with sufficient capacity while also minimizing the potential to perform pipeline capacity projects prior to their being needed.

ii. Unlikely – It is unlikely that the absence of a medium pressure monitoring system will result in a customer outage due inadequate gas supply availability.

5.9 St. Pierre TP Upgrade

i. System Reliability High – This is a capacity driven project that directly supports new customer additions.

ii. Almost Certain – The existing system has a fixed capacity and once it is reached it will not be possible to connect new customers.

5.10 Red River Letellier TP Pipeline Replacement

i. Customer Value High – Both transmission pipeline crossings are within an active slope failure zone and a large geotechnical bank failure or deep seated slope failure could easily damage both pipelines. This is why the project is rated at "high" even though there are two pipelines.

ii. Possible – Both transmission pipelines are within an active area of geotechnical instability and a leak occurred due to movement in 2015. It has been determined that further future geotechnical failures will occur. As the timing of geotechnical movement is difficult to predict a rating of possible has been applied.

5.11 Addressing Encroachment on Pipelines

i. Safety, Employee and Public High – Increasing separation from possible development to transmission pressure pipelines will assist in reducing the potential for third party damages and the consequence associated with a line failure or damage.

Customer Value High – An alternative to increasing easement width would be reduce allowable operating pressures to reduce consequence of a damage or failure. This can result in a very significant reduction in the pipeline capacity and can result in the requirement to install additional pipelines.

ii. Possible – Development in near proximity to existing pipelines is occurring.

5.12 Winnipeg HP Interconnection – Inkster Boulevard to King Edward Street

i. Customer Value High – Three major transmission pressure pipelines supply the City of Winnipeg. The high pressure main interconnection would permit the gas supply to the City of Winnipeg to be maintained with the loss of supply from any one of the three major transmission pressure pipelines.

ii. Possible – A damage or equipment failure to the transmission pipelines and facilities supplying the City of Winnipeg is possible at any time of the year.

b) The risk analysis results generate the highest risk score for the project.

C55-CIJ-PROJ

CAPITAL INVESTMENT JUSTIFICATION
FOR

2017-04049 PR 201/Red River Transmission Pressure Pipeline Replacements

Investment Type (Project)

BUDGET:	$1,604
CONTRIBUTIONS:	$0
NET BUDGET:	$1,604
	(values listed above are in thousands of dollars)
CORPORATE VALUE FRAMEWORK SCORE:	**Value:** 9,020 **Value/$K:** 6.05

DATE PREPARED: 2018/03/29

EC/MHEB APPROVAL MINUTE & DATE:

APPROVER	APPROVER TITLE	COMMENT	ORGANIZATIONAL UNIT	APPROVAL DATE
Steele, Chuck	DIRECTOR OF ENGINEERING & CONSTRUCTION		Director - Engineering & Construction	2018/07/11
STARODUB, TIM	GAS ENGINEERING & CONSTRUCTION DEPT MGR		Gas Engineering & Construction	2018/05/23
LAWRIE, SARAH	CHARTERED PROFESSIONAL ACCOUNTANT		Financial Advisory Services	2018/05/17
Greaves, Andrew	GAS DESIGN ENGINEER - CITY OF WINNIPEG		Gas Engineering & Construction	2018/02/16
Greaves, Andrew	GAS DESIGN ENGINEER - CITY OF WINNIPEG	On behalf Of Blazek, Greg (gblazek).	Gas Engineering & Construction	2018/02/16

CAPITAL INVESTMENT MASTER DATA

RESPONSIBLE OPERATING/CORPORATE GROUP:	Marketing & Customer Service	**REQUESTING OPERATING/CORPORATE GROUP:**	Marketing & Customer Service
RESPONSIBLE DIVISION:	Engineering & Construction	**REQUESTING DIVISION:**	Engineering & Construction
RESPONSIBLE DEPARTMENT:	Gas Engineering & Construction	**ISD: (YYYY/MM/DD)**	2019/12/31
I.M. NODE NUMBER:	2.2.40.15.04.22	**W.B.S. NUMBERs:**	P:28722
C55 INVESTMENT CODE:	14552		
SAP PROJECT TYPE:	24 - BOC-VP & Management	**C55 INVESTMENT SUB-CATEGORY**:	Single WBS
CORPORATE INVESTMENT CATEGORIES:	(Level 1) C3 / Sustainment (Level 2) CN / System Efficiency		

CONTACTS

PREPARED BY:	Greaves, Andrew GAS DESIGN ENGINEER - CITY OF WINNIPEG 52955	**REQUESTOR:**	N/A
PROJECT MANAGER:	Greaves, Andrew GAS DESIGN ENGINEER - CITY OF WINNIPEG 52955		

MANITOBA HYDRO
CAPITAL INVESTMENT JUSTIFICATION
2017-04049 PR 201/RED RIVER TP REPLACEMENT

RECOMMENDATION

Abandon two parallel, geotechnically unstable, pipeline crossings at a location under the Red River near Letellier, and install new crossings at a lower risk location to improve the reliability of the South Loop Transmission network, and reduce safety, compliance and environmental risks associated with the existing location.

SCOPE

Engage consulting and construction services to:

- Evaluate potential drill locations and select a location that will reduce or eliminate safety, compliance and environmental risks
- Complete a geotechnical assessment of the proposed area
- Design new pipeline crossings and provide construction drawings
- Complete land acquisition, environmental and external approvals as required
- Install new pipeline crossings
- Install valve control points to improve future operational flexibility of the transmission network (if required)

Existing corporate resources and agreements will be used to:

- Procure long lead materials

BACKGROUND

The South Loop Transmission network is fed from two primary natural gas stations and has two directional feeds. There are two (Nominal Pipe Size 4) transmission pressure pipelines in the South Loop Transmission network that cross the Red River near Provincial Road 201 at Roseau River. This South Loop provides natural gas service to communities such as Dominion City, Letellier, Winkler, Morden, Carman, Altona and Emerson.

Slope instability along the Red River near Provincial Road 201 at Roseau River has previously caused a leak on one of the crossing transmission lines. Manitoba Infrastructure relocated a bridge in the area as a result of these slope failures, and has stabilized the riverbanks north of the current transmission pressure pipe crossing. Geotechnical reports indicate that continued slope failures are likely in the area and any new drilling under the Red River would involve horizontal directional drilling through bedrock.

Land in the area is held by private landowners and Roseau River First Nation, with crossings by Municipal and Manitoba Infrastructure road right of ways.

JUSTIFICATION – BUSINESS CASE ANALYSIS (SUMMARY):

JUSTIFICATION

Relocating the Red River crossing to a more stable area eliminates the risks discussed below.

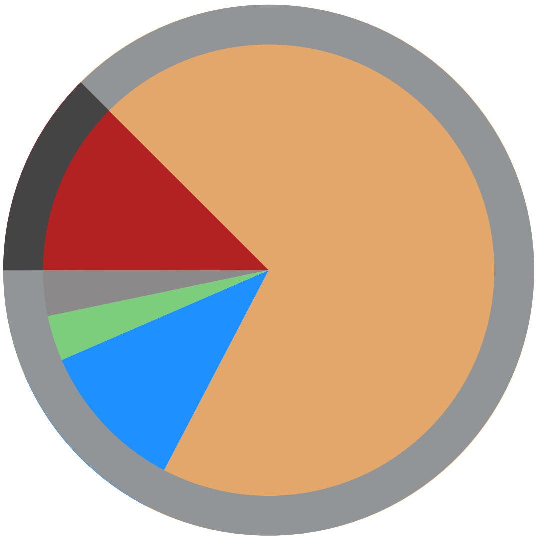
The South Loop Transmission network has two directional feeds from separate portions of the Transcanada Pipeline; therefore, in the event of the river crossing portion of the pipeline experiencing interrupted flow, the network could still be operated to provide natural gas service to communities on both sides of the Red River; however, only in a single feed configuration. All redundancy in this network would be eliminated, the operational flexibility and reliability of transmission pipelines in the area would be severely limited, and any further incidents on the South Loop Transmission Network could potentially result in a prolonged outage for some customers until flow under the Red River was restored.

Pipelines buried in a slope failure zone could potentially become shallow or exposed, failing to comply with minimum depth of cover requirements set by the Canadian Standards Association (CSA Z662). Manitoba Hydro must comply with this code by order of the Public Utilities Board.

Significant slope failures could damage pipelines, causing a gas leak. Although the leaked gas would likely escape into the atmosphere and not accumulate (i.e. short term event, confined to a localized area with a moderate environmental impact), the Red River is a navigable waterway and thus, an environmentally sensitive area.

The unplanned release of natural gas can also be hazardous, causing property damage to surrounding buildings, or injury or loss of life to people in the surrounding area. Although gas is likely to vent into the atmosphere at this specific location, gas that has leaked cannot be directly controlled and its path cannot be predicted with certainty. Possible gas migration and accumulation can occur under certain conditions, such as frozen ground or paved surfaces.

CORPORATE VALUE FRAMEWORK



Value Measure	Value Points	% of Value
Gas Distribution Reliability Benefit	8,429	70.24%
Safety Risk	1,301	10.84%
Environmental Risk	390	3.25%
Compliance Risk	390	3.25%
Total Cost	-1,490	12.42%
Total Value	**9,020**	
Value/$K	**6.05**	

ANALYSIS OF ALTERNATIVES:

ECONOMIC ANALYSIS		
Discount Rate	**For current corporate rates see P911 6.25%**	

Active Option	**NPV Benefits/(Costs)**	**CVF Score**	**Value/$K**
Preferred		9,020	6.05

Other Alternatives	**NPV Benefits/(Costs)**	**CVF Score**	**Value/$K**
None.			

INVESTMENT RISK ANALYSIS

The area immediately surrounding the existing crossing does not allow for easy relocation. The current budget includes a conservative rerouting of the pipelines to a location approximately a mile away. Further analysis may indicate that an alternative location is preferable, which may require more or less pipe to be installed.

Horizontal directional drilling has inherent risks, especially under a larger body of water. Bedrock drilling, increased pullback forces, and longer drill lengths all add to the complexity of the project. Multiple drill attempts are sometimes required on crossings, with failed attempts resulting in higher costs.

ESTIMATED COST FLOW

The annual projected cost flows are as follows (in thousands of dollars):

Fiscal Year	Budget	Contributions	Net Budget
Prev. Actuals	$0	$0	$0
2017/2018	$0	$0	$0
2018/2019	$263	$0	$263
2019/2020	$1,341	$0	$1,341
2020/2021	$0	$0	$0
2021/2022	$0	$0	$0
2022/2023+	$0	$0	$0
Total	**$1,604**	**$0**	**$1,604**

IMPACT ON O&A COSTS

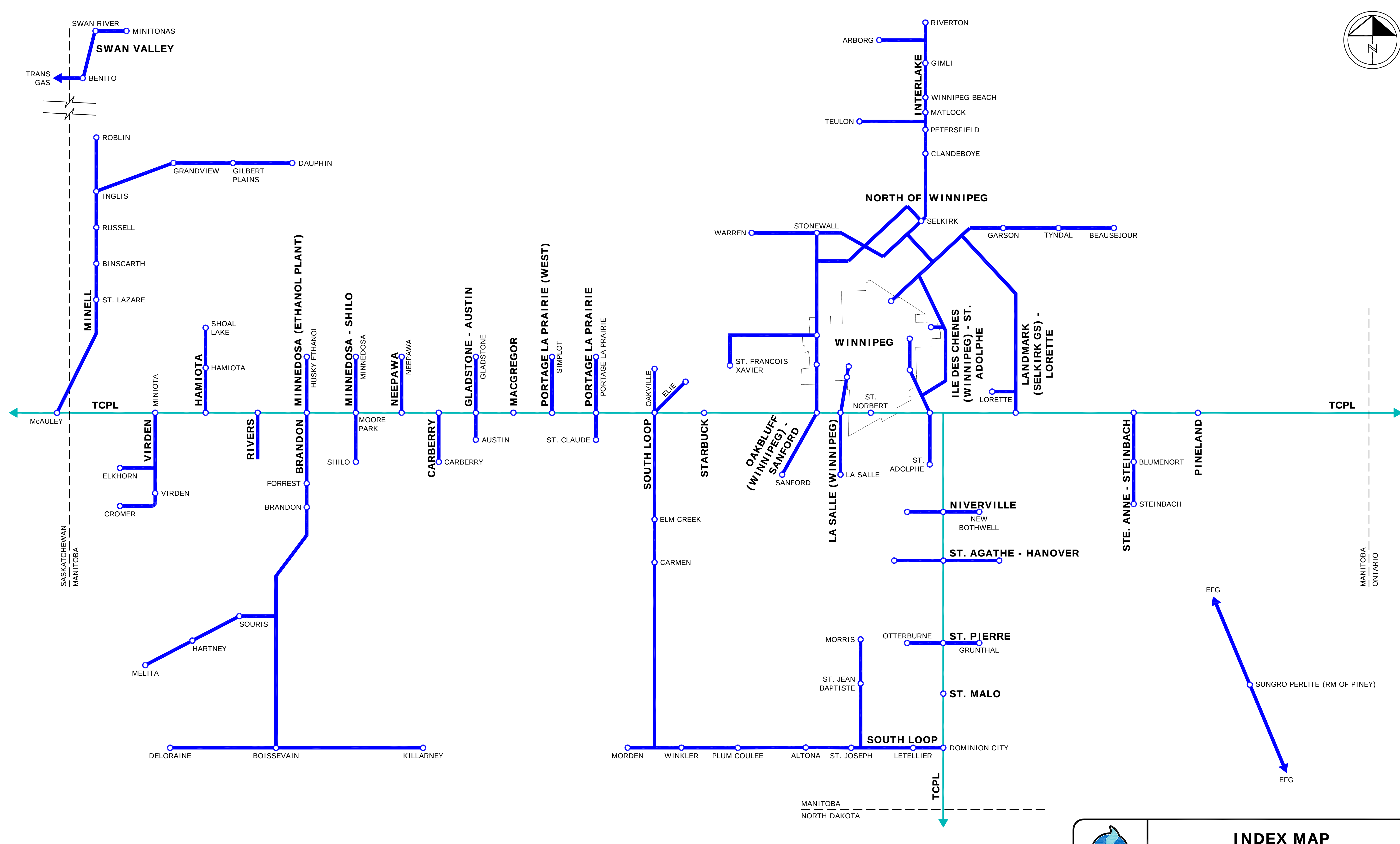
Minimal.

PROPOSED SCHEDULE
March 2019 – Complete engineering report (evaluation of chosen alternative) and geotechnical analysis December 2019 – Complete construction

RELATED INVESTMENTS
None.

OTHER ALTERNATIVES CONSIDERED
Leaving the at risk pipelines in place until a failure occurs. This is considered unacceptable as it compromises Manitoba Hydro's transmission gas system, puts the corporation at risk of not complying with governing standards and codes, and poses environmental and safety risks.

REFERENCE DOCUMENTS
None.



NO.	DATE	REVISIONS	BY	CKD.	APP.
1	2014-05	ADDED SWAN VALLEY	C.A.		
2	2017-04	UPDATED MAP	C.A.	K.M.	K.M.

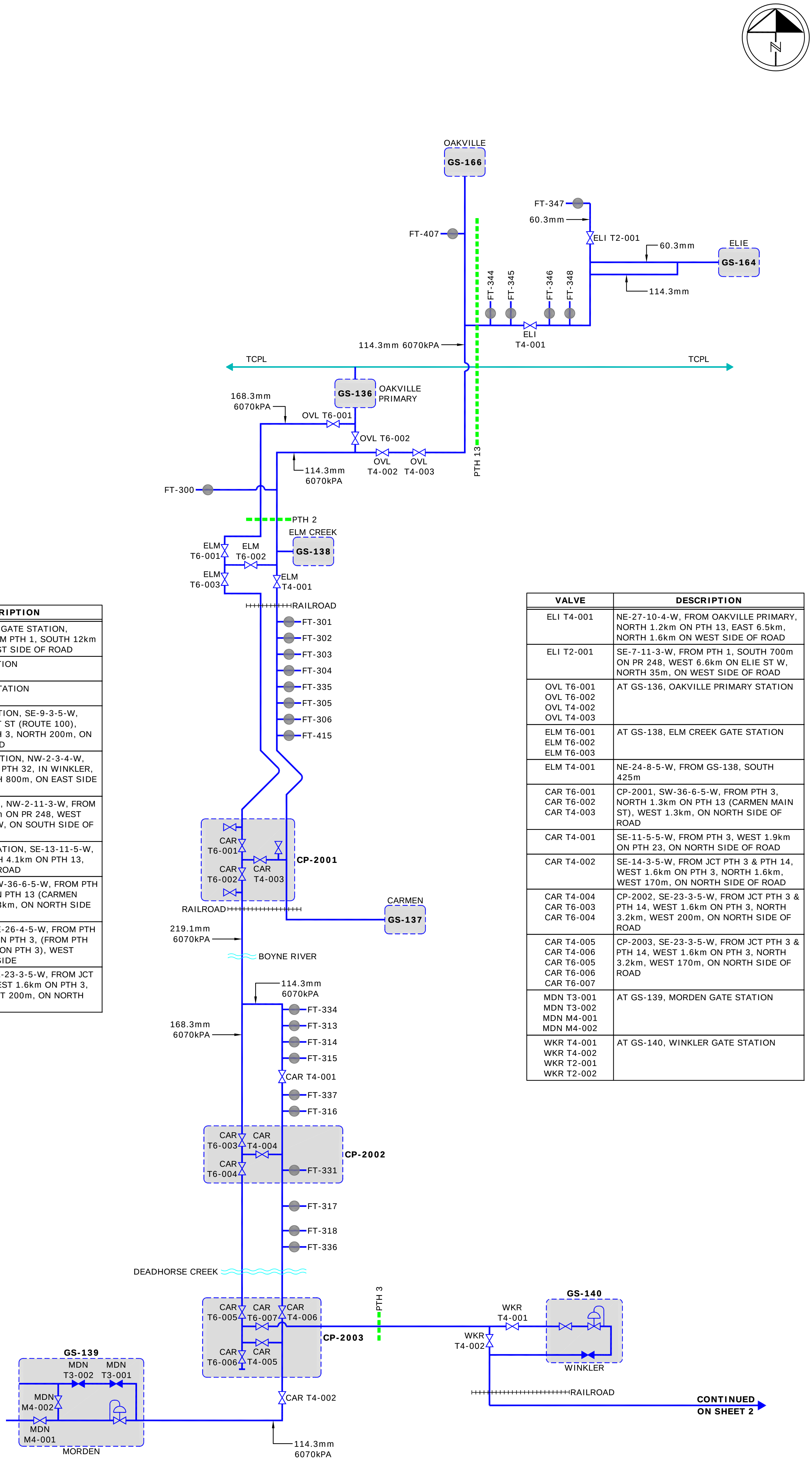
INDEX MAP

GAS PIPELINE SCHEMATIC

DRAWN	ORIG. DATE	DRAWING NO.	SHT	REV
C.A.	2012-01	1-T0000-GB-91110-0001	0001 OF 1	02

LEGEND

- GATE STATION
- VALVE (NORMALLY OPEN)
- VALVE (NORMALLY CLOSED)
- PRESSURE CONTROL VALVE
- FARM TAP
- TRANSMISSION LINE
- TRANS CANADA PIPELINE
- WATER CROSSING
- ROAD
- RAILROAD



GATE STATION	DESCRIPTION
GS-136	OAKVILLE PRIMARY GATE STATION, SE-24-10-5-W, FROM PTH 1, SOUTH 12km ON PTH 13, ON WEST SIDE OF ROAD
GS-137	CARMEN GATE STATION
GS-138	ELM CREEK GATE STATION
GS-139	MORDEN GATE STATION, SE-9-3-5-W, FROM MORDEN, 1ST ST (ROUTE 100), EAST 1.6km ON PTH 3, NORTH 200m, ON WEST SIDE OF ROAD
GS-140	WINKLER GATE STATION, NW-2-3-4-W, FROM JCT PTH 14 & PTH 32, IN WINKLER, EAST 1.6km, SOUTH 800m, ON EAST SIDE OF ROAD
GS-164	ELIE GATE STATION, NW-2-11-3-W, FROM PTH 1, SOUTH 700m ON PR 248, WEST 1.6km ON ELIE ST W, ON SOUTH SIDE OF ROAD
GS-166	OAKVILLE GATE STATION, SE-13-11-5-W, FROM PTH 1, SOUTH 4.1km ON PTH 13, ON WEST SIDE OF ROAD
CP-2001	VALVE STATION, SW-36-6-5-W, FROM PTH 3, NORTH 1.3km ON PTH 13 (CARMEN MAIN ST), WEST 1.3km, ON NORTH SIDE OF ROAD
CP-2002	VALVE STATION, NE-26-4-5-W, FROM PTH 23, SOUTH 3.2km ON PTH 3, (FROM PTH 14, NORTH 16.4km ON PTH 3), WEST 1.9km, ON SOUTH SIDE
CP-2003	VALVE STATION, SE-23-3-5-W, FROM JCT PTH 3 & PTH 14, WEST 1.6km ON PTH 3, NORTH 3.2km, WEST 200m, ON NORTH SIDE OF ROAD

VALVE	DESCRIPTION
ELI T4-001	NE-27-10-4-W, FROM OAKVILLE PRIMARY, NORTH 1.2km ON PTH 13, EAST 6.5km, NORTH 1.6km ON WEST SIDE OF ROAD
ELI T2-001	SE-7-11-3-W, FROM PTH 1, SOUTH 700m ON PR 248, WEST 6.6km ON ELIE ST W, NORTH 35m, ON WEST SIDE OF ROAD
OVL T6-001 OVL T6-002 OVL T4-002 OVL T4-003	AT GS-136, OAKVILLE PRIMARY STATION
ELM T6-001 ELM T6-002 ELM T6-003	AT GS-138, ELM CREEK GATE STATION
ELM T4-001	NE-24-8-5-W, FROM GS-138, SOUTH 425m
CAR T6-001 CAR T6-002 CAR T4-003	CP-2001, SW-36-6-5-W, FROM PTH 3, NORTH 1.3km ON PTH 13 (CARMEN MAIN ST), WEST 1.3km, ON NORTH SIDE OF ROAD
CAR T4-001	SE-11-5-5-W, FROM PTH 3, WEST 1.9km ON PTH 23, ON NORTH SIDE OF ROAD
CAR T4-002	SE-14-3-5-W, FROM JCT PTH 3 & PTH 14, WEST 1.6km ON PTH 3, NORTH 1.6km, WEST 170m, ON NORTH SIDE OF ROAD
CAR T4-004 CAR T6-003 CAR T6-004	CP-2002, SE-23-3-5-W, FROM JCT PTH 3 & PTH 14, WEST 1.6km ON PTH 3, NORTH 3.2km, WEST 200m, ON NORTH SIDE OF ROAD
CAR T4-005 CAR T4-006 CAR T6-005 CAR T6-006 CAR T6-007	CP-2003, SE-23-3-5-W, FROM JCT PTH 3 & PTH 14, WEST 1.6km ON PTH 3, NORTH 3.2km, WEST 170m, ON NORTH SIDE OF ROAD
MDN T3-001 MDN T3-002 MDN M4-001 MDN M4-002	AT GS-139, MORDEN GATE STATION
WKR T4-001 WKR T4-002 WKR T2-001 WKR T2-002	AT GS-140, WINKLER GATE STATION

NO.	DATE	REVISIONS	BY	CKD.	APP.
1	2017-09	REVISED SCHEMATIC	C.A.	L.G.	L.G.

GAS PIPELINE SCHEMATICS

SOUTH LOOP

GAS PIPELINE SCHEMATIC

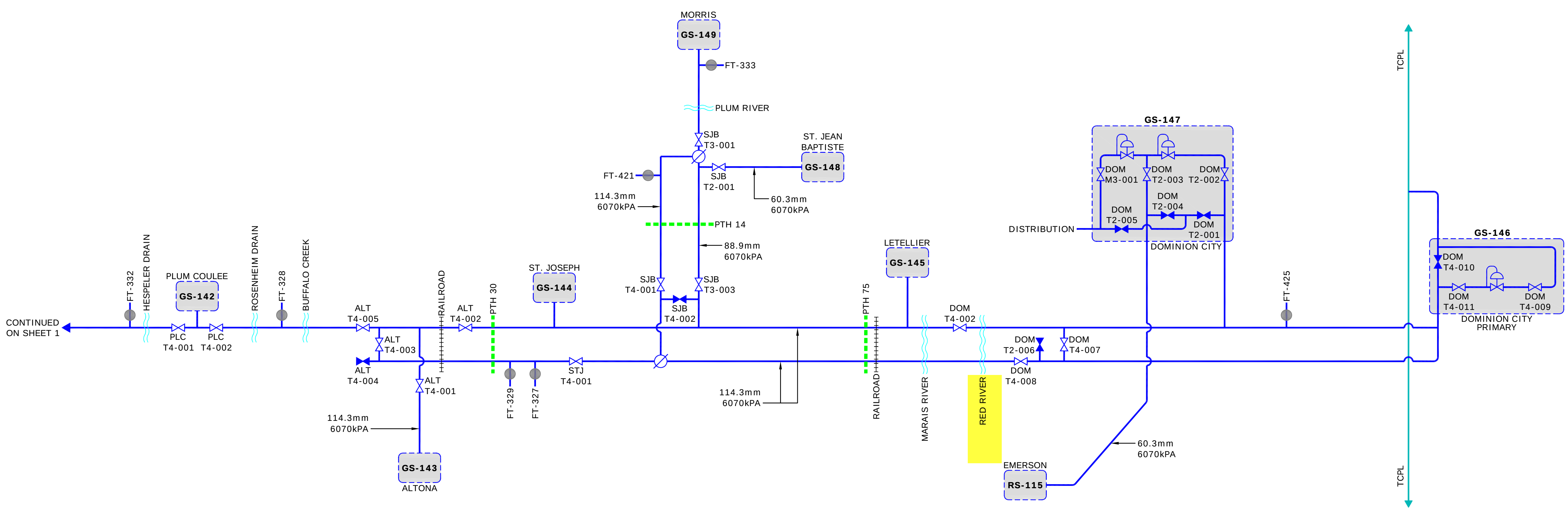
DRAWN: C.A. ORIG. DATE: 2012-01 DRAWING NO.: 1-T0000-GB-91110-0019 SHT: 0001 OF 2 REV: 01

LEGEND

- GATE STATION
- VALVE (NORMALLY OPEN)
- VALVE (NORMALLY CLOSED)
- STOPPLE
- PRESSURE CONTROL VALVE
- FARM TAP
- TRANSMISSION LINE
- TRANS CANADA PIPELINE
- WATER CROSSING
- ROAD
- RAILROAD

GATE STATION	DESCRIPTION
GS-142	PLUM COULEE GATE STATION, SE-2-3-3-W, FROM PTH 13, SOUTH 550m ON PR 306, ON WEST SIDE OF ROAD
GS-143	ALTONA GATE STATION, NW-8-2-1-W, FROM PTH 30, WEST 1.3km ON PR 201 (CENTRE AVE), NORTH 800m ON 5 ST NW, EAST 200m ON 10 AVE NW, ON NORTH SIDE OF ROAD
GS-144	ST. JOSEPH GATE STATION, NE-16-2-1-E, FROM PTH 75, WEST 6.1km ON PR 201, SOUTH 200m, ON WEST SIDE OF ROAD
GS-145	LETELLIER GATE STATION, SW-20-2-2-E, FROM PTH 75, EAST 470m ON PR 201, ON NORTH SIDE OF ROAD
GS-146	DOMINION CITY PRIMARY GATE STATION, NW-18-2-4-E, FROM PTH 75, EAST 18.3km ON PR 201, ON SOUTH SIDE OF ROAD
GS-147	DOMINION CITY GATE STATION, NE-17-2-3-E
GS-148	ST. JEAN BAPTISTE GATE STATION, FROM CARON ST IN ST. JEAN BAPTISTE, WEST 370m ON CENTRE AVE, SOUTH 120m ON THIRD ST, ON EAST SIDE OF STREET
GS-149	MORRIS GATE STATION, NW-34-4-1-E, FROM PTH 75, WEST 1.1km ON PTH 23 (BOYNE AVE), SOUTH 430m ON 5 AVE, ON WEST SIDE OF ROAD
RS-115	EMERSON

VALVE	DESCRIPTION
ALT T4-001 ALT T4-003 ALT T4-004 ALT T4-005	NE-17-2-1-W, FROM PTH 30, WEST 750m ON PR 201, SOUTH 200m (OFF ROAD) ON WEST SIDE OF RAIL TRACKS
ALT T4-002	NE-17-2-1-W, FROM PTH 30, WEST 750m ON PR 201, SOUTH 200m (OFF ROAD) ON EAST SIDE OF RAIL TRACKS
DOM T2-001 DOM T2-002 DOM T2-003 DOM T2-004 DOM T2-005 DOM M3-001	AT GS-147, DOMINION CITY GATE STATION
DOM T2-006 DOM T4-007 DOM T4-008	NE-14-2-2-E, FROM PTH 75, EAST 6.8km ON PR 201, SOUTH 170m, ON WEST SIDE
DOM T4-002	FROM PTH 75, EAST 3.4km ON PR 201, SOUTH 220m, EAST 130m (OFF ROAD)
DOM T4-009 DOM T4-010 DOM T4-011	AT GS-146, DOMINION CITY PRIMARY STATION
PLC T4-001 PLC T4-002	AT GS-142, PLUM COULEE GATE STATION
SJB T2-001 SJB T3-001	NW-35-3-1-E, FROM JCT PTH 75 & PR 217, NORTH 940m ON PTH 75, WEST 520m (OFF ROAD)
SJB T3-003 SJB T4-001 SJB T4-002	NW-14-2-1-E, FROM PTH 75, WEST 3.7km ON PR 201, ON SOUTH SIDE OF ROAD
STJ T4-001	AT GS-144, ST. JOSEPH GATE STATION



NO.	DATE	REVISIONS	BY	CKD.	APP.
1	2017-04	UPDATED SCHEMATIC	C.A.	K.M.	K.M.
2	2017-09	UPDATED SCHEMATIC	C.A.	L.G.	L.G.

GAS PIPELINE SCHEMATICS

SOUTH LOOP
GAS PIPELINE SCHEMATIC

DRAWN	ORIG. DATE	DRAWING NO.	SHT	REV
C.A.	2012-01	1-T0000-GB-91110-0019	0002 OF 2	02

REFERENCE:

Appendix 4.3 p. 54 of 64, Appendix 6.1 p. 26 of 27.

PREAMBLE TO IR (IF ANY):

In 2015, Centra experienced a pipeline leak at the NPS 4 transmission crossing under the Red River between Letellier and Dominion City. This leak event, which was caused by geotechnical instability of the river bank, was repaired without interruption of service to customers.

QUESTION:

a) Explain why the risk consequence for the Red River at Letellier TP Pipeline Replacement project is rated at "high" when there exists a redundant gas supply feed at this location and a previous failure of this pipeline was rectified without loss of service to customers.
b) Explain how long has the geotechnical monitoring been in place at the existing or proposed crossing locations and how Centra has confidence that the new crossing location is geotechnically stable.

RESPONSE:

a) Both pipelines were within a geotechnical bank slope failure which caused a leak on only one of the pipelines. Both pipelines are still within an active slope failure zone and a large geotechnical bank failure or deep seated slope failure could damage both pipelines. This is why the project is rated at "high" even though there are two pipelines.

b) Periodic geotechnical monitoring has been in place since the leak occurred in 2015. A new crossing location has not yet been finalized. A geotechnical evaluation will define the extent of the slope failure zone and provide recommendations for location of the new crossing.

Table 1: Risk Estimation Top 100 Segments

Identification				Attributes						Scores						
Rank	Id	Facility Code	Pipeline Sytem / Hydraulic Segment	Energized Date	Pipe Type	Pipe Size	Network MOP (kPa)	Length (m)	EHI Score	Corrosion Score	Nat. Forces Score	Const. /Mat. Defect Score	Freq. Score	Consequence Score	Risk Score
1	35971019	T3212.005	Winnipeg Interlake / Iles Des Chenes Line	1/1/1969	Stl	323.9	4830	236.2	2.9	2.3	3.6	0.5	2.7	5.6	14.9
2	37763138	T3001.003	Winnipeg 1 / LaSalle TP	1/1/1955	Stl	323.9	4830	1578.4	2.8	2.8	1.3	0.5	2.5	5.6	14.0
3	104529414	T3001.001c	Winnipeg 1 / LaSalle TP	1/1/1900	Stl	323.9	4830	560.6	2.8	2.8	1.3	0.5	2.5	5.6	14.0
4	35356274	D3007	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	365.8	1.7	6.6	0.7	2.9	3.3	4.0	13.4
5	36520683	T3201.002	Winnipeg Interlake / Iles Des Chenes Line	1/1/1962	Stl	406.4	4830	94.5	1.3	2.4	3.1	0.5	1.9	6.8	13.0
6	34297408	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	262.1	1.7	6.6	0.7	0.5	3.2	4.0	13.0
7	6882203	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	114.3	420	217.5	1.7	5.8	0.7	5.3	3.2	4.0	12.7
8	35353653	D3007	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	776.9	1.7	5.8	0.7	5.3	3.2	4.0	12.7
9	27316244	D3205	Winnipeg Interlake / Winnipeg E	1/1/1900	Stl	60.3	420	343.4	2.8	4.8	0.7	10.0	3.5	3.6	12.6
10	36026367	H3015	Winnipeg 1 / Winnipeg HP	1/1/1900	Stl	355.6	1720	1737.5	1.7	3.8	0.7	0.5	2.3	5.6	12.6
11	34296797	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	219.1	420	174.8	1.7	6.3	0.7	0.5	3.2	4.0	12.6
12	87290129	T3204.001	Winnipeg Interlake / Iles Des Chenes Line	1/1/1962	Stl	406.4	4830	1978.2	1.7	2.4	1.3	0.5	1.8	6.8	12.5
13	95620329	T3202.001b	Winnipeg Interlake / Iles Des Chenes Line	1/1/1900	Stl	406.4	4830	66.4	1.3	2.8	1.3	0.5	1.8	6.8	12.3
14	95620371	T3203.001a	Winnipeg Interlake / Iles Des Chenes Line	1/1/1900	Stl	406.4	4830	617.1	1.3	2.8	1.3	0.5	1.8	6.8	12.3
15	6881748	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	72.1	1.7	5.8	0.7	2.9	3.1	4.0	12.3
16	26702754	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	100.7	1.7	5.8	0.7	2.9	3.1	4.0	12.3
17	34297827	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	112.7	1.7	5.8	0.7	2.9	3.1	4.0	12.3
18	36221112	D3007	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	439.3	1.7	5.8	0.7	2.9	3.1	4.0	12.3
19	90045354	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	163	1.7	5.8	0.7	2.9	3.1	4.0	12.3
20	90750631	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	114.3	420	137.6	1.7	5.8	0.7	2.9	3.1	4.0	12.3
21	35602627	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	219.1	420	622.6	2.8	4.6	0.7	0.5	3.0	4.0	12.2
22	89494551	T3201.010a	Winnipeg Interlake / Iles Des Chenes Line	1/1/1900	Stl	406.4	4830	704.1	1.3	2.8	1.3	0.5	1.8	6.8	12.2
23	89494596	T3201.008a	Winnipeg Interlake / Iles Des Chenes Line	1/1/1900	Stl	406.4	4830	6.8	1.3	2.8	1.3	0.5	1.8	6.8	12.2
24	8044664	D2701	Rosser / Winnipeg NW	1/1/1900	Stl	60.3	420	971.9	1.7	7.8	0.7	2.9	3.8	3.2	12.1
25	34280001	D3002	Winnipeg 1 / Winnipeg W	1/1/1900	Stl	60.3	420	341.5	1.7	7.8	0.7	2.9	3.8	3.2	12.1
26	6881548	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	114.3	420	426.7	1.7	5.8	0.7	0.5	3.0	4.0	11.9
27	6881634	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	189.6	1.7	5.8	0.7	0.5	3.0	4.0	11.9
28	6881646	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	16.5	1.7	5.8	0.7	0.5	3.0	4.0	11.9
29	6881656	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	72.8	1.7	5.8	0.7	0.5	3.0	4.0	11.9
30	6881848	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	46.3	1.7	5.8	0.7	0.5	3.0	4.0	11.9
31	6881858	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	97.2	1.7	5.8	0.7	0.5	3.0	4.0	11.9
32	6881918	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	114.3	420	306.9	1.7	5.8	0.7	0.5	3.0	4.0	11.9
33	6882056	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	42.6	1.7	5.8	0.7	0.5	3.0	4.0	11.9
34	6882128	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	91.3	1.7	5.8	0.7	0.5	3.0	4.0	11.9
35	6882138	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	32	1.7	5.8	0.7	0.5	3.0	4.0	11.9
36	6882156	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	86.4	1.7	5.8	0.7	0.5	3.0	4.0	11.9

Identification				Attributes						Scores						
Rank	Id	Facility Code	Pipeline Sytem / Hydraulic Segment	Energized Date	Pipe Type	Pipe Size	Network MOP (kPa)	Length (m)	EHI Score	Corrosion Score	Nat. Forces Score	Const. /Mat. Defect Score	Freq. Score	Consequence Score	Risk Score
37	6882249	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	42.2	420	7	1.7	5.8	0.7	0.5	3.0	4.0	11.9
38	6882267	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	114.3	420	81.7	1.7	5.8	0.7	0.5	3.0	4.0	11.9
39	6882343	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	114.3	420	34.6	1.7	5.8	0.7	0.5	3.0	4.0	11.9
40	6882349	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	114.3	420	34.1	1.7	5.8	0.7	0.5	3.0	4.0	11.9
41	6882362	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	24.4	1.7	5.8	0.7	0.5	3.0	4.0	11.9
42	6882390	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	79	1.7	5.8	0.7	0.5	3.0	4.0	11.9
43	6882400	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	45.4	1.7	5.8	0.7	0.5	3.0	4.0	11.9
44	10143151	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	103.9	1.7	5.8	0.7	0.5	3.0	4.0	11.9
45	26702715	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	4.5	1.7	5.8	0.7	0.5	3.0	4.0	11.9
46	34297322	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	146.1	1.7	5.8	0.7	0.5	3.0	4.0	11.9
47	34297358	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	58.8	1.7	5.8	0.7	0.5	3.0	4.0	11.9
48	34297771	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	113.3	1.7	5.8	0.7	0.5	3.0	4.0	11.9
49	34318463	D2701	Rosser / Winnipeg NW	1/1/1900	Stl	60.3	420	23.1	1.7	5.8	0.7	0.5	3.0	4.0	11.9
50	34318472	D2701	Rosser / Winnipeg NW	1/1/1900	Stl	60.3	420	37.4	1.7	5.8	0.7	0.5	3.0	4.0	11.9
51	34318487	D2701	Rosser / Winnipeg NW	1/1/1900	Stl	60.3	420	27	1.7	5.8	0.7	0.5	3.0	4.0	11.9
52	34318493	D2701	Rosser / Winnipeg NW	1/1/1900	Stl	60.3	420	4.1	1.7	5.8	0.7	0.5	3.0	4.0	11.9
53	34318499	D2701	Rosser / Winnipeg NW	1/1/1900	Stl	60.3	420	13.4	1.7	5.8	0.7	0.5	3.0	4.0	11.9
54	34318523	D2701	Rosser / Winnipeg NW	1/1/1900	Stl	60.3	420	60.3	1.7	5.8	0.7	0.5	3.0	4.0	11.9
55	34318541	D2701	Rosser / Winnipeg NW	1/1/1900	Stl	60.3	420	17.4	1.7	5.8	0.7	0.5	3.0	4.0	11.9
56	34318547	D2701	Rosser / Winnipeg NW	1/1/1900	Stl	60.3	420	17.6	1.7	5.8	0.7	0.5	3.0	4.0	11.9
57	34318556	D2701	Rosser / Winnipeg NW	1/1/1900	Stl	60.3	420	28.3	1.7	5.8	0.7	0.5	3.0	4.0	11.9
58	35355468	D3007	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	378.9	1.7	5.8	0.7	0.5	3.0	4.0	11.9
59	37148380	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	492.3	1.7	5.8	0.7	0.5	3.0	4.0	11.9
60	40870865	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	219.1	420	37.1	1.7	5.8	0.7	0.5	3.0	4.0	11.9
61	79559332	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	227.3	1.7	5.8	0.7	0.5	3.0	4.0	11.9
62	90045274	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	32.5	1.7	5.8	0.7	0.5	3.0	4.0	11.9
63	90750650	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	219.1	420	181.9	1.7	5.8	0.7	0.5	3.0	4.0	11.9
64	90750719	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	114.3	420	5.6	1.7	5.8	0.7	0.5	3.0	4.0	11.9
65	98617849	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	74.7	1.7	5.8	0.7	0.5	3.0	4.0	11.9
66	37687685	D3103	Winnipeg 2 / Winnipeg SW	1/1/1900	Stl	60.3	420	112.7	1.7	7.8	0.7	0.5	3.7	3.2	11.8
67	96607077	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	2	1.6	5.9	0.8	0.5	3.0	4.0	11.8
68	36520878	T3201.003	Winnipeg Interlake / Iles Des Chenes Line	1/1/1962	Stl	406.4	4830	1181.2	1.3	2.4	1.9	0.5	1.7	6.8	11.8
69	35785360	H3015	Winnipeg 1 / Winnipeg HP	1/1/1900	Stl	355.6	1720	794.3	1.7	3.8	0.7	0.5	2.3	5.2	11.7
70	36496328	H2701	Rosser / Winnipeg HP	1/1/1900	Stl	406.4	1720	137.9	1.7	3.8	0.7	0.5	2.3	5.2	11.7
71	89955000	H3015	Winnipeg 1 / Winnipeg HP	1/1/1900	Stl	355.6	1720	275.2	1.7	3.8	0.7	0.5	2.3	5.2	11.7
72	89976949	H3042	Winnipeg 1 / Winnipeg HP	1/1/1900	Stl	323.9	1720	16.7	1.7	3.8	0.7	0.5	2.3	5.2	11.7

Identification				Attributes					Scores						
Rank	Id	Facility Code	Pipeline Sytem / Hydraulic Segment	Energized Date	Pipe Type	Pipe Size	Network MOP (kPa)	Length (m)	EHI Score	Corrosion Score	Nat. Forces Score	Const. /Mat. Defect Score	Freq. Score	Consequence Score	Risk Score
73	35374179	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	114.3	420	447.5	1.7	4.8	0.7	7.6	2.9	4.0	11.6
74	36221151	D3007	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	652.8	1.7	4.8	0.7	7.6	2.9	4.0	11.6
75	103520107	T3001.001f	Winnipeg 1 / LaSalle TP	10/1/2013	Stl	323.9	6210	923.6	2.8	0.7	1.3	0.0	1.7	6.8	11.6
76	35353252	D3007	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	396.4	1.7	5.6	0.7	0.5	2.9	4.0	11.5
77	35373783	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	219.1	420	530.2	1.7	5.6	0.7	0.5	2.9	4.0	11.5
78	33263466	D3005	Winnipe 1 / Winnipeg W	1/1/1900	Stl	60.3	420	590	2.8	5.8	0.7	2.9	3.6	3.2	11.5
79	34786531	D2704	Rosser / Winnipeg NW	1/1/1900	Stl	60.3	420	713.3	1.7	5.8	0.7	5.3	3.2	3.6	11.4
80	6882370	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	18.9	1.4	5.8	0.7	0.5	2.8	4.0	11.4
81	35784733	H3042	Winnipeg 1 / Winnipeg HP	1/1/1900	Stl	323.9	1720	745.5	1.7	3.8	1.5	0.5	2.4	4.8	11.4
82	34278001	D3003	Winnipeg 1 / Winnipeg W	1/1/1900	Stl	60.3	420	366	1.7	8.8	0.7	0.5	4.1	2.8	11.4
83	36520695	T3202.002	Winnipeg Interlake / Iles Des Chenes Line	1/1/1962	Stl	406.4	4830	1075.8	1.3	2.4	1.3	0.5	1.7	6.8	11.3
84	47364061	T3202.001	Winnipeg Interlake / Iles Des Chenes Line	1/1/1962	Stl	406.4	4830	179.4	1.3	2.4	1.3	0.5	1.7	6.8	11.3
85	47364118	T3203.004	Winnipeg Interlake / Iles Des Chenes Line	1/1/1962	Stl	406.4	4830	2562.8	1.3	2.4	1.3	0.5	1.7	6.8	11.3
86	62898549	T3203.003	Winnipeg Interlake / Iles Des Chenes Line	1/1/1962	Stl	406.4	4830	765.9	1.3	2.4	1.3	0.5	1.7	6.8	11.3
87	62898559	T3203.002	Winnipeg Interlake / Iles Des Chenes Line	1/1/1962	Stl	406.4	4830	2107.5	1.3	2.4	1.3	0.5	1.7	6.8	11.3
88	87290089	T3202.003	Winnipeg Interlake / Iles Des Chenes Line	1/1/1962	Stl	406.4	4830	122	1.3	2.4	1.3	0.5	1.7	6.8	11.3
89	6881668	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	15.5	1.3	5.8	0.7	0.5	2.8	4.0	11.2
90	6881678	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	60.3	420	22.3	1.3	5.8	0.7	0.5	2.8	4.0	11.2
91	61483631	T3201.005	Winnipeg Interlake / Iles Des Chenes Line	1/1/1962	Stl	406.4	4830	1626.3	1.3	2.4	1.3	0.5	1.6	6.8	11.2
92	61483641	T3201.004	Winnipeg Interlake / Iles Des Chenes Line	1/1/1962	Stl	406.4	4830	1653.4	1.3	2.4	1.3	0.5	1.6	6.8	11.2
93	87289730	T3201.001	Winnipeg Interlake / Iles Des Chenes Line	1/1/1962	Stl	406.4	4830	3831.4	1.3	2.4	1.3	0.5	1.6	6.8	11.2
94	8064030	D3008	Winnipeg 1 / Winnipeg NW	1/1/1900	Stl	114.3	420	32.6	1.7	5.3	0.7	0.5	2.8	4.0	11.2
95	33715826	D2704	Rosser / Winnipeg NW	1/1/1900	Stl	60.3	420	815	1.8	6.9	0.8	2.9	3.5	3.2	11.2
96	34159500	D2704	Rosser / Winnipeg NW	1/1/1900	Stl	60.3	420	787.5	1.8	6.9	0.8	2.9	3.5	3.2	11.2
97	33627951	D3205	Winnipeg Interlake / Winnipeg E	1/1/1900	Stl	60.3	420	1076.7	1.7	7.8	0.7	7.6	4.0	2.8	11.1
98	35800072	T3001.007	Winnipeg 1 / LaSalle TP	1/1/1955	Stl	323.9	4830	68	1.7	2.8	1.3	0.5	2.0	5.6	11.1
99	35801248	T3001.006	Winnipeg 1 / LaSalle TP	1/1/1955	Stl	323.9	4830	2004.1	1.7	2.8	1.3	0.5	2.0	5.6	11.1
100	36995520	T3001.008	Winnipeg 1 / LaSalle TP	1/1/1955	Stl	323.9	4830	681.5	1.7	2.8	1.3	0.5	2.0	5.6	11.1

13. Risk Evaluation of the 10 Highest Ranking Pipe Segments

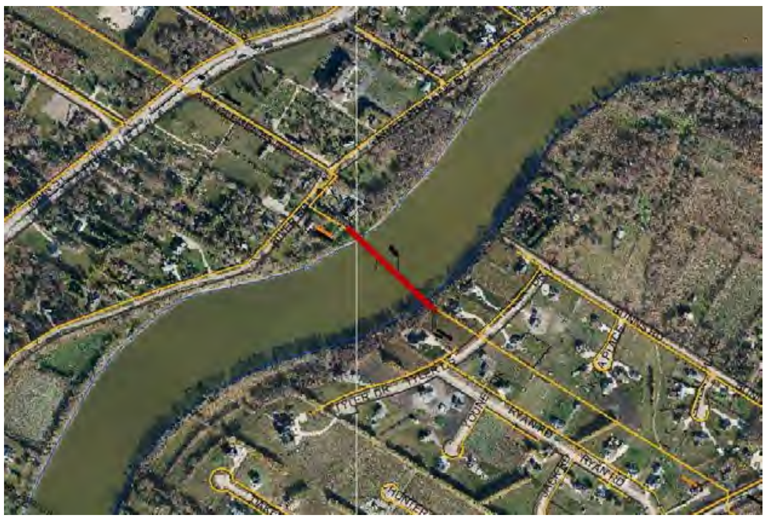
The following is an evaluation of the highest ranking pipe segments by risk score.

13.1. Transmission Pipe Red River Crossing near Selkirk

Rank: 1 | **ID:** 35971019 | **Facility Code:** T3212.005

Pipe Attributes: Steel 323.9mm transmission pipe (4830 kPa Network MOP). Energized in 1969.

Pipe Location: Red River crossing in the RM of St. Clements near Selkirk.



Scores:

Ext. Human Interf.(10)	Corrosion (10)	Natural Forces (10)	Const. / Mat. Defect (10)	Frequency Score (10)	Consequence Score (10)	Risk Score (100)
2.9	2.3	3.6	0.5	2.7	5.6	14.9

Primary Risk Drivers:

The primary frequency drivers are Natural Forces and External Human Interference due to an insufficient cover. This location is monitored as part of the Water Course Crossing Survey Program (identified as WCC-0110) and the Geotechnical Monitoring Program (WG 7).

Following 2011 flooding, the riverbank showed signs of instability and erosion. A depth of cover survey found the minimum cover to be 0.26m (1.2m required by CSA Z662) and the site was issued to design for remediation. The remediation is with design as MER 2013-04838 and has an anticipated in-service-date of 2015.

The primary consequence driver is that a large area would be impacted should a failure event occur.

Risk Significance:

The risk is significant as the location does not meet minimum depth of cover requirements as per Clause 4.11 of CSA Z662 (Cover and clearance).

Options analysis:

When the remediation is complete, the External Human Interference score will be reduced from 2.9 to 1.4 and the natural forces score will be reduced from 3.6 to 2.95. The resulting risk score will be reduced 29 % from 14.9 to 10.6. A risk score of 10.6 would be ranked 169th overall.

13.4. Transmission Pipe Seine River Crossing near Grande Pointe

Rank: 5	**ID:** 36520683	**Facility Code:** T3201.002

Pipe Attributes: Steel 406.4mm transmission pipe (4830 kPa Network MOP). Energized in 1962.

Pipe Location: Seine River crossing on Oak Grove rd. east of Grande Pointe.

Scores:

Ext. Human Interf.(10)	Corrosion (10	Natural Forces (10)	Const. / Mat. Defect (10)	Frequency Score (10)	Consequence Score (10)	Risk Score (100)
1.3	2.4	3.1	0.5	1.9	6.8	13.0

Primary Risk Drivers:

The primary frequency driver is Natural Forces. This location is monitored as part of the Water Course Crossing Survey Program (identified as WCC-0002) and the Geotechnical Monitoring Program (WG 13).

A review of the Water Course Crossing Survey Program identified this location was last surveyed in 1997 and had 1.5m of cover at that time (1.2m required by CSA Z662).

A review of the Geotechnical Monitoring Program shows this location to be a moderate rating site with high potential for scour and lateral erosion. It was visually inspected in 2012 and a recommendation to obtain a new depth of cover survey was recommended at that time.

The primary consequence driver is that a large area would be impacted should a failure event occur.

Risk Significance:

The risk is significant as this pipeline is a critical supply feed to the network and the likelihood that the crossing may have insufficient cover is high enough to warrant further investigation.

Options analysis:

If a new depth of cover survey is performed to confirm the cover over the pipe segment and the potential influence of any bank instability, a mitigation score would be applied and the resulting risk score would be reduced 27% from 13.0 to 9.5 for the first year. A risk score of 9.5 would be ranked 492nd overall.

- Portions of distribution pressure pipelines in D2704 (e.g. William Ave W, Elgin Ave W, Ross Ave W, Roy Ave, Pacific Avenue W, Alexander Ave, Logan Ave)
- Portions of distribution pressure pipelines in D3002 (e.g. Brownell bay, Hammond Road, Sandham Cr, O'Brien Cr, Rannock Ave, Cullen Dr, Lismer Cr, Fitzgerald Cr)
- The majority of distribution pressure pipelines in D3007 (e.g. West End, Daniel McIntyre Wolseley, St. Mathews)
- The majority of the distribution pressure pipelines in D3008 (e.g. Downtown, Exchange District, South Point Douglas, South Portage, Colony, Broadway Assiniboine, Armstrong Point)
- Portion of the high pressure pipeline in D3101 (Bishop Grandin Blvd)
- Portions of distribution pressure in D3202 (e.g. Van Hull Way)
- Portions of distribution pressure in D3203 (e.g.Tascona Rd, Bonaventure Drive)
- Portions of distribution pressure in D3205 (e.g. Ottawa Ave, Washington Ave, Jamison Ave, Bowman Ave, Larsen Ave, Harbison Ave W, Martin Ave W, Union, Chalmers Ave, Johnson Ave W, Poplar Ave)

The vast majority of the transmission system (95.8%) was determined to be of "not significant" risk. A small percentage (4.2%) of pipelines near Dauphin, Brandon, Winnipeg and Selkirk were evaluated as having "less significant" risk (See Figure 13, Figure 14 and Figure 15).

The objective of the Pipeline Risk Assessment is to inform management and pipeline integrity activity owners of pipeline segments with significant risk from a failure incident. A failure incident is defined in this report as an unintentional release of gas below grade.

The results of the Pipeline Risk Assessment are a potentially valuable tool for:

- Making effective choices among risk control measures.
- Supporting specific operating and maintenance practices for pipelines subject to integrity hazards;
- Assigning priorities among inspection, monitoring, and maintenance activities; and
- Supporting decisions associated with modifications to pipelines, such as rehabilitation or changes in service.

Further information such presentations, assistance with implementing risk control options, and pipe segment location data is available from the author by request.

The vast majority of the transmission system (95.8%) was determined to be of "not significant" risk and are coloured green on the map (Figure 12).

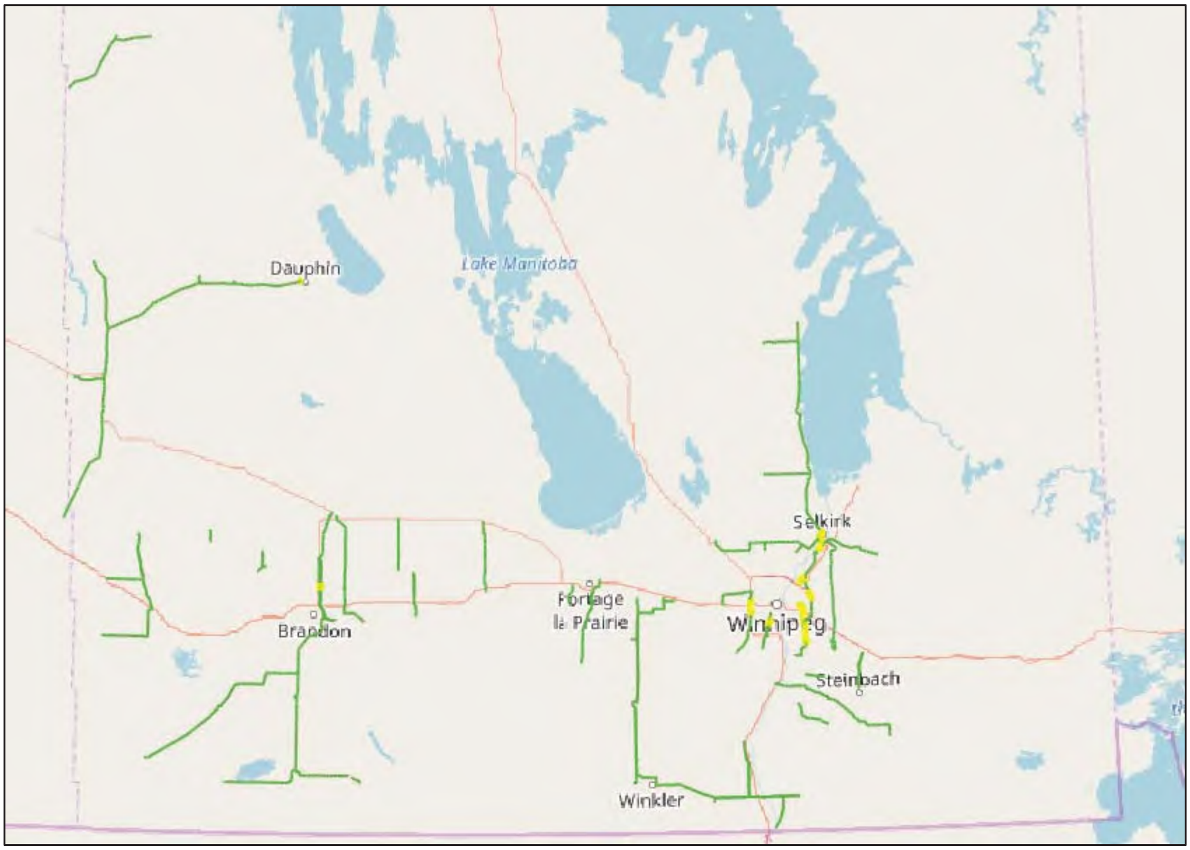


Figure 12: Transmission Pipelines - Thematic Map of Risk Evaluation Results

A small percentage (4.2%) of pipelines near Dauphin, Brandon, Winnipeg and Selkirk were evaluated as having "less significant" risk (See Figure 13, Figure 14 and Figure 15).

Figure 13: Transmission - Dauphin

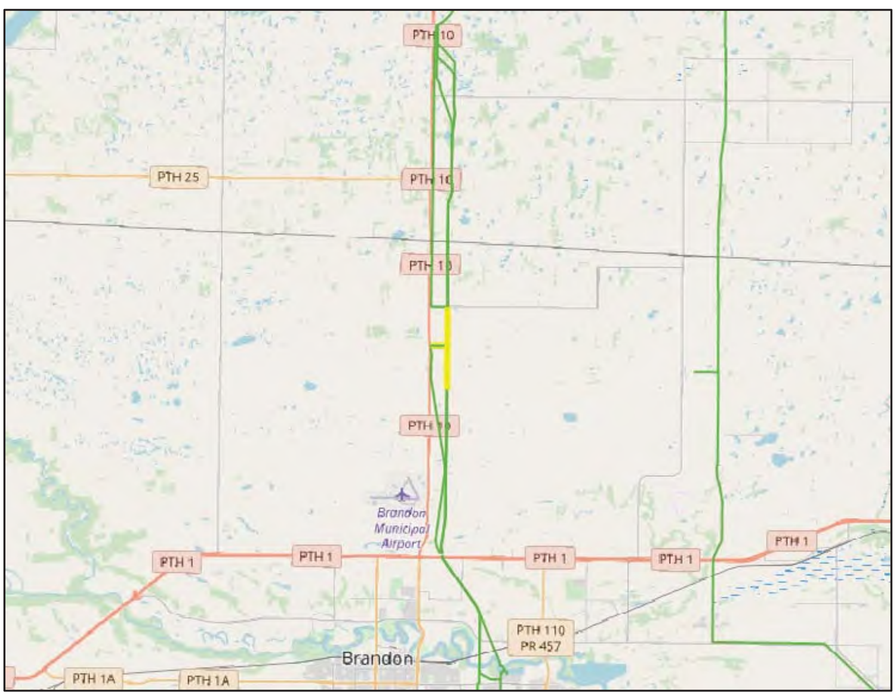


Figure 14: Transmission - Brandon

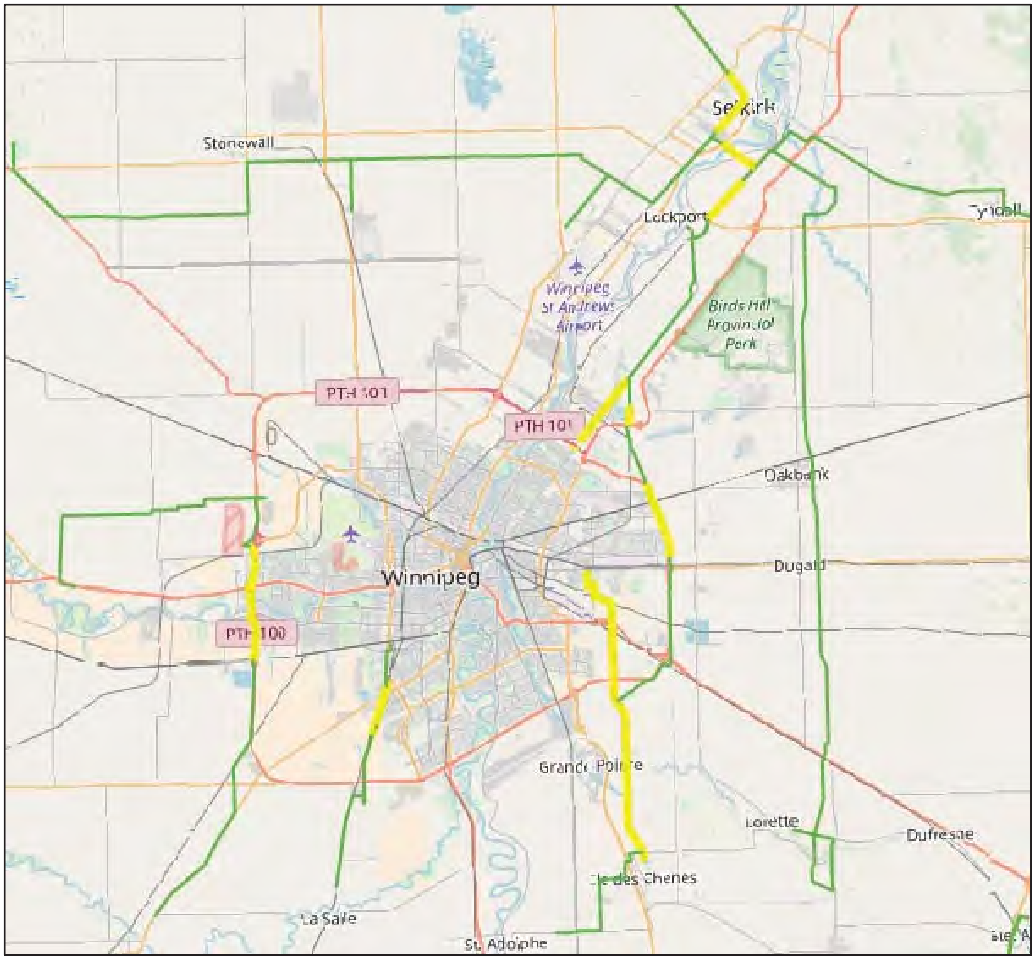


Figure 15: Transmission - Winnipeg and Selkirk

6.1.5. Risk Control Options

Pipeline Integrity Activities are summarized in the Pipeline System Integrity Management Plan (*Natural Gas Pipeline System Integrity Management Program,* 2015). Pipeline Integrity Activity owners should consider whether or not the activities they own are satisfactorily targeting the segments with the highest risk.

If the risk cannot be reduced with current Pipeline Integrity Activities, a site specific analysis may be required.

Pipeline Integrity Activities that are targeted to a specific hazard, such as corrosion, would benefit from reviewing the risk profile for that hazard. For example, the Cathodic Protection System Monitoring and Performance Evaluation activity owner should consider the pipe segments with a higher Corrosion / Degradation Risk.

NC55-CIJ-PROJ

CAPITAL INVESTMENT JUSTIFICATION FOR

Steinbach Upgrade – Natural Gas System
Project Category: Project

	(thousands of dollars)
BUDGET:	$4,456
CONTRIBUTIONS:	($0)
NET BUDGET:	$4,456
NPV BENEFIT/(COSTS)	($4,036)

DATE PREPARED: 2017/06/16

REQUIRES EC OR MHEB APPROVAL: Not Applicable
EC/MHEB APPROVAL MINUTE:
DATE APPROVED:

APPROVER	APPROVER TITLE	ORGANIZATIONAL UNIT COST CENTRE	SIGNATURE	APPROVAL DATE
Isaacson, Marie	Accountant, MFS-M&CS	50625	M Isaacson	2017-07-05
Aftanas, Alan	Gas Planning Engineer	52955	J. Aftanas	2017-07-05
Starodub, Tim	Gas Engineering & Const Department Manager	52955	T Starodub	2017-07-06
Steele, Chuck	Engineering &Construction Director	54200	Chuck Steele	2017 08 29
Rob Isaac ~~Prydun, Mark~~	CPGC Coord. ~~Bus Support & Capital Asset Mgmt Director~~	54200	R. Isaac	20170919
Vinish, Siobhan	VP Marketing & Customer Service	50120	SVinish	2018 01 23

CAPITAL INVESTMENT MASTER DATA			
RESPONSIBLE OPERATING/CORPORATE GROUP:	Marketing & Customer Service	**REQUESTING OPERATING/CORPORATE GROUP:**	Marketing & Customer Service
RESPONSIBLE DIVISION:	Marketing & Customer Service	**REQUESTING DIVISION:**	Marketing & Customer Service
RESPONSIBLE DEPARTMENT:	Gas Engineering & Construction		
I.M. NODE NUMBER:	**2.2.40.15.04.14**	**W.B.S. NUMBERs:**	**P:24373, P:26228**
C55 PROJECT CODE:	NON-C55		
SAP PROJECT TYPE:	30 Base Capital - Core Capital	**C55 PROJECT SUB-CATEGORY**:	Choose an item.
CORPORATE INVESTMENT CATEGORIES:	**LEVEL 1** C1 / Capacity & Growth **LEVEL 2** CF / System Load Capacity		
NERC COMPLIANCE*:	Choose an item.	*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.	

CONTACTS			
PREPARED BY:	Aftanas, Alan Gas Planning Engineer Gas Engineering & Construction	**REQUESTOR:**	Starodub, Tim Department Manager Gas Engineering & Construction
PROJECT MANAGER:	Blazek, Greg Gas Design Section Head Gas Engineering & Construction		

MANITOBA HYDRO
CAPITAL INVESTMENT JUSTIFICATION
Steinbach Upgrade – Natural Gas System

RECOMMENDATION

It is recommended to install a secondary natural gas pipeline to the south side of Steinbach as shown in Figure 1. The upgrade will consist of a new pressure reducing station at the southwest corner of Steinbach, 6.4 km of six-inch (168.3 mm) steel transmission pipeline and 6.4 km of eight-inch (219.1 mm) polyethylene (PE) distribution mains from the new pressure reducing station. The cost of this upgrade is estimated at $4,456,000 (conceptual level estimate; allow 25% for accuracy) with a recommended in-service date (ISD) of October 2021.

SCOPE

The recommended upgrade will consist of the following:

- A new Steinbach pressure reducing station located at the south end of the City of Steinbach.
- A new six-inch (168.3 mm) steel transmission pipeline originating from the existing Hanover transmission pipeline to supply the new gate station (6.4 km).
- 6.4 km of eight-inch (219.1 mm) polyethylene (PE) distribution mains from the new Steinbach gate station to feed the existing Steinbach distribution system.

Figure 1 – Recommended Steinbach Upgrade

BACKGROUND

The City of Steinbach and the surrounding rural municipalities have experienced strong natural gas load growth increasing by 2.3% per year compounding over the last 10 years. Steinbach is the fourth largest and the fastest growing city in Manitoba with a 17% increase in population between the 2011 and 2016, growing from a population of 13,524 to 15,829 (2016 Canadian Census data).

Steinbach consists of 4,423 natural gas customers and is the largest city in Manitoba which currently does not have a secondary gas supply. Steinbach was identified as a community vulnerable to a wide-spread outage of several days or more should the gas supply be interrupted as noted in the *"Evaluation of Secure Gas Supplies in Manitoba, Study No: SGS-2016*". The *Secure Gas Supply Study* recommended that Steinbach, as well as other communities, be evaluated using a common approach to mitigate gas outages. An evaluation of the Steinbach system was completed using this approach and is presented in the *"Steinbach Upgrade, 2016-07001r1"* Study and provides the basis for the recommendation in this CIJ.

Gas load on the Steinbach distribution system is projected to grow to approximately 587 mcfh (16,600 m^3/hr) by the year 2033 using a conservative growth rate of 2.0% non-compounding, and was used as the minimum capacity requirement for the upgrade. The existing Steinbach natural gas system is expected to be at the limits of its capacity by the year 2023 based on this conservative growth rate.

JUSTIFICATION – BUSINESS CASE ANALYSIS (SUMMARY)

JUSTIFICATION

The justification for the upgrade is as follows:

1. Provide capacity for 20 years of forecast growth to Steinbach and the surrounding area. Pipeline capacity will increase by over 300 mcfh (8,500 m^3/hr), from 440 mcfh (12,500 m^3/hr) to 750 mcfh (21,200 m^3/hr). Projections indicated that no new gas customers can be added after the year 2022 without a capacity upgrade.
2. To provide a secure, secondary source of gas to the area to prevent widespread outages from pipeline failure/damage and to facilitate planned pipeline maintenance.
3. If a pipeline failure were to occur on the existing system, the estimated time to repair and return the pipeline to service is estimated at four to six days and could affect all 5,590 customers (i.e. Steinbach and surrounding communities). The estimated cost of this outage is estimated at:
    a. Cost to Manitoba Hydro: estimated at $2.3 million to repair and restore the service (based on previous Manitoba Hydro gas outage experience).
    b. Value of Lost Load to customers: estimated at $5.5 million for a four day outage and $8.3 million for a six day outage (based on paper written by the Brattle Group using basic microeconomic theory, October 2013, 2017.
4. The incremental cost to provide a second gas supply over the lowest-cost capacity option is $2.5 million.
5. A gas outage during cold winter conditions would significantly increase load on the electrical system as customers switch to portable electric heaters and any other electrical heating supply. A high level

JUSTIFICATION – BUSINESS CASE ANALYSIS (SUMMARY)

assessment of the Steinbach electrical system concluded that the system could accept the anticipated increased load due to a natural gas outage, but could lead to permanent damage by overloading the feeders. The extent of damage and cost to replace the damaged feeders was not calculated.

6. It is not possible to use trucked compressed (CNG) or liquefied natural gas (LNG) to fully replace the pipe natural gas supply at all times of the year as both sources have insufficient capacity at peak loads.

ANALYSIS OF ALTERNATIVES:

ECONOMIC ANALYSIS		
Discount Rate	For current corporate rates see P911 **4.15%**	Nominal Discount Rate%

RECOMMENDED OPTION	**NPV Benefits/(Costs)** (thousands of dollars)
Install a Secondary pipeline from the south side of Steinbach. This is the only option that provides a secure secondary gas supply to the City of Steinbach. The incremental cost for the reliability component is $2.5 million over the lowest cost capacity-only option.	($4,036)

OTHER ALTERNATIVES CONSIDERED	**NPV Benefits/(Costs)** (thousands of dollars)
Loop the existing pipeline (install a parallel pipeline) with 6.8 km of four-inch (114.3 mm) pipe. This is the lowest cost option that provides capacity only.	($1,340)
Loop the existing pipeline (install a parallel pipeline) with 6.8 km of six-inch (168.3 mm) pipe. This option provides capacity only.	($1,985)

PROJECT RISK ANALYSIS

Risk associated with proceeding with the recommended upgrade include:

1. Construction cost escalation at a higher rate than anticipated over the next 2 to 3 years. Construction is planned to start in the summer of 2019. Construction escalation is calculated using Policy P911.

The purchase of property is required for the construction of a pressure regulating station. A preferred location has been identified; alternate locations can be used but may result in additional pipeline costs or result in reduced system efficiency.

ESTIMATED COST FLOW

The annual investment cost flows are as follows (in thousands of dollars):

Fiscal Year	Budget	Contributions	Net Budget
Prev. Actuals	$ 20	$ -	$ 20
2017/2018	$ 342	$ -	$ 342
2018/2019	$ 428	$ -	$ 428
2019/2020	$ 1,430	$ -	$ 1,430
2020/2021	$ 1,915	$ -	$ 1,915
2021/2022+	$ 321	$ -	$ 321
Total	$ 4,456	$ -	$ 4,456

IMPACT ON O&A COSTS

New gas infrastructure will incrementally increase operating and administration costs for the following:

- Corrosion and integrity monitoring,
- Pipeline maintenance,
- Valve and pressure reducing station equipment testing and maintenance,
- Odourization equipment operation and maintenance, and
- Documentation, accounting and regulatory activities.

This new infrastructure will add scope to Manitoba Hydro's existing natural gas operating and maintenance groups, which are primarily within the Marketing and Customer Service business unit.

Capacity upgrades will facilitate the addition of new gas customers which will generate new revenue.

PROPOSED SCHEDULE

Start design and approvals:	June 2017
Secure property for Station:	January 2018
Design Complete:	October 2018
Receive Environmental Approval:	March 2019
Construction Start:	May 2019
In Service Date:	October 2021

RELATED INVESTMENTS

None

REFERENCE DOCUMENTS

Steinbach Upgrade, Study No. 2016-07001

REFERENCE DOCUMENTS
2017 Manitoba Hydro's Natural Gas System Long-Term Development Plan: http://csd.hydro.mb.ca/dec/gec/gp/MH%20NG%20Long%20Term%20Dev%20Plan/2017%20Gas%20Long%20Term%20Development%20Plan%20_%20Low%20Res.pdf
Gas Planning Criteria Document GPCD-2014: http://csd.hydro.mb.ca/dec/gec/gp/Gas%20Pipeline%20Studies/Gas%20Planning%20Criteria%20Document.pdf

C55-CIJ-PROJ

CAPITAL INVESTMENT JUSTIFICATION
FOR

Provision of Secure Gas Supply- Portage la Prairie

Investment Type (Project)

BUDGET:	$1,594
CONTRIBUTIONS:	$0
NET BUDGET:	$1,594
	(values listed above are in thousands of dollars)

DATE PREPARED: 2018/02/12

EC/MHEB APPROVAL MINUTE & DATE:

APPROVER	APPROVER TITLE	COMMENT	ORGANIZATIONAL UNIT	APPROVAL DATE
Steele, Chuck	DIRECTOR OF ENGINEERING & CONSTRUCTION		Director - Engineering & Construction	2018/02/16
STARODUB, TIM	GAS ENGINEERING & CONSTRUCTION DEPT MGR		Gas Engineering & Construction	2018/02/12
LAWRIE, SARAH	CHARTERED PROFESSIONAL ACCOUNTANT	On behalf Of Isaacson, Marie (misaacson).	Financial Advisory Services	2018/02/12
Blazek, Greg	GAS DESIGN SECTION HEAD		Gas Engineering & Construction	2018/02/12
Blazek, Greg	GAS DESIGN SECTION HEAD		Gas Engineering & Construction	2018/02/12

CAPITAL INVESTMENT MASTER DATA			
RESPONSIBLE OPERATING/CORPORATE GROUP:	Marketing & Customer Service	**REQUESTING OPERATING/CORPORATE GROUP:**	Marketing & Customer Service
RESPONSIBLE DIVISION:	Engineering & Construction	**REQUESTING DIVISION:**	Engineering & Construction
RESPONSIBLE DEPARTMENT:	Gas Engineering & Construction	**ISD: (YYYY/MM/DD)**	**2022/03/31**
I.M. NODE NUMBER:	2.2.40.15.04.19	**W.B.S. NUMBERs:**	P:28550
C55 INVESTMENT CODE:	13439		
SAP PROJECT TYPE:	24 - BOC-VP & Management	**C55 INVESTMENT SUB-CATEGORY:**	Single WBS
CORPORATE INVESTMENT CATEGORIES:	(Level 1) C3 / Sustainment (Level 2) CF / System Load Capacity		

CONTACTS			
PREPARED BY:	Blazek, Greg GAS DESIGN SECTION HEAD 52955	**REQUESTOR:**	Blazek, Greg
PROJECT MANAGER:	Greaves, Andrew GAS DESIGN ENGINEER - CITY OF WINNIPEG 52955		

MANITOBA HYDRO
CAPITAL INVESTMENT JUSTIFICATION
Provision of Secure Gas Supply- Portage la Prairie

RECOMMENDATION

Provide pipeline modifications and additions to reduce the number of customers that may lose gas service in the event of a pipeline damage or failure. In 2019, add pipeline isolation valves on the parallel 114.3 mm transmission pipelines and on the 168.3 mm transmission pipeline at GS-182 at an estimated cost of $0.5M. In 2021, install a second 168.3 mm transmission pressure river crossing of the Assiniboine River with associated valves at an estimated cost of $1.1M.

SCOPE

The proposed work includes:
- Installation of a valve station on the south side of the Assiniboine River to permit independent operation of the two 114.3 mm transmission pipelines.
- Installation of a valve station on the 168.3 mm transmission pipeline at GS-182 to permit the isolation of downstream piping.
- Installation of approximately 1100 meters of 168.3 mm transmission main including a crossing of the Assiniboine River and isolation valves to permit both the new and existing river crossing to be fully isolated.

BACKGROUND

The City of Portage la Prairie is the fourth largest city in Manitoba supplied with natural gas. The system was constructed as a single feed system and is vulnerable to a single failure or damage that could potentially result in an outage for all downstream customers. As recommended in the Manitoba Hydro report “Evaluation of Secure Gas Supplies in Manitoba” (December 2016), a review of the natural gas supply system to Portage la Prairie was performed to determine the capacity of the current system, load growth projections and the security of the gas supply.

This review indicated:
- The transmission pipeline was built and expanded in a number of stages with portions built between 1957 and 1996. There are no known pipeline integrity concerns. However, the pipeline system has not been assessed for corrosion degradation, and older portions of the pipeline would be susceptible to corrosion mechanisms observed on other Manitoba Hydro pipelines. The Assiniboine River crossing has been replaced five times in the past due to river bank movement and stability issues. Ground movement of the in-service pipeline crossing the river is being monitored.
- Parallel 114.3 mm pipelines run 6 km from the Portage la Prairie pressure regulating station to the south side of the Assiniboine River crossing. One pipeline was installed in 1957 and the second in 1962. There are no valves on the north end of the pipelines that would permit independent operation of the pipelines leaving the community susceptible to an outage due to a single failure on a 55 or 60 year old pipeline.
- The likelihood of an outage is difficult to define as there is limited information on the condition of the pipeline. The consequence of continued operation of the pipeline system in its current configuration can be defined as a single failure could result in an outage.
- Following the guidance of the Manitoba Hydro electrical distribution planning, Portage la Prairie would be defined as an urban center and would be provided with redundancy permanently installed to address a lower tolerance for outages.

BACKGROUND

- In the event of a pipeline failure, the estimated time to repair a transmission line and return it to service is two days if the repair is being performed in readily accessible locations such as a road right of way or easement. However, the emergency replacement of the Assiniboine River crossing would take 30 days or more.
- It is not possible to provide sufficient trucked compressed natural gas (CNG) and liquefied natural gas (LNG) to fully replace the piped natural gas supply at all times of the year. The gas demand varies significantly through the year as natural gas largely serving building heating loads.
- The cost to Manitoba Hydro to respond to an outage of 4,600 customers is estimated at $1.8 million. The Value of Lost Load to these 4600 customers is estimated at $1.6 million for a two day outage and $24 million for a thirty day outage.
- Critical gas customers were identified as the Portage General Hospital, the Lions Prairie Manor Personal Care Home, and the Douglas Campbell Lodge. In the event of an outage, Manitoba Hydro owned CNG would be used to support the Hospital and a third party supply would be engaged as quickly as possible to support the Lions Prairie Manor and Douglas Campbell Lodge.

JUSTIFICATION – BUSINESS CASE ANALYSIS (SUMMARY):

JUSTIFICATION

Portage la Prairie is at risk of a major outage due to a single transmission pipeline damage or failure of a transmission pipeline system that includes pipe sections that are 60 years old. The number of customers in the community and associated gas supply requirements exceeds the supply abilities of an alternated trucked-in gas supply. The proposed modifications maintains the use of the existing assets while providing valves and a second river crossing that will permit a single transmission pipeline damage or failure to be isolated while maintaining gas supply to the customers. The estimated installation costs are less than the estimated Manitoba Hydro costs of responding to a full outage on this system. It is recommended that the project be implemented over a two year period starting in summer 2018.

In 2002 a new transmission pipeline system including a new connection to Trans Canada Pipe Lines (TCPL) was installed to supply a new major industrial load on the west side of Portage la Prairie. The two TCPL stations (GS-132-original Portage la Prairie station and GS-193 Portage Simplot) are only about 10 kilometers apart. Connection of the two systems would require 10 kilometers of 168.3 mm pipe and a further 4 kilometers of pipeline looping would to supply the Portage la Prairie load. The cost of this work is estimated at $4.5 million. This alternative is not recommended.

ANALYSIS OF ALTERNATIVES:

ECONOMIC ANALYSIS		
Discount Rate	**For current corporate rates see P911** **6.25%**	

Active Option	**NPV Benefits/(Costs)**
Recommended	($1,319)

Other Alternatives	**NPV Benefits/(Costs)**
Install pipe to connect transmission systems GS-132 and GS-193; install isolation valves at the north side of the Assiniboine River crossing and at GS-182	($4,422)

INVESTMENT RISK ANALYSIS
There will be a requirement to obtain easement to install above grade valve assemblies and potentially for a portion of the transmission main associated with the recommended river crossing. Easement and property continues to become more difficult to obtain. Preliminary design and costing is based on preferred locations, alternate locations can also be made to work but may add to the costs/decrease system performance. This risk is considered to be low. During previous work on the south side of the river near the proposed work area, high ground water levels were experienced that resulted in project delays and additional costs. Based on this past experience, the use of sand points to lower ground water levels at the work sites have been included in the project estimates. This capability will be built into the contract and used as required. The risk is considered to be addressed. The recommended water crossing will require a long horizontal direction drill. The presence of rock or cobbles can require additional work and incur additional costs to obtain a successful crossing. A detailed geotechnical analysis of the site will be obtained to assist in identifying the expected site conditions. A higher contingency will be carried in the estimate to permit unexpected conditions to be addressed if needed.

ESTIMATED COST FLOW

The annual projected cost flows are as follows (in thousands of dollars):

Fiscal Year	Budget	Contributions	Net Budget
Prev. Actuals	$0	$0	$0
2017/2018	$11	$0	$11
2018/2019	$70	$0	$70
2019/2020	$449	$0	$449
2020/2021	$104	$0	$104
2021/2022	$960	$0	$960
2022/2023+	$0	$0	$0
Total	**$1,594**	**$0**	**$1,594**

IMPACT ON O&A COSTS

Minimal.

PROPOSED SCHEDULE

The propose schedule is:

2017/18

- Obtain required easements for the valve stations.

2018/19

- Design and tender of the isolation valve stations at the parallel 114.3 mm lines and at GS-182.
- Order long lead items.
- Geotechnical analysis and provision of recommendations for river crossing.

2019/20

- Construct the isolation valve stations at the parallel 114.3 mm lines and at GS-182.
- Detailed design of river crossing.
- Obtain required easements and approvals for the river crossing.

2020/21

- Tender river crossing construction.
- Order long lead materials for the river crossing and associated valve stations

2021/22

- Construct the river crossing and associated valve stations

RELATED INVESTMENTS

None.

OTHER ALTERNATIVES CONSIDERED
Install pipe to connect transmission systems GS-132 and GS-193; install isolation valves at the north side of the Assiniboine River crossing and at GS-182 for an expected cost of $4.4M.

REFERENCE DOCUMENTS
Evaluation of Secure Gas Supplies in Manitoba 161215.pdf Evaluation of Secure Gas Supply for Portage la Prairie 170501 Sealed.pdf

REFERENCE:

Tab 4 p. 3 of 22

PREAMBLE TO IR (IF ANY):

QUESTION:

Provide the investment cost thresholds associated with the levels of management approvals required for Centra's capital projects or programs.

RESPONSE:

The table below provides the management approval level required for Centra's capital projects:

TOTAL PROJECT COST (GROSS OF CONTRIBUTIONS) Dollar Value $						
Approval Levels	≥ 50 000 000	≥ 25 000 000 & < 50 000 000	≥ 15 000 000 & < 25 000 000	≥ 2 000 000 & < 15 000 000	≥ 1 000 000 & < 2 000 000	< 1 000 000
MHEB Capital Committee	X					
Executive Committee		X				
CAMEC			X			
Vice-President				X		
Director					X	
Department Manager						X

Note: CAMEC is the Corporate Asset Management Executive Council.

The table below provides the management approval level required for Centra's capital programs:

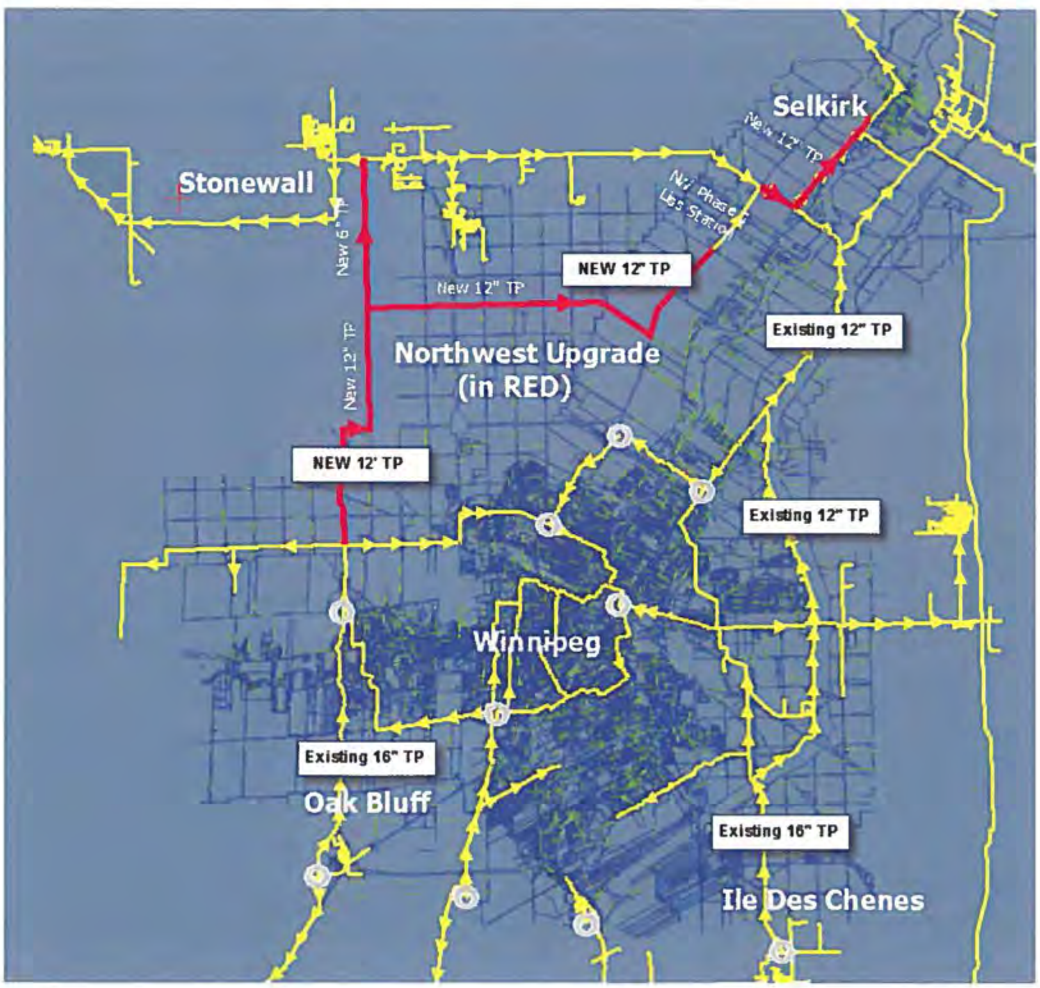
ANNUAL PROGRAM SPEND (GROSS OF CONTRIBUTIONS) Dollar Value $					
Approval Levels	≥ 50 000 000	≥ 25 000 000 & < 50 000 000	≥ 15 000 000 & < 25 000 000	≥ 2 000 000 & < 15 000 000	< 2 000 000
MHEB Capital Committee	X				
Executive Committee		X			
CAMEC			X		
Vice-President				X	
Director					X

Note: CAMEC is the Corporate Asset Management Executive Council.

EXECUTIVE SUMMARY

The Winnipeg Northwest Upgrade Project consists of a new 12 inch diameter transmission pipeline that will run just north of the City of Winnipeg, primarily in the east-west direction (refer to Figure ES:1). The pipeline will connect to the existing 16 inch Oak Bluff pipeline at Rosser and will run approximately 41 kilometers to the Liss Road pipeline in St. Andrews (Phase 1), and ultimately connect to the 12 inch Ile Des Chenes pipeline at Selkirk. The upgrade also has a 6 inch diameter branch that will flow directly north to the Town of Stonewall and 12 inch looping to Selkirk.

Figure ES:1 – Proposed Winnipeg Northwest Upgrade (shown in RED)
Winnipeg Transmission Pressure (TP) Network



The Winnipeg natural gas transmission network, which consists of 4 pipelines feeding the City of Winnipeg and to the north, is the backbone of Manitoba Hydro's natural gas system serving over 213,000 customers or 80% of Manitoba Hydro's gas customers. The Winnipeg Northwest Upgrade will provide needed transmission capacity north of Winnipeg and will help to build symmetry, strength and operational flexibility in the Winnipeg natural gas transmission network.

The reasons for the Winnipeg NW Upgrade are summarized as follows:

1. To provide transmission capacity to serve the strong growth just north of Winnipeg for the next 20 years.
2. To provide full redundant supply to the communities north of Winnipeg and to provide a partial ability to back-feed the City of Winnipeg line in an emergency (approximately 1,000 mcfh), such as damage to the Ile Des Chenes or Oak Bluff pipelines.
3. To provide required capacity in the Stonewall transmission branch to permit looping of this pipeline to be deferred or avoided.
4. To permit load to be shifted from the Ile Des Chenes system to the Oak Bluff system. The Oak Bluff pipeline is the same size as the Ile Des Chenes line, 16 inch, but the current load on the Oak Bluff system is only about 50% of the load on Ile Des Chenes. The ability to shift load from the Ile Des Chenes to the Oak Bluff system provides operational flexibility for maintenance/construction activities and will assist in responding to outages. Reducing the current load on the Ile Des Chenes system would permit this capacity to be available for future growth.

The 16 inch diameter Oak Bluff pipeline was built 25 year ago with sufficient capacity to facilitate growth to the west and northwest of Winnipeg. The recommended Winnipeg Northwest Upgrade will complete the original design intent of having the west side and east side pipeline share the loads of Winnipeg and provide a reliable two-way feed for the networks north of Winnipeg. This project is Phase 2 of the Winnipeg Northwest Upgrade project already approved and in construction in the summer of 2014.

This report evaluated options to best service the City of Winnipeg natural gas transmission network for the next 20 years. The following was concluded:

1. Gas load growth continues to be strong in Winnipeg and the Census Metropolitan Areas (CMA) and is expected to continue for the next 20 years at a rate of approximately 1.1% non-compounding (refer to Northwest Upgrade Phase 1 – Liss Road Station Study No: 2012-07068 and Appendix A for forecast gas loads).
2. The Stonewall Transmission pipeline requires upgrades at this time in order to avoid unacceptably high velocities under winter design conditions (exceeding design velocity criteria).

3. The do-nothing approach will result in the looping (i.e. installation of parallel pipelines) of the Stonewall pipeline at a cost of approximately $4 million and sooner than required looping of the 110 km pipeline feeding north of Selkirk at a cost of approximately $17 million. The do-nothing approach will leave the Winnipeg networks in an undesirable condition, vulnerable in an outage due to no addition of redundancy and inflexibility in the system, and reliant on additional piece-meal and costly upgrades.

Four options were evaluated for their ability to meet the following requirements:

1. Provide new capacity to Winnipeg and north of Winnipeg.
2. Provide redundant supplies to areas north of Winnipeg
3. Provide operational flexibility and reduced reliance on 50 year old Ile Des Chenes pipeline.
4. Avoid extensive piece-meal looping of portions of the transmission system.

The recommended option offers the following benefits, versus the do-nothing approach:

1. Improved network capacity for future growth in Winnipeg and north of Winnipeg.
2. Improves Winnipeg transmission network reliability, operating flexibility and redundancy in the case of an un-planned or planned outage (e.g. for maintenance or repair) for the City of Winnipeg and communities north of Winnipeg.
3. Avoidance and deferral of pipeline looping costs (i.e. parallel pipelines).

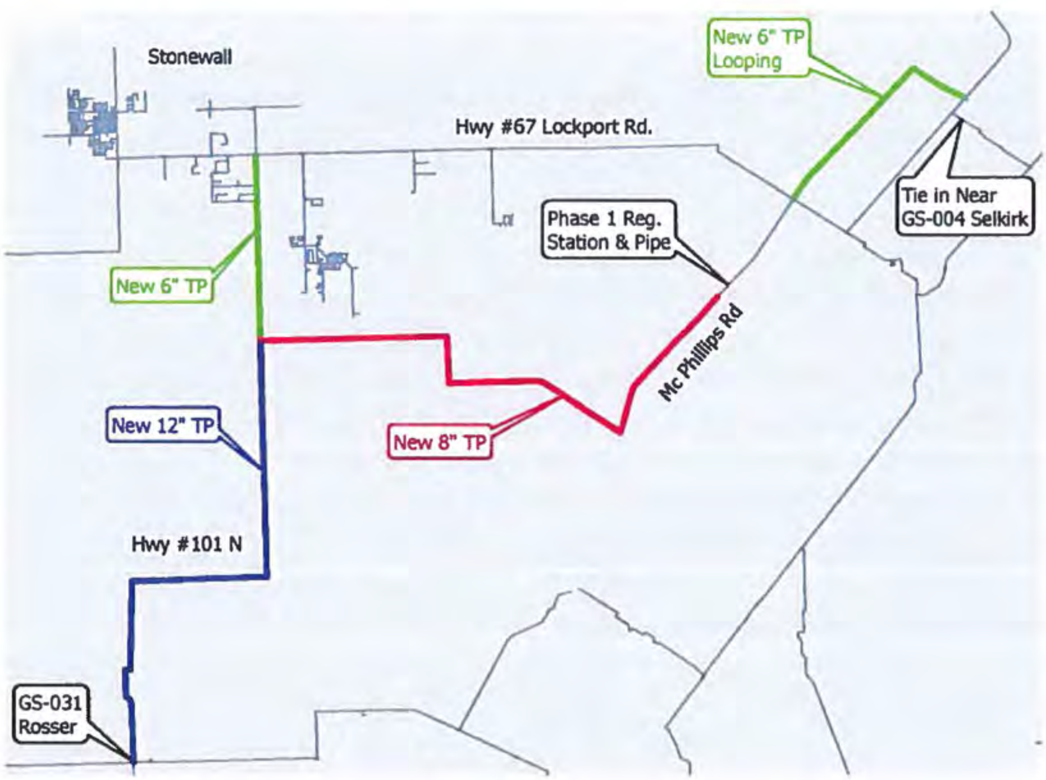
The cost of this project is estimated at $31,100,000 (conceptual level estimate – allow 20% for accuracy). The recommended in-service date (ISD) is October 15, 2016.

2.1 Option 1

Option 1 consists of a new 12" and 8" TP from GS-031 to the Phase 1 regulation station at Liss Road in St. Andrews. This option includes a 6" TP from the new 12" TP to the Town of Stonewall and 6" looping from Hwy #67 to existing plant near GS-004 Selkirk. Option 1 is shown in Figure 8 and consists of the following:

1. 19.8 km of 12" TP and 6.6 km of 6" TP going north from GS-031 at Selkirk Ave. and Hwy #101 to tie into the existing 4" TP on Hwy #67.
2. 20.8 km of 8" TP going east of the new TP to the phase 1 station at Liss Rd.
3. 4.4 km of 8" TP from the new Regulation Station to Hwy #67 (Phase 1).
4. 8.3 km of 6" TP looping from Hwy #67 running north along McPhillips Rd. to the existing plant near GS-004 Selkirk.

Figure 8 - Option 1

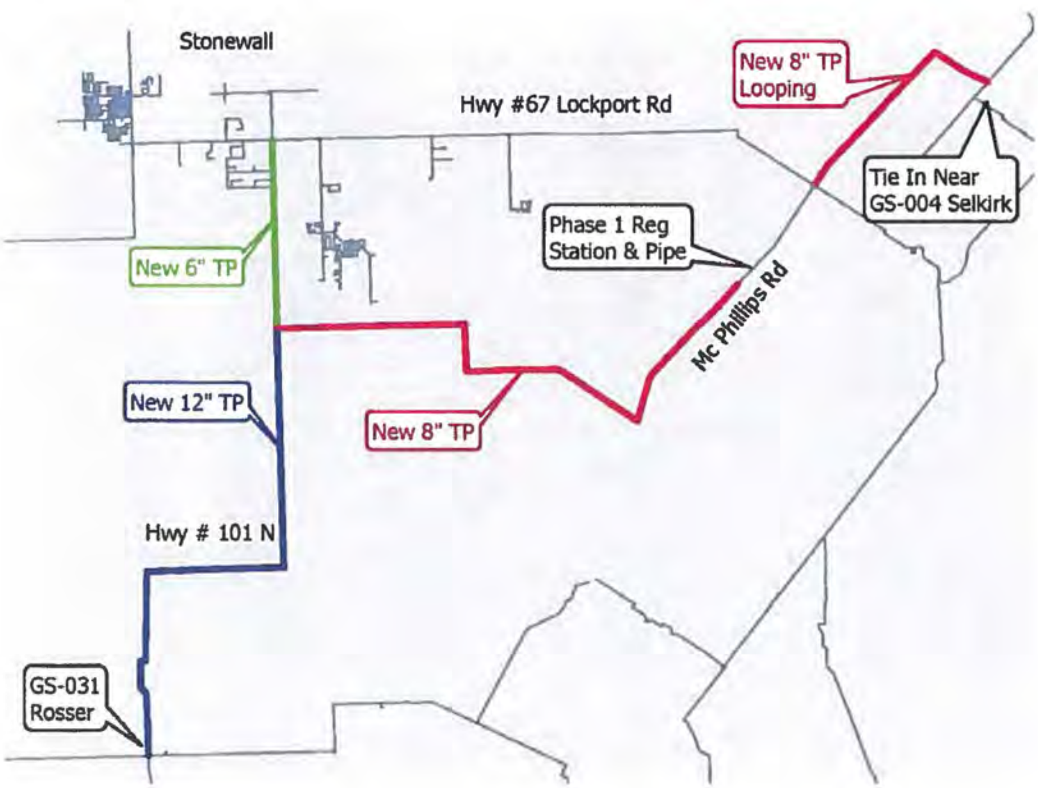


2.2 Option 2

Option 2 consists of a new 12" and 8" TP from GS-031 to the Phase 1 regulation station. This option includes a 6" TP from the new 12" TP to Stonewall and 8" looping from Hwy #67 to existing plant near GS-004 Selkirk. Option 2 is shown in Figure 9 and consists of the following:

1. 19.8 km of 12" TP and 6.6 km of 6" TP going north from GS-031 at Selkirk Ave. and Hwy #101 to tie into the existing 4" TP on Hwy #67.
2. 20.8 km of 8" TP going east of the new TP to the phase 1 station at Liss Rd.
3. 4.4 km of 8" TP from the new Regulation Station to Hwy #67 (Phase 1).
4. 8.3 km of 8" TP looping from Hwy #67 running north along McPhillips Rd. to the existing plant near GS-004 Selkirk.

Figure 9 - Option 2

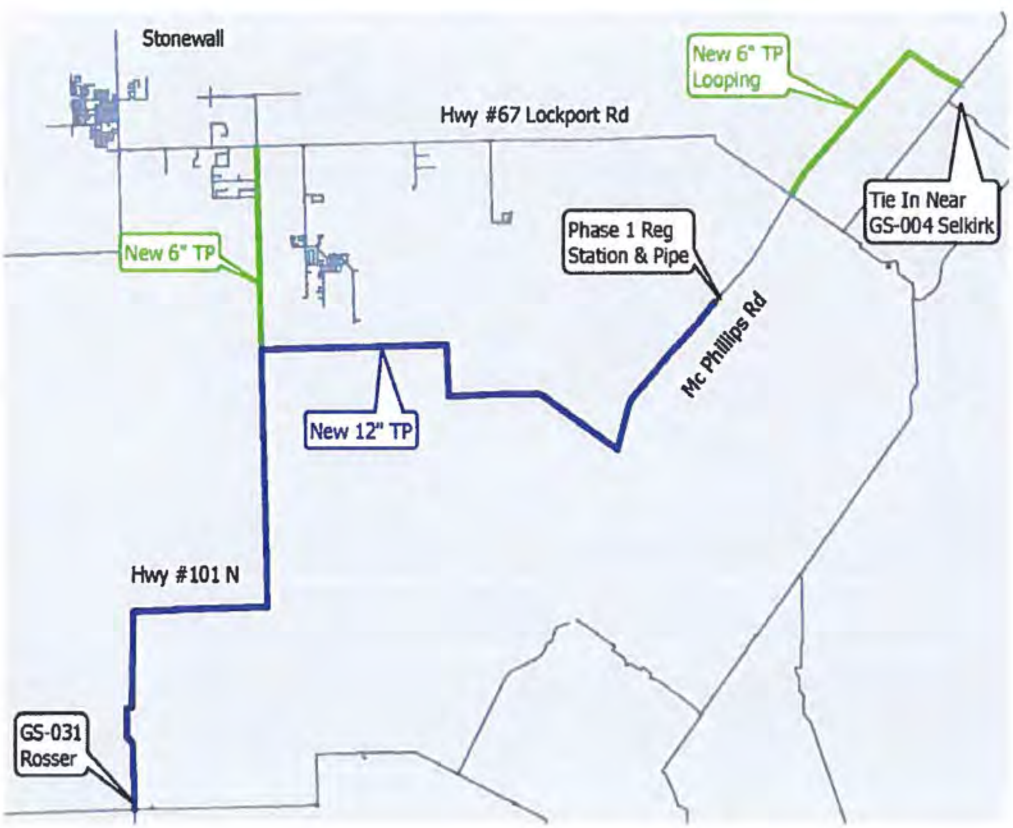


2.3 Option 3

Option 3 consists of a new 12" TP from GS-031 to the phase 1 regulation station. This option includes a 6" TP from the new 12" TP to Stonewall and 6" looping from Hwy #67 to existing plant near GS-004 Selkirk. Option 3 is shown in Figure 10 and consists of the following:

1. 19.8 km of 12" TP and 6.6 km of 6" TP going north from GS-031 at Selkirk Ave. and Hwy #101 to tie into the existing 4" TP on Hwy #67.
2. 20.8 km of 12" TP going east of the new TP to the phase 1 station at Liss Rd.
3. 4.4 km of 12" TP from the new Regulation Station to Hwy #67 (Phase 1).
4. 8.3 km of 6" TP looping from Hwy #67 running north along McPhillips Rd. to the existing plant near GS-004 Selkirk.

Figure 10 - Option 3

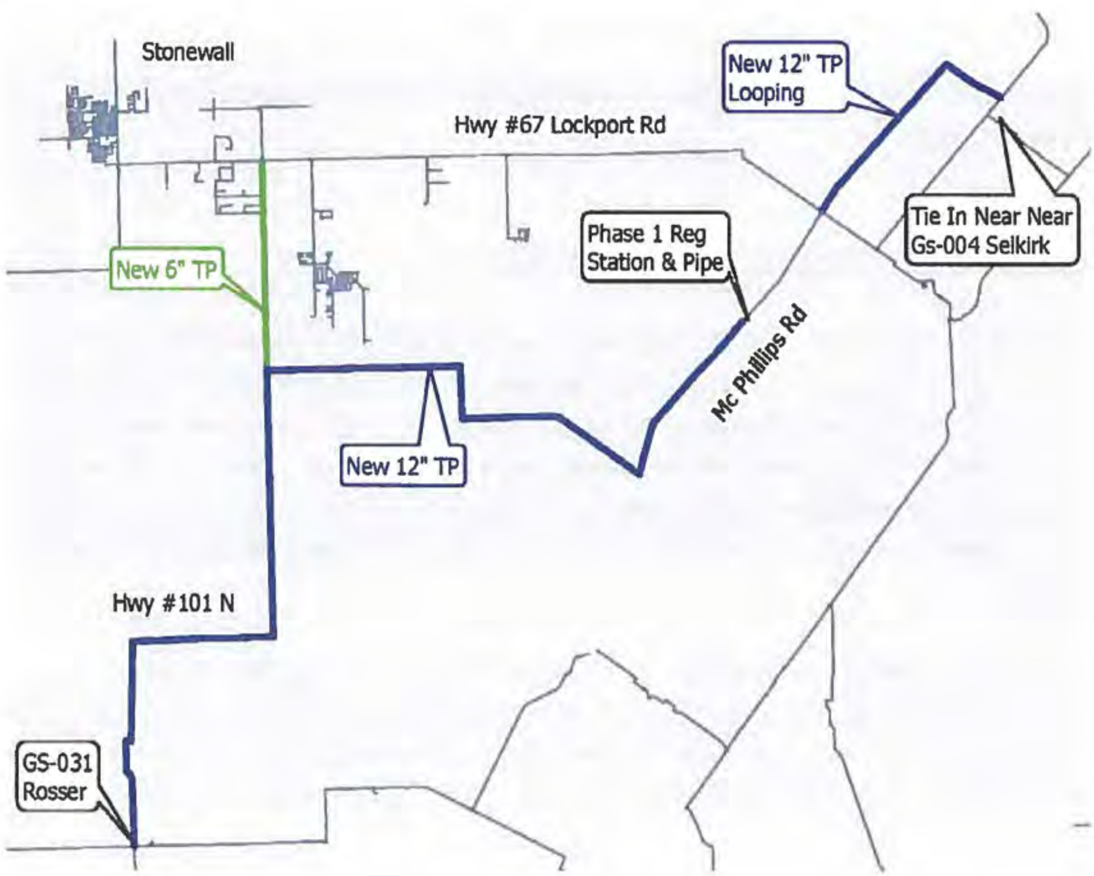


2.4 Option 4

Option 4 consists of a new 12" TP from GS-031 to the phase 1 regulation station. This option includes a 6" TP from the new 12" TP to Stonewall and 12" looping from Hwy #67 to existing plant near GS-004 Selkirk. Option 4 is shown in Figure 11 and consists of the following:

1. 19.8 km of 12" TP and 6.6 km of 6" TP going north from GS-031 at Selkirk Ave. and Hwy #101 to tie into the existing 4" TP on Hwy #67.
2. 20.8 km of 12" TP going east of the new TP to the phase 1 station at Liss Rd.
3. 4.4 km of 12" TP from the new Regulation Station to Hwy #67 (Phase 1).
4. 8.3 km of 12" TP looping from Hwy #67 running north along McPhillips Rd. to the existing plant near GS-004 Selkirk.

Figure 11 - Option 4



3.4 Evaluation of Options

The four options were evaluated based on the evaluation criteria set out in the Scope sections of this report. The evaluation results are summarized in Table 4.

Table 4 – Comparison of Options

Evaluation Criteria	Option 1	Option 2	Option 3	Option 4
Load shifted from IDC to Oak Bluff Primary Station (based on 2033 loads)	1,095 mcfh	1,115 mcfh	1,202 mcfh	1,272 mcfh
Share the Load of the north pipeline between IDC and Oak Bluff pipelines	Yes	Yes	Yes	Yes
Percent of load shifted to Oak Bluff (under normal operations)	40%	42%	52%	60%
Eliminate high velocities and provide 2-way feed in the Stonewall TP branch	Yes	Yes	Yes	Yes
Limit pressure drop to 75 psig and velocities to 15 fps	Yes	Yes	Yes	Yes
Redundant Capacity - provided to Wpg HP while maintaining pressures to the north (2013 loads)	1,000 mcfh	1,250 mcfh	1,680 mcfh	2,100 mcfh
Ability to supply minium network end pressures with TCPL pressure at Tarrif = 580 psig	Yes	Yes	Yes	Yes
Estimated Cost (conceptual level estimate)	$25.3 million	$26.1 million	$28.8 million	$31.1 million

All four options will meet the minimum evaluation criteria set out in the Scope section. However, each of the four options provides a different level of performance. In general, each option offers incrementally increased ability to shift loads or balance flows, and provides incrementally greater redundant capacity to support customers in an outage. Option 1 provides the lowest performance, while Option 4 provides the highest performance. These factors must be weighed against the incremental increase in cost of each option.

1.0 OVERVIEW

This appendix provides additional detail on capital plant and intangible additions over the period 2011/12 through 2019/20. For the purposes of this appendix, plant and intangible additions have been segregated into programs and projects with detailed descriptions provided for each. Annual plant additions have been provided at the depreciation account level (e.g. transmission-mains, distribution-regulators) and are also broken down by investment category (i.e. Capacity & Growth or Sustainment) and investment sub-category (e.g Customer Connections, Mandated Compliance). Lastly, this appendix provides information as to the apportionment of the Portfolio adjustment (discussed in Section 4.0) amongst the depreciation accounts.

Figure 1 summarizes the actual plant and intangible additions for Centra's capital programs and projects for 2011/12 to 2017/18, forecast plant and intangible additions for 2018/19 and 2019/20.

Figure 1: Plant & Intangible Additions

($ Thousands)	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19 Forecast Year	2019/20 Test Year
Programs	22,962	28,479	24,712	29,739	30,309	32,150	29,032	32,171	36,883
Projects	2,788	981	8,320	-	5,418	30,168	7,535	9,517	6,275
Portfolio Adjustment								(3,923)	(2,794)
Total Plant Additions	25,750	29,460	33,032	29,739	35,727	62,318	36,567	37,766	40,363

Each program and project is further classified by investment category. Investment categories are commonly used within the industry to provide stakeholders with a better understanding of the primary driver for the investment. The primary investment categories are further broken down into sub-categories.

The primary investment categories utilized by Centra are Capacity & Growth and Sustainment. Capacity & Growth investments provide for system expansion or address existing capacity constraints. Sustainment investments are required to ensure the continued and future performance capability of the system and address the issue of aging or obsolete assets. Further information on investment categories can be found in Tab 4, Appendix 4.4.

Figure 20: Plant & Intangible Additions – Corrosion Control Program by Investment Category

($ Thousands)									2018/19	
									Forecast	2019/20
Investment Category - Level 1	Investment Category - Level 2	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	Year	Test Year
Sustainment	System Efficiency	520	348	352	335	281	260	359	419	370
Total Plant Additions		520	348	352	335	281	260	359	419	370

Property Land Easements

This program was initiated in 2015/16 and involves activities to process grants of Right of User agreements under *The Gas Pipe Line Act* executed prior to June 2011 where the agreement and corresponding property rights instrument (e.g. easement) are not yet registered at the applicable Land Titles Office. An amendment to *The Real Property Act* in June 2011 allowed Centra a ten year window (to June 2021) to register such agreements regardless of present property tenure.

Plant and intangible additions by depreciation account for this program are shown in Figure 21 and Figure 22 summarizes the plant and intangible additions by investment category.

Figure 21: Plant & Intangible Additions – Property Land Easements Program

($ Thousands)								2018/19	
								Forecast	2019/20
	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	Year	Test Year
Intangible									
Land Rights	-	-	-	-	76	78	74	145	77
Total Plant Additions	-	-	-	-	76	78	74	145	77

Figure 22: Plant & Intangible Additions – Property Land Easements Program by Investment Category

($ Thousands)									2018/19	
									Forecast	2019/20
Investment Category - Level 1	Investment Category - Level 2	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	Year	Test Year
Capacity & Growth	Customer Connections	-	-	-	-	76	78	74	145	77
Total Plant Additions		-	-	-	-	76	78	74	145	77

3.0 PROJECTS

Projects are investments undertaken to add, replace and/or decommission an asset. The investment is planned on an individual basis with a defined beginning and end as well as a pre-defined scope, schedule and budget.

Figure 23 provides a summary of plant and intangible additions for all Centra projects, along with the investment categories driving the expenditure from 2011/12 through 2019/20.

Figure 23: Plant & Intangible Additions – Projects by Investment Category

($ Thousands)	Investment Category Level 1	Investment Category Level 2	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19 Forecast Year	2019/20 Test Year
Bunclody Natural Gas Crossing at Souris	Sustainment	Mandated Compliance	1,446								
CentrePort NPS 16 Natural Gas Transmission Main	Sustainment	Mandated Compliance	1,084	106							
Gas SCADA Replacement	Sustainment	System Renewal	258	32	3,056						
Ile des Chenes Natural Gas Transmission Network Upgrade	Sustainment	Mandated Compliance		843	(3)						
St Francois Xavier Transmission Upgrade	Capacity & Growth	System Load Capacity			3,713						
Morris Natural Gas Transmission Network Upgrade	Capacity & Growth	System Load Capacity			1,554						
GS 015 La Salle Primary Gate Station Regulation Upgardes	Sustainment	System Renewal					970				
Winnipeg North West Phase 1	Capacity & Growth	System Load Capacity					4,448	(10)	4		
Winnipeg North West Phase 2	Capacity & Growth	System Load Capacity						25,942	277		
Transcona Medium Pressure Natural Gas System Upgrade	Sustainment	System Efficiency						1,680	714		
Compressed Natural Gas Tube Trailers	Sustainment	System Efficiency						1,106			
CentrePort Canada - Phase 1	Capacity & Growth	System Load Capacity						1,451	(43)		
Compressed Natural Gas Trailer Filling Station	Sustainment	System Efficiency							4,381		
St Pierre Transmission Pressure Line Upgrade	Capacity & Growth	System Load Capacity							2,203	491	
St. Andrews Distribution System Upgrade	Sustainment	System Efficiency								1,294	
Winnipeg Natural Gas Transmission Easement Widening	Sustainment	Mandated Compliance								1,848	
Cathodic Protection Remote Monitoring	Sustainment	System Efficiency								489	
Brandon Primary Gate Station Re Construction	Sustainment	System Renewal								1,725	2,190
Natural Gas Medium Pressure Monitoring System Replacement	Sustainment	System Efficiency								1,370	776
Natural Gas Transmission Pressure System In Line Inspection	Sustainment	System Efficiency								2,301	1,983
PR 201 Red River Transmission Pressure Pipeline Replacement	Sustainment	System Efficiency									1,304
Steinbach Natural Gas System Upgrade	Capacity & Growth	System Load Capacity									21
Total Plant Additions Projects			2,788	981	8,320		5,418	30,168	7,535	9,517	6,275

Please note: negative plant additions primarily represent cost recovery on respective projects.

<u>Bunclody Natural Gas Crossing at Souris</u>

This project involved the replacement of the nominal pipe size (NPS) 6 steel transmission pressure crossing of the Souris River at Bunclody Bridge due to riverbank failure. The project included the installation of a temporary bypass, abandonment of the original crossing in the failed river bank and the installation of approximately 400 meters of new NPS 6 steel main in a NPS 12 steel casing. Plant and intangible additions by depreciation account for this project are shown in Figure 24.

Figure 24: Plant & Intangible Additions – Bunclody Natural Gas Crossing at Souris

($ Thousands)	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19 Forecast Year	2019/20 Test Year
Transmission Plant									
Mains - Transmission	1,446	-	-	-	-	-	-	-	-
Total Plant Additions	1,446								

<u>CentrePort NPS 16 Natural Gas Transmission Main</u>

This project involved relocation of the transmission pipeline to accommodate the installation of a new above grade highway interchange by Manitoba Infrastructure.

Figure 31: Plant & Intangible Additions – Winnipeg North West Phase I

($ Thousands)	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19 Forecast Year	2019/20 Test Year
Transmission Plant									
Land	-	-	-	-	113	-	-	-	-
Mains - Transmission	-	-	-	-	2,648	(81)	5	-	-
Distribution Plant									
Land	-	-	-	-	35	-	-	-	-
Mains - Distribution	-	-	-	-	727	-	-	-	-
Measuring & Regulating Equipment	-	-	-	-	461	67	-	-	-
Intangible									
Land Rights	-	-	-	-	464	3	(1)	-	-
Total Plant Additions	-	-	-	-	4,448	(10)	4	-	-

Winnipeg North West Phase 2

This project involved the installation of a second supply of natural gas to 15,000 customers in Selkirk and surrounding areas to protect against an outage, to increase capacity and to provide operational flexibility which would permit inspection and maintenance to be performed on the 50 plus year old Ile des Chenes pipeline. The project includes approximately 49 km of NPS 12 steel transmission pressure pipe, 6.6 km of NPS 6 steel transmission pressure pipe, isolation valves as required for gas maintenance and operations and pig launchers/receivers as required for pipeline integrity monitoring. Plant and intangible additions by depreciation account for this project are shown in Figure 32.

Figure 32: Plant & Intangible Additions – Winnipeg North West Phase 2

($ Thousands)	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19 Forecast Year	2019/20 Test Year
Transmission Plant									
Land	-	-	-	-	-	34	1	-	-
Mains - Transmission	-	-	-	-	-	24,831	286	-	-
Measuring & Regulating Equipment	-	-	-	-	-	471	49	-	-
Intangible									
Land Rights	-	-	-	-	-	605	(58)	-	-
Total Plant Additions	-	-	-	-	-	25,942	277	-	-

Transcona Medium Pressure Natural Gas System Upgrade

This project involved the conversion of transmission pressure pipeline to medium pressure to increase capacity of the medium pressure system. The project includes connecting the NPS 12 main to the medium pressure system at 8 locations and abandoning approximately 1.9 km of NPS 12 steel transmission main. Plant and intangible additions by depreciation account for this project are shown in Figure 33.

4

REFERENCE:

Tab 7 Figures 7.5 and 7.6

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Update the table previously provided in PUB/Centra II-172c of the 2013/14 GRA to show the Furnace Replacement Program fund activity and number of furnace and boiler replacements between 2012/13 and 2017/18 (actual), as well as 2018/19 to 2027/28 (outlook).

b) Clarify whether the estimated cost to “complete the transformation of standard efficiency furnaces and boilers over the next 10 years” is $14.2 million (as shown in Tab 7 p. 11) or $14.9 million (as shown in Figure 7.5). Similarly, clarify whether the estimated number of boilers to be replaced over the next 10 years is 78 (as shown in Tab 7 p. 11) or 94 (as shown in Figure 7.5).

RESPONSE:

a) Please see the attachment to this response for an update to the previously provided table.

b) The estimated cost to “complete the transformation of standard efficiency furnaces and boilers over the next 10 years” is $14.9 million as shown in Figure 7.5. The estimated number of boilers to be replaced to the end of fiscal year 2025/26, the time at which standard efficiency furnaces are estimated to be depleted from the market, is 78. An additional two years of program participation brings the total number of boilers to be replaced over the next 10 years to 94 as shown in Figure 7.5.

Centra Gas Manitoba Inc. 2019/20 General Rate Application
PUB/CENTRA I-100a Attachment

Furnace Replacement Fund ending March 31 (000's)	**2008/9 Actual**	**2009/10 Actual**	**2010/11 Actual**	**2011/12 Actual**	**2012/13 Actual**	**2013/14 Actual**	**2014/15 Actual**	**2015/16 Actual**	**2016/17 Actual**	**2017/18 Actual**	**2018/19 Forecast**	**2019/20 Forecast**	**2020/21 Forecast**	**2021/22 Forecast**	**2022/23 Forecast**	**2023/24 Forecast**	**2024/25 Forecast**	**2025/26 Forecast**	**2026/27 Forecast**	**2027/28 Forecast**
Opening Balance	$ 2,327	$ 5,972	$ 9,050	$ 11,644	$ 14,145	$ 16,071	$ 18,176	$ 19,272	$ 20,971	$ 22,922	$ 24,856	$ 27,151	$ 26,149	$ 7,551	$ 5,779	$ 4,120	$ 2,655	$ 1,348	$ 117	$ 82
Funding from SGS Class	$ 3,855	$ 3,800	$ 3,762	$ 3,838	$ 3,800	$ 3,800	$ 3,800	$ 3,800	$ 3,800	$ 3,800	$ 3,800	$ 545	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Disbursements	$ (264)	$ (815)	$ (1,312)	$ (1,627)	$ (2,167)	$ (2,012)	$ (3,191)	$ (2,394)	$ (2,170)	$ (2,298)	$ (2,137)	$ (2,395)	$ (2,192)	$ (2,002)	$ (1,830)	$ (1,591)	$ (1,383)	$ (1,260)	$ (38)	$ (40)
Interest	$ 54	$ 93	$ 144	$ 290	$ 287	$ 322	$ 336	$ 293	$ 320	$ 433	$ 632	$ 848	$ 895	$ 229	$ 171	$ 126	$ 76	$ 29	$ 4	$ 2
Proposed Disposition	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (17,300)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ending Balance	$ 5,972	$ 9,050	$ 11,644	$ 14,145	$ 16,071	$ 18,176	$ 19,272	$ 20,971	$ 22,922	$ 24,856	$ 27,151	$ 26,149	$ 7,551	$ 5,779	$ 4,120	$ 2,655	$ 1,348	$ 117	$ 82	$ 45
Number of Furnace Installations	280	508	445	662	630	605	796	673	547	561	510	459	413	372	335	284	242	217	0	0
Number of Boiler Installations	5	9	16	18	9	18	21	11	11	12	10	10	10	10	10	10	9	9	8	8
Cumulative Furnace Installations	280	788	1,233	1,895	2,525	3,130	3,926	4,599	5,146	5,707	6,217	6,676	7,089	7,461	7,796	8,080	8,322	8,539	8,539	8,539
Cumulative Boiler Installations	5	14	30	48	57	75	96	107	118	130	140	150	160	170	180	190	199	208	216	224

REFERENCE:

Tab 7 Figure 7.5 and 7.6; Tab 3 Section 3.1.2; Appendix 3.3

PREAMBLE TO IR (IF ANY):

"Centra will continue to accept applications under the FRP going forward and estimates that approximately $13 million will be needed from 2019/20 through to 2027/28 to replace the remaining eligible furnaces and boilers under the program."

"CGM18 has assumed the disposition of approximately $17 million (the excess funding) by the end of 2020/21. The details and timing of any planned dispositions or other allocations from this fund, such as returning the excess funding to customers, will be subject to the review and approval by Centra's Board of Directors and PUB approval will be sought in a future Centra regulatory proceeding."

QUESTION:

a) Please provide details on alternatives Centra has considered with the $17 million in excess funding.
b) If the $17 million was to be refunded to the SGS class through a rate rider, calculate the rate rider and the bill impacts (independent of other bill impacts in this application) if the refund is over:
   i. a one year time period;
   ii. a two-year time period;
   iii. a five-year time period.

RESPONSE:

a) Although Centra has assumed the disposition of approximately $17 million in excess funding by the end of 2020/21 under CGM18, no specific plans or details on the disposition of this funding have been assessed at this time or presented to its Board of Directors for their review. It is Centra's intention to seek stakeholder input on the potential alternatives to be assessed; however, some possible alternatives may include:

   - Return of the excess funding to ratepayers through a rate rider;

- Allocate the excess funding to support natural gas DSM programs through Efficiency Manitoba; or
- Allocate the excess funding to fund bill affordability initiatives.

b) Figure 1 provides the calculation of a FRP rider to be refunded over one-year, two-year and five-year time period. Figure 2 provides the SGS customer class bill impacts for each time period the FRP rider to be refunded.

Figure 1: Calculation of FRP rider to be refunded over different time period

	i) one -year	ii) two-year	iii) five-year
Total FRP fund balance to be refunded to the SGS customers	$17,000,000	$8,500,000	$3,400,000
2019/20 SGS Annual Volumes (10^3m^3)	[redacted]		
FRP refund rider ($\$/10^3m^3$)			
FRP refund rider ($\$/m^3$)			

1d

Figure 2: SGS customer class Bill Impacts for each time period the FRP rider to be refunded

	Annual Use		i) One year Period BILL IMPACTS		ii) Two year Period BILL IMPACTS		iii) Five year Period BILL IMPACTS	
	10^3m^3	Mcf	$	%	$	%	$	%
Small General Service	1.00	35	($25)	-6.2%	($12)	-3.1%	($5)	-1.2%
	1.98	70	($49)	-7.8%	($25)	-3.9%	($10)	-1.6%
(Typical Residential Customer)	2.22	78	($55)	-8.0%	($28)	-4.0%	($11)	-1.6%
	2.80	99	($70)	-8.4%	($35)	-4.2%	($14)	-1.7%
	3.20	113	($80)	-8.6%	($40)	-4.3%	($16)	-1.7%
	3.68	130	($92)	-8.8%	($46)	-4.4%	($18)	-1.8%
	11.33	400	($282)	-9.9%	($141)	-5.0%	($56)	-2.0%

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."

5

13) Determination of Monthly Billing Demand

The Monthly Billing Demand that will be used to calculate the Customer's Monthly Demand Charge shall be determined as follows:

a) **Monthly Billing Demand** will be the highest daily consumption, subject to sections V F) 3), V G) 7), VI D) 4), and VI E) 7), measured in Cubic Meters on any given day of the month, provided the month is a Winter Month, or in any Winter Month of the preceding eleven months. For Customers without twelve months of demand billing data, the Monthly Billing Demand may be estimated or otherwise specified by the Company.

b) **Exception**: During the months of November and March, the Company may (at its sole discretion) authorize certain Customers to use gas without invoking a higher Monthly Billing Demand. This flexibility will be available only to those Customers who do not regularly require significant volumes of gas in the Winter season, but whose non-winter requirements may extend into the Winter season for a short duration either at the start or at the end of the Winter season. Such flexibility may be provided at the sole discretion of the Company.

E) OTHER SERVICES

The Company may provide the following services:

a) Locate and mark at no direct charge, all Company owned underground plants on request to facilitate excavation or other construction.

b) Respond, at no charge, on a 24-hour emergency basis to reports of, explosion, fire, gas odour, leaks, fumes, over-pressure, overheating of natural gas space heating equipment or damaged plant, or any other service which, in the Company's opinion, is required for the maintenance and security of Company equipment.

c) Provide safety inspections, safety related adjustments and/or repairs to the natural gas burning portion of stoves, ranges, and all primary space and water heating residential and commercial appliances under 400,000 Btu/h (422 MJ/h). This includes, but is not limited to, repair of minor gas leaks, and the adjustment and replacement of controls and control parts. The Small General Class Customer will be responsible for the cost of parts. All other Customers will be responsible for the cost of parts and labour.

d) Service to commercial or industrial equipment over 400,000 Btu/h (422 MJ/h) will not normally be undertaken. The Company will respond, however, to commercial emergencies where business might be adversely affected by prolonged interruption of service. The Customer will be responsible for the cost of parts and labour.

e) Provide customers or customers' agents with basic billing. Routine queries for which a response can be developed with the commitment of 30 minutes or less of staff time will be addressed at no charge. For more complex inquiries, which require more than 30 minutes staff time, the customer will be responsible for the cost of labour, which will be billed at the approved Company Labour Rate (see Section XI, Company Labour Rate).

REFERENCE:

Customer Equipment Problem Program (EPP) report (p.7-16)

PREAMBLE TO IR (IF ANY):

The following questions are related to the information in this section combined with Table 4

QUESTION:

a) What kind of new furnace incentives and programs were given to customers during this 12 year period?
b) How many customers in Winnipeg and Rural have replaced their furnace over this time frame?
c) Have the parts to be replaced in the burner tip service agreement been updated to reflect the new EPP core good appliances worked on today?
d) What was the Burner Tip Service "Parts to be Replaced" list prior to the purchase of Centra Gas Inc.
e) What is the Customer EPP "Parts to be Replaced" list today?
f) Could this decline in "Parts to be Replaced" correlate to the hours reduced criteria of things allowed to be worked on?

RESPONSE:

a) Manitoba Hydro has provided a number of programs to finance new high efficiency natural gas furnaces.

   From 2005 to 2009, Manitoba Hydro offered residential customers incentives for upgrading their natural gas furnaces to high efficient models. This initiative provided an incentive of $245 on the customer's natural gas bill and helped to convert standard efficient furnaces in the market to high efficient models.

   In addition to the Residential Natural Gas Furnace Program, Manitoba Hydro also offered financing to help customers with the cost of replacing their heating system.

Since March 2001 the Home Energy Efficiency Loan (previously Power Smart Residential Loan) has provided convenient on bill financing for the purchase of a high efficiency natural gas furnace to customers with approved credit. Customers can finance up to $5,500 over a maximum 15 year term.

The Affordable Energy Program, which was launched in December 2007, assists homeowners and tenants with a limited income in upgrading their standard efficient natural gas furnace to a high efficiency natural gas furnace for $9.50 per month for five years.

Launched in November 2012, Pay As You Save ("PAYS") Financing offers extended financing terms for upgrading standard efficiency natural gas furnaces to high efficiency natural gas furnaces. PAYS Financing allows customers to use the energy savings from their upgrade to make the monthly payment, which means customers should not see an increase to their monthly energy bill.

b) 96,171 furnaces have been replaced in Manitoba between 2006 and 2017; 82,336 were in Winnipeg and 13,835 were non-Winnipeg ('rural').

c) The standard parts list covers space heating, water heating and cooking appliances, which is consistent with the PUB's direction in Order 85/13 to limit this service to primary space heating, water heating appliances and ranges.

d) As per Order 49/95, Centra was required to provide the following list of components on gas furnaces and hot water heaters:

- High limits;
- Pressure temperature relief valves;
- Gas valves;
- Regulators manifold;
- Thermocouples;
- Ignitors;
- Flame Monitoring components;
- Unitrols;

- Single pole thermostats;
- Fan controls;
- Transformers; and
- Millivolt relays

e) The current list of parts to be replaced include the following:

- Ignitors
- Flame sensors
- Thermocouples
- Pilot Generator
- Pilot Burner
- Gas Valves (Standing Pilot Only)
- Transformers
- Millivolt Relays
- Heat Only Thermostats (non- digital)

f) Centra believes the reduction in hours worked on CEPP calls is directly correlated to the installation of new natural gas high efficiency furnaces across the Province.

Control Part	Order 49/95 Unifor/Centra I-7d	Current Procedure Unifor/Centra I-7e
High Limits	✓	X
Pressure temperature relief valves	✓	X
Gas valves	✓	Standing pilot-type only
Regulators manifold	✓	X
Thermocouples	✓	✓
Ignitors	✓	✓
Flame Monitoring components	✓	✓
Unitrols	✓	✓
Single pole thermostats	✓	Heat-only, non-digital
Fan controls	✓	X
Transformers	✓	✓
Millivolt relays	✓	✓

PUB Advisor Table

REFERENCE:

Tab 12 pgs. 12-13 of 13, Appendix 12.4; 2013/14 GRA PUB/Centra I-130

PREAMBLE TO IR (IF ANY):

Centra states that it continues to offer the Equipment Problem Program ("Burner Tip Service") to its customers, consistent and fully compliant with the original intent of the program as summarized in Order 49/95, and as set forth above in the corresponding terms and conditions of service last reviewed and approved by the PUB at Centra's 2013/14 General Rate Application. Centra is not proposing any changes to the EPP or the related terms and conditions of the program as part of this Application.

QUESTION:

a) Provide Centra's November 15, 2018 response to Board Advisor questions regarding the Customer Equipment Problem Program ("Burner Tip Service").
b) Confirm whether Centra personnel will replace all the appliance parts identified in Order 49/95 at page 120.
c) For each of the past five years, provide a breakdown of the total number of Residential service calls, the total cost of service calls, and the average cost per service call broken down into space heating and water heating.
d) In Appendix 12.4 at page 21, Centra states: "Ignition modules and igniters are the common issues with ranges. As there are now a wide variety of range models and manufacturers, Manitoba Hydro does not repair many ranges annually. As there are so many different ranges, Manitoba Hydro is unsure of who the suppliers are and where to obtain parts." In light of this, how does Centra comply with Order 85/13 Directive 21 which requires Centra to offer the Equipment Problem Program for ranges?

RESPONSE:

a) See the attachment to this response.

b) Centra continues to ensure that the safety objectives of the EPP are being met and will replace standard parts that are listed in Order 49/95. Over the last quarter century, advancements in technology have been made to improve the safe operation and reliability of natural gas appliances. A number of safety components such as limit controls, flame monitoring components, fan controls and modulating gas valves have been integrated into new appliances. Centra does not stock all proprietary parts in its standard parts kit.

c) The following table provides a summary of the requested Customer Equipment Problem Program ("CEPP") data:

Fiscal years	2013/14	2014/15	2015/16	2016/17	2017/18
CEPP service cost	$ 1,980,959	$ 1,887,748	$ 1,367,777	$ 1,351,670	$ 1,295,969
CEPP service orders	16,731	13,961	12,244	11,728	10,881
Avg cost/call - space heating	$ 121.06	$ 138.25	$ 114.22	$ 117.84	$ 121.78
Avg cost/call - water heating	$ 106.38	$ 121.50	$ 100.37	$ 103.56	$ 107.02

d) Centra receives fewer than fifty calls per year for servicing ranges under the Customer Equipment Problem Program. Service personnel are able to make repairs using standard parts. As with other gas appliances, technological advancements have resulted in the integration of proprietary parts which are not part of the standard parts kit and can be challenging to obtain.

From: Gratton, Charlene
Sent: Thursday, November 15, 2018 11:26 AM
To: 'David Bonin'
Cc: Brady Ryall; Simonsen, Kurt (PUB); Rachel McMillin; Gregorashuk, Shannon; Steele, Chuck
Subject: RE: PUB/MH QCM Draft Agenda

At the November 8, 2018 QCM, Ryall Engineering raised questions as to whether Centra had made changes to its Equipment Problem Program ("EPP").

Centra can advise that it has not made any changes to Equipment Problem Program since its Terms and Conditions of Service were last reviewed and approved by the PUB at the 2013/14 General Rate Application. In that application to the PUB, Centra proposed changes to its Terms and Conditions to limit the service provided under the EPP to primary space heating and water heating appliances. In proposing those changes, Centra clarified it would continue to address all safety concerns, regardless of the appliance involved. In Order 85/13 and 89/13, the PUB approved the changes to the Terms and Conditions of Service proposed by Centra but directed Centra to continue to service stoves and ranges under the EPP.

The Terms and Conditions of Centra's EPP are set out under "Other Services" (Section IV. E) c)) of Centra's *Schedule of Sales and Transportation Services and Rates*, dated August 2, 2013 as follows:

> *Provide safety inspections, safety related adjustments and/or repairs to the natural gas burning portion of stoves, ranges, and all primary space and water heating residential and commercial appliances under 400,000 Btu/h (422 MJ/h). This includes, but is not limited to, repair of minor gas leaks, and the adjustment and replacement of controls and control parts. The Small General Class Customer will be responsible for the cost of parts. All other Customers will be responsible for the cost of parts and labour.*

The EPP, formerly known as Burner Tip, has been a service offered by Centra since the early 1990s. As outlined in PUB Order 49/95, issued following Centra's 1995 Test Year GRA, the focus of the program has always been, and continues to be, on safety and advice to the consumer. For all calls received under the EPP, Centra completes a diagnosis on the problem, makes immediate safety repairs, provides operating advice and makes referrals to heating dealers for more significant and complex repairs. As part of this program, Centra also responds to "no heat" calls in critically cold weather, completes some repairs and eliminates the health risk associated with no heat. Certain repairs can no longer be completed fully by Centra given significant industry advancements in technology and design in the wide variety of space and water heating appliances now available to customers, the complexity of the repair and/or obsolete replacement parts. In such cases, heating dealers are involved to complete the necessary and proper final repairs or to recommend that the customer obtain a new appliance.

In 2009, new regulations required that all new furnaces installed in the Province of Manitoba must meet high efficiency standards. The change has resulted in greater complexity and variety in the equipment utilizing proprietary parts. When the EPP was first developed, Centra stocked a list of standard parts which could be used to repair almost any furnace. With the introduction of many new manufacturers and models, it is impractical for Centra to maintain an inventory of parts for each individual make and model of furnace. When a Service Person encounters an equipment problem for which a specific brand and model of part is required, the customer is advised that Centra can order and obtain the part and return to install it, or the customer can call a heating dealer who specializes in that brand of equipment who may have the part in stock. As high-efficient furnaces now represent the majority of equipment installed in the Manitoba marketplace, this situation occurs more commonly than it used to. However, in Centra's view, the steps taken to ensure safety and to diagnose the problem are what was contemplated as part of the service provided under the EPP and do not constitute a change in the program from its original intent as
th

outlined in Order 49/95. As noted by Centra at the November 8 QCM Meeting, work completed by licensed heating dealers at a customer's request can include repairs or the installation of replacement gas valves, high temperature limits, and fan controls.

Centra continues to offer the EPP to its customers, consistent and fully compliant with the original intent of the program as summarized in Order 49/95, and outlined in the Terms and Conditions of Service approved by the PUB. As it has done in the past, Centra will bring forward to the PUB for review and approval any changes it would like to propose to the Terms & Conditions of Service related to the EPP.

Should you require further information, please contact Shannon Gregorashuk at 204-360-4270 or via email sgregorashuk@hydro.mb.ca.

Thank you

Charlene Gratton

--- Upon recessing at 3:42 p.m.
--- Upon resuming at 3:53 p.m.

THE CHAIRPERSON: Mr. Peters, I believe we can resume the proceedings.

MR. BOB PETERS: Yes, sir. Thank you.

CENTRA PANEL 3, RESUMED:
DARREN RAINKIE, Resumed
HANRI JACOBS, Resumed
MARK PRYDUN, Resumed
KELLY DERKSEN, Resumed
GREG BARNLUND, Resumed

CONTINUED CROSS-EXAMINATION BY MR. BOB PETERS:

MR. BOB PETERS: Mr. Chairman and Board members, you'll recall when I reviewed with this panel back on a page 147, there was the item labelled 'L', which talked about approvals to various terms and conditions of service that were included in the application.

And, Mr. Prydun, one (1) of those changes in the terms and conditions of service related to the Customer Equipment Problems Program.

Is that correct?

MR. MARK PRYDUN: That's correct, sir.

MR. BOB PETERS: And for those old-timers, like Mr. Rainkie, would that also be known as the -- as the Burner Tip Program?

MR. MARK PRYDUN: That's correct, sir.

MR. BOB PETERS: And do you know why Centra initially offered this Customer Equipment Problems Program, or the Burner Tip Program?

(BRIEF PAUSE)

MR. GREG BARNLUND: Mr. Peters, going back quite some time in the utility business, quite typically, Greater Winnipeg Gas predecessor company, and intercity gas utilities, predecessor companies to Centra offered a certain amount of appliance repair service as part of their -- part of their package of services that they offered to natural gas customers, in part, to promote the installation and use of natural gas appliances.

MR. BOB PETERS: And Centra has continued a Burner Tip Program, as I call it, since those years of inception, Mr. -- Mr. Barnlund?

MR. GREG BARNLUND: Yes, it has.

MR. BOB PETERS: And, Mr. Prydun, what

you're now asking the Board is that you on -- Centra only wants to propose continuing this burner tip service for primary space heating and hot water appliances.

Have I got that right?

MR. MARK PRYDUN: That's correct, sir.

MR. BOB PETERS: So let's just make sure the Board understands what you're asking. A customer could phone Centra because they have a problem with their fireplace, their barbecue, their pool heater. And -- and Centra would come out to provide servicing?

MR. MARK PRYDUN: Currently, that is what Centra does. What we are proposing is, is that for fireplaces, for pool heaters, barbecues, et cetera, we would refer those types of calls to a private contractor.

MR. BOB PETERS: Why does Centra want to stop servicing these other appliances other than the furnace and the hot water tank?

MR. MARK PRYDUN: Sir, as -- as part of our ongoing review of our services within our business unit, we have reviewed the Customer Equipment Problem Program. And we considered portions of that to be deemed as, perhaps, nonessential.

We are -- as part of our core business review, we are trying to understand the difference between a service that would be viewed as es -- essential and mandated to our operations, and that, perhaps, being viewed as somewhat not as essential to the health and well being of customers.

The types of appliances, such as fireplaces, barbecues, ranges, clothes dryers, the conclusion of customer service and distribution was that these types of calls would -- could be considered not dre -- detrimental if we discontinued that type of service.

MR. BOB PETERS: But if the customer phoned up and said, I've got a concern about the safety of an appliance because I might smell gas or something that I think is natural gas.

What does Centra do in that circumstance under the new proposal?

MR. MARK PRYDUN: Sir, under that proposal, or under the new proposal, those types of calls would continue to be coded as a safety-related call. Typically, if a customer calls in and says, I smell gas, or is panic stricken, or for any number of reasons, if the customer, and/or the -- the company believes that there is a safety situation or an emergency situation, we will continue to proceed with investigating the call.

MR. BOB PETERS: Maybe just a point of interest for the Board members, Mr. Prydun, is that one (1) is told that natural gas is odourless, but Centra puts into it a -- an odourant so that it can be detected?

MR. MARK PRYDUN: That's correct, sir.

MR. BOB PETERS: And so Centra proposes that on any safety-related calls, it'll continue as business as usually?

MR. MARK PRYDUN: That is correct, sir.

MR. BOB PETERS: But if it's to come out and have a look at a dryer, a fireplace, a range, BBQ, pool heater, or anything but a furnace and a hot water tank, the customer will be directed to presumably the -- an HVAC dealer of their choosing?

MR. MARK PRYDUN: That is correct, sir.

MR. BOB PETERS: Will Centra make a recommendation as to which HVAC dealer to use?

MR. MARK PRYDUN: No, at -- no, we will not, sir.

MR. BOB PETERS: Centra does have

preferred HVAC dealers, if I can use that word, in respect of the furnace replacement program?

MR. MARK PRYDUN: Well, we do have a list of dealers that are participating under the furnace replacement program. The terms of those arrangements are only with respect to the installation of new furnaces for customers that will be addressed through that program itself.

MR. BOB PETERS: Mr. Prydun, if we turn to page 304 in the book of documents, Tab 56, the Board will -- will have a -- a better idea of the -- the parameters of the Customer Equipment Problems Program or the Burner Tip Program, as I've been calling it.

For the residential customer seen at the bottom of page 304, Mr. Prydun, it appears that in fiscal '12/'13, so fiscal '13, the Corporation went out on about eleven hundred and thirty-two (1,132) calls that dealt with something other than a space heat or water heat issue?

MR. MARK PRYDUN: That's correct, sir.

MR. BOB PETERS: And then when we move over a few columns, and we see the average cost per call of seventy-eight dollars and twenty-one cents ($78.21), we can also see on page 305 that that's been quantified at eighty-eight thousand dollars ($88,000), correct?

MR. MARK PRYDUN: That's correct, sir.

MR. BOB PETERS: So Centra values and quantifies the savings at eighty-eight thousand dollars ($88,000)?

MR. MARK PRYDUN: From an activity rate for field-based labour, the eighty-eight thousand dollars ($88,000) would be correct, sir.

MR. BOB PETERS: And I suppose, Mr. Rainkie, is that eighty-eight thousand dollars ($88,000) material enough to be reflected in the -- in the application that's before the Board?

MR. DARREN RAINKIE: No, Mr. Peters, but I think there are other costs, as I understand it. Mr. Prydun's probably better to speak to this, but this is -- this is quantifying the cost of a call at the average activity rate, but there's also the cost of training staff, or the proliferation of various devices, I guess, natural gas devices that might be out there.

And so there are probably other costs other than just the raw costs of the labour going out there. And, you know, this is part of our review of our business to make sure that our costs are okay, and know it's -- you know, on the base of it the eighty-eight thousand (88,000) isn't a hugely material amount, but little amounts add up, I suppose, after time.

MR. BOB PETERS: And, Mr. Prydun, can you advise the Board of any additional costs over and above the eighty-eight thousand dollars ($88,000) that the Corporation expects to save if the Board approved the requested change in the terms and conditions of service?

MR. MARK PRYDUN: I cannot define quantitatively, the -- the costs that would be involved with training our field staff for the -- the undertaking of re -- servicing of fireplaces or -- or ranges, as -- as an example.

What we are aware of those is that the complexity of these types of appliances continue to grow, and the -- the variability and the types of models continues to grow as well. So it is putting a little bit of additional pressure on our ability to train our -- our field labour to competently undertake the -- the servicing of these appliances.

So consequently, we are experienced -- experiencing an upward trend in -- in training costs.

(BRIEF PAUSE)

MR. BOB PETERS: Mr. Prydun, does Centra Gas keep an inventory of spare parts, in my vernacular, or repair parts for some of these appliances other than the -- I'm talking other than the furnace and the water heater?

MR. MARK PRYDUN: Typically, the spare parts that are kept are for the -- the ones that are used for high volume. What we are also experiencing is just that there are parts that we do have to replace. And in the case of a fireplace, we would have to leave the premise. We'd have to leave the home because we would not stock that part.

We would have to go acquire that part, and then come back, and -- and service the customer on a second work order. That, in itself, is an inconvenience, as well.

MR. BOB PETERS: Is there a cost savings because of reduced inventory, or is it simply, you purchase what you need when you need it on these other than furnace and hot water tank calls?

MR. MARK PRYDUN: Typically, we purchase what we need, sir, because we're unaware what we would be looking to replace at the time.

MR. BOB PETERS: And, Mr. Prydun, do these costs manifest themselves by -- by fewer EFTs being allocated over the Centra side of the business? EFT meaning equivalent full-time employees.

(BRIEF PAUSE)

MR. MARK PRYDUN: There was a question, sir, that re -- asked on what the equivalent full-time pos -- field-time labour would be, and it was less than one (1). My -- from memory, I believe it was in the zero point eight (0.8) to zero point six (6) range.

And that associated labour also would be deployed to other types of work order assignments that is -- that is on our books.

MR. BOB PETERS: When Centra goes in and makes those calls, Mr. Prydun, does it do it for free?

MR. MARK PRYDUN: Under the Customer Equipment Problem Program, that's correct, sir.

MR. BOB PETERS: So the labour is free. The parts are extra cost?

MR. GREG BARNLUND: The labour is at no charge and the parts are at cost.

MR. BOB PETERS: And, Mr. Prydun, why doesn't Centra completely cease the program and recognize savings, if we look at page 305, perhaps, on average about $1.3 million a year total?

MR. MARK PRYDUN: If the question, sir, is was our proposal limited to just the -- the fireplace, the -- the ranges, the -- the pool heaters, et cetera, and not the water heaters and not the -- the space heating appliances, the answer to that was -- is that, in our business unit, we did not -- we could not demonstrate a high level of confidence that -- that we were going to be compromising customer well being and health of customers.

MR. BOB PETERS: So because of the customer safety factor, the Corporation's proposing to continue with the space heating and the water heating part of the equipment, the progra -- the -- the burner tip service, correct?

MR. MARK PRYDUN: Customer safety, customer well being, and customer health, sir.

MR. GREG BARNLUND: Mr. Peters, I might add, too, that we have to look outside the City of Winnipeg as well, in terms for our service territories. While City of Winnipeg -- there are quite a large number of mechanical contractors available to fill the market, that can't be said for every community that we provide service to. And so it's important -- we felt important to maintain service to the domestic space heating and water heating requirements of those customers, and we can be doing that across our service territory.

And -- and again, we have to look outside of just the City of Winnipeg, in terms of that.

MR. BOB PETERS: Is this request for the change in terms and conditions of service precipitated by the HVAC dealers in any way?

MR. GREG BARNLUND: I wouldn't say that it's precipitated by the HVAC dealers. I can tell you that there was consultation with the HVAC dealers in the last year, as we -- as we were evaluating the possibility of making this change. They've been consulted with and they've been advised, and we've also heard, I guess, their feedback throughout that process.

MR. BOB PETERS: They want you out of the business as much as possible, one would expect?

MR. GREG BARNLUND: I think that we're looking to work together quite collaboratively in the market. And we've been verbally reassured that they are satisfied with what we're applying for in this application.

MR. BOB PETERS: Did Centra consider going into competition with the HVAC dealers, and start charging a fee for the labour component, as well as the parts for the non-essential space heat and water heating?

MR. GREG BARNLUND: That is not one (1) of our objectives at all.

(BRIEF PAUSE)

MR. BOB PETERS: Mr. Prydun --

MS. MARILYN KAPITANY: Can I -- can I just ask --

MR. BOB PETERS: Yes.

MS. MARILYN KAPITANY: -- did you -- did you consider charging for the -- the space heaters and for the water heaters? And if not, why not?

MR. MARK PRYDUN: We -- we did undertake a cursory review of what other gas utilities are doing across Canada. It is correct that there are utilities that refer service to a private contractor. There are utilities that will perform a -- a fee-for-service as well.

The directions that -- that we were under, and -- and in the spirit of -- of how we wanted to focus on our -- our core services, the view was, is that this proposal was -- was in our bent -- best intr -- best interest as a business unit, and how we effectively use our -- our existing staff.

MS. MARILYN KAPITANY: Sorry, I wasn't asking if you had thought about charging for the non-essential. I was asking if you had thought about charging for what you called the 'essential', the -- the furnaces and water heaters?

MR. MARK PRYDUN: At this time, we did not.

MS. MARILYN KAPITANY: And can you just say why you didn't consider doing that?

MR. MARK PRYDUN: The overall spirit of -- of this, in part, was also due to rationalize our core services. And it was viewed, albeit this might be a very small part being considered to be a non-core service, the spirit of the exercise was such that -- that less than one (1) EFT could be deployed to a more important, perhaps, type of core service that is required to be offered by the company. If we would go ahead and charge for that service, it wouldn't economize the use of our internal EFTs.

THE CHAIRPERSON: I guess the question I have is with respect to the consultations that were done with HVAC dealers. Was any consultation done with consumers?

MR. GREG BARNLUND: Our consultations were strictly with the HVAC dealers that were involved in the industry.

THE CHAIRPERSON: Do you have some sense of -- some feedback or survey data that you collected that addresses the issue of customer satisfaction with this service?

(BRIEF PAUSE)

MR. MARK PRYDUN: We haven't done any for -- formal customer sur -- surveys, sir, since recently, I would say. At least, for the last decade.

THE CHAIRPERSON: I suspect that if I was to do a survey of my neighbours on this issue, that my neighbours would tell me that they're very satisfied with this service.

And do you -- I -- I guess I'm asking you, would there be any evidence to the contrary that you could provide that would cause me to change my view of my neighbours' opinion about this service?

MR. GREG BARNLUND: I -- I think it's important to re -- recognize that we're not speaking of eliminating the service entirely. We're -- we're speaking of -- of re-focussing the service to what we would say is the -- the core or the essential appliances that you would normally expect a homeowner to be concerned about, their -- their furnace and their water heater.

Typically, a lot of people will have a plumbing and heating dealer, or a appliance dealer that they bought their appliances -- their washer and dryer from -- from a -- a supplier. They'll probably go back to that particular dealer for service on the gas dryer.

We're just trying to make sure that we refocus on those core appliances. And -- and I'm not sure in terms of -- I think that there's a lot of acceptance from customers of the service we provide, in terms of us coming out to respond to any smell of gas, any carbon monoxide, any -- any issues like that.

And -- and obviously, there's probably a large number of customers, as we can see here, that would call us if they had difficulty lighting their furnace, or their water heater in the fall and we will still, without any hesitation, be providing that service.

THE CHAIRPERSON: Just for my -- my own understanding, I want to make sure I understand this, so the -- the burner tip goes out, and you get a call from a client or the cli -- you -- pardon me, is that typically how it happens, the -- the client tries to put on the device, and the device doesn't come on and so they call Centra.

You go into the house, you sort of establish that it's the -- pilot light's out or the burner's not functioning. You actually repair the device? I mean, you actually -- did I mis -- misunderstand you?

MR. MARK PRYDUN: It could be a variety of reasons, sir. Sometimes the -- the pilot light could be out, and it could be as simple as -- as Centra coming in and relighting the -- the appliance. Other times it could be a -- a certain component part that has failed, which we would replace, and then that would get the appliance restored to service again.

At other times, it could be a little bit more of a concerning safety problem. At times, we would undertake a rectification of that problem as well. In general though, the majority of calls related to furnaces though, are related -- are minor in nature, and are related to pilots that have gone out.

At times, and although this is diminishing with -- with the increasing trend towards new furnaces, customers would choose to shut off their pilot light deliberately, and then call Centra as the -- as we went -- came into the -- the fall time season, and ask to Company to come back and -- and relight their appliance.

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: To be clear, those customers who blow out the pilot light in the spring and ask you to -- ask Centra to relight it in the fall, you're still going to answer that call and not charge them to relight it, as I understood?

MR. MARK PRYDUN: Under the current terms and services, that's correct, sir.

MR. BOB PETERS: And also under the proposed terms and services?

MR. MARK PRYDUN: That's correct, sir.

MR. BOB PETERS: It's just that if a customer and phoned you and said they had trouble with their BBQ, you'd be telling them to go talk to someone else?

MR. MARK PRYDUN: Because a BBQ, as per our discussions, would be viewed as a -- a less essential type of service, sir.

MR. BOB PETERS: Thank you. Mr. Prydun, I want to turn to the new company labour rates and activity rates, because you're also asking the Board to approve new rates for -- for the services that are provided by Centra that are charged out, sir?

MR. MARK PRYDUN: Yes, that's correct.

MR. BOB PETERS: And just by way of -- on page 310 of the book of documents found under Tab 57, the currently-approved activity rates, as approved by this Board are contained on -- on page 310, sir?

MR. MARK PRYDUN: Yes.

MR. BOB PETERS: And to some extent, the Board will note that the rates charged depend on the location in which the service is being done?

MR. GREG BARNLUND: In the last approved rates that we had, that was the case. And we are moving to amalgamate those into a single service charge instead of having a separate charge by district in this application.

MR. BOB PETERS: Yes, but in the previous application, if you were outside the City of Winnipeg, the -- the labour rate was -- was higher?

MR. GREG BARNLUND: For damage repairs -- that was the category that had a separate rate for each district.

MR. BOB PETERS: All right. Now, the new rates that are proposed are found on page 307, sir?

MR. GREG BARNLUND: Yes, sir.

MR. BOB PETERS: And these are going to be rates that Centra charges to third parties, correct?

MR. GREG BARNLUND: Yes, sir.

MR. BOB PETERS: And so if there's a service line alteration request, that would be charged out at a hundred and twenty-one dollars ($121) an hour regular time or a hundred and sixty-nine dollars ($169) overtime?

MR. GREG BARNLUND: Yes, sir, that's correct.

MR. BOB PETERS: And included on this service type are damage repairs. And we did see earlier damage repairs on -- on page 310. This is when a third-party contractor damages some of Centra's plant?

MR. GREG BARNLUND: Yes.

MR. BOB PETERS: And then Centra

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REFERENCE:

McLaren Evidence p.17; Tab 8 Schedules 8.6.5, 8.7.5, 8.8.5; Tab 11 Schedule 11.4.0; IGU/Centra II-12

PREAMBLE:

The heating value margin deferral balances are allocated to each customer class based on each class's share of the total volumes, but that does not appear to be the basis for the accrual of the margin deferral balances, as the unit (per m^3) margin deferral differs for each class. For example the Special Contract class is allocated a substantial share of the margin deferral balance but does not contribute to the balance by the nature of its rate design.

QUESTION:

a) Provide an illustrative example, similar to the table below, for a single gas year which shows the accumulation of the Heating Value Margin Deferral balance. A constant actual heating value for the entire year may be assumed for this illustration. State any other assumptions necessary for this illustration. Show the percentage class contributions to the total Heating Value Margin Deferral balance.

	Total	SGS	LGS	HVF	ML	Int	SC	PS
Annual Volume (10^3m^3) [IGU/Centra II-12 Att.]								
Heating Value Revenue Deferral								
Heating Value Cost Deferral								
Heating Value Margin Deferral								
% Contribution to Total Margin Deferral								
Allocated Deferral Balance [IGU/Centra II-12 Att.]								
% of Allocated Margin Deferral [IGU/Centra II-12 Att.]								

b) Provide Mr. McLaren's views whether the allocation of Heating Value Margin Deferral balances could or should be changed to reflect the basis for the accumulation of the balances. Would such an approach be preferable to Christensen Associates' recommendation to simply exclude the Special Contract class from participation in the Heating Value Margin Deferral account? Are there other methods that would more closely align the basis for the accumulation of the Heating Value Margin Deferral balances with the disposition of these balances? If so, please provide.

ANSWER:

a)

Attachment 1 to this response provides an illustrative example. Volumes and heating values used in the Attachment 1 are illustrative only and do not reflect any actual or forecast information from the current proceeding. The calculations use the following formula provided in response to IGU/Centra I-27 (h)

Heating Value Revenue Deferral = (Actual Volumes - (Actual Volumes * Actual Heating Value/Forecast Heating Value)) * Blended Commodity Base Sales Rate
Heating Value WACOG Deferral = (Actual Volumes - (Actual Volumes * Actual Heating Value/Forecast Heating Value)) * Blended Commodity Base WACOG Rate

- Actual Volumes: 10^3 m^3s
- Blended Commodity Base Sales Rate = (Primary Gas Sales Rate * Billing
- %)+(Supplemental Gas Sales Rate * Billing %) + Distribution Sales Rate + Transportation Sales Rate
- Blended Commodity Base WACOG Rate = (Primary Gas WACOG Rate * Billing
- %)+(Supplemental Gas Sales WACOG * Billing %) + Distribution WACOG Rate + Transportation WACOG Rate

The following assumptions were made for this illustrative example:

1. Illustrative annual volume estimates – these are illustrative only and do not reflect actual or forecasts from this proceeding.
2. An actual heating value of 39.00 GJ/10^3 m^3 – again this is illustrative only and does not reflect actual values in this proceeding.
3. A forecast heating value of 39.00 GJ/10^3 m^3 included in rates (illustrative only).
4. Commodity volumetric charges as set out in Schedule 11.2.0 of the application (base rates only, no riders).
5. An assumption of 95% primary gas and 5% supplemental gas.
6. A blended commodity base WACOG rate equal to the primary gas supply and supplemental gas supply rates on Schedule 11.2.0 and assuming 95% primary gas and 5% supplemental gas.

This illustrative example shows that because of the different rate structures, each class contributes a different proportion to the heating value deferral amount. Rows 18 and 19 of the attachment provides a comparison assuming the balance is allocated based only on volumes as Mr. McLaren understands is Centra's current practice. A comparison of the two approaches shows that an allocation based only on volumes substantially increases the amount allocated to the HVF, Mainline and Special Contract customers compared to their actual contribution to the balance.

(b)

In Mr. McLaren's view it would be a substantial improvement to allocate the balances in the Heating Value Margin Deferral account to reflect the basis for the accumulation of the balances by each customer class. Mr. McLaren also notes that the difference between T-Service and Sales Service customer contributions to the balances should also be considered under such an approach. The contribution of each customer class could be calculated using a table similar to that provided in the Board's question. This would calculate the cost responsibility of each class, and then riders could be developed to recover the appropriate amounts for each class.

In Mr. McLaren's view this is a straightforward deferral account and rate design change that could be implemented in a compliance filing for this proceeding and should not wait for the subsequent proceeding on cost of service methods. No cost of service method changes are required to implement this change to the treatment of the heating value deferral account.

			SGS	LGS	HVF	ML	INT	SC	PS
1	Actual Annual Volume (10^3m^3)	1,311,000	500,000	300,000	100,000	100,000	10,000	300,000	1,000
2	Actual Heating Value ($GJ/10^3m^3$)	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00
3	Forecast Heating Value in rates ($GJ/10^3m^3$)	37.00	37.00	37.00	37.00	37.00	37.00	37.00	37.00
	<u>Heating Value Revenue Deferral</u>								
4	Actual Volumes (10^3m^3)		500,000	300,000	100,000	100,000	10,000	300,000	1,000
5	Actual Heating Value/Forecast Heating Value		1.081081	1.081081	1.081081	1.081081	1.081081	1.081081	1.081081
6	Primary Gas Sales Rate ($/cubic meter)		0.0816	0.0816	0.0816	0.0816	0.0816		
7	Supplemental Gas Sales Rate ($/cubic meter)		0.1559	0.1559	0.1559	0.1559	0.1559		
8	Distribution Sales Rate ($/cubic meter)		0.0866	0.0357	0.0073	0.0001	0.0012	0.0001	0.0083
9	Transportation Sales Rate ($/cubic meter)		0.0538	0.0516	0.0196	0.0057	0.006		
10	Blended Commodity Base Sales Rate ($/cubic meter)		0.225715	0.172615	0.112215	0.091115	0.092515	0.0001	0.0083
11	Total Heating Value Revenue Deferral ($000s)	(15,076)	(9,151)	(4,199)	(910)	(739)	(75)	(2)	(1)
	<u>Heating Value Cost Deferral</u>								
12	Actual Volumes		500,000	300,000	100,000	100,000	10,000	300,000	1,000
13	Actual Heating Value/Forecast Heating Value		1.081081	1.081081	1.081081	1.081081	1.081081	1.081081	1.081081
14	Blended Commodity Base WACOG Rate		0.085315	0.085315	0.085315	0.085315	0.085315		
15	Total Heating Value Cost Deferral ($000s)	(6,987)	(3,459)	(2,075)	(692)	(692)	(69)	0	0
16	Total Margin Cost Deferral ($000s)	(8,089)	(5,692)	(2,124)	(218)	(47)	(6)	(2)	(1)
17	% Contribution to Total Margin Deferral		70.4%	26.3%	2.7%	0.6%	0.1%	0.0%	0.0%
18	Total Margin Cost Deferral if allocated based on volume	(8,089)	(3,085)	(1,851)	(617)	(617)	(62)	(1,851)	(6)
19	% of total deferral.		38.1%	22.9%	7.6%	7.6%	0.8%	22.9%	0.1%

Notes:

1. Volumes in line 1 are illustrative only and do not reflect actual or forecast values from this proceeding.
2. Heating Values at lines 2 and 3 are illustrative only and do not reflect actual or forecast values from this proceeding.
3. Rates at lines 6 through 9 are taken from Schedule 11.2.0 of the Application (base rates, no riders).

REFERENCE:

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

PREAMBLE TO IR (IF ANY):

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

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

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

QUESTION:

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

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

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

RESPONSE:

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

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

c), d) and e)

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

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

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

For these reasons as well as that this approach not employed elsewhere, Centra does not intend to pursue further study of the use of customer as a proxy for distance.

Recommendation 28: With respect to combination allocator weights, CA recommends that Centra explore whether load factor conforms adequately to the impacts of the underlying two main cost drivers (peak day, distance) on facility costs. As a consequence CA recommends that Centra consider conducting a cross-sectional statistical analysis of costs and cost drivers, reflected in historical work order records (page 31).

Centra's Position and Rationale: Centra is supportive of CA's recommendation to review load factor used to weight peak and average. Using load factor as the basis to weight peak and average appears to be consistent with an approach stated by the National Association of Regulatory Utility Commissioners but its origins in Manitoba are unknown and likely are due to be reviewed. With respect to the recommended cross-sectional statistical analysis, Centra does not propose to carry out this work as it represents significant effort for a minor refinement.

Recommendation 29: With respect to seasonal rates, CA recommends Centra explore seasonal differentiation of tariff prices. This exploration should consider the cost of implementation, since seasonal prices involves a major change in Centra's cost allocation framework and tariff design (page 31).

Centra's Position and Rationale: Centra accepts that it may be more theoretically superior, from an economic perspective, to offer a seasonal rate that encourages off-season consumption. Seasonal rates can be attractive for utilities who construct facilities to meet peak demands (often with capacity going unused during off-peak periods). Off-season load would improve Centra's annual load factor which has benefits for purchased gas and pipeline contracts and for the use of Centra's fixed investment in its pipeline facilities. However, Centra is of the view that a broader public policy consideration is also at issue in Manitoba in that seasonal rates tend to adversely affect customers who are captive space heating customers. Additionally, seasonal rates would add further complexity to Centra's bill and may also increase its revenue stability risk if there is a large difference between forecast peak and actual peak usage. It is also recognized that the three-part rate structure employed for large volume customers already have a strong seasonal element. Centra finds that the disbenefits of seasonal rates outweigh the benefits and does not endorse CA's recommendation to create seasonal rates.

Recommendation 30: With respect to heating value deferral, CA recommends that Centra should include only customers with monthly bills that are determined according to energy sales volumes in the disposition of differentials attributable to heating value (page 31).

Centra's Position and Rationale: Centra accepts CA's recommendation with respect to the allocation of the disposition of the heating value deferral. Centra currently assigns heating value residuals to all customer classes on the basis of each class' contribution to total annual throughput. Heating value residuals accumulate if the heating value of gas delivered is greater or less than forecast resulting in customers consuming volumes that are greater or less than forecast. The deferral has been put in place to track the impact to gross margin that occurs when the energy content of gas is greater to or less than forecast. For most customer classes, gross margin is largely collected through volumetric rates. The Special Contract Class rate structure is predominantly fixed (with only unaccounted for gas collected volumetrically), and should not, therefore, participate in the disposition of the heating value deferral.

Recommendation 31: With respect to offering Transportation Service ("T-Service") to Large General Service ("LGS") customers, CA recommends that Centra consider retaining its T-service within its tariff package, providing that offering that service does not prove unduly burdensome to Centra. Preserving the T-service option preserves optionality, which is usually a good thing unless it is costly to do so (page 5).

Centra's Position and Rationale: In Order 65/11, the PUB approved Centra's request to implement a minimum daily nomination threshold because it was difficult to balance the daily load requirements of low volume gas users. As a result of this change, LGS customers are no longer eligible for T-service. Since the issuance of Order 65/11, no changes in operations have occurred and no LGS customer has expressed an interest in this service offering. Centra does not intend on re-implementing this service option at this time.

Recommendation 32: With respect to the Cooperative ("Co-Op") Class, CA recommends that Centra consider closing the Co-op service option due to the lack of use and low likelihood of increased participation (page 5).

Centra's Position and Rationale: Centra accepts CA's recommendation. Centra implemented a Co-op Class in 2003 that was created specifically for the North Cypress Energy Co-op (NCEC) with eligibility criteria such that all future Co-op entities served directly from Centra's Transmission facilities (among other criteria as set out in Centra's Terms and Conditions of Service) are eligible for the service option. Since that time, NCEC has dissolved, Centra acquired its assets and no customer has been eligible or expressed an interest for the service option. It is Centra's view that it is appropriate to close the Co-op Class service option.

Recommendation 33: With respect to Revenue to Cost ("RCC") ratios, CA suggests that "The COS methodology of Centra accommodate a range of acceptable RCC ratios, in a manner similar to that of MH's approach for electricity services" (page 32).

Centra's Position and Rationale: Centra is open to CA's recommendation recognizing that setting rates at unity broadly achieves the goal of collecting an appropriate share of the costs incurred by the utility to provide service to customer classes. However, a range approach is often preferable to the implementation of a specific RCC ratio to recognize the degree of judgment in conducting cost allocation studies regardless of the demand allocation method used.

Centra has previously set rates around a 97:103 range in the early and mid 1990's. While Centra views that it should in most cases strive to align rate levels to costs, it also views that under limited circumstances, deviating from unity may be a reasonable approach to provide rate stability. Proposed rate changes should consider the ability of consumers to respond to

REFERENCE:

IGU/Centra I-27 Heating Value Deferral, IGU/Centra I-1a-c. In addition, Manitoba Hydro's response to Cost of Service Study recommendations by Christensen Association Energy consulting shown below (source: MH Website rate case documents).

> **Recommendation 30:** With respect to heating value deferral, CA recommends that Centra should include only customers with monthly bills that are determined according to energy sales volumes in the disposition of differentials attributable to heating value (page 31).
>
> **Centra's Position and Rationale:** Centra accepts CA's recommendation with respect to the allocation of the disposition of the heating value deferral. Centra currently assigns heating value residuals to all customer classes on the basis of each class' contribution to total annual throughput. Heating value residuals accumulate if the heating value of gas delivered is greater or less than forecast resulting in customers consuming volumes that are greater or less than forecast. The deferral has been put in place to track the impact to gross margin that
>
> occurs when the energy content of gas is greater to or less than forecast. For most customer classes, gross margin is largely collected through volumetric rates. The Special Contract Class rate structure is predominantly fixed (with only unaccounted for gas collected volumetrically), and should not, therefore, participate in the disposition of the heating value deferral.

QUESTION:

a) Why has Centra decided to not follow the recommendation from Christensen Associates as they recommended that Koch should not participate in the disposition of the heating value deferral?

b) As the vast majority of Koch's payments to Centra are constant and independent of volume, please explain why Koch should pay a heating value deferral charge that varies with volume?

RESPONSE:

a) Centra continues to be supportive of the recommendation made by Christensen Associates that the Special Contract class should not be included in the refund or collection of the balance in the Heating Value Deferral Account. However, when considering the appropriate time to implement the recommendation, it is necessary to take into account the regulatory principles of fairness and equity as between and amongst customer classes with respect to the refunds and collections to date with respect to the Heating Value Deferral Account.

For illustration purposes, the total Heating Value Deferral Account balance allocated to the Special Contract class since 2002/03, as well the amount Centra is proposing to collect from the Special Contract class as part of this GRA, is shown in the summary table below:

[redacted]

2d

Over the period 2002-2016, the Special Contract class received a net refund of [redacted], a refund that would have otherwise been allocated to other customer classes under the Christensen recommendation. The total heating value (including carrying costs) accumulated in the Heating Value Deferral Account over the 2015/16, 2016/17 and the 2017/18 years that Centra is proposing to collect from the Special Contract class as part of this GRA is [redacted]. If Special Contract customers are excluded from the collection of the balance in the Heating Value Deferral Account in the current GRA, this amount would need to be allocated to, and collected from, the other customer classes (subject to PUB approval). 2d 2d

With the Special Contract class having received a net [redacted] benefit from this deferral over the course of 15 years, Centra believes there is a fairness argument that dictates that the current balances to be collected from customers should be apportioned in the same manner that previous balances have been refunded. At the same time the current proceeding allows for all parties to advise of their positions about appropriate treatment going forward. 2d

b) In accordance and consistent with the long-standing PUB approved treatment for refunding or collecting the Heating Value Deferral Account, the Heating Value Deferral Account balance is to be collected from all customer classes on a volumetric basis as part of this GRA.

deferral account to this customer class, recommended as part of the 2012 external review of Centra's cost allocation methodology.

10.8 Discontinuance of the Allocation of the Heating Value Deferral to the Special Contract Class May be a Consideration to Mitigate Bill Impacts

Centra purchases natural gas per unit of energy or heat content. The higher the heat content in the supplied natural gas, the richer the gas, and the less natural gas is required to serve load. The converse is also true, the lower the heat content in natural gas, the more volumes of natural gas are required to meet customer load.

Centra has used a standard conversion factor of [redacted] GJ/103m3 for many years. Prior to approximately 2016, the actual heating value, in large part, was lesser than forecast. However, since that time, the heat value has begun to rise. 1d

While Centra appears to be satisfied with the current forecasted level[13], apart from the matter of the Heating Value Deferral discussed below, it is unclear whether there are any other impacts as a result of higher heat content including for example, to Centra's forecast of demand, direct purchase deliveries (and potential under-deliveries) and T-service (potential under-deliveries and impacts on balancing obligations), and whether the cost of any shortfall recorded in a PGVA as a result is being recovered by the appropriate customers.

The Heating Value Deferral Account captures the volume impacts due to the variation in actual gas heating values from a base heat level that is embedded in approved rates. Centra purchases natural gas per unit of energy or heat content but bills customers based on volume, as registered through each customers meter. As noted above, to the extent that the actual heating content of gas per unit of volume is less (or more) than that embedded in rates, customers will use more (or less) natural gas.

Centra's rate structure is largely comprised of volumetric charges for most classes. To the extent that customers use more or less natural gas compared to that forecast and embedded in rates, this will contribute more or less to Centra's gross margin. This deferral mechanism has been in place for several decades and is intended to keep the utility and customer whole from a gross margin perspective as a result of differences between forecasted heat content and actual.

Until more recently, the energy content in the natural gas, on an actual basis, tended to be less than that reflected in rates, which meant, all else equal, that customers would consume more natural gas than forecasted and would otherwise contribute to higher gross margin than forecast. The amount captured in the deferral was then refunded periodically to customers.

[13] PUB/Centra I-105

Recently, the energy content of the natural gas supplied has tended to be richer than that forecasted in rates resulting in less natural gas consumption and a lower gross margin. This amount has been captured in a deferral account, as done in past years, however, it now has resulted in a positive deferral (that is, owing from customers to Centra), meaning Centra is under-recovering its gross margin. Given that a review of deferrals has not occurred since 2015, this has resulted in an overall amount owing to Centra of approximately $2.5 million[14].

In this Application, Centra has allocated this amount consistent with past practice, based on each class' actual consumption[15]. As shown in the table below, for many customer classes, this does not represent a significant portion of their allocated non-gas or total allocated costs[16]: However, for the Special Contract Class, this represents [redacted] of its allocated costs. 1e

	Total	SGS	LGS	HVF	Mainline	Interruptible	SC	PS	
Heating Value Deferral	2,519,879	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	2d,1e
Total Allocated Costs	325,784,091	134,975,474	57,156,395	13,751,619	2,281,973	1,650,883	[redacted]	[redacted]	1e
Non-Gas Costs	148,519,256	102,632,670	32,455,799	6,824,301	2,057,841	769,561	2,246,833	157,798	
% of Non-Gas Costs	1.7%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1e
% of Total Allocated Costs	0.8%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1e

As part of the Christensen Associates Cost of Service Methodology Review, the report of which was prepared in June 2012, it recommended Centra consider allocating the cost of the Heating Value Deferral to only customers with a volumetric rate structure. At page 14 of Manitoba Hydro's Response dated July 19, 2012, it stated:

> *"Centra accepts CA's recommendation with respect to the allocation of the disposition of the heating value deferral. Centra currently assign heating value residuals to all customer classes on the basis of each class' contribution to total annual throughput. Heating value residuals accumulated if the heating value of gas delivered is greater or less than forecast resulting in customers consuming volumes that are greater or less than forecast. The deferral has been put in place to track the impact to gross margin that occurs when the energy context of gas is greater to or less than forecast. For most customer classes, gross margin is largely collected through volumetric rates. The Special Contract Class rate structure is predominantly fixed (with only unaccounted for gas collected volumetrically), and should not, therefore, participate in the disposition of the heating value deferral."*

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[14] IGU/Centra II – 12 (c)

[15] IGU/Centra I – 27 (g)

[16] IGU/Centra I - 27; Schedule 10.1.2 (Update)

As part of Manitoba Hydro's Response to the CA Report (page 23), Centra stated that it agreed with CA's recommendation and would implement the change at the next GRA. However, as part of this Application, Centra states that it continues to allocate the Heating Value Deferral based on past practice:

> *"While Centra would agree that a variation in heating value would not have a measurable impact on the monthly margin recovered from the Special Contract class; it has maintained the past practice of allocating the Heating Value Deferral on a volumetric basis"*[17]

> *"…when considering the appropriate time to implement the recommendation, it is necessary to take into account the regulatory principles of fairness and equity as between and amongst customer classes with respect to the refunds and collection to date…"*[18] and

> *"Centra proposes to examine the application of the Heating Value Deferral account after the completion of this GRA and would advise the PUB and interveners of any changes that may be proposed on a go-forward basis."*[19]

An option available to the PUB as discussed above to mitigate the bill impact is of the Special Contract Class is to discontinue payment related to the Heating Value Deferral.

By allocating the Heating Value Deferral to all classes with the exception of the Special Contract Class, the following table reflects the approximate allocation by class[20]:

	Total	SGS	LGS	HVF	Mainline	Interruptible	SC	PS	
Total Allocated Heating Value Deferral	2,519,879	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1e

This would result in sizable increases in the allocation of the Heating Value Deferral by Class. However, the impacts are relatively minimal in comparison to Total Allocated Costs by Class (and overall bill) as shown in the following table:

[17] PUB/Centra II-55 (c,d,e)
[18] IGU/Centra II-4 (a)
[19] PUB/Centra II-55 (a-e)
[20] Approximate as a simplifying assumption made to reflect only the 2017/18 actual volumes by class per IGU/Centra 27

CENTRA GAS 2019/20 GENERAL RATE APPLICATION

INTERVENER EVIDENCE INFORMATION REQUESTS

CAC (D. RAINKIE, K. DERKSEN)

JULY 5, 2019

PUB/CAC(Derksen)-2 Reference: Derksen Evidence p.115

Preamble:

Ms. Derksen states: "*To the extent that the PUB is concerned that the significant bill impacts to larger volume customers warrant an alternate treatment from Centra's rate proposals, a deferral mechanism associated with the impacts of new Transmission investment payable overtime by the participatory classes is an appropriate option that could be considered.*"

Request:

a) Please explain how such a deferral mechanism would function, addressing as the following questions:

- What would be deferred – costs or the collection of revenues?
- Would a portion of the recent transmission investments be deferred from rate base? For how long?
- Would the costs be deferred from the calculation of the overall revenue requirement (i.e. depreciation and finance expense)?
- For how long should the deferred costs be amortized?
- Which classes are considered participatory, as all classes participate in the transmission function?
- If the proposed deferral is that of expected revenue, from which classes is it targeted?

b) Please explain whether and how carrying costs related to the deferred costs would be addressed.

Response:

Response to parts a and b:

Generally, the simpler the approach, the easier it is to implement, understand, and administer which correspondingly will minimize the cost.

The initial thinking is that it is not advisable to defer transmission-related rate base or the associated annualized cost through depreciation and finance expense as all customer classes are then impacted and there will be ripple effects of cost allocation also impacting the allocation of O&M and Net Income etc. which adds to the complexity. A deferral option, if adopted, should likely be limited to those classes most greatly impacted such as the Special Contract Class, perhaps other large volume classes – to minimize the administrative impacts and cost. It is not expected that the SGS Class participate.

For the classes that participate, a portion of their class revenue requirement flowing from the 2019/20 Cost Allocation Study could be captured in a deferral including carrying costs and disposed of through a rate rider for that class - over a 5 year period.

Reference: Section 10.8 Evidence of Darren Rainkie & Kelly Derksen

Preamble to IR:

IGU requires additional information on the recommendations with respect to the heating value deferral account.

Question:

a) If the heating value deferral account were eliminated what mechanisms or crosschecks could the PUB put in place to ensure that Centra's forecast heating values are reasonable for rate setting purposes?

Response:

a) In the alternative where the heating value deferral account is eliminated, the effects would impact Net Income on an actual basis. For rate setting purposes, it would appear reasonable that Centra be obligated to file for PUB review its forecasted heating value and supporting rationale as part of a general rate or cost of gas application, and that forecasted value would remain in effect until a subsequent order of the Board.

the bill impacts flowing from Centra's current Application, Centra suggests that such bill mitigation should focus on the gas year deferral balances allocated to this customer class. The bill impacts to the Special Contract Class are made up of a base rate impact of [redacted] and the gas year deferral balances of [redacted] (which are made up 2d, 1e primarily of Heating Value Margin and Unaccounted for Gas deferrals) as shown in Figure 3.4 on page 16 of the Pre-Hearing Update.

Centra suggests that extending the payment terms for collection of the total deferral balances allocated to this customer class would be most appropriate as it results in no adverse impacts to the bill impacts of other customer classes and is administratively simple to implement. Historically, the entire amount of the gas year deferral balances to be billed or refunded to the Special Contract class has been applied to the first bill following the rate change and collected as a lump sum payment. Extending the payment terms for up to 24 months would reduce the annual billed rate impact. For example, if two lump sum payments were billed November 30, 2019 and November 30, 2020, the bill impact for the Special Contract class on a billed rate basis would be reduced from [redacted] (excluding carrying cost, which would have to be borne 2d by the customer class) based on the Special Contract rates alone, or from [redacted] when commodity costs are factored into the impact calculation. Spreading the recovery over 24 monthly payments (including carrying cost) as opposed to annual payments may offer further relief.

If the PUB determines that the bill mitigation required is greater than that suggested above, the next option to be considered would take the form of fewer costs being allocated to this customer class (and reallocated to other classes). Centra is of the view that the option of assigning Heating Value Margin Deferral to each customer class based on non-gas volumetric revenue as discussed by Mr. McLaren on behalf of IGU has merit. While this change could also be considered as part of the generic Cost of Service review contemplated by the PUB, this action could also be taken now in order to provide greater relief to the Special Contract Class at this time.

The results of the allocation of the Heating Value Deferral Account Balance based on Centra's current methodology (shown on line 6) compared to the option noted above (shown on line 9) is provided in the following table:

Centra Gas Manitoba Inc.
2019/20 General Rate Application

1 Comparison of Allocation of Heating Value Deferral Account Balance for each Gas Year by customer class

2d 1e

2										
3			Total	SGS	LGS	HVF	ML	INT	SC	PS
4										
5	Heating Value (incl carrying costs) allocated	($)	3,859,713	1,253,019	995,043	391,710	276,483	86,010	[redacted]	
6	based on each class volumes	(%)	100%	32%	26%	10%	7%	2%		
7										
8	Heating Value (incl carrying costs) allocated	($)	3,859,713	2,755,195	987,609	95,798	7,776	13,336		
9	based on each class volumetric revenue	(%)	100%	71%	26%	2%	0.2%	0.3%		
10										
11	Diferrence between allocation methods ($)	($)	0	1,502,175	7,434	295,913	268,707	72,674		

Allocating the Heating Value Margin Deferral based on non-gas volumetric revenues would result in no Heating Value Margin Deferral being allocated to both the Special Contract and the Power Stations classes, and would reduce the balances allocated to all other classes except the SGS class. Based on this allocation methodology, Centra's typical residential customer would experience a billed rate impact for 1 year of $5 or 0.7% related to this change.

Minimum Margin Guarantee

It is not clear to Centra if Ms. Derksen is proposing the re-imposition of the Minimum Margin Guarantee for the Power Stations class, which she describes as an interim offset of transmission related costs, as a bill mitigation measure. If the PUB were to consider this proposal as a means to provide bill mitigation to other customer classes or for any other purpose, customers in the Power Stations class would experience effectively a 500.2% bill increase. For proper comparison purposes to the analysis provided above, if Centra's commodity cost of gas is included in the calculation this increase would be 115.1%. This customer class did not have any notice of such a proposed impact and the issue of bill mitigation for this customer class would clearly become an issue.

3.0 CAPITAL PROJECTS AND PROGRAMS

Centra has produced an abundance of evidence in this proceeding, including responses to two rounds of information requests posed by METSCO, in fully substantiating the need for all of its projects and programs and related expenditures. These projects and programs are required to comply with the myriad of legal requirements Centra is faced with and are fully endorsed by Centra's professional engineering expertise as necessary and required for the continued safe and reliable operation of the natural gas

7

The increase in non-gas costs allocated to the LGS customer class in the 2019/20 compared to 2013/14 is the result of an increase in forecast demand levels relative to other classes. This is driven by a forecasted increase in usage on the peak day. Additionally, the increase in the allocated portion of non-gas costs to LGS and HVF is also a result of their expected greater participation in DSM programs and therefore a greater allocation of DSM costs.

The Special Contract class' share of non-gas costs has increased significantly since the last GRA, driven by a change in the relative proportion of rate base that is transmission-related versus distribution-related as a result of significant transmission investments since Centra's last GRA, as discussed in Appendix 6.1. All customers utilize Centra's transmission system and the investment required for maintaining reliability and addressing plant obsolescence is borne by all customers, by virtue of the postage stamp approach to ratemaking. However, Special Contract, Mainline and Power Stations are transmission system customers and therefore, do not utilize the distribution system. As such, these classes pay costs related to transmission and on-site facilities but have no cost responsibility for distribution facilities.

As the results of Rate Base are used to drive the allocation of finance expense, capital taxes, corporate allocation, net income and certain elements of O&A costs, the increase in transmission related assets resulted in more costs being allocated to transmission served customers such as the Special Contract customer class. Additionally, the major transmission investments are causing finance expense and capital taxes to increase compared to 2013/14 GRA.

For the purposes of the preparation of the Cost Allocation Study, Primary Gas and Supplemental Gas are treated as discrete customer classes in order to allocate non-gas related costs associated with procuring and managing those gas supplies. Those non-gas related costs are recovered in the Primary Gas and Supplemental Gas overhead rates. Centra is requesting approval of a new Primary Gas Overhead Rate (non-gas cost component) of $0.94/10^3m^3 (Schedule 10.1.2, line 49) compared to the 2013/14 GRA approved Overhead Rate of $0.87/10^3m^3 as part of this

CENTRA GAS 2019/20 GENERAL RATE APPLICATION

INTERVENER EVIDENCE INFORMATION REQUESTS

CAC (D. RAINKIE, K. DERKSEN)

JULY 5, 2019

PUB/CAC(Derksen)-2 Reference: Derksen Evidence p.115

Preamble:

Ms. Derksen states: "*To the extent that the PUB is concerned that the significant bill impacts to larger volume customers warrant an alternate treatment from Centra's rate proposals, a deferral mechanism associated with the impacts of new Transmission investment payable overtime by the participatory classes is an appropriate option that could be considered.*"

Request:

a) Please explain how such a deferral mechanism would function, addressing as the following questions:

- What would be deferred – costs or the collection of revenues?
- Would a portion of the recent transmission investments be deferred from rate base? For how long?
- Would the costs be deferred from the calculation of the overall revenue requirement (i.e. depreciation and finance expense)?
- For how long should the deferred costs be amortized?
- Which classes are considered participatory, as all classes participate in the transmission function?
- If the proposed deferral is that of expected revenue, from which classes is it targeted?

b) Please explain whether and how carrying costs related to the deferred costs would be addressed.

Response:

Response to parts a and b:

Generally, the simpler the approach, the easier it is to implement, understand, and administer which correspondingly will minimize the cost.

The initial thinking is that it is not advisable to defer transmission-related rate base or the associated annualized cost through depreciation and finance expense as all customer classes are then impacted and there will be ripple effects of cost allocation also impacting the allocation of O&M and Net Income etc. which adds to the complexity. A deferral option, if adopted, should likely be limited to those classes most greatly impacted such as the Special Contract Class, perhaps other large volume classes – to minimize the administrative impacts and cost. It is not expected that the SGS Class participate.

For the classes that participate, a portion of their class revenue requirement flowing from the 2019/20 Cost Allocation Study could be captured in a deferral including carrying costs and disposed of through a rate rider for that class - over a 5 year period.

allocation must also be consistent with overarching public policy such as postage stamp ratemaking, which has been the long-standing practice in this jurisdiction for decades.

10.7 It is Not Appropriate to Make One-Off Fundamental Changes to the Centra Cost Allocation Methodology in the Absence of a Full Methodological Review or Phase-In Impacts of new Transmission Investment Through a Zone of Reasonableness

The significant bill impacts to the Special Contract Class are expected with the large addition in transmission investment. However, in these cases the Applicant would typically consider options to smooth in the rate impacts. Unfortunately, Centra has not provided any options in their evidence in this regard.

Manitoba Hydro (electric) uses several mitigation measures including net income deferral (allowing debt/equity targets to fall), deferral accounts such as the Bipole III deferral, and to a lesser extent the Zone of Reasonableness.

A Zone of Reasonableness for gradually phasing in costs (allowing customer class RCCs below and above unity for a period of time), particularly for those customer classes experiencing significant increases is generally a reasonable approach. As it specifically relates to Centra's 2019/20 GRA, however, it is not advisable to make arbitrary changes to Centra's cost allocation methodology in the absence of a full methodological review that considers the cohesiveness of the full suite of methodologies employed. There are bill mitigation measures that can be employed to address bill impacts and volatility. One-off fundamental changes to address significant bill impacts can lead to unintended consequences.

It is also not reasonable to allow the impacts associated with new transmission investment to be gradually phased in through a Zone of Reasonableness given that the SGS Class has been overcontributing to cost in the period since 2013/14. To gradually implement the rate changes flowing from this Application through a ZOR means that this option would perpetuate the overcontribution/subsidization of the impacted class (s) by the SGS class.

To the extent that the PUB is concerned that the significant bill impacts to larger volume customers warrant an alternate treatment from Centra's rate proposals, a deferral mechanism associated with the impacts of new Transmission investment payable overtime by the participatory classes is an appropriate option that could be considered.

Additionally, as discussed in the following section, another option open to the PUB to mitigate the impacts to the Special Contract customer is to discontinue the allocation of the heating value

M A N I T O B A	)	**Order No. 123/14**
	)	
THE PUBLIC UTILITIES BOARD ACT	)	**October 30, 2014**

BEFORE: Régis Gosselin, B ès Arts, MBA, CGA, Chair
Marilyn Kapitany, B.Sc. (Hon), M.Sc., Member
Neil Duboff, BA (Hons), LLB, TEP, Member

INTERIM ORDER IN RESPECT OF CENTRA GAS MANITOBA INC.'S PRIMARY GAS RATES AND NON-PRIMARY GAS RATE RIDERS EFFECTIVE NOVEMBER 1, 2014

1.0 EXECUTIVE SUMMARY

By this Order, the Public Utilities Board (Board) approves Centra Gas Manitoba Inc.'s (Centra) October 15, 2014 interim *ex parte* Application for a new Primary Gas rate and varies Centra's July 31, 2014 interim Application for Non-Primary Gas Rate Riders.

In respect of Centra's two Applications and by this Order:

- The Board grants Centra's interim *ex parte* Application for a new November 1, 2014 Primary Gas rate, resulting in a Primary Gas billed rate of $0.1665/m^3 compared to an existing Primary Gas rate of $0.1551/m^3. On its own, this represents an annual bill increase of approximately 2.8% (or $24 per year) for a typical residential consumer.

- The Board grants Centra's interim Application for Non-Primary Gas Rate Riders in part and approves, effective November 1, 2014:

  - Supplemental Gas rate riders sufficient to recover approximately $23.3 million (50 percent of the forecast October 31, 2014 Supplemental Gas Purchased Gas Variance Account balance) over a period of two years; and

  - Rate riders with respect to Centra's Transportation and Distribution Purchased Gas Variance Accounts, Centra's Heating Value Margin Deferral Accounts, and its Prior Period deferral account to dispose of the balances in these deferral accounts over a one-year timeframe.

Centra attributes the currently projected net Supplemental Gas PGVA balance of $46.7 million owing by consumers to Centra to extreme weather conditions and unusual market circumstances experienced during the 2013/14 winter heating season. Specifically, the cold winter increased total gas supply requirements for the 2013/14 gas year from a weather-normalized amount of 47.9 million gigajoules (GJ) to 55.5 million GJ, an increase of almost 16 percent.

Centra further cited high price volatility at markets served directly off the TransCanada Pipelines Mainline, caused by a combination of cold weather, declining storage inventories across North America, and extraordinarily high TransCanada Pipelines discretionary transportation services tolls. Those tolls were enabled by the National Energy Board's 2013 decision to grant TransCanada Pipelines unfettered discretion to set prices for short-term discretionary transportation services. As a result, the market prices for gas at hubs where Centra purchased its Supplemental Gas were extraordinarily high during the three-month period from January to March 2014. This is the timeframe when most of the PGVA balance was incurred.

The resulting combined annual bill impact from the revised Primary Gas rate and the Non-Primary Gas rate riders is an increase of 5.0% (or $43 per year) for a typical residential customer. Annual bill impacts for customers in other classes (except T-service customers) range from increases of 3.2% to 12.5%, depending on customer class and annual consumption.

4.3 Board Findings

Based on its review of Centra's confidential filings, the Board is satisfied that, on a *prima facie* basis for purposes of an interim Order, Centra has demonstrated that the utility's Supplemental Gas costs during the winter of 2013/14 were incurred for the ratepayers in Manitoba. The specific details of Centra's transactions will require additional analysis and review at the 2015 Cost of Gas Hearing.

Based on these findings, the Board is prepared to implement a rate rider on an interim basis that, if kept in place, would recover 50% of Centra's anticipated October 31, 2014 Supplemental Gas PGVA balance of $23.3 million over a two-year timeframe. Assuming normal weather, this rate rider will recover 25 percent of the Supplemental Gas PGVA balance between November 1, 2014 and October 31, 2015, or $11.7 million.

The Board will decide, based on a full hearing at Centra's next Cost of Gas Application, whether and over what timeframe the remainder of the Supplemental Gas PGVA balance should be recovered.

In reaching this decision, the Board is balancing the need to achieve a partial PGVA recovery immediately with a clear recognition that a full public review of the facts that gave rise to the PGVA balance and the options for its disposal has not yet taken place. In particular, Centra's confidential filing of Information Request responses meant that approved Interveners did not have an opportunity to test Centra's evidence. In its submission, CAC articulated a concern shared by the Board.

The need to achieve partial recovery immediately arises out of concern for ratepayer equity. The majority of the gas purchases that led to the Supplemental Gas PGVA balance were accrued in the winter of 2013/14, and an additional balance relates to the previous gas year. Since the population of Manitoba is not static, but people constantly move in and out of the jurisdiction, there is a strong imperative to recover costs shortly after they were incurred. At the same time, the Board recognizes that a recovery of the entire Supplemental Gas PGVA over a one-year timeframe could lead to 'rate shock' for customers. The Board is also aware that the market and weather conditions that resulted in the extraordinarily high Supplemental Gas costs could be repeated in the coming winter. If the PGVA balance is not at least partially recovered this winter, there is a possibility that the recovery of the past PGVA balance will be compounded with a PGVA balance that accrues in the coming winter.

In the Board's view, the partial interim recovery established by this Order strikes the appropriate balance between early recovery, rate shock avoidance, and the need for a public review process with respect to the prudency of the expenditures.

3.5 RATE DESIGN AND ZONE OF REASONABLENESS

Centra stated that it is open to the Christensen and Associates recommendation that the cost of service methods accommodate a range of acceptable RCC ratios. Centra notes that it has previously set rates around a 97:103 range in the early and mid 1990s. Centra states its view that it should in most cases strive to align rate levels to costs, it also views that under limited circumstances, deviating from unity may be a reasonable approach to provide rate stability.[32] Centra also stated that an appropriate means of addressing bill impacts caused by plant additions may be to temporarily set aside the concept of setting rates at a revenue/cost ratio of 1.0 for all classes and instead adopt a zone of reasonableness in the setting of class rates.[33]

In Order 164-16 the Board noted that while a cost of service study appears to be arithmetically exact, it involves a number of decisions that require the application of judgement. Because of this, and to address goals of gradualism in the ratemaking process, many utilities do not set rates such that the RCC ratios are exactly unity. Instead many utilities and their regulators recognize a zone of reasonableness.[34]

Other gas regulators have also accepted revenue to cost ranges of reasonableness. For example, in Order G-4-18 the British Columbia Utilities Commission directed Fortis BC Energy Inc. to use a revenue to cost ratio range of reasonableness of 95 percent to 105 percent to inform its rate design and rebalancing proposals.[35] The Alberta Utilities Commission noted in its decision with respect to AltaGas Utilities Inc's 2013-2017 Phase II application resulted in rate class revenue to cost ratios within the 95 to 105 per cent range which had been approved by the Commission in previous decisions.[36]

3.6 SUMMARY AND RECOMMENDATIONS

There are a number of issues that the Board should review related to Centra's Cost of Service and Rate Design methods, including:

- **Peak and Average versus Coincident Demand Allocators:** Changes on Centra's system, in particular the increased transmission spending (that appears to be driven by peak capacity requirements and customer growth) and the migration of customers away from interruptible service merits additional consideration of whether Centra's cost allocation methods are sufficiently tracking the degree to which investments in new capacity related assets are driven by the need to meet system peaks rather than average use throughout the year. If the Board were to determine that

[32] Page 16 of 25. Attachment 11 to PUB Completeness Review.
[33] IGU/CENTRA I-28 (a) and (b).
[34] Page 24 of 116. Order 164/16 dated December 20, 2016.
[35] Page 2 of BCUC Order G-4-18 dated January 9, 2018.
[36] Paragraph 75, Page 17. AUC Decision 2014-139 with respect to AltaGas Utilities Inc.'s 2013-2017 performance based regulation Phase II negotiated settlement dated May 23, 2014.

the cost causation of these assets relates primarily to the design capacity or peak day, then a coincident demand method may better track cost causation.

- **Load factor as the basis to weight peak and average allocator**: Even in the event the Board determined that the peak and average approach remains reasonable, using the load factor as the basis to weight the peak and average allocator means that a substantial portion of costs follow annual energy or commodity use, rather than coincident peak day use. Centra states that using load factor as the basis to weight peak and average appears to be consistent with an approach stated by the National Association of Regulatory Utility Commissioners but its origins in Manitoba are unknown and likely are due to be reviewed. Centra confirmed in the current proceeding it has not undertaken further review of matter to date.[37]

- **Postage Stamp Ratemaking:** Centra has noted that the philosophy of postage stamp ratemaking has its origins during a period when the natural gas system in Manitoba was very different than it is today. Given the considerable impact on some customers of sharing costs for substantial new investments that do not provide direct benefits, it may be timely to investigate alternative methods for sub-functionalizing and/or direct assigning certain costs, such as the Winnipeg North West project, to the groups of customers that are directly causing those assets to be required and directly benefit from their construction.

Based on this, it is recommended that the Board defer approving any rate adjustments based on the results of Centra's cost of service study until it has had the opportunity for a full review of Centra's cost of service methods. Such a review could be modelled after the review undertaken for Manitoba Hydro's cost of service study that resulted in the Board's Order 164/16. Key elements of such a review would include:

- The review of Centra's cost of service study should consider the changes to Centra's customer mix and operations and how those influence the need to adjust existing cost of service study methods.

- The review should consider the methodological issues raised in this report, as well as issues identified by other intervenors and the Board.

- The Board should consider retaining its own independent expert to prepare a report with recommendations that is available to all parties. This could help alleviate some procedural fairness concerns about only certain parties being granted access to confidential materials.[38]

Although not recommended, in the event the Board decides to make some level of rate adjustments arising from this proceeding to reflect the current cost of service study results, the Board should consider the

[37] IGU/CENTRA I-13 (b).
[38] The BCUC used a similar approach in its review of FEI's 2016 Rate Design Application as summarized in page 4 of 38 of Appendix A to Order G-4-18.

substantial impact on some customer groups of the proposed rate and bill increases for some customers proposed in the current application (20 to 40% for base rates to Mainline and High Volume Firm T-Service customers).[39] Allowing some discretion in the range of revenue to cost coverage ratios, rather than targeting exactly 100% cost of service for all customers, would help mitigate these rate increases and be consistent with how rates are set for other utilities in Manitoba. In addition, the Board may consider the principle of gradualism in the transition of rates into the zone of reasonableness.

[39] See Page 2 of 2 of Schedule 11.1.10.

REFERENCE:

Tab 10

PREAMBLE TO IR (IF ANY):

IGU requires additional information to understand the cost allocation results.

QUESTION:

Please provide a table showing the 2019/20 revenue to cost comparison ratios by customer class at:

i. Existing rates;
ii. Proposed rates

RESPONSE:

Please see the attachment to this response.

1	**2019/20 Revenue to Cost ratios for all classes (Revenue at Existing Non-Gas Rates)**														
4–6		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	FRPGS Fixed Price	
8	Revenue at Existing Non-Gas Rates	152,524,872	109,941,344	30,132,872	6,274,676	8,024	1,484,485	1,385,423	236,483	845,414	2,112,524	77,672	8,340	17,615	
9	(per Schedule 10.1.6, line 35)														
10	Cost of Service (Non-Gas)	148,519,256	102,632,670	32,455,799	6,824,301	8,233	2,057,841	2,246,833	157,798	769,561	[redacted]			21,155	1e
11	(per Schedule 10.1.2, line 43)														
13	Non-Gas Revenue Sufficiency/(Deficiency)	4,005,616	7,308,674	-2,322,927	-549,625	-209	-573,357	-861,410	78,685	75,853				-3,540	
14	Revenue to Cost Ratio (Revenue at Existing Non-Gas Rates)	103%	107%	93%	92%	97%	72%	62%	150%	110%				83%	1e
20	**2019/20 Revenue to Cost ratios for all classes (Revenue at Proposed Non-Gas Rates)**														
22–24		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	FRPGS Fixed Price	
26	Non-Gas Rates (per schedule 11.4.1)														
27	BMC		14.00	77.00	1,008.09	264.05	1,080.75	187,222.83 *	6,559.41	1,035.29					
29	Demand Transportation				10.62	16.94	15.20	0.00	0.00	5.37					
30	Demand Distribution				182.70	166.22	232.34	0.00	0.01	88.40					
32	Commodity Transportation		3.27	3.21	2.02	1.55	1.56	0.00	0.00	1.76					
33	Commodity Distribution		78.36	42.64	9.37	0.00	0.85	0.00	0.07	3.24	0.91	1.60	1.59	37.67	
36	Billing determinants (per schedule 10.1.1, line 16 to 22)	[redacted]													
37	Upstream Demand (10^3m^3-day)														
38	Upstream Commodity (10^3m^3)														
39	Upstream Customer (customers)														
41	Downstream Demand (10^3m^3-day)														1d
42	Downstream Commodity (10^3m^3)														
43	Downstream Customer (customers)														
46	Non-Gas Revenue		[redacted]												
47	BMC	58,718,928													
49	Demand Transportation	180,282													
50	Demand Distribution	5,016,453													1e
52	Commodity Transportation	5,806,226													
53	Commodity Distribution	78,797,365													
55	Total Revenue at Proposed Non-Gas Rates	148,519,256	102,632,670	32,455,799	6,824,301	8,233	2,057,842	2,246,833	157,798	769,561	[redacted]		10,232	21,155	1e
57	Cost of Service (Non-Gas)	148,519,256	102,632,670	32,455,799	6,824,301	8,233	2,057,841	2,246,833	157,798	769,561	[redacted]		10,232	21,155	1e
58	(per Schedule 10.1.2, line 43)														
60	Non-Gas Revenue Sufficiency/(Deficiency)	0	0	0	0	0	0	0 0	0	0	0	0	0	0	
61	Revenue to Cost Ratio (Revenue at Proposed Non-Gas Rates)	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	
66	*Special Contract BMC in the amount of $187,222.83 represents the Non-Gas portion of BMC														

Reference: Section 10.7 Evidence of Darren Rainkie & Kelly Derksen

Preamble to IR:

IGU requires additional information to understand the recommendation related to the zone of reasonableness.

Question:

a) On Page 5 of Order 164/16 the PUB stated:

> "While the results of a COSS appear to be arithmetically exact, a COSS involves considerable judgment."

Do Mr. Rainkie and Ms. Derksen believe this statement is true for Centra's cost of service study? Please explain why or why not.

Response:

Yes, our view is that a cost of service study involves informed judgment including for Centra's cost of service study. It is understood that the intent of a cost of service study is to evaluate the relative fairness of rates between customer classes. Revenue to Cost Coverage Ratios (RCC) are determined from a cost of service study and indicate the proportion of costs recovered from the revenue arising from each customer class. A Zone of Reasonableness (ZOR) is often employed by utilities to assist in evaluating the RCC ratios considering several factors. First, the results of a cost of service study are approximate (given the judgement involved, data quality, and data limitations), and a ZOR may be employed to recognize the range the uncertainty that's involved in cost allocation. Secondly, other factors including public policy considerations may result in establishing rates that do not equal revenue for a class. Third, there are other ratemaking objectives to be achieved including rate stability. Methodology and cost changes can result in RCCs that vary from year to year. This may include imposing a rate increase for a class in one year and a rate decrease the next year. A ZOR would allow for flexibility to avoid rate instability that might otherwise occur.

Centra moved away from a ZOR in 1997 to unity on account of industrial customer pressure as well as PUB direction, despite the impact on SGS customers. For Centra, in contrast to Manitoba Hydro's electric operations, there is a greater degree accuracy of the results of its COSS. The reason is that a large proportion of the costs incurred to serve natural gas customers is incurred for the cost of commodity, the price of which is established through an external natural gas market. On the electric side of Manitoba Hydro's operations, MH produces the commodity using common plant and more uncertainty exists as to the categorization of costs such as between energy and demand.

Centra also accepted that considerations of fairness and equity were largely accommodated through its cost allocation methodology such that reliance on a ZOR was less necessary. Setting rates based on unity has been in place since 1997 although it is acknowledged that achieving unity is somewhat notional given that it is a point in time calculation and its base of determination is constantly shifting. There have been only a couple of occasions over that 20-year period that rates were not re-based to unity and generally bill mitigation measures have been largely accommodated through a deferral-type of mechanism.

CAC's independent experts view generally that deviating from unity through a ZOR is a reasonable approach for purposes of rate stability. However, in the case before the PUB, it is not advisable for a several reasons as follows:

- First, the SGS class has been overcontributing during the period since Centra's last GRA in 2013/14.
- Second, despite the acknowledged informed judgement in cost allocation that often gives rise to a ZOR, that has not been the methodology in place for Centra who moved away from that kind of methodology in large part because of the past position of industrial customers.
- Third, the RCC for the Special Contract Class is currently approximately 60%. If a temporary ZOR is implemented for purposes of bill mitigation, a ZOR no larger than +/- 3% in light of Centra's operations is reasonable. Even in a very extreme case, in light of Centra's operations, a ZOR of 90% - 110% will be of little practical consequence to address bill mitigation and rate stability given this class' RCC.

For these reasons, it is advisable that there be no further delay in rate relief afforded to the SGS class. Bill mitigation measures such as a deferral mechanism and/or adjustment to the allocation of the heating value deferral is viewed to be fair, reasonable, and more effective.

b) On page 16 of 25 of the Christensen Report (Attachment 11 to the PUB Completeness Review) Centra states with respect to adopting a range of acceptable RCC ratios:

"Centra has previously set rates around a 97:103 range in the early and mid 1990's. While Centra views that it should in most cases strive to align rate levels to costs, it also views that under limited circumstances, deviating from unity may be a reasonable approach to provide rate stability."

i. Were Mr. Rainkie and/or Ms. Derksen involved in preparing, reviewing or approving Centra's response to the Christensen Report?

ii. Do Mr. Rainkie and Ms. Derksen agree that deviating from unity may be a reasonable approach to provide rate stability? Why or why not?

Response:

Part i)

Yes, Ms. Derksen was involved in the preparation of Centra's response to the Christensen Report.

Part ii)

Please refer to the response to IGU/CAC-I 6 (a) above.

MR. BOB PETERS: And under that annual differentiation one (1) year, the residential rate, whatever the Board awarded, would have to go up an additional 2.10 percent and, likewise, the General Service Medium and the General Service Large zero to 30 kV would, likewise, also get higher than average rate increases to make up for the revenue shortfall that's not coming from the General Service Small non-demand?

MS. KELLY DERKSEN: That's the assumption underpinning this particular response which I -- which I don't agree with. And one (1) of the reasons I don't agree with is that that 10 percent differential is being charged to customer classes that are below unity, and that's problematic to me.

And I think it conflicts certainly with Order 59/'18 last year where the Board directed differential rates. And differential rates, the increment was to be charged by all customer classes either who were blow the zone of reasonableness or within the zone of reasonableness, so it conflicts with that.

It also is suggestive that those customer classes who are below unity are -- somehow, that they're under contributing. And from my perspective, as well as Manitoba Hydro's perspective, through their response to Coalition 38, states that, if you are within the zone of reasonableness, you're assumed to be fully funding the costs that you impose on the system.

And so, I take issue with the assumptions underpinning both of the responses to 61 -- PUB 61 and AMC 5 for that and other reasons. And I don't think that they can be used as a basis of rate differentiation flowing from this application.

MR. BOB PETERS: Your suggestion is that the two (2) problems that I heard from your answer, Ms. Derksen, was -- one (1) is you didn't find this treatment to be consistent with Board order 59/'18, which was the last Board order, correct?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And the second was that, once you hit the zone of reasonableness, that's close enough, and don't assume that, even if you're below unity, that you're not covering your costs?

MS. KELLY DERKSEN: Yes. A zone of reasonableness is also called a range of reasonableness, which is how I actually prefer to call it. And it's called a rangeable -- range of reasonableness for a reason. It's saying that those

REFERENCE:

Appendix 11, page 16-17 of 25, Revenue to Cost (RCC) Ratios

PREAMBLE TO IR (IF ANY):

Regarding CA's Recommendation 33 on RCC ratios, Centra's position and rationale included:

> Centra has previously set rates around a 97:103 range in the early and mid 1990's. While Centra views that it should in most cases strive to align rate levels to costs, it also views that under limited circumstances, deviating from unity may be a reasonable approach to provide rate stability. Proposed rate changes should consider the ability of consumers to respond to the change and to avoid rate shock. It may be worthwhile to consider RCC ratios other than unity in circumstances where large increases to a class (or classes) may create hardship for consumers. Such circumstances could include dramatic commodity price spikes that occur from time to time or phasing in methodology changes to cost allocation.

QUESTION:

a) Did Centra consider setting a range for RCC ratios in light of the rate changes being proposed to customer classes? Please explain.

b) Did Centra consider phasing in methodology changes to cost allocation or for capital additions? Please explain.

c) What does Centra define as rate shock in relation to short-term and long-term rate changes for customer classes?

RESPONSE:

a) and b)

Centra has not proposed any form of rate smoothing in its Application, but recognizes that the rate base impact of large plant additions can result in a wide range of bill impacts to its customer classes. An appropriate means of addressing bill impacts caused by such plant additions may be to temporarily set aside the concept of setting rates at a revenue/cost ratio of 1.0 for all classes, and instead adopt a zone of reasonableness in the setting of class rates. However, Centra would expect to be kept whole for the recovery of its approved revenue requirement, which would require the "phasing in" of the impact of revenue changes between customer classes such that some customer classes would have revenue/cost ratios in excess of 1.0 and some would experience ratios less than 1.0.

c) Please see the response to CAC/CENTRA I-19a.

REFERENCE:

Tab 10 (pg 5)

PREAMBLE TO IR (IF ANY):

Centra states that it is not seeking a general revenue increase in this Application and has not made substantial changes to its Cost Allocation approach since the 2013/14 GRA.

Centra also states that system load growth will require installation of additional pipe and system to meet increased system demands and will drive future changes in Centra's net income requirements .

In Tab 11 of the GRA, Centra has provided the bill impacts associated with the changes in costs flowing from its Application that despite no general revenue increase being sought range from overall decreases to significant bill increases.

QUESTION:

b) Please discuss the appropriateness of the use of a Zone of Reasonableness:
   i. To smooth in the potential harsh impacts associated with asset investment for Centra non-gas costs.
   ii. Understanding that given the typical length of time between GRA's will naturally result in revenue to cost ratios (for non-gas costs) that deviate from unity and that long absences can result in significant deviations from unity.
c) Please provide what other Canadian gas LDC's approaches are to rate-setting and their rationale – what ZOR (or unity) is accepted?
d) Please provide the revenue-to-cost ratios flowing from the 2019/20 Cost Allocation Study prior to a revenue/rate adjustment to bring classes to unity.

RATIONALE FOR QUESTION:

To understand Centra's ratemaking objectives for purposes of this Application, its view of the weight to ascribe to them, the significance of the bill impacts flowing from the proposed rate changes and how other Canadian gas utilities are using these ratemaking tools.

RESPONSE:

b) Centra's rates are notionally set at "unity" which is a revenue/cost ratio of 1.0. Prior to 1997, rates were set within a zone of reasonableness of 0.97 to 1.03.

Centra proposed to move its rate setting approach from a zone of reasonableness to a revenue/cost ratio of 1.0 for all customer classes in the 1996 Cost Allocation and Rate Design review before the PUB. Centra's proposal was made in consideration of the concerns expressed in past regulatory proceedings by large volume customers. Large volume customers and particularly the Special Contract class customer expressed their support for rates to be cost-based and to be set as close to unity as possible.

However, one outcome of setting rates at unity is that all rates will be set strictly based upon the output of the cost allocation study. Therefore, it is difficult to smooth rate changes and the resulting bill impacts.

Setting customer class rates at unity also tends to increase rate volatility (rate movements in both upward and downward directions). Cost allocation outcomes are influenced by changes in customer load and changes in rate base. Changes in the load forecast and in the composition of rate base will introduce change into the allocation of costs between customer classes, independent of changes in revenue requirement.

With regard to the statement in part ii) of the question, Centra notes that cost allocation studies are prepared on a prospective basis based upon weather normalized forecasts of customer load, forecast gas costs and forecasts of revenue requirements. It is understood that actual experienced costs and customer consumption may vary from this forecast. In the next subsequent GRA, Centra prepares a new cost allocation study reflective of new forecast information and the resulting rates are set, once again, at unity. Centra is unclear as to how the setting of rates using a zone of reasonableness would differ in this regard.

c) Although Centra has not undertaken extensive research on the question, it is understood that the use of a zone of reasonableness is generally accepted for other Canadian natural gas LDCs.

d) Please see the Centra's response to IGU/CENTRA I-15.

8

V. SPECIAL TERMS AND CONDITIONS: TRANSPORTATION SERVICE (T-SERVICE)

A) A Transportation Service agreement setting out Customer specific information shall be established between the Company and the Customer for Transportation Service under the High Volume Firm Class, Mainline Class, or Interruptible Class, having a minimum term of one year. The agreement shall remain in effect for successive periods of one year, unless written notice of termination is given by either party to the other at least 90 days prior to the expiration of the agreement or any renewal thereof.

B) Subject to the conditions set out in subsection V. A) hereof, High Volume Firm Class, Mainline Class, or Interruptible Class customers may elect to receive Transportation Service where the customer's daily nomination equals or exceeds ~~200~~ 2,500 GJ under normal operating conditions, excluding shut-downs for routine maintenance activities and holidays.

C) The T-Service Customer shall deliver to the Company at the designated Receipt Point(s) and the Company shall receive from the T-Service Customer and transport a volume of gas, as determined in accordance with subsection D) hereof, from said Receipt Point(s) to the designated Delivery Point(s).

D) The volume of gas delivered by the T-Service Customer and received and transported by the Company shall, on each day, equal the quantity of gas consumed by the Customer at its facility on such day as determined by the Company's measuring stations located at or near the Delivery Point, less the volume of Backstop Gas (if any) sold to the Customer by the Company on such day pursuant to subsection G) hereof.

E) The Company shall not be obligated to transport, in any one day, any gas in excess of the Daily Contract Demand designated for delivery to each designated Delivery Point for each type of service.

F) The T-Service Customer shall pay for all gas delivered by the T-Service Customer and received and transported by the Company at the T-Service Rates approved from time to time by the Board.

G) In the event that a T-Service Customer fails or anticipates failure to deliver the necessary volume of gas to the designated Receipt Point:

1) The T-Service Customer shall promptly notify the Company if the Customer has reason to believe that deliveries of gas by or for the Customer to the Company at the Receipt Point(s) will be impaired in whole or in part. At such time, the Customer shall indicate whether it will require gas from the Company and the volume required during such period of impairment. If the Company is unable to provide Backstop Gas as requested by the Customer, the Customer shall be obligated to restrict it's consumption to the volume of gas it can deliver into the system.

2) On any day when, as a result of impairment, the T-Service Customer requires gas from the Company, the Company may, subject to availability of supply, sell to the Customer such quantity of Backstop Gas as is agreed between the parties, and the Customer shall pay for any Backstop Gas the greater of:

a) its pro-rata share of the total cost of Backstop gas purchased on behalf of T-Service customers by the Company~~appropriate share pro-rata with other T-Service Customers purchasing Backstop Gas, on such day, of the total cost~~, including all costs associated with purchasing and having that supply delivered to the Receipt Point. These charges are in addition to the normal T-Service Volumetric Charges; or

b) the equivalent Sales Service Volumetric Rate.

On such day, the Backstop Gas shall be deemed to be the first volumes delivered to the Customer.

3) Volumes delivered to the Customer as Backstop Gas shall be included in the determination of the Monthly Billing Demand.

H) The provisions of this paragraph shall only be applicable if service hereunder is pursuant to one of the Company's Interruptible Transportation services.

1) The Company may, at its sole option, on notice to the T-Service Customer, curtail or discontinue service hereunder down to the level of Firm Transportation Service (if any) to which the T-Service Customer is entitled. ~~Such notice shall be made by telephone, electronic, or other communication device, or in person, and~~Upon receipt of notice by the Company, the Customer shall curtail its consumption of gas to the extent requested by the Company within two (2) hours of receipt of notice.

2) In recognition of the curtailable nature of Interruptible Service the Customer agrees, at their sole expense, to:

a) Install, maintain and have ready to operate at all times a stand-by fuel source of sufficient size and capacity to satisfactorily replace the natural gas energy supply furnished by the Company, and to,

b) Ensure that sufficient supplies of stand-by fuel are available at all times, and that the Customer has sufficient personnel resources available to operate the stand-by fuel system at any time upon notice from the Company, and to,

c) Utilize the stand-by fuel source in the event that the Company gives notice to the Customer of a curtailment of service.

3) In recognition of the Customer's service as Interruptible Transportation Service furnished by the Company hereunder, the Company shall not be liable for damages to person or property resulting from curtailment of service, or the Customer's failure to provide adequate stand-by equipment and fuel, or to use such equipment properly and sufficiently.

4) In the event that the T-Service Customer fails to comply with any such notice of curtailment, then the Company may at its option:

a) Physically discontinue Transportation Service hereunder during any period of curtailment; and/or

b) Charge and collect from the Customer for all gas received and transported hereunder during any such period at the Unauthorized Over-Run Delivery Charge, or such lesser amount per m^3 as the Company, in its sole discretion, may decide upon~~.~~; and/or

c) Charge and collect from the Customer the Firm T-Service Delivery rates for a 12 month period subsequent to the failure to interrupt. This provision shall not relieve the Customer from continuing to operate as, and meet all of the obligations of, an Interruptible Customer during this 12 month period. Continued failure to abide by the terms of Interruptible Service shall entitle the Company to return the Customer to Firm Transportation Service on a permanent basis.

5) The Company shall have the further right to curtail the transportation of gas hereunder without notice and without any liability whatsoever for any resultant damage to the Customer for any one or more of the following reasons:

a) Repairs to its distribution system; or

b) Transportation of gas being prevented or interrupted for any cause reasonably beyond the control of the Company~~.~~; or

c) For breach by the Customer of any of the terms and conditions hereof.

6) With respect to each Delivery Point(s), the T-Service Customer shall be subject to a monthly bill equal to the Basic Monthly Charge, the applicable Monthly Demand Charge, and Volumetric Charges for volumes delivered.

7) Volumes taken by the Customer in contravention of curtailment notice shall be included in the determination of the Monthly Billing Demand.

I) Where the T-Service Customer is entitled to both Firm and Interruptible Transportation Service to a particular Delivery Point, the volume of gas transported by the Company to such Delivery Point on any day shall be deemed to be transported firstly under Firm Service up to the level of Firm Daily Contract Demand, and secondly under Interruptible Service; provided, however, that if on any day, the Customer's Interruptible Service is curtailed, the gas under Firm Service shall be deemed to have been transported, up to the time of curtailment, at an even hourly flow at a rate equal to the Firm Daily Contract Demand, divided by 24.

J) The T-Service Customer shall notify the Company ~~by e-mail or fax,~~ no later than 2:00 p.m. ~~Winnipeg time~~CCT on the day prior to delivery (except during periods when the Customer has advised the Company that no transportation service is required) of:

~~1) The Customer's nomination for the following day with TCPL; and,~~

~~2)~~1) The Customer's forecasted gas consumption and the Customer's Nominated Volume on the TCPL Mainline for the following day.

Such Nominated Volume and forecasted consumption shall be deemed to remain in effect from day to day unless changed by the Customer and notice of such change is given to the Company at subsequent intraday nomination windows. ~~in the manner aforesaid~~. If on any day in the event that the T-Service Customer's actual gas consumption for that day is to deviate from the forecasted gas consumption and Nominated Volume identified in J) ~~2~~1. above the Customer shall notify the Company at the earliest opportunity of any such deviation, and the T-Service Customer shall make reasonable efforts to make the necessary forecast and nomination adjustments required with TCPL and the Company.

~~K) Prior to 10:00 a.m. Winnipeg time each day, the T-Service Customer will advise the Company by telephone, fax or e-mail of the meter reading at each Delivery Point as at 9:00 a.m. Winnipeg time on that day.~~

~~L)~~K) The T-Service Customer shall provide notice to the Company advising of the particulars of any authorized agent at law it has appointed to carry forth its obligations pursuant to the Transportation Service agreement identified in sub-section A.) hereof. Until further notice is provided by the T-Service Customer to the Company advising of any change to or termination of such agency appointment, the Company shall be entitled to rely upon any act or thing done, or document executed by the authorized agent pursuant to the Transportation Service agreement in the same manner and as though such act or thing had been done, or such document has been executed by the T-Service Customer. The T-Service Customer shall indemnify and hold the Company harmless against any and all claims relating to, arising out of or resulting from the actions of the authorized agent pursuant to the Transportation Service agreement.

~~M)~~L) In the event that a Sales Service Customer elects to become a T-Service Customer, the Customer will indemnify and save the Company harmless against any costs incurred by the Company upstream of the Receipt Point for which the Company is unable to obtain relief. The Company reserves the right to determine the level of capacity that may be released to the Customer or his agent.

~~N)~~M) The T-Service Customer hereby releases the Company from the Company's obligation to supply gas (except in accordance herewith) to the Customer for so long as the Transportation Service Agreement remains in force. If the Customer wishes to recommence purchasing gas from the Company, the Customer acknowledges and agrees that it will be treated in the same manner as a new Customer applying for Sales Service and will be subject to the provisions in Section IV. H) 2. hereof regarding requests for transfer from Transportation Service to Sales Service.

~~O)~~N) If the T- Service Customer or its authorized agent causes delivery imbalances relating to the delivery of gas to the Company's distribution system, the Company may impose ~~any im~~balancing fees ~~costs or charges~~ on the Customer.

REFERENCE:

Appendix 3.1 – Projected operating statement

PREAMBLE TO IR (IF ANY):

IGU requires more information to understand Centra's projected operating statement

QUESTION:

Please provide a schedule that shows amounts included in the projected operating statement for each year from 2019 through 2028:

a) Forecast revenues from Centra's proposed balancing fees for Transportation Service customers.
b) Forecast costs related to fees paid to TCPL for imbalances in excess of tolerances.
c) Please provide billing determinants and rates underlying all calculations in parts (a) and (b) above

RESPONSE:

a), b) and c)

Balancing fees have no net impact to Centra's income statement (the referenced Appendix 3.1). Like all other upstream gas costs (including offsetting revenues from Centra's Capacity Management Program and potentially from T-Service balancing fees), any amounts collected from T-Service customers will be refunded to Sales Service customers dollar for dollar, with no margin or profit retained by Centra.

Centra's cost allocation methodology will be unaffected by balancing fees. As is the case today, they will impact the magnitude of the closing balance of the Transportation PGVA at the conclusion of each Gas Year and subsequent rate riders to either refund or collect these balances to or from customers.

Please see the response to PUB/CENTRA I-147b which explains that Centra does not have a forecast of revenues from Centra's proposed balancing fees for T-Service customers. Going forward, actual experience will be the best basis on which to forecast the net of balancing fees collected from T-Service customers and balancing fees paid to TCPL, which will either be a credit or debit to the Transportation PGVA. Centra's preferred outcome is that it collects little to no revenue from T-Service balancing fees, but rather that T-Service accounts are balanced on a daily basis.

Centra's 2018/19 Gas Year forecast of costs related to balancing fees is $250,000, an estimate based on Centra's historical experience (see below).

Gas Year	Centra's Balancing Fees[1]
2018/19 forecast	$250,000
2017/18	$199,000
2016/17	$157,000
2015/16	$203,000
2014/15	$221,000
2013/14	$254,000
2012/13	$194,000
2011/12	$204,000

As described above, there is no calculation per se of balancing fees. Rather, the $250,000 is an estimate based on Centra's historical experience. There are no billing determinants and rates underlying the aforementioned actual and forecast costs related to balancing fees.

Centra's 2019/20 Gas Year forecast of gas costs, including balancing fees, will be filed in July 2019 as part of Centra's pre-hearing update. However, Centra can advise that its 2019/20 forecast of balancing fees in the July update will be $250,000. This figure is a reasonable placeholder for 2019/20 given that Centra cannot know how T-Service customers will react to the financial incentive to balance their accounts. Ideally, T-Service customers and their nominating agents will respond to the introduction of this financial incentive by pro-actively managing their positions and mitigating balancing fees to the extent possible. When actual realized outcomes associated with the new balancing fee structure become available at the end of the 2019/20 Gas Year, Centra will re-assess its forecast of balancing fees at that time.

[1] Net of balancing fees recovered from T-Service customers

REFERENCE:

Tab 12 – Terms and Conditions of Service

PREAMBLE TO IR (IF ANY):

IGU requires further information to understand the requested changes to Centra's Terms and Conditions of Service

QUESTION:

d) For each rate class, please provide the current number of customers subscribing to sales service compared to T-Service.

e) For each year from 2011/12 to present, please provide the number of customers who have migrated from T-service to Sales Service and vice versa.

RESPONSE:

d) As of March 2019, the following table identifies the number of customers in each respective rate class. As noted in Centra's Application filing,[1] the total number of T-Service customers is 15.

[1] Tab 12, page 3 of 13, line 25

Rate Class	Number of Customers
	System Supply
SRES-S	[redacted]
SCOM-S	
LGS-S	
HVF-S	
MLF-S	
INT-S	
	Fixed Rate Offering
SRES-F	[redacted]
SCOM-F	
LGS-F	
	WTS
SRES-W	[redacted]
SCOM-W	
LGS-W	
HVF-W	
	T-Service
HVF-T	[redacted]
MLF-T	
PSB-T	
PSS-T	
SPEC-T	
TOTAL	

1d

e) The following table represents the number of customers that have migrated to/from T-Service by fiscal year since 2011/12.

Fiscal Year	Migrated From T-Service to Sales Service	Migrated From Sales Service to T-Service
2011/12	0	0
2012/13	0	0
2013/14	1	0
2014/15	1	2
2015/16	0	0
2016/17	0	0
2017/18	2	0
2018/19	0	0

REFERENCE:

Tab 12 – Terms and Conditions of Service

PREAMBLE TO IR (IF ANY):

IGU requires further information to understand the requested changes to Centra's Terms and Conditions of Service

QUESTION:

f) Please provide copies of all presentations and other materials referenced on lines 6 through 15 of page 5 of Tab 12 including the October 2016 presentation.

g) Please provide the number of existing T-Service customers who use less than 2,500 GJ/day and the number of existing T-Service customers who use more than 2,500 GJ/day. Please also provide the breakdown for customers referenced in part (e) above.

h) With reference to the statement at page 6, lines 13 through 17, please quantify the 'significant daily imbalances' both in terms of the customer's daily usage and as a percentage of Centra's average daily load.

i) Please provide the current TCPL fees for imbalances referenced at line 30 of page 6 of Tab 12.

j) Based on existing usage, what is the range of financial impacts that current T-Service customers would be charged as a result of Centra's balancing fee proposal if no changes are enacted in customer operations.

k) Please provide an illustrative example of how balancing fees would be charged based on a typical event Centra has experienced. Please ensure the example shows the units or billing determinants, the per unit charge and the total charge.

l) If Centra collects gas balancing fees in excess of what Centra pays to TCPL, how will excess revenues be refunded to Centra customers and if so, how will they be proportioned?

m) What differences, if any in balancing fee collection is Centra proposing between customers who buy gas from Centra versus customers who do not buy gas from Centra?

n) What methodologies will Centra use to determine if the 50% fee level needs to be adjusted in the future and by what amount?

o) Will Centra collect balancing fees when they are due to external events beyond a customer's control such as power failures or extreme weather and if so, why?
p) For T service customers subjected to balancing fees now, how was the daily tolerance and cumulative tolerances determined?
q) Was the same methodology in determining balancing fees employed for all T service customers?
r) Are there any other indirect charges proposed to be collected by Centra related to balancing other than foregone Capacity Management revenue?
s) How will Centra confirm to customers, including special contract class customers, that it will comply with contract terms with respect to balancing charges?

RESPONSE:

f) Please see the response to PUB/Centra I-149 a) for a copy of the October 2016 presentation to T-Service customers. Please see the response and attachments to PUB/Centra I-149 b) for the additional information provided to T-Service customers.

g) Please see the response to PUB/Centra I-150 b). Of those customers who migrated to and from T-Service since 2011/12, none of them have average daily consumption of more than 2,500 GJ/day.

h) Please see the attachment to this response.

i) Please see the response to PUB/CENTRA I-145a.

j) The premise of this question is unclear given that the purpose of the new balancing fee structure is to incent customers to make improvements relative to their current forecasting and balancing efforts, if that is what is meant by "customer operations". Please also see the response to PUB/CENTRA I-147b.

k) The mechanics and calculation of the proposed balancing fees are provided in the pro-forma monthly reporting that Centra has been providing to all T-Service customers and nominating agents for more than two and a half years now, and can be reviewed at Attachment 1 to PUB/CENTRA I-149b. Please also see the response to IGU/CENTRA I-26.

l) Please see the response to IGU/CENTRA I-1a through c.

m) For T-Service customers, balancing fees, if applicable, would be itemized and recovered on the customer's next monthly bill. For all Sales Service customers (regardless of whether they are system-supplied or WTS), balancing fee collection occurs through the Transportation PGVA and related rate riders. Please also see the response to IGU/CENTRA I-1a through c.

n) Centra's preferred outcome is to collect no balancing fees. Centra's objective is to incent improved T-Service account balancing that better aligns with the terms and condition of T-Service and customers' contractual commitments. Ideally, T-Service customers will respond to the introduction of the new balancing fee structure by pro-actively managing their positions and mitigating balancing fees to the extent possible, in which case the 50% fee level will not need to be adjusted.

Centra will monitor the performance of T-Service customers by tracking their average and maximum daily imbalances over time, as illustrated in the response to PUB/CENTRA I-150c. Given the baseline from which performance will be assessed, which is that under the status quo methodology 11 of 15 customers know that they will never incur balancing fees and respond accordingly, it should not be difficult to demonstrate some degree of improvement.

o) Under the TCPL Mainline's balancing fee structure, shippers are subject to balancing fees regardless of:

    i. a shipper's position relative to the pipeline's position (i.e., there is no exemption from paying fees for an imbalance because the shipper's position [pack or draft] is contrary to the pipeline's position);
    ii. extreme weather; and
    iii. whether a shipper is experiencing operational problems (e.g., unplanned maintenance or an outage at a facility).

The TCPL Mainline's balancing fees work in this manner because it must incent the behaviour needed to protect the integrity and reliability of the pipeline and to ensure that customers' needs downstream of Centra's delivery areas can be met. These are critical objectives in the successful operation of the pipeline as a "system", which consists of many shippers in many markets. In summary, the system would not work without strong financial penalties for imbalances.

As for the specific example of a power failure, Centra advised T-Service customers in their meetings with them that they should continue with the existing practice of contacting their Manitoba Hydro account representative in the event of a power failure at their facility, and that those situations would need to be assessed and addressed on a case by case basis.

p) The daily and cumulative absolute tolerances were established as a direct result of feedback from T-Service customers and their nominating agents. Centra's original proposal was to mirror the TCPL Mainline's balancing fee structure which would have provided customers with a daily absolute tolerance of 2% (on a simplified basis). However, the feedback provided during Centra's consultation with T- Service customers was that 2% was too restrictive and difficult to attain. That feedback resulted in Centra altering its original proposal to provide absolute daily and cumulative tolerances of approximately 7%.

q) Please see the response to PUB/CENTRA I-145e for a description of the current methodology. Going forward, balancing fees will consistently be modeled on the TCPL Mainline's balancing fee structure, as described in the response to PUB/CENTRA I-145a.

r) Please see the response to PUB/CENTRA I-147a.

s) Balancing fees, if applicable, will be itemized and recovered on the customer's next monthly bill. Detailed reporting will be provided as back-up to the customer's bill, an example of which can be found in Attachment 1 to PUB/CENTRA I-149b.

Centra Gas Manitoba Inc.
2019/20 General Rate Application

1	T-Service Customer	Average Daily Available Volume (GJ)*	Average Absolute Daily Imbalance (GJ)	Average Absolute Daily Imbalance as % of Average Daily Available	Maximum Absolute Daily Imbalance (GJ)	Maximum Absolute Daily Imbalance as % of Average Daily Available	1d Average Absolute Daily Imbalance as % of Centra's Average Daily Load
2	Customer A	1,641	215	13%	1,528	93%	[redacted]
3	Customer B	1,930	215	11%	1,453	75%	[redacted]
4	Customer C	2,035	290	14%	1,857	91%	[redacted]
5	Customer D	4,166	146	4%	1,970	47%	[redacted]
6	Customer E	6,467	1,109	17%	4,287	66%	[redacted]
7	Customer F	8,439	817	10%	3,588	43%	[redacted]
8	Customer G	683	134	20%	1,034	151%	[redacted]
9	Customer H	1,579	350	22%	1,408	89%	[redacted]
10	Customer I	[redacted]	[redacted]	2%	[redacted]	44%	[redacted]
11	Customer J	2,280	295	13%	1,166	51%	[redacted]
12	Customer K	1,446	190	13%	1,546	107%	[redacted]
13	Customer L	285	48	17%	302	106%	[redacted]
14	Customer M	824	187	23%	907	110%	[redacted]
15	Customer N	750	61	8%	542	72%	[redacted]
16	Customer O	1,424	156	11%	1,326	93%	[redacted]

2d

17 *Note: Daily Available Volume (also referred to as Net Nomination) includes both nomination and applicable balancing nomination.

REFERENCE:

Tab 12 pgs. 1-2 pf 13

PREAMBLE TO IR (IF ANY):

TransCanada Pipelines Limited ("TCPL") Mainline charges Centra as the downstream operator for any imbalances, whether caused by Centra or T-service customers in Centra's delivery areas. Centra is requesting approval to charge T-service customers for imbalances to incent these customers to balance their load with daily gas nominations.

QUESTION:

a) Provide a schedule and description of the TCPL Mainline balancing fees imposed on Centra if the deliveries to the MDA or SSDA are not in balance within a specific tolerance.
b) Explain whether the TCPL Mainline balancing fees or balancing tolerances have been materially revised or amended since 2007. If so, clarify what revisions or amendments were implemented, together with when these changes came into effect.
c) Provide Centra's proposed balancing fee schedule for T-Service customers.
d) Explain how Centra determines that its T-Service customers have deliveries that are in an imbalance position on a daily and intradaily basis and how Centra communicates these imbalances to its customers.
e) Explain how Centra currently attributes the TCPL Mainline balancing charges, which are the result of combined imbalances from all of Centra's customer groups, to imbalances caused by individual customers (or customer groups) and how these charges are currently recovered from T-Service customers.

RATIONALE FOR QUESTION:

RESPONSE:

a) Please see pages 13 and 14 of Centra's October 2016 presentation filed in response to PUB/Centra I-149 a) for a schedule and description of the TCPL Mainline balancing fees imposed on Centra for delivery area imbalances, reproduced for ease of reference as an attachment to this response. The benchmark toll referenced in the formulae in this attachment is the prevailing Empress to Kingston Public Utilities Commission Eastern Delivery Area ("KPUC EDA") toll. At the time the presentation was prepared, the Empress to KPUC EDA toll was $59.66807/GJ/month (daily equivalent of $1.9617/GJ). The KPUC EDA toll is now $44.93333/GJ/month (daily equivalent of $1.4773/GJ), effective February 1, 2019 as approved by the National Energy Board ("NEB"). The term "billed excess" noted in the description of TCPL Mainline balancing fees means any imbalance greater than the tolerance afforded in the applicable Tier, and less than the tolerance afforded in next highest Tier.

b) Other than routine changes to the benchmark toll as a result of system-wide toll changes on the TCPL Mainline, the only change to balancing fees since 2007 of which Centra is aware came about as a result of TCPL's 2011 Application for Business and Services Restructuring Proposal (the RH-003-2011 proceeding before the NEB). TCPL proposed in that proceeding to eliminate toll zones on the Mainline, which was ultimately approved by the NEB. This had the associated effect of transitioning the benchmark toll for balancing fees in the Mainline Tariff from the Eastern Zone toll to the FT toll from Empress to the KPUC EDA, as that distance of haul does not fluctuate and it closely matched the Eastern Zone load centre.[1] This change came into effect July 1, 2013.

c) Centra's proposed balancing fee structure is modeled on the TCPL Mainline balancing fee schedule outlined in the response to part a) above with two exceptions, both of which were designed to mitigate the financial impact of imbalances on T-Service customers once the new fee structure comes into effect:
    i. Centra is proposing to implement its fee structure at 50%[2] of TCPL's; and
    ii. Centra has afforded T-Service customers more generous absolute daily and cumulative tolerances than that which TCPL affords Centra. On a simplified basis,

[1] RH-003-2011 Reasons for Decision, PDF page 100 of 276, NEB ID: A51040-1
[2] The approved KPUC EDA daily equivalent FT toll is currently $1.4773/GJ, thus Centra's calculation of balancing fees is based on $0.73865/GJ (i.e., $1.4773/GJ multiplied by 0.5).

Centra's daily tolerance is 2% while T-Service customers have been afforded daily tolerances of approximately 7%.[3]

The mechanics and calculation of the proposed balancing fees are provided in an example of the pro-forma monthly reporting that Centra has been providing to T-Service customers and nominating agents for more than two and a half years now, and can be reviewed at Attachment 1 to PUB/Centra I-149 b).

d) To determine T-Service customer imbalances on a daily and intraday basis, Centra compares T-Service notifications against T-Service customer consumption data. T-Service notifications received from T-Service customers or their nominating agents include the following information:

- Nomination: the total amount of supply being delivered to the MDA;
- Balancing nomination: the quantity of a previous day's pack that is being used by the customer ("from Centra"); or the quantity of a previous day's draft that is being paid back by the customer ("to Centra"); and
- Net nomination: the net quantity of supply (i.e. the total of the nomination plus any "from Centra" nomination or minus any "to Centra" nomination) being delivered to the MDA, representing the total customer facility requirement.

Centra tracks the daily position of each customer, calculated as net nomination less actual consumption. If the T-Service notification provided by the T-Service customer or nominating agent does not match or closely track the metered consumption data, or does not adequately address a pack or draft from the previous day, Centra staff reach out to the customer or nominating agent by email or telephone, whereby they seek to clarify intent, answer questions, provide guidance if necessary, and request that nomination adjustments be made at the next available nomination window.

Additionally, the following reports are used to communicate imbalances and provide the information necessary to assess the need for nomination adjustments throughout the day:

[3] With two exceptions.

- **Daily Position Report** - Provides month-to-date daily nominations, daily consumption and resulting daily imbalances;
- **Hourly Consumption (previous gas day)** - Provides hourly, metered consumption at each customer facility for the previous gas day; and
- **Hourly Consumption (current gas day)** - Provides hourly, metered consumption for customer facilities for the current gas day.

These reports are sent as frequently as requested by T-Service customers and their nominating agents (currently twice daily but Centra can provide hourly consumption reports to T-Service customers and nominating agents as frequently as 24 times per day). Daily position reports provide aggregate daily information that should be assessed in concert with hourly consumption reporting, as well as forecast consumption requirements. This combination of reporting provides real-time data[4], such that actual consumption can be compared with known and forecast operating conditions (including weather, scheduled facility testing or maintenance, unscheduled facility shut-downs, etc.). The goal of the reporting – under both the current and proposed balancing fee structures – is to facilitate nomination adjustments by T-Service customers or their nominating agents at the various nomination windows throughout the gas day, such that T-Service account imbalances can be minimized.

e) Currently, if all of the following four conditions are met[5], T-Service customers are assessed a pro-rata portion of the TCPL Mainline's Limited Balancing Agreement (LBA) fees charged to Centra based on their imbalance as a percentage of the overall delivery area imbalance:
   1) LBA fees are charged to Centra for the entire delivery area;
   2) customer imbalance is greater than +\- 2,000 GJ;
   3) customer imbalance is greater than +\- 4% (imbalance as a percentage of net nomination); and
   4) customer imbalance contributed to the overall delivery area imbalance.

[4] Subject to a short delay to accommodate report generation and transmission.
[redacted] 2d

This approach was based on the premise that T-Service would be used by high load factor customers, with sufficient natural gas consumption to warrant the additional effort required to manage their own upstream gas arrangements, while capturing the savings afforded by foregoing any contribution towards Centra's upstream gas costs.

Balancing fees, if applicable, are itemized and recovered on the customer's next monthly bill. Any LBA fees beyond those which are recoverable from T-Service customers under this current methodology are recovered from Sales Service customers, as are other costs associated with T-Service imbalances.

Mainline Balancing Fee Structure applicable to Centra

4 tiers of Daily balancing fees

Tier 1 Tolerance calculation = greater of 2,111 GJ, or 2% of Nomination less imbalance makeup OR , 2% of the average of the last 30 days of nominations

Tier 1 Daily Fee = 0.2 x $1.96169/GJ (KPUC EDA Eastern Zone toll) x Billed Excess

Tier 2 Tolerance calculation = greater of 4,221 GJ, or 4% of Nomination less imbalance makeup OR , 4% of the average of the last 30 days of nominations

Tier 2 Daily Fee = 0.5 x $1.96169/GJ (KPUC EDA Eastern Zone toll) x Billed Excess over and above Tier 1

Tier 3 Tolerance calculation = greater of 8,443 GJ, or 8% of Nomination less imbalance makeup OR , 8% of the average of the last 30 days of nominations

Tier 3 Daily Fee = 0.75 x $1.96169/GJ (KPUC EDA Eastern Zone toll) x Billed Excess over and above Tier 2

Tier 4 Tolerance calculation = greater of 10,553 GJ, or 10% of Nomination less imbalance makeup OR , 10% of the average of the last 30 days of nominations

Tier 4 Daily Fee = 1.0 x $1.96169/GJ (KPUC EDA Eastern Zone toll) x Billed Excess over and above Tier 3

Mainline Balancing Fee Structure applicable to Centra

2 tiers of Cumulative balancing fees

Tier 1 Tolerance calculation = greater of 4,221 GJ, or 4% of Nomination less imbalance makeup OR , 4% of the average of the last 30 days of nominations

Tier 1 Cumulative Fee = 0.15 x $1.96169/GJ (KPUC EDA Eastern Zone toll) x Billed Excess

Tier 2 Tolerance calculation = greater of 6,332 GJ, or 6% of Nomination less imbalance makeup OR , 6% of the average of the last 30 days of nominations

Tier 2 Cumulative Fee = 0.25 x $1.96169/GJ (KPUC EDA Eastern Zone toll) x Billed Excess over and above Tier 1

PUB Advisor Document - Proposed Centra Balancing Fee Structure vs. TCPL Balancing Fee Structure

	Level of Daily Imbalance	TCPL Balancing Fee ($/GJ)	Proposed Centra Balancing Fee ($/GJ) - 50% of TCPL
Daily Tolerance	Less than 2%	$0.00000	$0.00000
Tier 1	2% up to 4%	$0.29546	$0.14773
Tier 2	4% up to 8%	$0.73865	$0.36933
Tier 3	8% up to 10%	$1.10798	$0.55399
Tier 4	10% or Greater	$1.47730	$0.73865

	Level of Cumulative Imbalance	TCPL Balancing Fee ($/GJ)	Proposed Centra Balancing Fee ($/GJ) - 50% of TCPL
Cumulative Tolerance	Less than 4%	$0.00000	$0.00000
Tier 1	4% up to 6%	$0.22160	$0.11080
Tier 2	6% or Greater	$0.36933	$0.18466

Sources:

PUB/Centra I-149b Attachment 2
PUB/Centra I-149a-Attachment 1
PUB/Centra I-145a

REFERENCE:

Tab 12 pgs. 1-6 of 13

PREAMBLE TO IR (IF ANY):

QUESTION:

a) In a format similar to the table below, provide the total balancing charges levied by TCPL, as well as the charges actually passed on to its customers (both Centra's Sales Service customers and T-Service customers), for TCPL Mainline delivery imbalances incurred at the MDA and SSDA since 2015/16. Provide data by fiscal year or gas year, whichever is more readily available.

Year		2015/16	2016/17	2017/18	2018/19 *
Total TCPL Mainline Balancing Charges Incurred by Centra for MDA and SSDA [$]					
Portion of Total TCPL Mainline Balancing Charges Incurred by Centra that were Passed on to Centra's Customers	Sales Service Customers [$]				
	T-Service Customer 1 [$]				
	T-Service Customer 2 [$]				
	T-Service Customer 3 [$]				
	Etc..				

* If available

b) In a format similar to the table above, provide the total balancing charges that would have been passed on to Sales Service customers and each T Service customer if Centra had charged balancing fees based on 50% of the TCPL balance fee structure, as Centra now proposes.

c) Similar to b) above, provide the total balancing charges that would have been passed on to Sales Service customers and each T-Service customer if Centra had passed on 100% of the balance fees actually levied by TCPL in proportion to the imbalance caused by each T-service customer or Sales Service customer group.

d) Confirm whether T-Service customer delivery imbalances have, at times, offset imbalances caused by Centra's Sales Service customers, resulting in the Centra avoiding incurring balancing fees. If so, estimate the total avoided balancing charges over the past three months.

e) Confirm whether Centra intends to charge balancing fees to its T-Service customers for daily imbalances even in situations where the MDA and SSDA are in balance and thus TCPL does not levy balancing charges to Centra.

f) Clarify Centra's rationale for its proposal to apply 50% of the TCPL balancing fee formula to all T-Service customers. For example, why 50% and not some other value? Does this mean that large T-Service customers that are currently charged 100% of the balancing fees will incur lower balancing charges from Centra?

RESPONSE:

a) The table below provides the total balancing fees levied by TCPL on Centra, as well as the charges Centra passed on to its customers (both Sales Service and T-Service customers) for TCPL Mainline delivery imbalances incurred at the MDA and SSDA since 2015/16.

		Gas Year			
		2015/16	**2016/17**	**2017/18**	**2018/19 YTD***
TCPL Balancing Charges Incurred by Centra for MDA & SSDA		$214,739	$243,856	$273,504	$51,708
TCPL Balancing Charges Recovered from T-Service Customers	T-Service Customer A	($12,121)	($86,816)	($73,292)	($25,088)
	T-Service Customer B	$0	($705)	($446)	($262)
	T-Service Customer C	($776)	($172)	($1,471)	($1,026)
Net TCPL Balancing Charges Applicable to Sales Service Customers		($201,843)	($156,163)	($198,294)	($25,332)

* Year-to-Date ("YTD") for the period of November 2018 thru March 2019.

However, balancing fees are but a small portion of the costs that Centra incurs as a result of T-Service imbalances. Centra is obligated to balance its delivery areas as the designated downstream operator. As a result, Centra is effectively forced to counteract T-Service imbalances and does this by using the assets at its disposal (e.g., storage and related transportation in winter, and Western Canadian supply contract flexibility throughout the year), the costs of which are recovered solely from Sales Service customers. Centra also must reserve a buffer on a daily basis to contend with the uncertainty of T-Service imbalances (both their direction and magnitude).

These actions by Centra (i.e., counteracting T-Service imbalances and maintaining a buffer to contend with the uncertainty of their positions) result in costs well in excess of the balancing fees charged by TCPL, both:

i. opportunity costs in the form of foregone Capacity Management revenue; and
ii. further direct costs (in addition to the balancing fees charged by TCPL) in the form of higher commodity costs associated with the delay of transactions from day-ahead to intra-day (i.e., a higher purchase price or a lower sales price, the later in the gas day the transaction takes place).

b) Centra does not know the total balancing charges that would have been passed on to Sales Service customers and each T Service customer if Centra had charged balancing fees based on 50% of the TCPL Mainline's balance fee structure because this has not yet happened. Centra cannot know how T-Service customers will, ultimately, react to the financial incentive to balance their accounts.

Centra's preferred outcome is to collect no balancing fees. Centra's objective is to incent improved T-Service account balancing that better aligns with the terms and condition of T-Service and customers' contractual commitments. Ideally, T-Service customers will respond to the introduction of the new balancing fee structure by pro-actively managing their positions and mitigating balancing fees to the extent possible.

The table below provides the pro-forma balancing fee outcomes that would have been experienced if Centra's proposed balancing fee structure had been in place since 2016/17 *and T-Service customers made no attempt to improve their balancing performance*. The fees below were not charged because the proposed balancing fee structure is not yet in place – they reflect what could happen if T-Service customers and their nominating agents take no action in response to the financial incentive associated with the new balancing fee structure.

		Gas Year		
		2016/17	2017/18	2018/19 YTD*
Pro-Forma Balancing Charges Recovered from T-Service Customers at 50% of Prevailing TCPL Toll	T-Service Customer 1	($101,596)	($116,228)	($47,474)
	T-Service Customer 2	($77,007)	($51,075)	($24,781)
	T-Service Customer 3	($53,131)	($35,168)	($17,690)
	T-Service Customer 4	($55,074)	($51,246)	($19,210)
	T-Service Customer 5	($35,241)	n/a	n/a
	T-Service Customer 6	($30,998)	($15,355)	($25,890)
	T-Service Customer 7	($132,256)	($136,625)	($119,001)
	T-Service Customer 8	($15,608)	($24,092)	($1,819)
	T-Service Customer 9	($88,966)	($76,899)	($36,271)
	T-Service Customer 10	($44,180)	($39,984)	($19,404)
	T-Service Customer 11	($22,526)	($16,067)	($9,234)
	T-Service Customer 12	($16,058)	($12,250)	($7,348)
	T-Service Customer 13	($64,034)	($46,912)	($19,556)
	T-Service Customer 14	($9,199)	($8,781)	($2,207)
	T-Service Customer 15	($44,248)	n/a	n/a
	T-Service Customer 16	($72,365)	($72,947)	($26,897)
	T-Service Customer 17	($58,117)	($56,562)	($22,588)
	Total	($920,602)	($760,191)	($399,372)

* For the period of November 2018 thru March 2019.

c) Centra does not have the requested information. Please also see the responses to parts a) and d) of this Information Request.

d) Confirmed, but Centra cannot estimate total avoided balancing charges over the past three months in this manner because this request implies that T-Service customers are part of a pool when they are not. The premise on which T-Service was originally introduced, and how it is designed and functions, is that a customer who elects T-Service is contractually committing to manage its own upstream gas arrangements, including the need to forecast and balance its account on a daily basis.[1] If a T-Service customer wishes to be part of a pool of customers, Centra provides other service options (System Supply and WTS) with this service attribute.

[1] Either individually or with the assistance of a nominating agent on their behalf.

e) Confirmed, recognizing however that Centra has afforded T-Service customers more generous daily and cumulative absolute tolerances than that which TCPL affords Centra,[2] up to which T-Service customers will not be charged any balancing fees. Please see an example of this at IGU/Centra I-26.

Under the TCPL Mainline's balancing fee structure, shippers are subject to balancing fees regardless of:

i. a shipper's position relative to the pipeline's position (i.e., there is no exemption from paying fees for an imbalance because the shipper's position [pack or draft] is contrary to the pipeline's position);
ii. extreme weather; and
iii. whether a shipper is experiencing operational problems (e.g., unplanned maintenance or an outage at a facility).

The TCPL Mainline's balancing fees work in this manner because it must incent the consistent behaviour needed to protect the integrity and reliability of the pipeline and ensure that customers' needs downstream of Centra's delivery areas can be met. These are critical objectives in the successful operation of the pipeline as a "system", which consists of many shippers in many markets. In summary, the system would not work without strong financial penalties for imbalances. These penalties are not waived because an out of balance shipper's position happens to be, by virtue of chance, contrary to that of another shipper. In that circumstance, shippers would not know whether to respond to the price signal of balancing fees, which would lead to inconsistent behavior and defeat the purpose of the financial incentive.

f) The spectrum of potential change to T-Service terms and conditions is wide, ranging from doing nothing (i.e., status quo), recognizing the harm to Sales Service customers, to providing notice to existing T-Service customers of the need for them to adhere to the terms and conditions of T-Service by a certain date or their participation in the service will be terminated as a consequence.

[2] On a simplified basis, Centra's daily tolerance is 2% while T-Service customers have been afforded daily tolerances of approximately 7%.

The balancing fee structure that Centra seeks to implement is a middle ground approach. The 50% of TCPL Mainline balancing fees proposed by Centra represents the midpoint of TCPL's balancing fee structure and was chosen to reasonably balance the competing objectives of providing a sufficient financial consequence so as to incent daily forecasting/balancing and mitigating the financial impacts on T-Service customers.

It is possible that large T-Service customers that are currently charged TCPL balancing fees at the 100% level[3] could pay less to Centra once the new fee structure is in place if their balancing performance improves relative to their historical performance. This would be a desired outcome from Centra's perspective, signifying the efficacy of the financial incentive. Conversely however, it is also possible that large T-Service customers will pay more to Centra once the new fee structure is in place, thereby appropriately offsetting the direct and indirect costs of their imbalances to the account of Sales Service customers.

[3] Recognizing that Centra's current practice involves the assessment of four conditions as described in the response to PUB/Centra I-145 e).

REFERENCE:

Tab 12 pgs. 1-6 of 13; 2007/08 Centra GRA Tab 11, Attachment 1 p. 30 of 50; 2011/12 COG PUB/Centra 39

PREAMBLE TO IR (IF ANY):

In 2007, as part of its 2007/08 & 2008/09 General Rate Application, Centra proposed and obtained Board approval for changes to the T Service terms and conditions of service to address the recovery of TCPL Limited Balancing Agreement fees.

In the response to PUB/Centra 39 in the 2011/12 Cost of Gas proceeding, Centra stated that:

"… only the four largest T-Service customers are able to be monitored for the assessment or pass through of any charges from TCPL. The daily nominations of the remaining 13 T-Service customers are relatively small such that the assessment of load balancing charges on an individual basis is very difficult."

In this 2019/20 GRA, Centra states:

"Centra's practice has been to recover only its direct costs from the largest volume T-Service customers who periodically drive the utility to incur balancing fees assessed by the TCPL Mainline. […] The utility's approach with the smaller volume T-Service customers has been very accommodating to date."

QUESTION:

a) Confirm whether Centra currently charges 100% of the TCPL Mainline delivery balancing charges attributed to the "largest volume T-Service customers" to those T-Service customers.
b) In light of Centra's previous request to amend the terms and conditions of service to allow recovery of balancing charges from all T-Service customers, explain why Centra has not sought recovery of balancing charges from smaller T-Service customers.
c) In light of the inability to monitor smaller T-Service customers for imbalances as stated in the 2011/12 Cost of Gas proceeding, explain how Centra now intends to levy balancing fees against all T-Service customers.

RESPONSE:

a) Not confirmed. Please see the response to PUB/Centra I-145 e) regarding the conditions that must be met under Centra's current cost recovery methodology. However, if those conditions are met 100% of the TCPL Mainline's unit balancing fee is currently applied by Centra.

b) Centra's systems, business processes and capabilities have evolved over time. As a result, monitoring smaller T-Service customers for imbalances is no longer a constraint. Additionally, market circumstances changed markedly with the introduction of unlimited pricing discretion on the TCPL Mainline in 2013. Prior to this, T-Service customers could readily address the circumstance where they were drafting the MDA by purchasing Interruptible Transportation ("IT") service on the TCPL Mainline. The price of IT service at that time was effectively capped at a 10% premium over the daily equivalent Firm Transportation ("FT") rate. Pricing discretion eliminated this price cap and correspondingly increased the operating challenges for T-Service customers in Manitoba. Perversely, T-Service customers now have a financial incentive to *not* address imbalances, particularly smaller volume customers or their nominating agents,[1] leaving Centra to use Sales Service assets to bring its delivery areas into balance. Since pricing discretion was implemented, T-Service customers or their nominating agents have ignored and even outright refused Centra's direction to address imbalances, in clear contravention of Section V., part D) of Centra's Special Terms and Conditions of T-Service and the executed contracts between the parties. Pricing discretion has also had the effect of increasing the time and effort expended by Centra's staff in trying to ensure that T-Service accounts are balanced.

Comprehensive change to the service was clearly required, which would financially incent T-Service customers to forecast their consumption and balance their accounts on a daily basis, and recover at least some of the costs (including indirect costs)

[1] Under Centra's current cost recovery methodology, smaller volume customers rarely if ever meet condition 2) as described in the response to PUB/Centra I-145 e).

being borne by Sales Service customers. However, Centra's current T-Service cost recovery methodology has been in place for decades, thus any proposed change to it was viewed by T-Service customers as a change in practice. Accordingly, Centra commenced a consultation process with T-Service customers in October of 2016. As part of the dialogue that ensued, a number of T-Service customers shared the view that the PUB should review and vet any proposed changes to T-Service terms and conditions of service. Centra acted on this preference and delayed implementation until the issue could be heard by the PUB as part of a General Rate Application ("GRA"). The first opportunity to file these changes was with Centra's November 30, 2018 GRA filing (Section 12.1).

c) Centra has been transparent with T-Service customers about how it intends to levy balancing fees going forward, providing detailed pro-forma reporting of the new approach to all T-Service customers and nominating agents from October 2016 to current (April 2019). Attachment 1 to PUB/CENTRA I-149b is an example of this pro-forma reporting.

REFERENCE:

PUB/Centra I-145, I-147(e), PUB/Centra I-149(b) Attachment 2, IGU/Centra I-22(p), IGU/Centra I-26

QUESTION:

a) Why does Centra describe the balancing tolerance as “approximately 7%” and not provide a specific percentage? Provide the absolute daily imbalance tolerance and the cumulative imbalance tolerances. Explain the two exceptions noted in the footnote to PUB/Centra I-145(c).

b) Explain how the 150 GJ and 300 GJ absolute tolerances shown in PUB/Centra I-149b Attachment 2 were derived and whether these tolerances apply to all T-Service customers.

c) Are the absolute daily and cumulative balancing tolerances static or do they vary daily with the magnitude of the nomination? Are there contractual levels of nominations between Centra and T-Service customers such that the balancing tolerances are static?

d) Confirm whether Centra’s proposal to implement a T-Service Balancing fee structure “at 50% of TCPL’s”, effectively implies that Centra will apply the same calculations for the TCPL daily and cumulative balancing fees shown in PUB/Centra I-145a-e Attachment 1, but apply 50% of the prevalent KPUC EDA Eastern Zone Mainline toll to any billed excess above the various tolerance Tiers (and base these Tier billed excess using the more generous daily and cumulative tolerances referenced in (a) above).

RESPONSE:

a) Absolute daily and cumulative tolerances would be assigned to T-Service customers on the basis of their average daily consumption[1] over the prior gas year where in general terms, the higher the average daily consumption the greater the tolerance afforded. The following chart illustrates the groupings of absolute daily and cumulative tolerances that would be assigned to T-Service customers based on ranges of customers’ average daily consumption:

[1] By contrast, Centra measures balancing performance against average daily available (i.e., net nomination).

Average Daily Consumption (GJ/day)	Number of Customers	Absolute Daily Tolerance	Absolute Cumulative Tolerance
Less than 1,000	4	+/- 50 GJ	+/- 100 GJ
1,000 to less than 1,700	4	+/- 100 GJ	+/- 200 GJ
1,700 to less than 2,500	3	+/- 150 GJ	+/- 300 GJ
2,500 to less than 5,000	3	+/- 250 GJ	+/- 500 GJ
[redacted]	1	+/- 500 GJ	+/- 1,000 GJ

This approach helps to ensure relative consistency amongst the majority of T-Service customers, with all but 2 of fifteen customers having absolute daily tolerances that allow for imbalances between 6% and 8% of their average daily available. The two 2d exceptions are [redacted] whose absolute daily tolerances allow for imbalances of [redacted], respectively. These exceptions are related to the magnitude of these customers' average daily consumption: [redacted] is by far the smallest T-Service customer at less than [redacted], while [redacted] is the largest T-Service customer at just over [redacted]. Accordingly, these customers' absolute daily tolerances fall 2d outside the norm of approximately 7% for Centra's T-Service customers.

b) Please see the response to part a) above. The illustrative example in Attachment 2 to the response to PUB/CENTRA I-149b depicts a customer whose average daily consumption is between 1,700 GJ/day and 2,500 GJ/day. As such, its absolute daily tolerance is +/- 150 GJ and its absolute cumulative tolerance is +/- 300 GJ.

c) Absolute daily and cumulative tolerances would be assigned and set a year at a time, and re-assessed on an annual basis using actual historical consumption information from the most recently completed gas year.

There are no contractual levels of nominations between Centra and T-Service customers. As described in the response to PUB/CENTRA I-147a, Centra must reserve a buffer on a daily basis to contend with the uncertainty of T-Service nominations and both the direction and magnitude of their imbalances.

d) Confirmed.

REFERENCE:

Labonte Evidence pp. 5, 7, and 8, PUB/Centra II-57a-d

PREAMBLE:

"FFC manages natural gas supply and pipeline nomination functions for numerous clients on many pipelines across Canada and the United States. The proposed Centra imbalance fee structure provides the lowest quantity of daily tolerance […] with the least amount of flexibility to offset imbalances prior to assessment of fees when compared to any other jurisdiction."

QUESTION:

a) Please describe the balancing tolerances that must be exceeded on other pipelines used by France Financial Consulting before balancing fees apply (including the name of the applicable jurisdiction).

b) Please explain whether the other jurisdictions referenced by France Financial Consulting also have a lack of local storage options or whether the applicable gas distribution area is served by a single interprovincial or interstate gas transmission pipeline.

c) Please provide Mr. Labonte's recommended balancing tolerances for each category of daily consumption as outlined in PUB/Centra II-57(a).

ANSWER:

a) and b)

Page 6 of my evidence provides two other jurisdictions I am familiar with through FFC's client operations. For reference this includes:

- TransGas pipeline system targeted thresholds of +/-1,000 GJ/day per day regardless of consumption levels. There are no penalties for imbalances but the utility expects customers to trend back to within tolerances.
- TransCanada's NGTL Alberta pipeline system – has a tolerance band equal to the greater of +/-2,000 GJ or +/-4% of deliveries. Customers also have the ability to buy and sell with other shippers to manage imbalances.

FFC also provides services to clients with operation in other jurisdictions, see below for details on each jurisdiction's balancing procedures.

- Union Gas (Ontario) requires our clients to provide both a twelve (12) month average estimated monthly consumption profile as well as twelve (12) months of firm monthly average nominations prior to the start of each gas year (November to October). Upon commencement of such gas year Union Gas generates a monthly report showing the difference between quantities delivered under the firm nomination and actual plant consumption for a given month. Any imbalance at the end of a given month is carried over to the following month. FFC, on behalf of its clients may decide to offset any month-end imbalance via a purchase or sale with the selected supplier or decide to carry-over such imbalance to the following month. If the imbalance is deemed excessive by Union Gas at the end of a given month it will request client to offset the imbalance, which FFC executes on behalf of our clients. In the event a client ignores the Union Gas request to balance its account Union Gas will buy (account pack) or sell (account draft) at punitive pricing relative to market pricing.
- Xcel Energy (North Dakota) accepts daily nominations from our client, with on-line reporting showing the difference between natural gas quantities delivered (nomination) and actual plant consumption for each day during a given month. Xcel Energy does not impose fees for any imbalance arising during a given month, regardless of the quantity of such imbalance. For each month end Xcel Energy will buy (account pack) or sell (account draft) at punitive pricing relative to market pricing. FFC is able, on behalf of its client, manage any month end balance to close to zero (0).

All referenced pipelines have direct or indirect access to storage facilities. As noted by Centra Gas in response to IGU/CENTRA I-24a&b TransGas Limited is directly interconnected with 5 other pipeline systems. Centra notes in response to PUB/CENTRA I-149(d) that it also has access to the Park and Loan Service ('PALS') which is uses as required and when available, similarly to other Mainline shippers.

c)

Prior to providing FFC's recommendation balancing on tolerances for each category outlined in PUB/Centra II-57(a), it would be useful to review Centra's interactions with current FFC clients since the fall of 2016 that has led to Centra's currently proposed balancing fee structure currently before the PUB.

- Centra presentations to its T-Service clients during the fall of 2016 and early 2017 detailing Centra's proposed imbalance fee structure showed a tolerance band of +/- zero (0) for all T-Service customers regardless of consumption levels.
- Upon objection by T-Service customers Centra increased the band to +/- 50 GJ's sometime in early 2017 for all T-Service customers regardless of consumption levels. My recollection is Centra communicated the increase via an email note.
- Centra once again revised its tolerance bands as detailed in the table below, without to my recollection of any communication to FFC or its current T-Service clients of such revision.

Average Daily Consumption (GJ/day)	Number of Customers	Absolute Daily Tolerance	Absolute Cumulative Tolerance
Less than 1,000	4	+/- 50 GJ	+/- 100 GJ
1,000 to less than 1,700	4	+/- 100 GJ	+/- 200 GJ
1,700 to less than 2,500	3	+/- 150 GJ	+/- 300 GJ
2,500 to less than 5,000	3	+/- 250 GJ	+/- 500 GJ
[redacted]	1	+/- 500 GJ	+/- 1,000 GJ

- Since Centra's original presentation proposing a new balancing fee structure most of Centra's communication to FFC's current T-Service clients has been a monthly report emailed by Centra to our clients detailing theoretical penalties each client would have occurred if the proposed and unapproved fee structure were in place. To my knowledge there has been no consultation between Centra and FFC's current T-Service clients on the proposal since early 2017 when Centra increased their tolerance band from +/- 0 GJ's to +/- 50 GJ's.

At this time, FFC's recommendation for all unredacted T-Service customers in the table above is for daily +/- 500 GJ tolerance bands. FFC proposes that development of a tiered structure based on usage and/or lowering of the GJ tolerance bands below 500 GJ may be possible but would require consultations with Centra to develop tools to enable T-Service customers to offset imbalances prior to assessment of fees by Centra.

REFERENCE:

PUB/CENTRA IGU/CGM-I-1a

PREAMBLE TO IR (IF ANY):

Centra states in this response:
"Any amounts collected from T-Service customers will be refunded to Sales Service Customers dollar for dollar."

QUESTION:

a) Can Centra please confirm, per the quote above, that any balancing fees collected from T-Services customers that are surplus to any balancing fees charged to Centra by TCPL will not be refunded back to T-Service Customers. If not, why?
b) How will Centra reward those companies who balance their gas better than others? Can you provide an illustrative example?
c) In Centra's view, have Sales Service customers ever benefitted from avoiding balancing charges due to T-service customers having offsetting loads?
d) In Centra's view, would removing all T-service and special contract customers (i.e. removing the loads entirely, not transitioning those loads to sales service) from the system result in higher balancing costs for existing sales service customers? Why or why not.

RESPONSE:

a) Confirmed, because T-Service imbalances result in costs borne by Sales Service customers as described in the responses to PUB/CENTRA I-147a and PUB/CENTRA II-58d. Additionally, please see the response to PUB/CENTRA II-58c which explains the reasons for balancing fees not being cost-based.

b) The premise of this question inappropriately suggests that it is Centra's role to "reward" those companies who balance their gas better than others. To the contrary, T-Service customers have a contractual obligation to balance their accounts on a daily and intra-day basis, which is consistently not being met by the majority of T-Service customers.

Under Centra's balancing fee proposal, companies who "balance their gas" (i.e., balance their nominations with consumption) better than others will pay relatively less or no balancing fees. An illustrative example of this was provided in the response to IGU/CENTRA I-26.

c) Please see the response to PUB/CENTRA I-148 b.

d) All else equal, removing T-service customers including special contract customers from the system would currently result in lower balancing costs for Sales Service customers because:
    i. Centra actively monitors and manages its Sales Service account balance on a daily and intra-day basis while most T-Service customers do not; and
    ii. Sales Service customers absorb the vast majority of costs (direct and indirect) associated with T-Service imbalances.

Under Centra's balancing fee proposal, cross-subsidization of T-Service customers by Sales Service customers would be mitigated because more appropriate incentives would exist for T-Services customers to balance their accounts on a daily and intra-day basis.

REFERENCE:

PUB/Centra I-147, IGU/Centra I-1a-c

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Given the assumptions made in the responses to PUB/Centra I-147 (a) and (b), confirm the following difference in TCPL-to-Centra and Centra-to-T-Service customers balancing charges that could have resulted in gas years 2016/17 and 2017/18. If not confirmed, correct the table below as required.

Balancing Charges	Gas Year		Source
	2016/17	2017/18	
TCPL to Centra	$243,856	$273,504	PUB/Centra I-147a
Centra to T-Service Customers	$920,602	$760,191	PUB/Centra I-147b
Difference	**-$676,746**	**-$486,687**	

b) In the response to PUB/Centra I-147(d), Centra states that T-service customers are not part of a "pool" and thus Centra did not provide the balancing charges avoided due to T-service customers offsetting Centra's Sales Service imbalances. However, does TCPL treat the Manitoba Delivery Area as a "pool" in that balancing fees are charged on the aggregate imbalance of Sales Service and T-service customers?

c) Centra states that it will charge balancing fees to T-service customers even if TCPL does not levy balancing charges against Centra. In this sense, is it correct that these charges do not represent cost recovery from Centra's T-Service customers? Would this view also apply to TCPL, which levies balancing fees on Centra even if the Mainline is in balance or if Centra's balance is contrary to the Mainline's position? Is the Mainline a cost of service pipeline whose charges to customers (shippers) are based on the approved costs of the pipeline? What other charges does Centra levy on its customers that are approved by the PUB but are not directly cost-based or have an incentive nature (for example, unauthorized over-run charges to Interruptible customers)?

d) Confirm whether the following is correct for Centra's current practice, or, if not confirmed, make corrections or clarifications: If a T-service customer drafts the

Mainline, Centra uses its supply, storage, and transportation assets to try to bring the Centra MDA into balance. It does this by nominating additional volumes on the Mainline (presumably with unutilized FT capacity) and also nominates additional commodity supplies from its Western Canadian gas supplier (currently ConocoPhillips). The fixed cost of the FT is already part of the fixed costs paid for by Sales Service customers, so there are no incremental variable costs for the additional pipeline nominations, but there are opportunity costs for foregone capacity management revenues. The costs of the additional commodity supplied by Centra will also fall to Sales Service customers.

In the reverse situation, if a T-service customer packs the Mainline, Centra will adjust its nominations down for Sales Service customers to try to bring the MDA into balance. Centra will then have additional unused FT capacity which it could release to possibly generate capacity management revenues. Centra will also nominate fewer commodity supplies from its Western Canadian supplier (ConocoPhillips), which will lower Centra's commodity costs for its Sales Service customers.

RESPONSE:

a) Confirmed.

b) Yes, Centra's delivery areas are treated as pools by TCPL. By electing T-Service however, T-Service customers are opting out of the pools managed by Centra. As described in the response to PUB/CENTRA I-145e, the central premise of T-Service is that customers electing it are choosing to manage their *individual* upstream natural gas portfolios, thereby opting out of Centra's upstream contracting and activities as represented by the pools that Centra manages within its delivery areas. T-Service customers avoid any cost responsibility for Centra's upstream portfolio thus, to be fair, they should not be entitled to selectively use Centra's portfolio to offset their imbalances without an appropriate balancing fee structure in place.

c) Similar to the National Energy Board ("NEB")-approved TCPL Mainline balancing fee structure, Centra is seeking approval from this Board to institute balancing fees that are not cost recovery-based because:

1) Centra has an obligation to the TCPL Mainline to ensure that its delivery areas are balanced, both to protect the integrity and reliability of the pipeline and to ensure that customers at the far downstream end of the system obtain their gas. This is not a casual requirement. It is thus critical that shippers do not routinely pack or draft outside of tolerance. Both the NEB and shippers on the TCPL Mainline support the concept of balancing fees in their current form because they are necessary to appropriately incent balancing behaviour. The fees are significant and are not cost-based because they must strongly deter and minimize account imbalances.

2) Centra incurs balancing fees regardless of:
    i. The TCPL Mainline's line-pack position. The pipeline overall may be balanced but Centra will incur fees if its delivery areas are out of balance in excess of tolerance and regardless of the reason for the imbalance (e.g., there is no exemption if Centra and/or its customers are contending with unplanned maintenance or an outage); and
    ii. Centra's position (pack or draft) relative to the pipeline's position. Similarly, there is no exemption from paying fees for an imbalance because Centra's position is contrary to (i.e., helping) the pipeline's position.

   Neither of these features of the NEB-approved TCPL Mainline balancing fee structure is cost-based, yet they exist for the reasons described in part 1) above. Fines or fees are routinely used to guide behaviour, e.g., speeding fines are not cost-based because they're effected to serve as a strong deterrent to behaviour that could harm others and result in extraordinary societal (i.e., system) costs.

3) Balancing fees are but a small portion of the costs that Centra incurs as a result of T-Service imbalances. Centra also incurs opportunity costs in the form of foregone Capacity Management revenue and further direct costs in the form of higher commodity costs associated with the delay of transactions from day-ahead to intra-day (i.e., a higher purchase price or a lower sales price, the later in the gas day the transaction takes place).

With respect to the other charges that are approved by the PUB that are not directly cost-based or have an incentive nature, please see the following table:

Charge	Comments
Unauthorized Overrun Delivery Charge and Unauthorized Overrun Gas Charge	Charged to customers that fail to curtail service upon notice from Centra and who otherwise are not supplied with Alternate Supply Service. This charge was established to provide a better incentive to interruptible customers during a period of curtailment.
Late Payment Charge	Late payment charges are assessed on accounts remaining unpaid after the due date. While revenues from late payment charges help to recover the cost of collection activities, the late payment charge is also assessed to provide incentive to customers to pay their bills on time.
Gas Meter Test Fee	The Meter Test Fee is applied when a customer requests that their meter be removed from service to be tested for accuracy by Measurement Canada. The fee is only applied in cases where the meter is found to be recording within acceptable tolerances. As noted in Tab 12 of Centra's Application, the proposed Meter Test Fee is set below the actual costs of both the electric and gas meter dispute costs to ensure that customers who believe there is a problem with their meter do not face a fee so high that it acts as a deterrent to having the test performed. At the same time, the fee needs to be high enough that customers don't request a test be performed every time they perceived their bill to be too high.
ABC (Agency Billing & Collection) Fee	Agency Billing and Collection ("ABC") Service is offered in conjunction with Western Transportation Service. ABC Service allows Centra to bill Customer's for Primary Gas on behalf of a Broker, using the Broker's Primary Gas price. The Customer makes a single payment to the Company. The Broker pays to Centra $0.25 per customer per month for ABC service. As noted in Centra's response to PUB/Centra I-155, this $0.25 nominal fee does not fully recover the overall cost of maintaining the ABC Service. Centra's actual incurred ABC costs over and above the amounts recovered directly from WTS Brokers via ABC fees are recovered from all gas customers in their rates in return for the benefits of being able to choose their Primary Gas supplier.

d) The inference in this question appears to be that the impacts of T-Service customers' routine imbalances (packs and drafts) may offset one another over time such that the result is neutral for Sales Service customers. To the contrary and as Centra described in its response to PUB/Centra 147 a), the actions taken by Centra to counteract T-Service imbalances and the need to maintain a buffer to contend with the uncertainty of their positions currently results in costs borne solely by Sales Service customers well in excess of the direct costs of the balancing fees charged by TCPL, both:

i. opportunity costs in the form of foregone Capacity Management revenue; and

ii. further direct costs (in addition to the balancing fees charged by TCPL) in the form of higher commodity costs associated with the delay of transactions from day-ahead to intra-day (i.e., a higher purchase price or a lower sales price, the later in the gas day the transaction takes place).

With regard to the specifics of Centra's current practice, if a T-Service customer drafts the Manitoba Delivery Area (MDA) for example, Centra may use its supply, storage and transportation assets to bring the delivery area into balance in any of the following ways depending on the circumstances at the time:

- If there is unutilized TCPL Mainline FT capacity from Empress, additional supply may be nominated by Centra;
- If there is unutilized storage withdrawal capability and associated transportation capacity on ANR and GLGT, additional supply may be nominated from storage;
- Supplemental Gas may be purchased to serve the delivery area; or
- If Centra has the operational capability to repay a loan in the coming days, this service may be taken from the TCPL Mainline (depending on availability).

If a T-Service customer packs the MDA, Centra may use its supply, storage and transportation assets to bring the delivery area into balance in any of the following ways, depending on the circumstances at the time:

- Reduce the Western Canadian supply nomination or sell excess supply;
- Reduce the supply nomination from Centra's storage inventory; or
- If Centra has the operational capability to utilize incremental gas in the coming days, Centra may execute a park with the TCPL Mainline (depending on availability).

Centra confirms that:

- There are no variable transportation costs associated with incremental supply nominations on the TCPL Mainline by Centra to bring the delivery area into balance if T-Service customers are drafting the system, other than compressor fuel paid to TCPL with gas in kind, the cost of which is recoverable from Sales Service customers;
- There are variable storage and transportation costs associated with storage nominations used to balance the MDA, which are also borne by Sales Service customers;
- Given that decisions about T-Service customers' positions cannot be made day-ahead, they result in Sales Service customers bearing the incremental costs (or reduced value) of supply nominated or sold on an intra-day basis;
- Additionally, uncertainty over whether T-Service customers will address packs or drafts (due to the absence of an appropriate balancing fee structure) results in delayed decisions on capacity management transactions, representing foregone capacity management revenue to the account of Sales Service customers, specifically the difference in revenue that could have been earned if Centra made its decisions earlier in the gas day rather than having to wait until the ID2 or ID3 nomination window. The value of this timing difference averaged $0.24/GJ over the 2016/17 and 2017/18 gas years; and
- The costs associated with purchases of Supplemental Gas to balance the MDA are borne by Sales Service customers, rather than the T-Service customer(s) that caused the imbalances.

REFERENCE:

PUB/CENTRA I-147 a-f

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please confirm if the net TCPL Balancing Charges for 2015/16 ($201,843); 2016/17 ($156,163); and 2017/18 ($198,294) in the response to PUB/CENTRA I-147 (a) are equivalent to the values provided in page 2 of the response to IGU/CENTRA I-1 (a-c). If not, please provide an explanation.

b) In Centra's view, do sales service customers properly bear any cost responsibility for the Net balancing charges outlined in part (a) above?

c) Please provide a quantified estimate of the annual costs Centra incurs in terms of opportunity costs in the form of foregone capacity management revenue; and further direct costs in terms of higher commodity costs associated with the delay of transactions as described in the response to PUB/CENTRA I-147(a). Please clearly state all assumptions used in developing the estimates.

d) Please confirm:
   i. that the response to PUB/CENTRA I-147 b indicates that Centra would have charged T-service customers $920,602 in 2016/17 and $760,191 in 2017/18 if Centra's proposed balancing fees had been in place for those periods and customers did not alter their operating behaviour. If not confirmed, please provide a detailed explanation.
   ii. Whether or not any amounts in addition to those in part (i) would have been collected from special contract customers.

e) Please provide a version of the table in the response to PUB/CENTRA I-147 (a) that shows the Net TCPL Balancing Charges Applicable to Sales Service Customers assuming Centra's proposed balancing fee structure had been in place beginning in 2015/16 and customers did not alter their behaviour.

f) Please describe the reserve buffer that Centra uses on a daily basis to address the uncertainty of T-Service imbalances. Please provide the quantitative daily amount and if it changes seasonally, making sure to provide the peak and minimum.

g) How does Centra know the daily gas requirements of System Gas Users? How does Centra manage the daily gas uncertainty of System Gas Users?

h) Please describe the reserve buffer that Centra uses on a daily basis to contend with the uncertainty of System Gas imbalances. Please provide the quantitative daily amount and if it changes seasonally, making sure to provide the peak and minimum.

i) With respect to the response to PUB/CENTRA I-147 (d), please provide a reference to previous filings and PUB decisions that support the statement "The premise on which T-Service was originally introduced.....is that a customer who elects T-Service is contractually committed to manage its own upstream gas arrangements, including the need to forecast and balance its account on a daily basis."

j) Centra states in response to PUB/CENTRA I-147 (d) "If a T-Service customer wishes to be part of a pool of customers, Centra provides other service options with this service attribute".

Would Centra consider:

k) Allowing several T-Service customers to pool their service together through a single nominating agent? Please explain why or why not.

    ii. Allowing shippers to trade imbalances between each other to make-up imbalances? If so, how would Centra propose to implement this? If not, why not?

RESPONSE:

a) Not confirmed. Please see the response to IGU/CENTRA II-5a for a reconciliation and explanation of historical balancing fees.

b) This question should be considered within the broader context of the total cost of T-Service imbalances, rather than TCPL balancing fees alone, however it is Centra's view that Sales Service customers should reasonably bear balancing costs to the extent they caused them to be incurred. Currently, Sales Service customers are unduly cross-subsidizing T-Service customers and have been for a number of years.

By contrast, Centra's proposed balancing fee structure would directionally ensure fairness in relation to balancing costs which include TCPL balancing fees.

c) The quantum of direct and indirect (i.e., opportunity) costs associated with T-Service imbalances is material and exceeds the direct cost of balancing fees incurred from TCPL. As described in the response to parts f) and h) below, at least [redacted] of Centra's operational buffer is associated with the uncertainty impact that T-Service customers currently have on Centra's daily decision-making, which drives reduced Capacity Management ("CM") revenue and increased costs: 1c

- During the summer months, accommodating the uncertainty of T-Service imbalances results in both foregone CM revenue and increased commodity costs given the required delay of transactions. The delay of a sale of excess capacity results in foregone CM revenue as a result of moving from a day-ahead transaction to an intra-day transaction, the historical average of which is approximately $0.25/GJ. Similarly, higher commodity costs result from delaying a commodity purchase or sale to a later intra-day nomination window in order to balance the MDA. While the continuous change in spot market prices makes quantification impractical in this case, the diminished liquidity at later nomination windows definitely results in lower value for Centra's gas sales and higher costs for Centra's gas purchases. Given variability in weather and market conditions, Centra estimates summer opportunity and direct costs of at least [redacted]. 1a
- During the winter months, the opportunity costs associated with accommodating the uncertainty of T-Service imbalances take the form of foregone CM revenue due to the requirement of [redacted] 1a, 1c and reducing the volume of [redacted]. However, these volumes can vary widely based on weather and operational requirements. As a result, foregone revenue during the winter period exists but cannot be estimated with accuracy.

1 [redacted] 1a

In summary, while not all direct and indirect costs can be quantified with precision given the challenges associated with valuing transactions that were never executed and the multitude of different and changing market conditions (such as seasonal differences in portfolio optimization activities, basis differentials in the market, and pipeline restrictions) that impact operational decisions on the day, Centra would not have undertaken the significant effort associated with introducing and refining a T-Service balancing fee structure if the cost to Sales Service customers of the status quo was not material, in fact exceeding the direct cost of balancing fees incurred from TCPL.

Additionally, there is no benefit to Centra of balancing fees other than to:

i. Incent improved balancing performance for the important reasons described in the response to PUB/CENTRA II-58c;
ii. Minimize the inefficiency and associated cost of Centra staff having to coax T-Service customers and/or nominating agents on a daily basis to do that which is a requirement of the service; and
iii. Directionally address an unfairness that has existed for a number of years.

d)

i. Confirmed.
ii. The information in the table in the response to PUB/CENTRA I-147b is inclusive of special contract customers. Thus, no amounts in addition to those provided in this table would have been collected from special contract customers.

e) Centra does not agree with the premise of this question which is to assume that T-Service customers will make no attempt to improve their balancing performance once the incentive of balancing fees are in effect. This is unrealistic. If a financial incentive is implemented in the form of the proposed balancing fee structure, it is reasonable to expect that T-Service customers' balancing performance will improve.

Additionally, Centra has already provided two and a half years of pro-forma reporting to all T-Service customers and nominating agents, and summarized this information in the response to PUB/Centra I-147 b). Accordingly, Centra respectfully declines to calculate pro-forma results for a further one year historical period which would be labour intensive and not value-added.

f) and h)

The operational buffer referenced in the response to PUB/Centra I-147 a) and in part c) above varies daily based on a number of factors including:

i. weather (which drives consumption);
ii. the season within which Centra is operating (which influences the range of potential weather to which Centra needs to be prepared to respond);
iii. market conditions (e.g., whether restrictions are in place on any of the pipelines on which Centra transports gas which may influence the amount of buffer used on the day); and
iv. the current uncertainty related to whether and to what degree T-Service customers will balance their accounts.

This operational buffer ranges between [redacted] 1c
of Centra's operational buffer.

g) Centra forecasts the daily gas requirements of Sales Service customers (i.e., system-supplied and WTS-supplied customers) by maintaining a database of historical consumption data that it cross-references with key weather variables (e.g., temperature, wind chill, cloud cover) as provided by multiple weather forecast services for the coming day(s) and actual hourly metered consumption data from throughout the Manitoba market. Centra is also attuned to market conditions as described in parts f) and h) above.

Once daily consumption has been forecast, including defining a range of consumption with a low end, the pick, and a high end, Centra then actively monitors hourly consumption relative to forecast and has the following options available to it to respond to variation from forecast:

i. Increase or decrease supply by adjusting nominations to match updated consumption information at day-ahead and intra-day nomination windows, as required (at up to 5 nomination windows per gas day during summer and at up to 6 nomination windows per gas day during winter);

ii. Use the TCPL Mainline's Park and Loan Service ("PALS")[2]; and/or

iii. Execute purchases (if drafting) and sales (if packing) of gas in the market with other counterparties who operate on the TCPL Mainline.

By comparison, there is a current T-Service customer who advised during Centra's customer consultations that it hadn't evaluated its daily consumption *in a year*, another who routinely submits a monthly forecast of gas consumption to its nominating agent and to Centra, and others who forecast their consumption on a weekly basis at best, all within a gas market that operates on a daily and intra-day basis and regardless of their contractual obligation to balance their accounts on a daily basis.

i) Centra did not rely on previous filings and PUB decisions to support its statement that the premise on which T-Service was originally introduced, and how it is designed and functions. A customer who elects T-Service is contractually committing to manage its own upstream gas arrangements including the need to forecast and balance its account on a daily basis. The current terms and conditions of T-Service outline this requirement, as described in Centra's evidence.[3]

j) and k), i) and ii)

The premise of these questions suggests that Centra would act as a clearing house for commodity imbalances to and from T-Service customers. Centra is neither set up, nor compensated, to perform this function which would inevitably result in greater costs and effort on Centra's part. Given the extent to which Sales Service customers are, and have been, cross-subsidizing T-Service customers, Centra does not support the addition of yet another layer of complexity and administrative cost for the benefit of T-Service customers and nominating agents and to the detriment of Sales Service customers. Sales Service, including both system supply and WTS options, is available for customers that do not wish to manage their upstream gas arrangements on a daily basis using

[2] Subject to availability and as described in the response to PUB/Centra I-149 d).

[3] Tab 12, pages 2-3.

existing market options, while Centra's balancing fee proposal is low cost and appropriately incents improved balancing performance.

REFERENCE:

PUB/Centra I-147b, PUB/Centra I-150c Attachment 1, IGU/Centra I-22h Attachment 1

PREAMBLE TO IR (IF ANY):

The table provided in PUB/Centra I-147b provides the pro-forma balancing fee outcomes that would have been experienced if Centra's proposed balancing fee structure had been in place since 2016/17 and T-Service customers made no attempt to improve their balancing performance.

QUESTION:

a) File a revised version of the table provided in PUB/Centra I-147b for the 2017/18 year only assuming Centra's proposed balancing fee structure had been in place and all T-Service customers had made a 10% improvement in the daily balancing performance. That is, their daily nominations were 10% more accurate than they actually were.
b) File a revised version of the table provided in PUB/Centra I-147b for the 2017/18 year only assuming Centra's proposed balancing fee structure had been in place and all T-Service customers had a 50% improvement in the daily balancing performance.

RESPONSE:

a) and b):

The actions Centra would have taken in response to T-Service imbalances, and the resulting delivery area imbalances and balancing fees assessed by TCPL would all have been different if T-Service customers' balancing performance was different historically. Centra's decisions are made in real time, at up to six different nomination windows for each gas day. Accordingly, Centra cannot model the historical impacts of improvements in T-Service customers' balancing performance without recreating a total of 1,976[1] decision points and all of the potential resultant outcomes, which is not feasible.

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[1] (151 days of the winter season x 6 nomination windows) + (214 days of the summer season x 5 nomination windows) = 1,976

Directionally, a 10% improvement in T-Service customers' daily balancing performance would result in a greater than 10% reduction in their balancing fees and, similarly, a 50% improvement in T-Service customers' daily balancing performance would result in a greater than 50% reduction in their balancing fees. In both of these circumstances, T-Service customers' absolute daily and cumulative tolerances would remain the same, thus the amount of the imbalance on which balancing fees are assessed would diminish proportionally. Put another way, the closer T-Service customers get to operating within their absolute daily and cumulative tolerances, the greater the likelihood they will pay no balancing fees. Please see the response to IGU/Centra I-26 which illustrates a scenario in which a T-Service customer would pay no balancing fees despite its daily and cumulative imbalances.

REFERENCE:

PUB/CENTRA I-149 c and IGU/CENTRA I-24 a and b

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please itemize and elaborate on the 'significantly more economic alternatives that Centra routinely avails itself of and which are also available to T-Service customers or their nominating agents' referenced in the response to IGU/CENTRA I – 24 (a) and (b).
b) Has Centra ever investigated on its own or been approached by another party about the possibility of developing new local storage options in Manitoba? If not, when not. If yes, please discuss why such options have not been developed.

RESPONSE:

a) Any of the following actions are available to a T-Service customer or its nominating agent in order to balance their account within tolerance:
    i. Increase or decrease supply by adjusting nominations to match updated consumption information at day-ahead and intra-day nomination windows, as required;
    ii. Use the TCPL Mainline's Park and Loan Service ("PALS")[1]; and/or
    iii. Execute purchases (if drafting) and sales (if packing) of gas in the market with other counterparties who operate on the TCPL Mainline.

    Some T-Service customers routinely avail themselves of these options but most T-Service customers (or their nominating agents) do not, the latter group balking at the associated costs relative to their current free option to swing on Centra's assets which are contracted and paid for by Sales Service customers.

[1] Subject to availability and as described in the response to PUB/CENTRA I-149d.

Any of the readily available and industry recognized above-noted options are immensely more cost effective than would be options like developing local storage[2] and peak shaving facilities, which could require capital investment in the hundreds of millions of dollars.

b) Centra has investigated the possibility of developing local storage in Manitoba but it is not economic relative to market alternatives.

[2] PUB/CENTRA I-149c.

REFERENCE:

Tab 12 – Terms and Conditions of Service

PREAMBLE TO IR (IF ANY):

IGU requires further information to understand the requested changes to Centra's Terms and Conditions of Service

QUESTION:

a) Please provide a comparison of Centra's proposed tolerances and tolerance ranges with the current tolerances and tolerance ranges of other utilities in Canada, where available to Centra. Please also specifically provide the tolerance information for:
   i. TransGas Pipelines
   ii. NOVA Gas Transmission
   iii. Union Gas Limited
   iv. Xcel Energy
b) For the utilities listed in part a) and any other examples listed, please provide all tools and mechanisms in place as part of the utility service for customers to mitigate imbalances.
c) Please explain all due diligence processes Centra Gas undertook in preparation of its balancing fee proposal, including consideration and research undertaken of other utility offerings for balancing fees.
d) Please provide the results of all studies, research, and due diligence performed by Centra in the past 5 years on the balancing fee proposal.
e) For the utilities listed in part a) please explain different customer classes, rate designs and rate structures that are in place for T-Service customers, and as they may relate to balanced usage levels. Please explain if Centra Gas considered changes to its customer classes or rate offerings other than its proposed reduction for usage thresholds to 2,500GJ/day.

RESPONSE:

a) and b)

Please see the response to PUB/Centra I-149 c). Centra is also aware that some utilities have invested in high cost peak shaving facilities to replicate local storage in balancing their market, mitigating price risk and reducing their costs by improving their load factor. Natural gas is liquefied and stored in ultra-low temperature cryogenic tanks, with the liquefied natural gas ("LNG") then regasified and used for peak shaving purposes. Alternatively, peak shavers without liquefaction facilities may rely on LNG tanker trucks that are filled with LNG purchased from a third-party liquefaction facility to refuel their LNG storage tanks. However, these types of investments are very costly and would not appear to meet the economic efficiency test when compared with the significantly more economic alternatives that Centra routinely avails itself of and which are also available to T-Service customers or their nominating agents.

Regardless, Centra is not positioned similarly to these utilities, thus their balancing tolerances and ranges would not appear to be relevant. For example: TransGas Limited has access to numerous local storage caverns in Saskatchewan and is directly interconnected with 5 other pipeline systems as follow:

i. NGTL;
ii. TCPL Mainline;
iii. Foothills;
iv. Havre Pipeline Company; and
v. WBI (Williston Basin Interstate).

c) and d)

Given Centra's unique characteristics (no local storage and captive to the TCPL Mainline for physical deliveries), its due diligence process focused on consulting with its T-Service customers. Following the October 2016 kick-off meeting on the need for changes to the service, Centra has done the following:

i. Centra changed its original proposal to afford T-Service customers daily and cumulative absolute tolerances[1] and at higher levels than Centra's;[2]

[1] Calculated as percentages of average daily available volumes (i.e., daily nomination and applicable balancing nomination).

ii. Centra developed pro-forma reporting in response to T-Service customers' requests for pro-forma reporting to help them understand the mechanics and calculation of the proposed balancing fees. Thirty-one (31) months of this pro-forma reporting has now been provided to T-Service customers and their nominating agents (from October 2016 through April 2019). An example of the reporting is filed as Attachment 1 to PUB/CENTRA I-149b;

iii. Centra provided to all T-Service customers a written description of each of the three supply service options available to existing T-Service customers (i.e., System Supply, WTS, and T-Service), filed as Attachment 2 to PUB/CENTRA I-149b;

iv. Centra held multiple conference calls with each T-Service customer and their nominating agent (where applicable) to review and address questions about the proposed balancing fee structure and Centra's service options, and to discuss potential actions that can be taken going forward to address imbalances and mitigate fees; and

v. Centra proposed in its Application to grandfather all existing T-Service customers from the need to qualify for the proposed new volumetric eligibility threshold.

e) Centra did not consider changes to its customer classes or rate offerings. As described in the response to PUB/CENTRA I-149c, one of Centra's key considerations was cost-effectiveness. Centra's proposal requires little to no system set-up and does not require additional staffing or modifications to rate design, making it highly cost effective.

Centra based its proposal on the proven, long-standing TCPL Mainline balancing fee structure. Given that physical deliveries of gas to Centra's delivery areas are from the TCPL Mainline, there is no need to re-invent the wheel on this matter.

[2] With one exception.

REFERENCE:

PREAMBLE:

Centra seeks to understand the position of certain IGU members on the balancing fee proposal for T-Service customers in Manitoba, given the status quo that balancing fees are subsidized by Sales Service customers.

QUESTION:

What is the position of Gerdau Long Steel North America – Manitoba Mill on Centra's balancing fee proposal for T-Service customers in Manitoba? Please explain.

ANSWER:

Representatives from Gerdau stated that from a principled standpoint Gerdau is supportive of a cost based balancing fee over a punitive based penalty. Gerdau supports that costs incurred to the Centra system that are a direct result of T-Service class imbalances should be allocated to that class and not the Sales Service classes, based on cost causation principles.

In addition, Gerdau is not supportive of Centra's proposal to increase the T-Service daily usage threshold from 200 GJ per day to 2,500 GJ per day. Gerdau would like to preserve flexibility in service options for customers in Manitoba. Allowing T-service customers to pool to exchange imbalances amongst themselves would facilitate this. This is similar to options available in some US states to Gerdau for both pools operated by the utility and by customer/third parties.[1] Gerdau operates as a T-Service customer in other jurisdictions where options exist to help manage daily imbalances.

[1] See for example, the Michigan Government website which summarizes transportation natural gas services offered in Michigan by applicable natural gas utilities, where NSP, WPS, Michigan Gas Utilities all offer pooling options for T-service customer balances: https://www.michigan.gov/mpsc/0,4639,7-159-16385-424394--,00.html

REFERENCE:

Tab 12 pgs. 1 and 6 of 13; 2011/12 COG Tab 9 p. 5 of 7

PREAMBLE TO IR (IF ANY):

At the 2011/12 Cost of Gas, Centra proposed and subsequently received Board approval for changes to the Special Terms and Conditions for Transportation Service that introduced a minimum daily nomination eligibility threshold of 200 GJ/day under normal operating conditions.
At this 2019/20 GRA, Centra is applying to increase the T-Service daily nomination threshold from 200 GJ/day to 2,500 GJ/day under normal operating conditions.

QUESTION:

a) Explain Centra's rationale for the 2,500 GJ/day value proposed as the new T-Service volumetric eligibility threshold. Why is 2,500 GJ/day the appropriate threshold and not some other threshold?
b) Absent being grandfathered under Centra's proposal, how many of the current T-Service customers would not meet the 2,500 GJ/day threshold and thus would no longer be eligible for T-Service?
c) In a format similar to the table below, provide the average and maximum daily imbalances for the past year of all T-Service customers.

Customer	Average Daily Consumption [GJ/day]	Average Daily Imbalance [% of Daily Consumption]	Maximum Daily Imbalance [% of Daily Consumption]
T-Service Customer 1			
T-Service Customer 2			
T-Service Customer 3			
Etc.			

RESPONSE:

a) T-Service was originally designed for and is best suited to high load factor customers, particularly those with sufficient natural gas consumption to warrant the additional effort required to manage their own upstream gas arrangements, while capturing the savings afforded by the lower T-Service rate. For example, T-Service originated in Manitoba because of very large industrial consumers[1] of natural gas, with average consumption well in excess of 2,500 GJ/day.

Centra's observations of which T-Service customers currently meet their contractual obligations (i.e., daily balancing of their accounts in the normal course) also informed its volumetric eligibility threshold proposal. Currently, 4 of 15 T-Service customers reasonably address their imbalances on a daily and intra-day basis.

Centra may have been neutral on the current volumetric eligibility threshold for T-Service if balancing fees were to be collected at 100% of the TCPL Mainline's fee level and based on daily absolute tolerances of 2%. However, Centra's balancing fee proposal includes two major concessions to T-Service customers:

i. TCPL Mainline fees have been reduced by 50%; and
ii. More generous daily and cumulative absolute tolerances have been provided.

For all of these reasons, 2,500 GJ/day is a reasonable volumetric eligibility threshold for T-Service. In Centra's view raising the eligibility threshold is a sensible way to limit new entrants to T-Service to those who are inherently invested in actively forecasting their consumption and balancing their accounts on a daily and intra-day basis as required.

b) Absent being grandfathered under Centra's proposal, 11 of 15 current T-Service customers would not meet the 2,500 GJ/day threshold. The average daily consumption of 1 of these 11 customers is expected to increase in or around the year 2020 such that

[1] For example, Simplot Canada, B.C. Sugar, Inland Cement.

it would then meet the 2,500 GJ/day threshold. Accordingly, a total of 5 of 15 customers would meet the new threshold, absent the grandfathering provision proposed by Centra.

c) Please see Attachment 1 to this response.

Centra Gas Manitoba Inc.
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Line	T-Service Customer	Average Daily Available Volume (GJ)*	Average Absolute Daily Imbalance (GJ)	Average Absolute Daily Imbalance as % of Average Daily Available	Maximum Absolute Daily Imbalance (GJ)	Maximum Absolute Daily Imbalance as % of Average Daily Available	
1							
2	Customer A	1,641	215	13%	1,528	93%	
3	Customer B	1,930	215	11%	1,453	75%	
4	Customer C	2,035	290	14%	1,857	91%	
5	Customer D	4,166	146	4%	1,970	47%	
6	Customer E	6,467	1,109	17%	4,287	66%	
7	Customer F	8,439	817	10%	3,588	43%	
8	Customer G	683	134	20%	1,034	151%	
9	Customer H	1,579	350	22%	1,408	89%	
10	Customer I	[redacted]	[redacted]	2%	[redacted]	44%	2d
11	Customer J	2,280	295	13%	1,166	51%	
12	Customer K	1,446	190	13%	1,546	107%	
13	Customer L	285	48	17%	302	106%	
14	Customer M	824	187	23%	907	110%	
15	Customer N	750	61	8%	542	72%	
16	Customer O	1,424	156	11%	1,326	93%	

17 *Note: Daily Available Volume (also referred to as Net Nomination) includes both nomination and applicable balancing nomination.

to customers regardless of whether a shipper is experiencing unplanned maintenance or outages. In the specific case of power outages, Centra states that customers should continue to contact their Manitoba Hydro account representatives and that those situations would need to be assessed and addressed on a case by case basis.[49]

4.4 SUMMARY

In evaluating the merits of Centra's proposal, the PUB should consider the following:

- **Centra's proposal is not a direct cost-based rate:** Centra acknowledges this in its evidence and indicates that in 2016/17 and 2017/18 its proposal would have resulted in charges to T-Service customers well in excess of its direct costs for balancing fees charged by TCPL.
- **Centra acknowledges the fees would apply even when customers have no ability to respond:** Centra states that the fee would apply, even in the case of power outages or other instances when customers may not be able to respond to imbalances.
- **Centra provides no forecast of balancing fee revenues in the test year:** Centra indicates that going forward actual experience will be the best basis on which to forecast revenues.[50]

Given the uncertain implications for future revenues and customer operations, the PUB should be cautious in considering Centra's proposal. There are a number of problematic issues with Centra's current proposal and the PUB should not approve the changes as currently proposed.

Measures the PUB may wish to consider to mitigate the proposal could include:

- Directing Centra to work further with customers to revise the proposal. Particular areas of focus could include limiting the applicability of the fees during periods when customers cannot respond to balancing issues, particularly related to power outages; and consideration of options to work with Centra and/or other T-Service customers to ensure the system as a whole remains in balance;
- Given the uncertainty in customer response, phase in the charges more gradually than the 50% of TCPL figure selected by Centra and report regularly to the PUB on charges collected and direct costs incurred.
- Capping charges applicable to customers under the proposal to only the amount Centra actually incurs in balancing charges from TCPL, at least until Centra can provide more detailed documentation of its claims for indirect costs than it has made available in the current proceeding.

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[49] IGU/CENTRA I-22 (o).
[50] IGU/CENTRA I-1 (a) to (c).

REFERENCE:

McLaren Evidence p. 14

PREAMBLE:

McLaren recommends: "Given the uncertainty in customer response, phase in the charges more gradually than the 50% of TCPL figure selected by Centra and report regularly to the PUB on charges collected and direct costs incurred."

QUESTION:

Please explain the suggested timeframe over which Centra's proposed 50% of TCPL fee structure could be phased in, together with the possible fee step increases used throughout the suggested phase-in period. Also describe the metrics that could be used to assess the response of T-Service customers during the suggested phase-in period.

ANSWER:

Mr. McLaren's preferred approach would be for Centra to develop a working group with its customers to develop a revised proposal that could be jointly recommended to the PUB for approval.

In the event an interim approach based on the current proposal before the Board is implemented Mr. McLaren suggests the following could be considered for at least one year of operating experience:

1. Implementing the fees at 25% of TCPL's fee structure with a cap equal to the total balancing fees actually incurred by Centra. That is, fees charged to customers would not exceed actual charges from TCPL to Centra over the same period.
2. Tracking the following for at least one full operating year under the interim fee structure:
    a. Total number of imbalance events
    b. Total volumes of imbalances
3. Comparing the figures tracked in part 2 against performance over at least the three previous years.

REFERENCE:

McLaren Evidence p. 14; IGU/Centra II 7a-j; PUB/Centra II-58a-d

PREAMBLE:

McLaren states: "consideration of options to work with Centra and/or other T-Service customers to ensure the system as a whole remains in balance."

QUESTION:

a) Please explain whether, under either the existing Centra terms and conditions of service or the TCPL Mainline tariff, existing T-Service customers already have the ability to execute gas purchases and sales amongst each other or with Centra to minimize their own daily imbalances.

b) Please explain whether Mr. McLaren or IGU's members are aware of any local gas distribution companies facilitating imbalance exchanges within the local delivery area of a larger interprovincial or interstate transmission pipeline operator. If so, please provide further details.

c) Please provide Mr. McLaren's views regarding Centra's position that by electing T-Service, T-Service customers are opting out of the pools managed by Centra.

d) Explain how Centra could facilitate a process whereby T-Service shippers (or their agents) could trade imbalances between each other and provide views on the cost responsibilities of such a process.

ANSWER:

a) Through d)

In Mr. McLaren's view, from an operating perspective Centra should be indifferent to the following scenarios:

1. A situation where three T-Service customers are all precisely in balance on their individual loads; and
2. The same three T-Service customers are in balance across all three of their loads, but with some variation at an individual customer level (e.g. one customer is over and one customer is under).

However, as Mr. McLaren understands Centra's proposal, the first scenario would not incur balancing fee charges but the second scenario would, even though the net impact across the system is the same.

With respect to Centra's position that by electing T-Service, customers are opting out of the pools managed by Centra, the Board should consider whether Centra should be able to have sole control over such pooling or aggregating functions in Manitoba.

In Mr. McLaren's view it would be reasonable for the customers choosing to pool their purchases and aggregate loads to pay any direct fees charged by nominating agents or other parties for these services.

REFERENCE:

Brown Evidence pp. 2, 6, and 7

PREAMBLE:

QUESTION:

a) For the Koch Fertilizer plant, identify the nomination windows available to Koch Canada Energy Services and any limitations or constraints on its ability to adjust nominations in order to balance actual consumption with nominations.

b) Please provide additional explanation of the Elapsed Pro-rated Scheduled Quantity (EPSQ) and how EPSQ constrains adjustments to nominations. If possible, provide a numerical example.

ANSWER:

a)

Nomination Deadlines – all times MCT:

- Timely: 1200 for FERC pipelines, 1230 for TCPL, day before flow
- Evening: 1700, day before flow
- Intra-day 1: 0900, day of flow
- Intra-day 2: 1330, day of flow
- Intra-day 3: 1800, day of flow

Nomination deadlines cannot be changed, and if nominations are entered after the deadline, the pipeline will reject changes. To balance the Koch Fertilizer plant it can take a number of nominations on a number of pipelines to move gas away from the Manitoba Delivery Area (MDA). Schedulers generally need at least 30 minutes before a nomination window deadline to ensure all nominations and counterpart nominations are adequately submitted to each pipelines EBB (Electronic Bulletin Board).

b)

EPSQ is part of TCPL's tariff. Based on the number of hours of flow remaining in the gas day, Shippers are limited by EPSQ when reducing flow. Increasing a nomination is not subject to EPSQ. As such, EPSQ limitations reductions for each cycle are limited to:

- Timely: 100%
- Evening: 100%
- Intra-day 1: 79.16%
- Intra-day 2: 62.50%
- Intra-day 3: 45.83%

File found at link provided in PUB/IGU-Labonte-1
(p. 5 of 5, lines 128-129):

http://www.tccustomerexpress.com/docs/ml_nominations/mainline-nomination-timelines-april-2016.pdf

Current NAESB Windows vs Revised NAESB Windows (including STS windows)

Time Shifts - All times in CCT		Current NAESB Standards	Revised NAESB Standards	Revised TransCanada Windows*
Timely	Timely Day - Ahead Nomination Deadline	11:30 AM	1:00 PM	1:30 PM
	Confirmations	3:30 PM	4:30 PM	4:30 PM
	Schedule Issued	4:30 PM	5:00 PM	5:00 PM
	start of Gas Flow	9:00 AM	9:00 AM	9:00 AM
Evening	Evening Day - Ahead Nomination Deadline	6:00 PM	6:00 PM	6:00 PM
	Confirmations	9:00 PM	8:30 PM	8:30 PM
	Schedule Issued	10:00 PM	9:00 PM	9:00 PM
	start of Gas Flow	9:00 AM	9:00 AM	9:00 AM
STS 11:00	STS 11 Nomination Deadline	9:00 AM	9:00 AM	9:00 AM
	Confirmations	10:00 AM	10:00 AM	10:00 AM
	Schedule Issued	11:00 AM	11:00 AM	11:00 AM
	start of Gas Flow	11:00 AM	11:00 AM	11:00 AM
Intraday 1	ID1 Nomination Deadline	10:00 AM	10:00 AM	10:00 AM
	Confirmations	1:00 PM	12:30 PM	12:30 PM
	Schedule Issued	2:00 PM	1:00 PM	1:00 PM
	start of Gas Flow	5:00 PM	2:00 PM	2:00 PM
STS 17:00	STS 17 Nomination Deadline	3:00 PM	Removed, ID3 Added	Removed, ID3 Added
	Confirmations	4:00 PM	Removed, ID3 Added	Removed, ID3 Added
	Schedule Issued	5:00 PM	Removed, ID3 Added	Removed, ID3 Added
	start of Gas Flow	5:00 PM	Removed, ID3 Added	Removed, ID3 Added
Intraday 2	ID 2 Nomination Deadline	5:00 PM	2:30 PM	2:30 PM
	Confirmations	8:00 PM	5:00 PM	5:00 PM
	Schedule Issued	9:00 PM	5:30 PM	5:30 PM
	start of Gas Flow	9:00 PM	6:00 PM	6:00 PM
Intraday 3	ID 3 Nomination Deadline		7:00 PM	7:00 PM
	Confirmations		9:30 PM	9:30 PM
	Schedule Issued		10:00 PM	10:00 PM
	start of Gas Flow		10:00 PM	10:00 PM
STS 01:00	STS 0100 Nomination Deadline	11:00 PM	11:00 PM	11:00 PM
	Confirmations	12:00 AM	12:00 AM	12:00 AM
	Schedule Issued	1:00 AM	1:00 AM	1:00 AM
	start of Gas Flow	1:00 AM	1:00 AM	1:00 AM
STS 05:00	STS 0500 Nomination Deadline	3:00 AM	3:00 AM	3:00 AM
	Confirmations	4:00 AM	4:00 AM	4:00 AM
	Schedule Issued	5:00 AM	5:00 AM	5:00 AM
	start of Gas Flow	5:00 AM	5:00 AM	5:00 AM

***The TransCanada Mainline will continue to impliement the 30 minute delay on the Timely Window, however there will be a 6 month trial period to ensure that operationally the delay incorpated into the changes in the NASEB standards do not cause any issues.**

REFERENCE:

McLaren Evidence p. 14; Tab 12 p. 6 of 13

PREAMBLE:

Centra proposes to increase the threshold for eligibility for T-service from 200 GJ/day to 2,500 GJ/day.

QUESTION:

Please provide Mr. McLaren's views and findings regarding Centra's proposed changes to the T-Service volume eligibility threshold.

ANSWER:

Mr. McLaren understands Centra's proposed changes to the T-Service volume eligibility threshold would substantially limit access to this rate option for future customers. As Centra notes in response to PUB/CENTRA I-150 (b), 11 of 15 current T-Service customers would not meet the 2,500 GJ/day threshold.

In Mr. McLaren's view the Board should be concerned about proposals that limit customer options and should consider proceeding cautiously with the proposed change to the eligibility threshold, perhaps deferring the increase in the threshold until after some actual experience with a change to the balancing fee charges.

REFERENCE:

Brown Evidence p. 5; PUB/Centra I-145(d)

PREAMBLE:

"Centra can provide hourly consumption reports to T-Service customers and nominating agents as frequently as 24 times per day." [PUB/Centra I-145(d)]

Koch appears to receive consumption reports from Centra three times daily.

QUESTION:

Please explain whether KCES or Koch Fertilizer have requested, or could benefit from, more frequent gas consumption reports from Centra.

ANSWER:

When the plant consumption is changing or coming back online from a turnaround, we receive the consumption data more frequently throughout the day, but due to nomination deadline constraints hourly reports do not provide more opportunities to manage imbalances.

Based on EPSQ limitations and nomination deadlines, there are times when a customer simply is not able to fully adjust the nominations to perfectly match what a plant is physically able to take or consume, so there will be an imbalance regardless of any amount of reporting.

REFERENCE:

Brown Evidence p. 7

PREAMBLE:

QUESTION:

Confirm whether KCES can balance via buys and sells with other Manitoba customers and whether these transactions are constrained by TCPL restrictions or market restrictions. Can these buys and sells with Manitoba customers occur when gas markets are closed?

ANSWER:

KCES often buys and sells gas from and to other Manitoba customers and from and to Centra Manitoba specifically, but only on the TCPL system, not the Centra pipeline system. Transactions are constrained by the nomination cycle timeline. Currently, KCES only does deals with customers on the TCPL system, not on the Manitoba system.

Section 3: Centra's Proposed Changes to Balancing Fees

8. Please describe your understanding of why Centra is proposing changes?

Centra plans to charge balancing fees to incent customers to balance gas volume better than they do today. It is my understanding there are only a few customers that do not manage imbalance levels well, but I do not know the quantity of those imbalances.

9. In your view, is Centra's proposal consistent with your experience in other jurisdictions?

a. Tolerance levels:

Other pipelines typically have a higher tolerance level, for example, instead of 1-3% being exempt from fees, 5, 10 and 15% are the most prevalent ranges allowed. Almost all have different operating conditions under which the tighter tolerance ranges can be utilized if needed, but not on an ongoing basis. For example, if the tolerance range is up to 10% or more normally, but the pipeline is in constrained operating conditions, it can declare a warning including notice that imbalances must be managed more tightly during that time. After the operating constraints pass, the tolerance returns to its original level.

b. Minimum volume before balancing fees:

There is usually a minimum volume threshold that must be met before balancing fees apply. This is helpful and fair for small customers who may be out of balance by a percentage of flow, but where the actual volume level is not significant in the context of the overall natural gas system operations.

c. Trading:

Almost all balancing services allow customers to trade imbalances with other customers. If one customer is short and another long, within certain regions or operating areas, those customers are allowed to offset each other's imbalance.

d. Other options:

Aside from service options to manage imbalances, most transporters allow agents to aggregate imbalances across many customers to manage at a higher level. The agent is then responsible for its overall balance daily instead of each customer on its own.

10. Please describe any concerns you have about Centra's new balancing fee proposal.

Balancing fees should not be a revenue generator for the company nor be a customer subsidy. The net proceeds or profits in the balancing program should be refunded annually at a minimum and distributed to the customer groups that are subject to balancing fees. Refund allocations should be based on the lowest imbalance (as a percentage of volume delivered) customers within defined time periods (daily or monthly at the longest) receiving the highest percentage of the refunds.

The tolerance levels proposed by Centra are too small and the small tolerance range is unnecessary for operating reasons or to incent customers to proactively balance. Centra has not shown why the current balancing fees are not adequate.

Centra should continue netting imbalances and charging only the customers who cause Centra to incur costs. The incentive to balance *will still exist since the customer will not know during the imbalance period whether it will be charged or not*.

11. Please describe what options customers in Manitoba have to avoid the balancing fees under Centra's new proposal.

Very few options on the Centra system allow a customer to manage its imbalances. The primary tools available are on assets (pipeline, storage) off the Centra system.

12. Moving forward, what are your recommendations to the PUB with respect to Centra's proposed balancing fee structure? Briefly describe what you think the PUB should do with Centra's proposal or specific changes they should look at directing Centra to implement.

Centra should retain its current balancing process and fees. It should also review best practices such as allowing trading across customers.

REFERENCE:

Labonte Evidence p. 2

PREAMBLE:

QUESTION:

a) Please summarize the contractual requirements, along with the associated daily balance tolerance, imposed by TransCanada on the Manitoba T-Service customers managed by France Financial Consulting.

b) File excerpts of the contracts between France Financial Consulting or its clients and TransCanada (or other parties providing transportation to these clients on the Mainline) that pertain to balancing requirements, making any required redactions to protect customer-specific or commercially sensitive information.

c) File excerpts of the contracts between France Financial Consulting's T-service clients and Centra that pertain to balancing requirements, making any required redactions to protect customer-specific or commercially sensitive information.

ANSWER:

Preamble to responses:

In an effort to provide transparency in the overall procurement process France Financial Consulting ("FFC") implements on behalf of its T-Service clients to secure reliable natural gas supply and to manage our customer's individual Centra T-Service accounts, the following provides an overview of contractual, operational and balancing activities FFC provides for its Centra T-Service clients.

- FFC works with each client to determine the appropriate daily quantity of TransCanada Energy ("TCE") Empress (Alberta Export Point) to Centram MDA (Manitoba Receipt Point) firm mainline capacity to hold for estimated plant consumption levels (i.e. – 1,000 GJ/Day) and the appropriate length of term for such firm contracts (i.e. – 1 to 5 years). FFC secures TCE firm capacity agreements with required capacity and term on behalf of our clients, with such agreements executed between our clients and TCE. FFC ensures these transportation agreements remain in good standing with TCE and makes recommendations on any renewals. At no time, past or present, has FFC been a signatory to these agreements.

- Upon execution of any agreement by an FFC client with TCE for firm pipeline capacity from Empress to Manitoba, our clients must then secure natural gas supply to fill the contracted TCE mainline pipeline capacity on a daily basis for the term of any agreement. FFC utilizes its expertise within natural gas markets as well as our long-term experience with various natural gas suppliers to make recommendations to each of our clients on the selection of a company to deliver such natural gas supply. In addition to price considerations, and more importantly, natural gas suppliers must also have a demonstrated track record of delivering secure supply and managing any TCE mainline capacity held by our clients within National Energy Board (NEB) regulatory approved tariffs for TCE's mainline pipeline.
- On behalf of our clients the selected service provider procures daily physical natural gas requirements to fill our client's firm TCE mainline capacities as well as balancing such capacities in accordance with NEB approved tariffs and policies. Selected supplier is able to efficiently provide these services through a TCE temporary assignment form, where FFC clients assign their TCE Empress to Manitoba mainline service capacity to its selected natural gas supplier for a term negotiated between the parties. At no time past or present has FFC managed our current client's TCE firm mainline capacities.
- Past and current suppliers for FFC T-Service clients have at the time, and currently hold and/or manage significant TCE mainline capacities well in excess of our client's requirements (other North American customers/business) and to markets across North America (outside of Manitoba). The scope and scale of selected service providers ensures maximum flexibility when delivering FFC clients natural gas requirements into Manitoba.
- FFC provides intermediary services for each client and its selected supplier to manage the daily differences between natural gas supply delivered by the aforementioned service provider at Centram MDA and actual natural gas consumed at its plant located within the province of Manitoba.
- On a daily basis, for each day during the year including weekends and holidays, FFC reviews the Centra account balance for each client and executes required buys and sells between each client and its natural gas supplier to balance each clients accounts.

- Prior to the fall 2016 at which time Centra introduced its currently proposed and to-date unapproved balancing tolerance bands, FFC for the most part managed its client's accounts to our understanding of the current Centra balancing tolerance bands of +/- 2,000 GJ's which we presume are PUB approved. FFC on several occasions agreed to Centra requests to either buy or sell natural gas quantities to assist in balancing their pipeline system, with no obligation to do so under the current balancing tolerance bands.
- I am not certain if the current tolerance threshold was approved by the PUB or implied by Centra for T-Service customers historically. To my knowledge our existing T-Service Clients have never been assessed imbalance fees under the current balancing policy of +/- 2,000 GJ.
- Within separate emails sent by Centra's Ms. Laurie MacDonald on November 1, 2016 to FFC providing our current T-Service client's individual theoretical daily balancing historical data under the proposed and unapproved tolerance bands for the period October 1, 2015 to September 30, 2016, Centra's data clearly shows that FFC's client Centra accounts were well within current tolerance band of +/- 2,000 GJ's. See below for data summary provided by Centra, which for confidentiality purposes is reported as an average for our existing T-Service clients.

GJ's	**October 1, 2015 to September 30, 2016**		
Average - Existing FFC Clients	**Average**	**Minimum**	**Maximum**
Daily Imbalance	**(1)**	**(765)**	**630**
Cummulative Imbalance	**15**	**(843)**	**834**

- Post 2016, and in response to Centra's presentations on their currently proposed and to-date unapproved balancing fee structure, FFC recognized Centra's concerns regarding the current +/- 2,000 GJ tolerance band. Without any obligation to do so under the current balancing policy, FFC worked with its clients to implement appropriate levels of communication from each of our client's plant personnel to provide consumption estimates as well as immediate notice of unscheduled operational disruptions. These communications providing consumption estimates have been refined since implementation in 2017.
- FFC manages daily imbalances by advising selected supplier of an intra-day purchase or sale of natural gas from/to a T-Service client, followed by and intra-

day notification to Centra advising of any such transaction. These balancing transactions occur during business days, weekends and holidays.

- The threshold levels for Centra's proposed balancing fee are for the PUB to approve in this GRA. Centra's position in this proceeding has been that customers have not been meeting these proposed and unapproved thresholds. Respectfully, Centra's position of measuring T-Service customers performance since late 2016 early 2017 to a proposed and unapproved standard is not appropriate.
- Under the current T-Service balancing requirements, as to my knowledge none of FFC's T-Service current clients have been charged imbalance penalties under what we presume are current PUB approved policies, it follows that our Clients hold appropriate agreements to effectively manage such service under current policy.
- Following conclusion of the GRA and a ruling by the PUB on balancing fees to be implemented, FFC will ensure that its T-Service Clients negotiate with its supplier any changes required to existing contractual arrangements to balance to any PUB approved balancing standard, presuming such approval represents an industry standard balancing mechanism.

a)

TCE's current NEB approved Mainline Pipeline System contractual requirements are detailed within its Transportation Tariff for Firm Transportation Service and can be found at:

http://www.tccustomerexpress.com/docs/ml_regulatory_tariff/05_FT_Toll_Schedule.pdf

TCE's current NEB approved Mainline Pipeline System General Terms and Conditions and can be found at:

http://www.tccustomerexpress.com/docs/ml_regulatory_tariff/General%20Terms%20and%20Conditions%20-%20NOVEMBER%201%202017.pdf

Daily and Cumulative Balancing Fees are set out in Section XXII. Nominations and Unauthorized Quantities of TCE's General Terms and Conditions document, linked above (Sheet No. 35 - 38).

Section XXII, subsections 7 and 8 of the TCE's General Terms and Conditions outlines requirements for balancing, provided below (Sheet No. 39 – 43).

With respect to allowable intra-day nominations provided by TCE for its mainline shippers, details can be found at:
http://www.tccustomerexpress.com/docs/ml_nominations/mainline-nomination-timelines-april-2016.pdf

As noted above in the preamble for this response, FFC relies on its suppliers to manage FFC T-Service client's TCE mainline capacities in accordance with TCE's NEB approved rules and regulations.

b)

A redacted contract summary for one of FFC's clients for Firm Transportation Service with TransCanada has been provided as Attachment PUB/IGU-Labonte-1(b).

The contract itself does not provide details regarding balancing requirements, which are addressed in the General Terms and Conditions, with link and relevant excerpts provided in response to PUB/IGU-Labonte-1(a) above. Collectively, TCE's Firm Transportation Service, General Terms and Conditions and Contract Summary govern all activities including nomination and balancing requirements on the Mainline Pipeline System.

FFC has never executed a pipeline capacity agreement directly with TCE.

c)

FFC clients to my knowledge have never executed contracts or agreements directly with Centra, and I could not find any such agreement in a review of my client's records.

To my knowledge there is no such formal agreement for balancing requirements and T-Service customers are governed by the Terms and Conditions, which Centra has provided on the record with proposed black-lined amendments as Appendix 12.1.

CONTRACT SUMMARY **TransCanada PipeLines Limited**

Shipper:	[redacted]
Class of Service:	**Firm Transportation (FT)**
Contract Date:	[redacted]
Contract Demand:	[redacted] GJ' s per day
Contract Number:	[redacted]
Date of Commencement:	[redacted] day of [redacted], [redacted]
Date of Expiry:	[redacted] day of [redacted], [redacted]
Receipt Point and Interconnecting Pipeline:	Empress - NOVA Gas Transmission Ltd.
Delivery Point and Interconnecting Pipeline:	Centram MDA - Centra Gas Manitoba Inc.
Domestic/Export Contract:	Domestic
Note:	[redacted]
Prepared by:	Matthew Wharton / Gordon Betts

- Centra does not provide any compensation/financial benefit for T-Service customers that assist in balancing.

7. Please described your understanding of the current penalty structure that exists when T-Service or Special Contract customers are out of balancing tolerances.

- I understand that currently Centra charges T-Service customers when customer imbalance exceeds +/- 2,000 GJ's.
- Do not recall seeing this tolerance band in writing, it however has been mentioned by Centra on several occasions.
- I'm aware of at least one instance where Centra implemented its current balancing fee policy. A client of FFC was assessed a penalty when its account exceeded the aforementioned tolerance due to my recollection of a plant upset that occurred late in the day.
- As back-up to the balancing fee that was charged in this instance, Centra provided the customer with a copy of TransCanada's Transportation Tariff.

8. Please explain the methods T-Service or Special Contract customers in Manitoba use to stay within tolerances and avoid penalties.

FFC executes the following daily to minimize account imbalance fees for its T-Service Clients:

- Same Day (Gas Day 1) - Clients provide Next Day ahead (Gas Day 2) consumption estimates & advises of any changes to Gas Day 1 estimates
- FFC Gas Day 1
  – secures supply for Gas Day 2 and advices Centra of Next Day scheduled quantity
  - buy or sell quantities for Gas Day 1 that since the fall of 2016 I have attempted to maintain imbalances to within +/- 100 GJ's, including on weekends.
  - able to **buy** unlimited quantities to balance account (when companies are under its daily usage amount), **sales** quantities required to balance are restricted and can result in an imbalance that cannot be zeroed (when customer deliveries are over daily usage amounts).

- FFC has since 2008 not managed account balances to the current +/- 2,000 GJ's band, instead working with Centra to maintain our client's account to as close to zero as reasonably possible using industry standard practices (see response to Question 15).

9. Please discuss what types of situations might lead to a T-Service or Special Contract customer being outside of balancing tolerances.

a) Examples where Customers are **Able** To Modify Scheduled Deliveries Within Nomination Windows (and therefore, with enough lead time can usually avoid an imbalance):
> scheduled plant outage (for whatever reason)
> scheduled Centra & Hydro natural gas & power outages

b) Some examples that have occurred where the Customer was **Unable** To Modify Scheduled Deliveries Within Nomination Windows (and therefore would incur an imbalance compared to the nomination made to Centra the day prior):
> plant equipment failure
> power/electricity failure, caused by lightning strikes, Hydro line problems, etc…
> roof failure due to heavy and rapid snow falls
> staff unable to reach plant due to extreme weather related adverse road conditions
> trucks & rail cars also unable to reach plant due to extreme weather related adverse road conditions resulting in plant shutdown due to high product storage levels or lack of raw materials
> on short notice client advised by rail company that scheduled rail cars delayed
> rapid and extreme temperature changes dramatically affecting natural gas consumption
> Water supply disruptions

Section 3: Centra's proposed changes to Balancing Fees

10. Please describe your understanding of Centra's proposed changes to calculating and applying balancing fees.

REFERENCE:

Evidence of Gil Labonte, page 4 of 9, paragraph 8, second bullet

PREAMBLE:

In reference i) Mr. Labonte states that FFC is “able to buy unlimited quantities to balance account (when companies are under its daily usage amount), sales quantities required to balance are restricted …”.

Centra seeks to understand the actions FFC can and cannot take to balance its T-Service customers’ accounts.

QUESTION:

Please explain why FFC is able to buy unlimited gas quantities to balance but is “restricted” from selling gas quantities to balance. In the response, please explain this restriction including who imposes this restriction on FFC and why?

ANSWER:

A T-Service client is unable to offset a pack position on a given day by selling such pack to its supplier if that client’s gas nomination to Centra on that given day is at (0) zero. This restriction is imposed upon our T-Service clients by our supplier due to the supplier being subject TC Energy’s Mainline tariff.

REFERENCE:

Labonte Evidence p. 7

PREAMBLE:

"There is no other pipeline that I work with that does not allow customers to balance via buy/sells with other shippers."

QUESTION:

a) Please describe the nature of the other pipelines referenced. Are these major interprovincial, or interstate transmission pipelines, or are they distribution pipeline systems downstream of major pipelines?

b) Please identify who oversees and manages these interactions in other jurisdictions. In Manitoba, would Centra have to facilitate these types of transfers between all T-Service customers? Why or why not?

c) Please describe how Centra prevents, or proposes to prevent, its T-Service customers, as shippers on the Mainline with deliveries to the Manitoba Delivery Area (MDA), from buying and selling amongst each other to balance their own daily nominations to the MDA.

d) Confirm whether Manitoba T-service customers can balance via buys and sells with each other and whether this can occur when gas markets are closed.

ANSWER:

a)

My expertise does not extend to detailed knowledge of individual pipeline systems and operations and so I have limited my response to the extent I am able to provide comment based on my understanding.

The pipeline systems that FFC clients use include:

- ***TransGas Pipelines*** - Intra-Provincial with major connections to Alberta (NGTL), TCE (Mainline)
- ***NOVA Gas Transmission*** – Intra-Provincial with major connections to TCE export capacities (east & west)

- ***Union Gas*** – No detailed knowledge
- ***Xcel Energy*** – To my knowledge a distribution pipeline only with a major connection to the Viking Pipeline (believe and inter-state pipeline)

b)

One of the balancing tools provided by certain pipelines listed in part (a) above allows customers to balance their accounts via buy and sell transactions with other customers. These transactions are typically referred to as “Title Transfers” and allow customers of a particular pipeline company to execute transfers of natural gas quantities with other customers to assist in balancing each of their accounts prior to implementation of applicable imbalance fees. It is my experience that only the pipeline company is able to execute Title Transfers between its customers.

c) and d)

It is FFC’s understanding that Centra will not facilitate Title Transfers as described within b) above under its current proposal. For example, Centra T-Service Customer A cannot request Centra to directly transfer a quantity of natural gas from/to its Centra account from/to Centra T-Service Customer’s B account. A Title Transfer option would provide each T-Service customer with 13 other T-Service customers as counter-parties to balance its Centra account.

Without Title Transfers, a T-Service customer is only able to transact with one counter-party, its supplier, to balance its Centra account.

To FFC’s knowledge it is not industry practice within any North American natural gas market jurisdiction for end use customers to execute after hours buy and sell transactions to balance accounts. Manitoba T-Service customers are not able to transact after hours.

However, it is my understanding that many utilities across North America hold after hours agreements directly with capable suppliers to manage their overall pipeline systems during significant and sudden demand swings.

- Centra's proposal will collect fees daily based on each T-Service customer's imbalance, yet only pay TransCanada tolls based on the aggregate imbalance quantity.

13. Please describe what options customers in Manitoba have to avoid the balancing fees under Centra's new proposal.

- Regardless of how diligent a party is in estimating consumption, and how aggressively it transacts same day buys and sells to balance its account, the complexity of processing plants will result in numerous daily imbalances exceeding +/- 50 or 100 GJ's
- This proposal will be especially punitive when plants suffer operational upsets in the late evening (after markets have closed) with no opportunity to sell natural gas quantities until the next morning

14. In your experience, what tools or mechanisms are in place in other jurisdictions that allow customers to avoid balancing charges?

- Other jurisdictions offer more flexible daily tolerance quantity with ability for shippers to buy & sell imbalances.
  - From my experience in Saskatchewan on the TransGas pipeline system, targeted thresholds of +/-1,000 GJ/day per day regardless of consumption levels. There are no penalties for imbalances but the utility expects customers to trend back to within tolerances.
  - For example, TransCanada's NGTL Alberta pipeline system – has a tolerance band equal to the greater of +/-2,000 GJ or +/-4% of deliveries. Customers also have the ability to buy and sell with other shippers to manage imbalances.[2]
- Buyers & Sellers transacting daily prior to Centra finalizing end of day imbalances and related penalties.

[2] Nova Gas Transmission Ltd. Terms and Conditions respecting Customer's Inventories and Related Matters, Effective date December 1, 2012. Available online: http://www.tccustomerexpress.com/docs/ab_regulatory_tariff/ngtl-gtt-appendix-d.pdf

- Monthly tolerances with pipeline buying a shipper's end of month pack at a discount to market pricing and selling a shipper's end of month draft at a premium to market pricing.
    - This is the case for our client in North Dakota, where Xcel does not charge for daily imbalances under normal operation but at month end where imbalances exist pays out any pack or charges for any draft at pre-determined and regulatory approved pricing. Imbalances do not carry forward to the next month. In this jurisdiction customers have the entire month to balance within tolerance bands and can transact with other customers/participants.
- There is no other pipeline that I work with that does not allow customers to balance via buy/sells with other shippers. It can easily be set up for participants to transact amongst themselves in Manitoba, for example France Financial manages three customers in Manitoba and executes buy and sells between its clients when appropriate to balance their accounts. Centra could easily facilitate these types of transfers between all T-Service customers.
- Notice from pipeline to out-of-balance shippers to trend towards a balanced position within a defined period of time and subject to penalties upon failure to comply
- Ability for Nominating agents to balance their customer's imbalances in aggregate

15. Moving forward, what are your recommendations to the PUB with respect to Centra's proposed balancing fee structure?

- Although most T-Service customers individually, or through nominating agents, have voluntarily complied with Centra's recent push towards tighter daily imbalances than the current +/- 2,000 GJ limit, past balancing performance by individual T-Service customers must be evaluated in the context of the current +/- 2,000 GJ daily limit
- Any daily transactions executed while within the +/- 2,000 GJ limit was voluntary and helps demonstrate that particular T-Service customers recognize the existing tolerance band is excessive compared to industry standard practice
- FFC as nominating agent for T-service customers in Manitoba, understands Centra's requirement to tighten daily imbalance tolerances and to set a balancing fee structure within a tighter band than +/- 2,000GJ.

- However, in my view as nominating agent, Centra's proposed daily tolerance band limits go too far the other way and are as unreasonable as the current +/- 2,000 GJ limit given the operational complexity of processing facilities.
- The excessively tight +/- 50 and +/-100 GJ bands combined with Centra not providing any tools for T-Service customers to resolve any daily imbalance prior to penalties being assessed is an outlier when compared to industry standard practice.