REFERENCE:

Tab 1 – Letter of Application, Page 2 Items e), f) & g) - Lines 1 - 11

PREAMBLE TO IR (IF ANY):

Centra is requesting PUB approval of updated depreciation rates and new depreciation accounts for “rate setting purposes” in item e) in Tab 1, Page 2 of the Application. Centra is requesting PUB “endorsement” of regulatory deferral accounts/proposed amortization periods and to discontinue the DSM deferral accounts in items f) and g) in Tab 1, Page 2 of the Application.

QUESTION:

a) Please explain why Centra is requesting PUB “endorsement” of the changes outlined in the preamble with respect to items f) and g) compared to PUB “approval” for items a) to e) and h) to o).

RATIONALE FOR QUESTION:

To provide clarity with respect to the approvals that are being sought from the PUB by Centra in this Application.

RESPONSE:

Under current legislation, Centra acknowledges that its accounting policies and the applied for treatment of the deferral accounts referenced in f) and g) impact upon, and are implicit within, the amount of rate base and/or cost of service that is ultimately approved and used by the PUB in setting just and reasonable rates that are in the public interest. As such, while Centra is not specifically required to receive explicit PUB “approval” of items f) and g) per the legislation, it is requesting endorsement of these items in order to obtain the audit evidence required by Centra’s external auditors to validate the annual regulatory deferral and amortization amounts that are recorded in its financial statements.

REFERENCE:

Tab 1 – Letter of Application, Page 2 Items e), f) & g) - Lines 1 - 11

PREAMBLE TO IR (IF ANY):

Centra is requesting PUB approval of updated depreciation rates and new depreciation accounts for "rate setting purposes" in item e) in Tab 1, Page 2 of the Application. Centra is requesting PUB "endorsement" of regulatory deferral accounts/proposed amortization periods and to discontinue the DSM deferral accounts in items f) and g) in Tab 1, Page 2 of the Application.

QUESTION:

b) Please explain the requirement/meaning of the added term "for rate-setting purposes" with respect to item e). Please explain if Centra will be using different depreciation rates/accounts for financial reporting purposes?

RATIONALE FOR QUESTION:

To provide clarity with respect to the approvals that are being sought from the PUB by Centra in this Application.

RESPONSE:

b) The reference to item "e)" above is Centra's request for approval from the PUB to commence using depreciation rates for rate setting purposes based on the 2014 Depreciation Study. Notably, the 2014 Depreciation Study determined depreciation rates based on both the Equal Life Group ("ELG") and Average Service Life ("ASL") depreciation methodologies. Both the ELG and ASL depreciation rates determined in the study excluded a net salvage percentage add-on.

   For clarity, Centra has been using the ELG based depreciation rates from the 2014 Depreciation study for financial reporting purposes since its transition to IFRS in

2015/16. This was a requirement for compliance with the financial reporting requirements of IFRS and will not change based on the outcome of this Application. Since its transition to IFRS, Centra has also been reducing the annual ELG based depreciation expense to an amount equivalent to a PUB approved ASL based depreciation balance through the Net Movement in Regulatory Deferrals account. Currently, the annual adjustment through the Net Movement account reduces depreciation expense to levels based on 2010 ASL (no salvage) depreciation rates as the 2010 study is the last depreciation study approved by the PUB for Centra. As such, the final depreciation expense charged to net income and used for rate setting purposes is based on the 2010 ASL (no salvage) depreciation rates.

As part of this Application, Centra is requesting PUB approval of the updated ASL (no salvage) depreciation rates as determined in the 2014 Depreciation study. If approval is received, commencing in the test year 2019/20, the adjustment through the Net Movement account will reduce the annual ELG based depreciation expense to levels based on the 2014 ASL (no salvage) depreciation rates which will act to further reduce the depreciation expense (thereby increasing net income) and used for rate setting purposes. Notably, the net result of the update to the ASL (no salvage) depreciation rates in the 2014 Depreciation Study is a reduction in depreciation expense compared to the 2010 study.

REFERENCE:

Tab 1 – Letter of Application, Page 2 Items e), f) & g) - Lines 1 - 11

PREAMBLE TO IR (IF ANY):

Centra is requesting PUB approval of updated depreciation rates and new depreciation accounts for “rate setting purposes” in item e) in Tab 1, Page 2 of the Application. Centra is requesting PUB “endorsement” of regulatory deferral accounts/proposed amortization periods and to discontinue the DSM deferral accounts in items f) and g) in Tab 1, Page 2 of the Application.

QUESTION:

c) Please explain if Centra is requesting interim or final approval of non-gas costs for 2019/20.

RATIONALE FOR QUESTION:

To provide clarity with respect to the approvals that are being sought from the PUB by Centra in this Application.

RESPONSE:

Centra is seeking final approval of non-gas costs for 2019/20 in this Application.

REFERENCE:

Tab 2 – Overview of the Application, Appendix 2.1 – Centra Franchise Map, Appendix 2.2 – Manitoba Hydro Organizational Structure, Appendix 2.3 – Manitoba Hydro Annual Business Plan 2018/19, Completeness Filing – Attachment 1 – Manitoba Hydro Corporate Risk Management Report – Fall 2018, Order 85/13 – Page 69 and Order 108/15 – Page 26

PREAMBLE TO IR (IF ANY):

In Order 85/13, at Page 69, the PUB found that it … "is interested in knowing Centra's strategic direction, including where Centra will be investing ratepayer dollars in the coming years, and also what Centra's customers can expect on Centra in terms of improved service levels…the Board finds Centra's overall strategic vision lacking. The Corporate Strategic Plan provides targets and goals at a high level, but does not answer the Board's question of the corporate direction Centra is headed… The Board requests that Centra consider these questions and provide the Board with a more articulated vision in its next rate application"

In Order 108/15, at Page 26, the PUB found that "Previously, Centra had a division manager of gas supply; a position that is currently vacant. Furthermore …. responsibility for gas operations appears to have been combined with several other duties assigned to senior managers of Manitoba Hydro. The Board therefore recommends that Centra review its managerial structure to ensure that its operational decision makers … have clear lines of responsibility to a senior manager. The Board expects to review Centra's management structure further at the next General Rate Application. At that hearing, the Board also expects to review Centra's strategic plan, including the utility risk analysis and capital expenditure plan."

QUESTION:

a) Please provide an updated listing the 132 communities in the Centra natural gas service territory as noted in Tab 2, Page 1, Section 2.1.2, lines 21 to 22.

RATIONALE FOR QUESTION:

To update CAC's understanding of Centra's service territories, strategic planning priorities, management structure and risk management assessments given prior findings of the PUB and the passage of six years since the last Centra GRA.

RESPONSE:

The communities in the Centra natural gas service territory are as follows:

1 ALTONA
2 ARBORG
3 AUSTIN
4 BEAUSEJOUR
5 BENITO
6 BINSCARTH
7 BLUMENORT
8 BOISSEVAIN
9 BRANDON
10 CARBERRY
11 CARMAN
12 CHORTITZ
13 CLANDEBOYE
14 CROMER
15 DAKOTA TIPI
16 DAUPHIN
17 DELORAINE
18 DOMINION CITY
19 DUFROST
20 DUGALD
21 EAST SELKIRK
22 EAST ST PAUL
23 ELIE
24 ELKHORN
25 ELM CREEK
26 EMERSON

27 FIRDALE
28 FORREST
29 FORREST STATION
30 GARSON
31 GILBERT PLAINS
32 GIMLI
33 GLADSTONE
34 GNADENFELD
35 GONOR
36 GRANDE POINTE
37 GRANDVIEW
38 GRETNA
39 GRUNTHAL
40 HAMIOTA
41 HARROWBY
42 HARTNEY
43 HEADINGLEY
44 HOWDEN
45 HUSAVIK
46 ILE DES CHENES
47 INGLIS
48 KILLARNEY
49 KLEEFELD
50 KOLA
51 LA BROQUERIE
52 LA SALLE
53 LANDMARK
54 LETELLIER
55 LINDEN
56 LOCKPORT
57 LORETTE
58 MACGREGOR
59 MARCHAND
60 MATLOCK
61 MCTAVISH
62 MELITA
63 MINIOTA

64 MINITONAS
65 MINNEDOSA
66 MITCHELL
67 MORDEN
68 MORRIS
69 NAROL
70 NEEPAWA
71 NEW BOTHWELL
72 NIVERVILLE
73 OAK BLUFF
74 OAKBANK
75 OAKVILLE
76 OTTERBURNE
77 PANSY
78 PETERSFIELD
79 PLUM COULEE
80 PONEMAH
81 PORTAGE LA PRAIRIE
82 RANDOLPH
83 REINFELD
84 RIVERS
85 RIVERTON
86 ROBLIN
87 ROSENORT
88 RUSSELL
89 SANDY HOOK
90 SANFORD
91 SARTO
92 SCHANZENFELD
93 SELKIRK
94 SHILO
95 SHOAL LAKE
96 SIDNEY
97 SOURIS
98 SOUTHPORT
99 SPRINGFIELD
100 SPRUCEWOODS

101 ST ADOLPHE
102 ST ANDREWS
103 ST CLAUDE
104 ST CLEMENTS
105 ST GERMAIN SOUTH
106 ST JEAN BAPTISTE
107 ST JOSEPH
108 ST LAZARE
109 ST MALO
110 ST NORBERT
111 ST PIERRE JOLYS
112 STARBUCK
113 STE AGATHE
114 STE ANNE
115 STEINBACH
116 STONEWALL
117 STONY MOUNTAIN
118 SWAN RIVER
119 TEULON
120 TOUROND
121 TYNDALL
122 VILLAGE OF DUNNOTAR
123 VIRDEN
124 WARREN
125 WEST ST PAUL
126 WHEATLAND
127 WHYTEWOLD
128 WINKLER
129 WINNIPEG
130 WINNIPEG BEACH
131 WOODLANDS
132 ZHODA

REFERENCE:

Tab 2 – Overview of the Application, Appendix 2.1 – Centra Franchise Map, Appendix 2.2 – Manitoba Hydro Organizational Structure, Appendix 2.3 – Manitoba Hydro Annual Business Plan 2018/19, Completeness Filing – Attachment 1 – Manitoba Hydro Corporate Risk Management Report – Fall 2018, Order 85/13 – Page 69 and Order 108/15 – Page 26

PREAMBLE TO IR (IF ANY):

In Order 85/13, at Page 69, the PUB found that it … "is interested in knowing Centra's strategic direction, including where Centra will be investing ratepayer dollars in the coming years, and also what Centra's customers can expect on Centra in terms of improved service levels…the Board finds Centra's overall strategic vision lacking. The Corporate Strategic Plan provides targets and goals at a high level, but does not answer the Board's question of the corporate direction Centra is headed… The Board requests that Centra consider these questions and provide the Board with a more articulated vision in its next rate application"

In Order 108/15, at Page 26, the PUB found that "Previously, Centra had a division manager of gas supply; a position that is currently vacant. Furthermore …. responsibility for gas operations appears to have been combined with several other duties assigned to senior managers of Manitoba Hydro. The Board therefore recommends that Centra review its managerial structure to ensure that its operational decision makers … have clear lines of responsibility to a senior manager. The Board expects to review Centra's management structure further at the next General Rate Application. At that hearing, the Board also expects to review Centra's strategic plan, including the utility risk analysis and capital expenditure plan."

QUESTION:

b) Figure 2.1, Page 2 of Tab 2, provides a high-level Corporate Strategic Framework and Page 2, item 2 of Centra's December 12, 2018 letter (completeness filing) to the PUB indicates that the 2018/19 Annual Business Plan provided to the Minister of Crown Services was not intended to replace the Corporate Strategic Plan (CSP). Page 9 of

Appendix 2.3 (Manitoba Hydro Annual Business Plan 2018/19) indicates that the corporation commenced the development of a new CSP in 2018/19. Please (i) explain if the new CSP will contain more detailed goals and strategies related to gas operations (ii) are there any plans to improve customer service levels given the projected indicative rate increases in CGM18 (ii) are there any plans to pursue further optimization of integrated planning between electric and gas operations of Manitoba Hydro and (iv) are there plans to expand natural gas into unserved areas of Manitoba.

RATIONALE FOR QUESTION:

To update CAC's understanding of Centra's service territories, strategic planning priorities, management structure and risk management assessments given prior findings of the PUB and the passage of six years since the last Centra GRA.

RESPONSE:

Manitoba Hydro is in the process of developing a long term strategic plan for the company, including both electric and gas operations. The content of the plan with respect to goals and strategies, customer service levels and further integration of electric and gas operations or the expansion of natural gas service have not yet been decided.

REFERENCE:

Tab 2 – Overview of the Application, Appendix 2.1 – Centra Franchise Map, Appendix 2.2 – Manitoba Hydro Organizational Structure, Appendix 2.3 – Manitoba Hydro Annual Business Plan 2018/19, Completeness Filing – Attachment 1 – Manitoba Hydro Corporate Risk Management Report – Fall 2018, Order 85/13 – Page 69 and Order 108/15 – Page 26

PREAMBLE TO IR (IF ANY):

In Order 85/13, at Page 69, the PUB found that it … "is interested in knowing Centra's strategic direction, including where Centra will be investing ratepayer dollars in the coming years, and also what Centra's customers can expect on Centra in terms of improved service levels…the Board finds Centra's overall strategic vision lacking. The Corporate Strategic Plan provides targets and goals at a high level, but does not answer the Board's question of the corporate direction Centra is headed… The Board requests that Centra consider these questions and provide the Board with a more articulated vision in its next rate application"

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QUESTION:

c) On pages 10 and 11 of Appendix 2.2, Manitoba Hydro indicates that it has identified several strategic initiatives necessary to strengthen and align the corporation, including maintaining positive relationships with a number of key stakeholders that are listed. Please indicate if (i) Centra views the parties to the regulatory process (PUB and

Intervenors) as key stakeholders and (ii) and summarize any strategic actions plans that it has developed to improve relationships with the stakeholders involved in the regulatory process.

RATIONALE FOR QUESTION:

To update CAC's understanding of Centra's service territories, strategic planning priorities, management structure and risk management assessments given prior findings of the PUB and the passage of six years since the last Centra GRA.

RESPONSE:

i. Yes, Centra views the parties to the regulatory process (PUB and Intervenors) as key stakeholders.

ii. The business plan identifies stakeholder relations as an ongoing and multi-year initiative. Seeking stakeholder input has been identified as one of the first phases in the development of Manitoba Hydro's 20 year Strategic Business Plan. Stakeholder engagement is likely to begin during the first half of 2019/20.

REFERENCE:

Tab 2 – Overview of the Application, Appendix 2.1 – Centra Franchise Map, Appendix 2.2 – Manitoba Hydro Organizational Structure, Appendix 2.3 – Manitoba Hydro Annual Business Plan 2018/19, Completeness Filing – Attachment 1 – Manitoba Hydro Corporate Risk Management Report – Fall 2018, Order 85/13 – Page 69 and Order 108/15 – Page 26

PREAMBLE TO IR (IF ANY):

In Order 85/13, at Page 69, the PUB found that it … "is interested in knowing Centra's strategic direction, including where Centra will be investing ratepayer dollars in the coming years, and also what Centra's customers can expect on Centra in terms of improved service levels…the Board finds Centra's overall strategic vision lacking. The Corporate Strategic Plan provides targets and goals at a high level, but does not answer the Board's question of the corporate direction Centra is headed… The Board requests that Centra consider these questions and provide the Board with a more articulated vision in its next rate application"

In Order 108/15, at Page 26, the PUB found that "Previously, Centra had a division manager of gas supply; a position that is currently vacant. Furthermore …. responsibility for gas operations appears to have been combined with several other duties assigned to senior managers of Manitoba Hydro. The Board therefore recommends that Centra review its managerial structure to ensure that its operational decision makers … have clear lines of responsibility to a senior manager. The Board expects to review Centra's management structure further at the next General Rate Application. At that hearing, the Board also expects to review Centra's strategic plan, including the utility risk analysis and capital expenditure plan."

QUESTION:

d) Figure 2.1 on page 2 of Tab 2 provides a mission statement for Manitoba Hydro consolidated operations only and no vision statement for either electric or gas operations. Please explain if Manitoba Hydro/Centra Gas have plans to develop a vision statement related to gas operations, and if so, what is the timeframe for its development.

RATIONALE FOR QUESTION:

To update CAC's understanding of Centra's service territories, strategic planning priorities, management structure and risk management assessments given prior findings of the PUB and the passage of six years since the last Centra GRA.

RESPONSE:

Manitoba Hydro is undertaking the development of a 20 year Strategic Business Plan that will set the direction for Manitoba Hydro and its subsidiaries, including Centra. Manitoba Hydro began the process in Spring 2019.

REFERENCE:

Tab 2 – Overview of the Application, Appendix 2.1 – Centra Franchise Map, Appendix 2.2 – Manitoba Hydro Organizational Structure, Appendix 2.3 – Manitoba Hydro Annual Business Plan 2018/19, Completeness Filing – Attachment 1 – Manitoba Hydro Corporate Risk Management Report – Fall 2018, Order 85/13 – Page 69 and Order 108/15 – Page 26

PREAMBLE TO IR (IF ANY):

In Order 85/13, at Page 69, the PUB found that it … "is interested in knowing Centra's strategic direction, including where Centra will be investing ratepayer dollars in the coming years, and also what Centra's customers can expect on Centra in terms of improved service levels…the Board finds Centra's overall strategic vision lacking. The Corporate Strategic Plan provides targets and goals at a high level, but does not answer the Board's question of the corporate direction Centra is headed… The Board requests that Centra consider these questions and provide the Board with a more articulated vision in its next rate application"

In Order 108/15, at Page 26, the PUB found that "Previously, Centra had a division manager of gas supply; a position that is currently vacant. Furthermore …. responsibility for gas operations appears to have been combined with several other duties assigned to senior managers of Manitoba Hydro. The Board therefore recommends that Centra review its managerial structure to ensure that its operational decision makers … have clear lines of responsibility to a senior manager. The Board expects to review Centra's management structure further at the next General Rate Application. At that hearing, the Board also expects to review Centra's strategic plan, including the utility risk analysis and capital expenditure plan."

QUESTION:

Pages 3 to 6 of Tab 2, provides information on "some of the activities" (Page 2 line 17) that Centra undertakes to deliver value and meet customer expectations. Please provide a summary of the strategic business plans/initiatives of the divisions/departments that provide services to gas operations to respond to the PUB's concern from Order 85/13, Page

69, that high-level plans and targets related to Manitoba Hydro consolidated operations do not provide sufficient information with respect to the strategic direction of gas operations.

RATIONALE FOR QUESTION:

To update CAC's understanding of Centra's service territories, strategic planning priorities, management structure and risk management assessments given prior findings of the PUB and the passage of six years since the last Centra GRA.

RESPONSE:

As described in Centra's Tab 2 evidence, the key gas-specific activities undertaken are gas supply; safety and reliability of the distribution system which includes customer safety education and emergency response; and customer service which includes customer choice in gas supply service options (System Supply, WTS, FRPGS and T-Service), customer education, DSM and Affordable Energy programming, natural gas expansion where economic, and Centra's various customer interfaces. In addition, extensive information on strategy and operations is filed in the following Tabs of Centra's GRA filing:

- Reliable and cost-effective gas supply - Tabs 8 and 9;
- Reliable and cost effective distribution of natural gas - Tab 3 for the operations financial forecast (no general revenue increase); Tab 4 for safety and reliability of the distribution system including the 2018-2023 Natural Gas Asset Management Capital Investment Plan;[1]
- Customer service - Tab 7 for DSM and Affordable Energy programming; Tab 13 for main extensions and franchise expansions, and stakeholder consultation processes.

Also, Manitoba Hydro is in the process of developing a 20 year Strategic Business Plan. Please see the response to CAC/Centra I-2 c) as well.

[1] Appendix 4.3

REFERENCE:

Tab 2 – Overview of the Application, Appendix 2.1 – Centra Franchise Map, Appendix 2.2 – Manitoba Hydro Organizational Structure, Appendix 2.3 – Manitoba Hydro Annual Business Plan 2018/19, Completeness Filing – Attachment 1 – Manitoba Hydro Corporate Risk Management Report – Fall 2018, Order 85/13 – Page 69 and Order 108/15 – Page 26

PREAMBLE TO IR (IF ANY):

In Order 85/13, at Page 69, the PUB found that it … "is interested in knowing Centra's strategic direction, including where Centra will be investing ratepayer dollars in the coming years, and also what Centra's customers can expect on Centra in terms of improved service levels…the Board finds Centra's overall strategic vision lacking. The Corporate Strategic Plan provides targets and goals at a high level, but does not answer the Board's question of the corporate direction Centra is headed… The Board requests that Centra consider these questions and provide the Board with a more articulated vision in its next rate application"

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QUESTION:

f) Please provide a revised Organization Structure chart (Page 5 of Appendix 2.2) to provide a gas operations managerial structure (to facilitate the PUB review outlined on Page 26 of Order 108/15) which provides information down to the departmental level, delineates between those departments that are dedicated only to gas operations, departments that provide integrated services to gas and electric operations and does not include those departments that only provide services to electric operations.

RATIONALE FOR QUESTION:

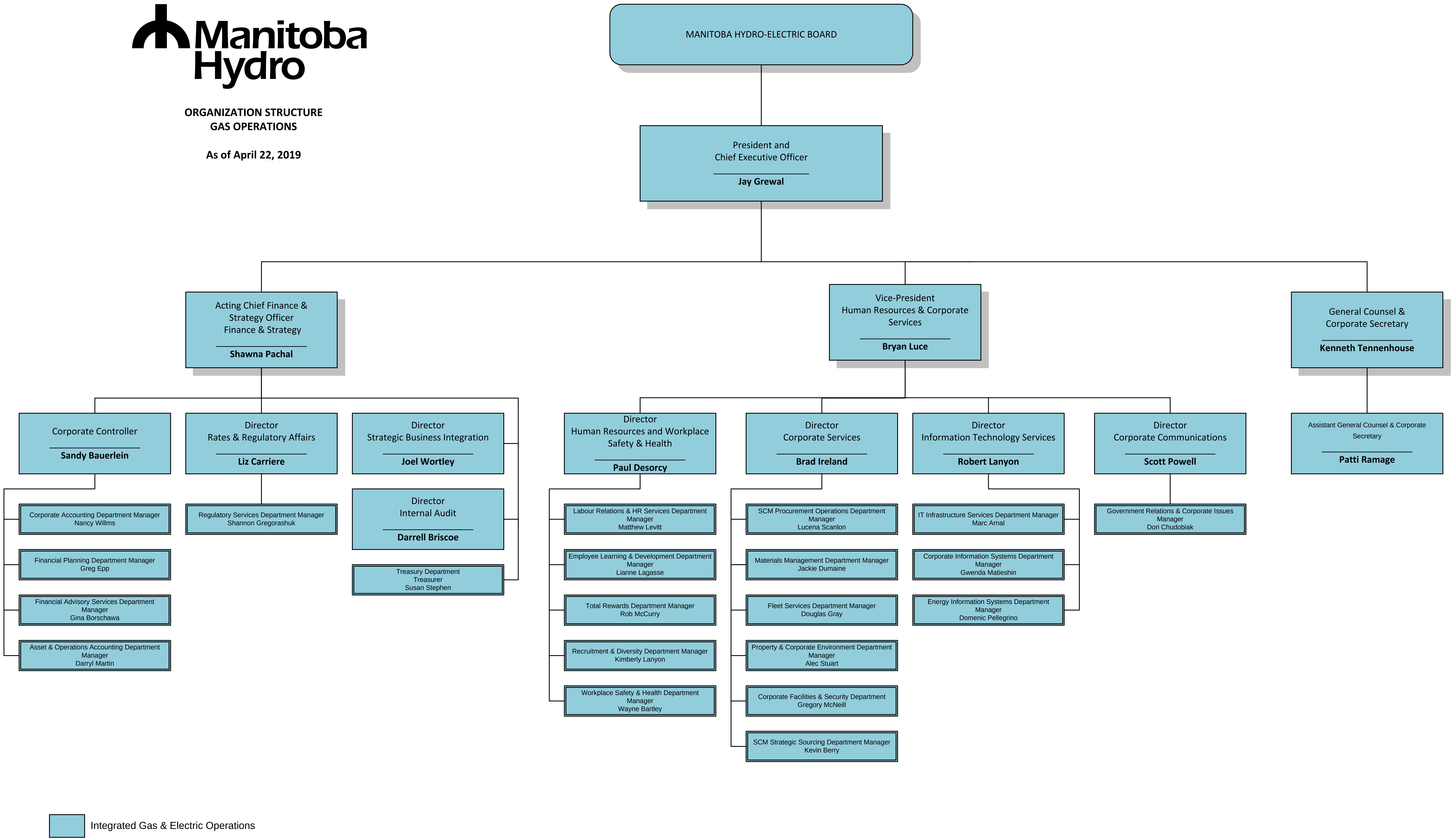
To update CAC's understanding of Centra's service territories, strategic planning priorities, management structure and risk management assessments given prior findings of the PUB and the passage of six years since the last Centra GRA.

RESPONSE:

Please see the attachment to this response for organizational charts.

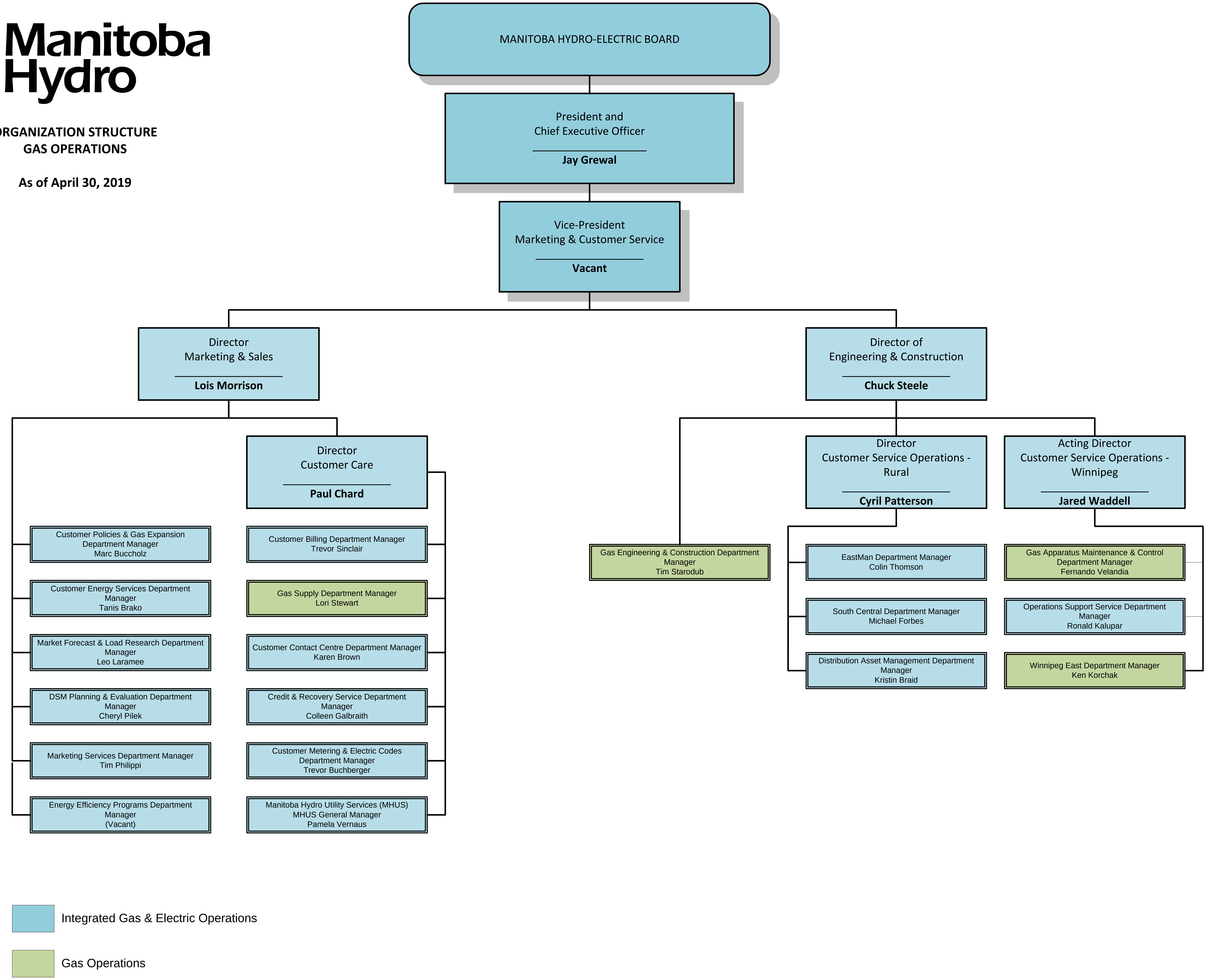
ORGANIZATION STRUCTURE
GAS OPERATIONS

As of April 22, 2019



ORGANIZATION STRUCTURE
GAS OPERATIONS

As of April 30, 2019



REFERENCE:

Tab 2 – Overview of the Application, Appendix 2.1 – Centra Franchise Map, Appendix 2.2 – Manitoba Hydro Organizational Structure, Appendix 2.3 – Manitoba Hydro Annual Business Plan 2018/19, Completeness Filing – Attachment 1 – Manitoba Hydro Corporate Risk Management Report – Fall 2018, Order 85/13 – Page 69 and Order 108/15 – Page 26

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QUESTION:

g) Please explain if there are plans to further review the gas management structure as part of future planning now that the VDP is completed and if any plans for changes are being implemented for the 2019/20 fiscal year.

RATIONALE FOR QUESTION:

To update CAC's understanding of Centra's service territories, strategic planning priorities, management structure and risk management assessments given prior findings of the PUB and the passage of six years since the last Centra GRA.

RESPONSE:

During the VDP, Manitoba Hydro Executives responsible for the gas management structure reviewed and aligned the organizational structure as part of an overall effort to streamline operations and management. There are no specific plans for changes in 2019/20 but the effectiveness of the recent changes continues to be monitored. Further changes may be made where circumstances warrant.

REFERENCE:

Tab 2 – Overview of the Application, Appendix 2.1 – Centra Franchise Map, Appendix 2.2 – Manitoba Hydro Organizational Structure, Appendix 2.3 – Manitoba Hydro Annual Business Plan 2018/19, Completeness Filing – Attachment 1 – Manitoba Hydro Corporate Risk Management Report – Fall 2018, Order 85/13 – Page 69 and Order 108/15 – Page 26

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In Order 85/13, at Page 69, the PUB found that it … "is interested in knowing Centra's strategic direction, including where Centra will be investing ratepayer dollars in the coming years, and also what Centra's customers can expect on Centra in terms of improved service levels…the Board finds Centra's overall strategic vision lacking. The Corporate Strategic Plan provides targets and goals at a high level, but does not answer the Board's question of the corporate direction Centra is headed… The Board requests that Centra consider these questions and provide the Board with a more articulated vision in its next rate application"

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QUESTION:

h) Attachment 1 of Centra's December 12, 2018 Completeness Filing provides the Corporate Risk Management Report from the fall of 2018, which is largely focused on risks that impact electricity operations with only 3 risk profiles that are specific to gas operations (A.3 Non-commodity Gas Rates, A.6 Upstream Gas Costs and D.5 System

Shutdown (Gas)). Please provide Centra's perspectives on Risk Trends and Changes, Highest Priority Risks, Other Areas of Concern and High Consequence Risks that are specific to or most significantly impact gas operations (similar to Sections 2.1, 4.0, 5.0 and 6.0 of Attachment 1 which is mainly focused on electric operations).

RATIONALE FOR QUESTION:

To update CAC's understanding of Centra's service territories, strategic planning priorities, management structure and risk management assessments given prior findings of the PUB and the passage of six years since the last Centra GRA.

RESPONSE:

There is only one Corporate Risk Management Report (as referenced) associated with Manitoba Hydro and all its subsidiaries (including Centra) that discusses significant corporate-wide themes including "Risk Trends and Changes, Highest Priority Risks, Other Areas of Concern and High Consequence Risks". Many of the risks discussed in the report, in addition to the three specific to natural gas operations as noted by the intervenor, apply to all of Manitoba Hydro's operations.

Additional commentary on the themes specific to Centra's operations are as follows:

<u>Risk Trends and Changes:</u>

Changing environmental requirements and legislation has the potential to impact Centra, Centra's costs and Centra's customers:

- The current implementation of the carbon tax is not a direct impact on Centra but will directly affect Centra's customers. With the current tax proposed to increase to a maximum $50/tonne, natural gas in Manitoba will remain an economically attractive energy source but still result in higher total energy bills for the Centra customers. Further increases in this tax in the future may affect this relative economic position.
- The Government of Canada is developing a Clean Fuel Standard to reduce Canada's greenhouse gas emissions through the increased use of lower carbon fuels, energy sources and technologies. A goal is to achieve 30 million tonnes of annual reductions

in greenhouse gas emissions by 2030. The Clean Fuel Standard regulations will set separate requirements for liquid, gaseous and solid fossil fuels. The regulations for gaseous and solid fuel streams are targeted for final regulations in 2021 and coming into force in 2023. Natural gas supplied by distribution utilities for heating and general consumption will be within the scope of the regulations while natural gas used as feedstocks in industrial processes will not be. While not yet confirmed, it appears that there will be an objective to reduce the carbon intensity of the gas delivered by gas distribution companies by between 5 and 10%. This requirement may be phased in. There are several options that can be combined for compliance including:

- Purchase of Credits;
- Produce/Purchase Renewable Natural Gas;
- Fuel Switching to lower carbon fuels, including the use of natural gas for transportation; and,
- Carbon Capture & Storage.

While significant unknowns remain, Centra is participating in a Canadian Gas Association task force to assist in following the progression of this regulation and identifying options to assist in meeting the regulations.

Highest Priority Risks

Centra has not identified any major risks as being critical and requiring specific attention over the next 12 months or longer.

Other Areas of Concern

The implementation of an asset management system over the next two to three years will better define investment decisions and may result in additional requirements for gas capital beyond current levels.

The implementation of an advanced meter infrastructure ("AMI") program may also influence investment levels. As noted on page 13 of Tab 13 of the Application, if a decision is made to pursue AMI a business plan will be filed with the PUB prior to proceeding with AMI implementation.

<u>High Consequence Risks</u>

Many communities supplied by natural gas rely on a single natural gas supply and are vulnerable to a single failure causing an outage. The requirement to have service personnel respond to inspect and re-light individual customers following the return to service of the gas supply results in high potential costs for Centra. The loss of gas supply may result in the gas customers incurring significant costs due to the loss of gas (alternate heating supplies, business losses, damages). With aging infrastructure, the provision of alternate gas supplies through trucked gas supplies or additional piped supplies becomes more important.

REFERENCE:

Tab 2 – Overview of the Application, Appendix 2.1 – Centra Franchise Map, Appendix 2.2 – Manitoba Hydro Organizational Structure, Appendix 2.3 – Manitoba Hydro Annual Business Plan 2018/19, Completeness Filing – Attachment 1 – Manitoba Hydro Corporate Risk Management Report – Fall 2018, Order 85/13 – Page 69 and Order 108/15 – Page 26

PREAMBLE TO IR (IF ANY):

In Order 85/13, at Page 69, the PUB found that it … "is interested in knowing Centra's strategic direction, including where Centra will be investing ratepayer dollars in the coming years, and also what Centra's customers can expect on Centra in terms of improved service levels…the Board finds Centra's overall strategic vision lacking. The Corporate Strategic Plan provides targets and goals at a high level, but does not answer the Board's question of the corporate direction Centra is headed… The Board requests that Centra consider these questions and provide the Board with a more articulated vision in its next rate application" In Order 108/15, at Page 26, the PUB found that "Previously, Centra had a division manager of gas supply; a position that is currently vacant. Furthermore …. responsibility for gas operations appears to have been combined with several other duties assigned to senior managers of Manitoba Hydro. The Board therefore recommends that Centra review its managerial structure to ensure that its operational decision makers … have clear lines of responsibility to a senior manager. The Board expects to review Centra's management structure further at the next General Rate Application. At that hearing, the Board also expects to review Centra's strategic plan, including the utility risk analysis and capital expenditure plan."

QUESTION:

i) Tab 3 of the Application (Gas Operations Financial Forecast CGM18) does not provide any Key Variable Sensitivity Analysis similar to that which is commonly provided with electric rate applications (for example Page 44 of Appendix 3.1 of the MH 2017/18 & 2018/19 GRA). Please provide a table of sensitivity analysis for key variables (ie., interest rates, volume growth, warmer/colder than normal weather etc) that impact the gas operations financial outlook (CGM18), as well as sensitivities related to potential variances to spending targets for i) Gas O&A ii) Gas Business Operations Capital and iii) Gas DSM.

RATIONALE FOR QUESTION:

To update CAC's understanding of Centra's service territories, strategic planning priorities, management structure and risk management assessments given prior findings of the PUB and the passage of six years since the last Centra GRA.

RESPONSE:

i) The following figure provides the 2019/20 retained earnings impacts of the following key variables:

- Weather – the Gross Margin forecast is prepared assuming normal weather. The colder/warmer than average weather sensitivities assume 10% warmer/colder than average effective degree days. Extreme temperatures can have a significant impact on Centra's earnings. For example, in 2011/12, Centra experienced a decrease in effective degree days of [redacted] which reduced net income by approximately [redacted] million. Two years later, in 2013/14, Centra experienced an increase in effective degree days of [redacted] which increased net income by approximately [redacted] million. 1d
- Customer Growth – the Gross Margin forecast is prepared assuming an impact of approximately $1 million for customer growth over the previous year. This analysis will look at that growth potentially doubling to $2 million or no growth, lowering the forecast by $1 million.
- Interest rates – the interest rate forecast is derived on a consensus basis and the underlying independent consultant forecasts are received without a probability of occurrence. The interest rate sensitivities assume a 50bp higher or lower than forecasted short-term, long-term, and floating interest rates.

Key Variability Sensitivity Impacts to 2019/20 Retained Earnings
(In Millions)

	Increase/ (Decrease) 2019/20
Warmer than normal weather	[redacted]
Colder than normal weather	
Customer growth	1.011
No Customer growth	(1.011)
Interest rate decrease (50bp)	0.629
Interest rate increase (50bp)	(0.630)

The sensitivity analysis above focuses on key variables that are outside of the Corporation's control and therefore does not include the variations between plan and actual results for O&A, Gas Business Operations Capital ("BOC") and Demand Side Management ("DSM"). The targets for Centra's investments in O&A, BOC and DSM have been set at necessary levels in order to meet the Corporation's responsibility to provide for an ongoing safe and reliable supply of natural gas to its customers. In addition, the 2019/20 DSM budget reflects direction from the Province to maintain a continuation of current DSM programs while responsibility transitions to Efficiency Manitoba.

REFERENCE:

Tab 2 – Section 2.2 Overview of Application Pages 6 to 7

PREAMBLE TO IR (IF ANY):

As outlined on pages 6 and 7 of Tab 2 of the Application, the last general revenue increase for Centra was approved by the PUB in Order 85/13 and the reversion to the non-gas portion of rates to levels approved in the 2009/10 and 2010/11 GRA was approved by the PUB in Order 79/17.

QUESTION:

a) Please provide the compliance filing flowing from Order 85/13 (material consistent with the response to PUB/Centra II-144 (a) from the 2013/14 Centra GRA).
b) Please provide the compliance filing flowing from Order 79/17 (material consistent with the response to PUB/Centra II-144 (a) from the 2013/14 Centra GRA).
c) Please provide any Centra IFF's filed with the PUB between the 2013/14 GRA and the filing of the 2019/20 GRA as well as associated correspondence.
d) Please file the 2018/19 Centra audited financial statements, when available.

RATIONALE FOR QUESTION:

To place the compliance filings containing the last changes to the non-gas portion of Centra rates on the public record to allow for comparisons with the revenue requirements and rates sought in the 2019/20 GRA. To understand the progression of Centra's financial position and financial outlook since the 2013/14 GRA.

RESPONSE:

a) Please see Attachment 1 to this response for the compliance filing flowing from Order 85/13.

b) A compliance filing was not required following Order 79/17. An updated cost allocation study was not completed in the preparation of Centra's August 1, 2017 proposed rate schedules reflecting Directive 5 of Order 108/15. Rather, August 1, 2017 rates were prepared by combining the non-gas rates approved by PUB Order 66/11 with non-Primary gas cost portion of rates approved by the PUB Order 108/15.

c) Please see Attachment 2 to this response for CGM13 to CGM16 filed with the PUB following the 2013/14 GRA and prior to the filing of the 2019/20 GRA, as well as associated correspondence.

d) Centra will file with the PUB its 2018/19 audited financial statements once the corporation's annual results have been publically released.

CENTRA GAS MANITOBA INC.
2019/20 GENERAL RATE APPLICATION

A copy of CAC/CENTRA I-3a-d Attachment 1 and 2 can be found at the links below:

https://www.hydro.mb.ca/regulatory_affairs/pdf/natural_gas/general_rate_application_2019/information_requests/cac-centra_i-3a-d-attachment_1.pdf

https://www.hydro.mb.ca/regulatory_affairs/pdf/natural_gas/general_rate_application_2019/information_requests/cac-centra_i-3a-d-attachment_2.pdf

REFERENCE:

Tab 3 – Section 3.1 Gas Operations Financial Forecast pg 1-2, Appendix 3.1 – CGM18

PREAMBLE TO IR (IF ANY):

Page 1 of Tab 3, lines 7 to 9 of the Application indicates that Gas Operations Financial Forecast (CGM18) is the primary forecast to determine the need for changes to Centra's rates. CGM18 was approved by Centra's Board of Directors on October 26, 2018. On page 27 of Order 85/13, the PUB found the following with respect to the fair return to Manitoba Hydro related to Centra Gas:

"The Board is not convinced that Centra requires a higher Net Income than has previously been approved, meaning $3 million per year. The Board has ruled that the Corporate Allocation forms part of the return to Centra and that a return of $14 to $16 million represents a fair return to Manitoba Hydro."

QUESTION:

a) On Page 2 of Tab 3, lines 2 to 9, Centra outlines the seven key economic and financial inputs underlying CGM18. On page 1, lines 15 to 22 of the March 22, 2019 Supplement to the Application, Centra lists the select planning assumptions that have been updated. Please provide a table which summarizes (i) the dates of completion for each of the key inputs to CGM18 and (ii) which of the key inputs is Centra planning to update before the oral hearing and the anticipated dates of completion of each key input.
b) On Page 1 of Tab 3, line 21, Centra states that "CGM18 assumes no general revenue increase for the 2019/20 Test Year". Please provide the quantitative analysis to support the assertion that there is no general revenue increase requested for 2019/20.
c) Please provide CGM18 (including projected financial ratio calculations) with and without the proposed/indicative rate increases, in a format similar to PUB/Centra II-139 from the 2013/14 GRA.
d) Further to the information requested in PUB/Centra I-2 (b) of this proceeding, please provide the CGM18 scenario (including adjusted proposed and indicative rate increases and projected financial ratio calculations) maintaining $3 million of net income in each

year, with and without the adjusted proposed/indicative rate increases, in a format similar to PUB/Centra II-139 from the 2013/14 GRA.

e) Please place a copy of the response to PUB/Centra I-16 d (CGM12 with IFRS deferral to 2015/16, grandfathering of regulatory accounting, $3 million net income) from the 2013/14 GRA on the record of this proceeding.

RATIONALE FOR QUESTION:

To review Centra's assertion that there is no general revenue increase proposed for 2019/20 and understand changes in the Centra IFF since the 2013/14 GRA.

RESPONSE:

a) Please see the following table for the dates of completion for the planning assumptions for both the November 30, 2018 General Rate Application as well as the March 22, 2019 Supplemental filing.

	Centra Gas 2019/20 GRA November 30, 2018	Supplemental Filing Mar 22, 2019
Forecast of Macroeconomic Indicators (e.g. GDP, CPI)	April 2017	April 2018
Forecast of Interest and Exchange Rates	June 2018	December 2018
Natural Gas Volume Forecast	October 2017	November 2018
Cost of Gas Forecast	January 2018	October 2018
Gross Margin Forecast	January 2018	January 2019
Capital Expenditures Forecast	March 2018	February 2019
Operating & Administrative Expense Forecast	March 2018	February 2019

Centra intends to file a pre-hearing update in July 2019, providing updated information on actual and forecast gas costs, which will include actual gas cost information to March 2019 and forecast gas costs based on an April 2019 strip date. An update to the forecast of interest and exchange rates (updated Appendix 3.8) will be provided at the time of Centra's rebuttal evidence (August 2019), as required by Directive 4 of Order 85/13.

b) Please refer to the Supplement to Centra's 2019/20 General Rate Application, page 7, Figure 2 which demonstrates there is no additional revenue requirement requested for 2019/20. The non-gas costs of $149.6 million are shown net of the removal of the

Furnace Replacement Program. As such, there is no request for a general revenue increase.

c) The table below depicts CGM18 for the ten year forecast in a similar fashion as the response to PUB/Centra II-139 from the 2013/14 GRA.

CGM18
(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
Weighted Average Cost of Gas Sold **	159	158	166	166	165	165	164	163	162	163
Gross Margin	149	150	150	151	151	152	152	152	153	152
Other	2	2	2	2	2	2	2	2	2	2
	151	151	152	153	153	154	154	154	155	154
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)	(5)	(7)	(10)	(14)	(17)	(20)	(24)	(27)
Net Movement in Regulatory Deferral **	3	3	3	3	3	3	2	3	3	2
Net Income (loss) before proposed rate increases* **	**3**	**2**	**(2)**	**(4)**	**(8)**	**(12)**	**(17)**	**(21)**	**(27)**	**(32)**
additional revenue requirement****	-	-	6	10	14	17	21	24	28	32
Net Income (loss) after proposed rate increases	**3**	**2**	**5**	**7**	**7**	**7**	**7**	**8**	**7**	**7**
Retained Earnings before proposed rate increases	79	81	80	76	68	55	38	17	(10)	(42)
Retained Earnings after proposed rate increases	79	81	86	93	99	106	113	120	127	134
Financial Ratios - with rate increase										
Equity Ratio (PUB Approved Methodology)	32%	31%	29%	29%	29%	29%	29%	29%	29%	29%
EBITDA Interest Coverage	2.85	2.74	2.78	2.80	2.80	2.72	2.68	2.67	2.59	2.56
Capital Coverage	0.78	0.70	0.58	1.07	1.09	1.09	1.09	1.10	1.12	1.11
Financial Ratios - without rate increase										
Equity Ratio (PUB Approved Methodology)	32%	31%	29%	27%	26%	24%	21%	18%	15%	11%
EBITDA Interest Coverage	2.85	2.74	2.52	2.35	2.18	1.97	1.78	1.63	1.45	1.29
Capital Coverage	0.78	0.70	0.42	0.79	0.71	0.61	0.52	0.42	0.34	0.22

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

	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%

d) The table below depicts PUB/Centra I-2 b) of this proceeding (scenario maintaining $3 million of net income in each year) for the ten year forecast in a similar fashion as the response to PUB/Centra II-139 from the 2013/14 GRA.

PUB CENTRA I 2b - $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
Weighted Average Cost of Gas Sold **	159	158	166	166	165	165	164	163	162	163
Gross Margin	149	150	150	151	151	152	152	152	153	152
Other	2	2	2	2	2	2	2	2	2	2
	151	151	152	153	153	154	154	154	155	154
EXPENSES										
Operating and Administrative	63	61	62	63	64	65	66	68	69	70
Finance Expense	22	23	25	26	28	29	30	31	33	34
Depreciation and Amortization	24	25	27	28	29	31	31	32	33	34
Capital and Other Taxes	17	17	18	18	19	19	20	20	21	21
Other Expenses	12	13	13	12	12	12	12	12	12	11
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
	150	152	157	160	163	168	171	175	179	182
Net Income before Net Movement in Regulatory Deferral	1	(1)	(5)	(7)	(10)	(14)	(17)	(21)	(25)	(28)
Net Movement in Regulatory Deferral **	3	3	3	3	3	3	2	3	3	2
Net Income (loss) before proposed rate increases* **	**3**	**2**	**(2)**	**(4)**	**(8)**	**(12)**	**(17)**	**(21)**	**(27)**	**(32)**
additional revenue requirement****	-	-	5	7	11	14	18	21	25	29
Net Income (loss) after proposed rate increases	**3**	**2**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**
Retained Earnings before proposed rate increases	79	81	80	76	68	55	38	17	(10)	(42)
Retained Earnings after proposed rate increases	79	81	84	87	90	93	96	99	102	105
Financial Ratios - with rate increase										
Equity Ratio (PUB Approved Methodology)	32%	31%	29%	28%	28%	27%	27%	27%	26%	26%
EBITDA Interest Coverage	2.85	2.74	2.72	2.64	2.63	2.55	2.52	2.47	2.42	2.39
Capital Coverage	0.78	0.70	0.54	0.97	0.99	0.99	1.01	0.99	1.04	1.03
Financial Ratios - without rate increase										
Equity Ratio (PUB Approved Methodology)	32%	31%	29%	27%	26%	24%	21%	18%	15%	11%
EBITDA Interest Coverage	2.85	2.74	2.52	2.35	2.18	1.97	1.78	1.63	1.45	1.29
Capital Coverage	0.78	0.70	0.42	0.79	0.71	0.61	0.52	0.42	0.34	0.22

* 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.

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

******Additional Revenue Requirement**

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Percent Increase	0.00%	0.00%	1.68%	0.32%	1.34%	0.97%	1.17%	0.68%	1.43%	0.97%
Cumulative Percent Increase	0.00%	0.00%	1.68%	2.01%	3.37%	4.38%	5.60%	6.32%	7.83%	8.88%

e) Please see the attachment to this response for a copy of PUB/Centra I-16 from the 2013/14 General Rate Application.

PUB/CENTRA I-16

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Reference Tab 5 Page 2 of 30 Schedule 5.1.0**

Order 128/09

d) **Please file an IFF scenario reflecting $3 million in net income in 2013/14 and beyond, as well as the continuation of rate-regulated accounting under IFRS. Indicate the level of rate increases required to maintain the level of net income.**

ANSWER:

Please see the schedule below. Please note that the 1.19% rate increase for 2013/14 indicated in this IFF scenario assumes that the rate increase is implemented on May 1, 2013.

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

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
REVENUES											
General Consumers											
at approved rates	319	312	356	351	349	348	349	349	350	350	351
additional revenue requirement*	0	4	9	4	9	13	15	17	19	21	23
	319	316	365	355	358	361	363	367	368	372	374
Cost of Gas Sold	176	168	212	203	202	201	201	201	201	201	201
Gross Margin	143	148	153	152	156	160	162	166	167	171	173
Other	2	2	2	2	2	2	2	2	2	2	2
	145	150	155	154	158	162	164	168	169	173	175
EXPENSES											
Operating and Administrative	67	69	71	70	71	73	74	76	77	79	81
Finance Expense	18	17	19	20	22	23	23	24	25	26	26
Depreciation and Amortization	28	30	31	30	31	32	32	33	32	33	32
Capital and Other Taxes	18	19	19	19	19	20	20	20	20	20	21
Corporate Allocation	12	12	12	12	12	12	12	12	12	12	12
	143	147	152	151	155	159	161	165	166	170	172
Net Income	2	3	3	3	3	3	3	3	3	3	3

* Additional Revenue Requirement										
Percent Increase	1.19%	1.48%	-1.49%	1.50%	1.03%	0.47%	0.82%	0.25%	0.82%	0.28%
Cumulative Percent Increase	1.19%	2.69%	1.16%	2.68%	3.74%	4.24%	5.09%	5.35%	6.22%	6.51%

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

For the year ended March 31	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
ASSETS											
Plant in Service	656	679	704	732	764	786	809	832	857	883	909
Accumulated Depreciation	(232)	(240)	(250)	(255)	(262)	(271)	(281)	(291)	(301)	(312)	(324)
Net Plant in Service	424	439	454	477	502	515	528	541	556	571	585
Construction in Progress	2	2	2	2	2	4	6	8	8	8	9
Current and Other Assets	73	68	68	68	68	68	68	68	68	68	68
Goodwill and Intangible Assets	9	8	6	5	4	3	3	3	3	3	3
Regulated Assets	79	78	76	73	69	63	57	49	43	37	32
	586	594	607	625	645	653	662	669	678	687	697
LIABILITIES AND EQUITY											
Long-Term Debt	295	300	330	350	370	370	380	390	400	390	420
Current and Other Liabilities	99	89	68	63	61	66	62	57	54	71	49
Contributions in Aid of Construction	35	45	45	45	44	45	44	43	42	41	41
Share Capital	121	121	121	121	121	121	121	121	121	121	121
Retained Earnings	36	39	42	46	49	52	55	58	61	64	67
	586	594	607	625	645	653	662	669	678	687	697

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

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
OPERATING ACTIVITIES											
Cash Receipts from Customers	355	354	403	389	392	396	398	401	403	407	409
Cash Paid to Suppliers and Employees	(291)	(335)	(341)	(340)	(340)	(342)	(344)	(347)	(349)	(352)	(354)
Interest Paid	(19)	(19)	(20)	(21)	(23)	(24)	(24)	(25)	(26)	(26)	(27)
	45	0	41	28	29	29	29	30	29	29	29
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	60	40	30	20	20	-	10	10	10	10	30
Retirement of Long-Term Debt	(63)	-	(35)	-	-	-	-	-	-	-	(20)
Other	-	-	-	-	-	-	-	-	-	-	-
	(3)	40	(5)	20	20	-	10	10	10	10	10
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(37)	(39)	(39)	(45)	(48)	(37)	(37)	(37)	(37)	(37)	(39)
Other	(0)	(1)	(0)	(0)	(0)	(1)	(1)	(1)	(0)	(0)	(0)
	(37)	(39)	(39)	(45)	(48)	(38)	(38)	(37)	(38)	(38)	(39)
Net Increase (Decrease) in Cash	5	1	(3)	3	1	(9)	2	3	2	2	0
Cash at Beginning of Year	(13)	(9)	(8)	(11)	(8)	(7)	(16)	(14)	(11)	(10)	(8)
Cash at End of Year	(9)	(8)	(11)	(8)	(7)	(16)	(14)	(11)	(10)	(8)	(8)

REFERENCE:

Tab 3 – Section 3.1.2 Furnace Replacement Program (pg 2-3), Appendix 3.1 – CGM18 and Appendix 3.3 – Projected FRP Balance

PREAMBLE TO IR (IF ANY):

On Page 3 of Tab 3, lines 10 to 11, Centra indicates that CGM18 has assumed the disposition of approximately $17 million (the amount of excess FRP funding) by the end of 2020/21. In Appendix 3.3, Page 1, Centra includes a disposition of $17.3 million in the 2020/21 fiscal year as part of the FRP continuity schedule.

Centra states on Page 3 of Tab 3, lines 11 to 14 that "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 describe the assumptions that Centra has made to model the disposition of the $17 million excess FRP funding in CGM18 and provide a quantitative analysis that demonstrates the impact of these assumptions on the CGM18 projected income statement, balance sheet and cash flow statement.

RATIONALE FOR QUESTION:

To understand how the assumptions made by Centra with respect to the disposition of the excess FRP funding impact the 2019/20 proposed and future projected indicative rate increases toc customers as well as Centra's financial position.

RESPONSE:

a) As noted in the response to PUB/CENTRA I-102a, no specific plans or details of this disposition have been assessed at this time or presented to Centra's Board of Directors for their review. CGM18 assumed a disposition of the Furnace Replacement Program liability of approximately $17 million effective in fiscal year 2020/21. The accounting entry used to model this disposition was a debit to clear out the FRP liability account and a credit to cash (short-term debt).

The following schedules provide the impact on CGM18 statements if the $17 million FRP disbursement was not made.

GAS OPERATIONS
PROJECTED OPERATING STATEMENT
CGM18 less CGM18 with No FRP Disbursement
(In Millions of Dollars)

For the year ended March 31	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
REVENUES										
Domestic Revenue										
Cost of Gas at Approved Rates	-	-	-	-	-	-	-	-	-	-
Non-Gas Costs	-	-	-	-	-	-	-	-	-	-
Furnace Replacement Program	-	-	-	-	-	-	-	-	-	-
Late Payment Charges and Broker Revenue	0	0	0	0	(0)	(0)	(0)	(0)	0	(0)
	0	0	0	0	(0)	(0)	(0)	(0)	0	(0)
additional revenue requirement*	-	-	-	(0)	0	(0)	0	0	0	0
	0	0	0	(0)	0	(0)	0	0	0	0
Weighted Average Cost of Gas Sold **	-	-	-	-	-	-	-	-	-	-
Gross Margin	0	0	0	(0)	0	(0)	0	0	0	0
Other	-	-	(0)	0	(0)	(0)	0	(0)	(0)	(0)
	0	0	(0)	(0)	0	(0)	0	0	0	0
EXPENSES										
Operating and Administrative	-	-	-	-	-	-	-	-	-	-
Finance Expense	(0)	0	(0)	0	0	0	0	0	0	0
Depreciation and Amortization	-	-	-	-	-	-	-	-	-	-
Capital and Other Taxes	(0)	(0)	0	0	0	0	0	0	0	0
Other Expenses	-	-	-	-	0	0	0	0	0	(0)
Corporate Allocation	-	-	-	-	-	-	-	-	-	-
	(0)	(0)	0	0	0	0	0	0	1	0
Net Income before Net Movement in Reg. Deferral	0	0	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(0)
Net Movement in Regulatory Deferral **	0	(0)	0	(0)	(0)	(0)	(0)	0	0	0
Net Income	0	0	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(0)

** The adjusted gross margin reflects the cost of gas charged to customer through rates (WACOG). The difference between WACOG and the actual cost of gas purchased is captured in PGVA accounts and either refunded to or collected from customers in future rates. Net movement has been adjusted for PGVA, resulting in a nil effect on net income.

*** Additional Revenue Requirement**										
Percent Increase	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Cumulative Percent Increase	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Financial Ratios										
Equity (PUB Approved Methodology)	0.00	(0.00)	(0.38)	(0.75)	(0.80)	(0.84)	(0.89)	(0.94)	(1.00)	(1.07)
EBITDA Interest Coverage	0.00	0.00	(0.00)	(0.03)	(0.02)	(0.03)	(0.03)	(0.03)	(0.04)	(0.03)
Capital Coverage	(0.00)	0.00	(0.45)	(0.02)	(0.02)	(0.03)	(0.03)	(0.03)	(0.03)	(0.03)

GAS OPERATIONS
PROJECTED BALANCE SHEET
CGM18 less CGM18 with No FRP Disbursement
(In Millions of Dollars)

For the year ended March 31	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
ASSETS										
Plant in Service	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Accumulated Depreciation	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Net Plant in Service	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Construction in Progress	-	-	-	-	-	-	-	-	-	-
Current and Other Assets	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Goodwill and Intangible Assets	-	-	-	-	-	-	-	-	-	-
Total Assets before Regulatory Deferral	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Regulatory Deferral Balance	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
LIABILITIES AND EQUITY										
Long-Term Debt	-	-	20	10	20	20	20	30	20	20
Current and Other Liabilities	0	(0)	(20)	(10)	(19)	(19)	(19)	(28)	(18)	(17)
Deferred Revenue	0	0	0	0	0	0	0	0	0	0
Share Capital	0	0	0	0	0	0	0	0	0	0
Retained Earnings	0	(0)	(0)	(0)	(1)	(1)	(1)	(2)	(2)	(3)
Total Liabilities and Equity before Regulatory Deferral	0	0	0	0	(0)	0	0	0	(0)	0
Regulatory Deferral Balance	0	(0)	0	(0)	(0)	0	(0)	0	0	0
	0	0	0	0	(0)	0	0	0	(0)	0

GAS OPERATIONS
PROJECTED CASH FLOW STATEMENT
CGM18 less CGM18 with No FRP Disbursement
(In Millions of Dollars)

For the year ended March 31	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
OPERATING ACTIVITIES										
Net Income	(0)	0	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(0)
Add Back:										
Depreciation and Amortization	-	-	-	-	-	-	-	-	-	-
Net Movement Impacts on Depreciation, Amortization and Finance Expense	(0)	0	(0)	(0)	0	(0)	0	0	(0)	0
Adjustments for Non-Cash Items	-	-	-	-	-	-	-	-	-	-
Adjustments for Changes in Non-Cash Working Capital Accounts	0	-	(17)	0	0	0	0	(0)	(0)	0
Interest Paid	(0)	0	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Cash Provided by Operating Activities	(0)	0	(17)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	-	-	20	(10)	10	-	-	10	(10)	-
Retirement of Long-Term Debt	-	-	-	-	-	-	-	-	-	-
Cash Provided by Financing Activities	-	-	20	(10)	10	-	-	10	(10)	-
INVESTING ACTIVITIES										
Additions to Property, Plant and Equipment	-	-	-	-	-	-	-	-	-	-
Additions to Intangible Assets	-	-	-	-	-	-	-	-	-	-
Additions to Regulatory Deferral Balances	-	-	-	-	-	-	-	-	-	-
Contributions Received	-	-	-	-	-	-	-	-	-	-
Cash Used for Investing Activities	-	-	-	-	-	-	-	-	-	-
Net Increase (Decrease) in Cash	(0)	0	3	(11)	9	(1)	(1)	9	(11)	(1)
Cash at Beginning of Year	(0)	(0)	0	3	(8)	1	(0)	(1)	7	(4)
Cash at End of Year	(0)	(0)	3	(8)	1	(0)	(1)	7	(4)	(5)

REFERENCE:

Tab 3 – Section 3.1.2 Furnace Replacement Program (pg 2-3), Appendix 3.1 – CGM18 and Appendix 3.3 – Projected FRP Balance

PREAMBLE TO IR (IF ANY):

On Page 3 of Tab 3, lines 10 to 11, Centra indicates that CGM18 has assumed the disposition of approximately $17 million (the amount of excess FRP funding) by the end of 2020/21. In Appendix 3.3, Page 1, Centra includes a disposition of $17.3 million in the 2020/21 fiscal year as part of the FRP continuity schedule.

Centra states on Page 3 of Tab 3, lines 11 to 14 that "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:

b) Please (i) confirm that the FRP funding was directed by Order of the PUB and (ii) explain why Centra assumes that the disposition of the FRP balance is subject to the authority of its Board of Directors as compared to the jurisdiction of the PUB.

RATIONALE FOR QUESTION:

To understand how the assumptions made by Centra with respect to the disposition of the excess FRP funding impact the 2019/20 proposed and future projected indicative rate increases toc customers as well as Centra's financial position.

RESPONSE:

(i) Confirmed.

(ii) As noted on page 3 of Tab 3 of the Application (and as quoted in the Preamble to this question), Centra expects to seek approval of the Public Utilities Board in a future regulatory proceeding on any planned disposition or other allocations from this fund.

REFERENCE:

Tab 3 – Section 3.1.2 Furnace Replacement Program (pg 2-3), Appendix 3.1 – CGM18 and Appendix 3.3 – Projected FRP Balance

PREAMBLE TO IR (IF ANY):

On Page 3 of Tab 3, lines 10 to 11, Centra indicates that CGM18 has assumed the disposition of approximately $17 million (the amount of excess FRP funding) by the end of 2020/21. In Appendix 3.3, Page 1, Centra includes a disposition of $17.3 million in the 2020/21 fiscal year as part of the FRP continuity schedule.

Centra states on Page 3 of Tab 3, lines 11 to 14 that "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:

c) Please explain why the excess funding cannot 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.

RATIONALE FOR QUESTION:

To understand how the assumptions made by Centra with respect to the disposition of the excess FRP funding impact the 2019/20 proposed and future projected indicative rate increases toc customers as well as Centra's financial position.

RESPONSE:

Please see the response to PUB/CENTRA I-102a-b.

REFERENCE:

Tab 3 – Section 3.1.2 Furnace Replacement Program (pg 2-3), Appendix 3.1 – CGM18 and Appendix 3.3 – Projected FRP Balance

PREAMBLE TO IR (IF ANY):

On Page 3 of Tab 3, lines 10 to 11, Centra indicates that CGM18 has assumed the disposition of approximately $17 million (the amount of excess FRP funding) by the end of 2020/21. In Appendix 3.3, Page 1, Centra includes a disposition of $17.3 million in the 2020/21 fiscal year as part of the FRP continuity schedule.

Centra states on Page 3 of Tab 3, lines 11 to 14 that "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:

d) Further to the information requested in PUB/Centra I-102 (b) of this proceeding, please provide CGM18 financial scenarios (as well as adjusted proposed/indicative rate increases and projected financial ratio calculations) assuming that that the $17 million of excess FRP funding is refunded to residential customers over a period of (i) one (ii) two and (iii) five years commencing November 1, 2019.
e) On page 5, lines 29 to 34 of the March 22, 2019 Supplement to the Application, Centra indicates that there would be additional funding of $0.4 million of the Furnace Replacement Program assuming a November 1, 2019 implementation of rates flowing from this regulatory proceeding and that this will have a negligible impact on its projected net income for 2019/20. Please explain how the Furnace Replacement Program is accounted for in Centra's financial statements and whether these additional funds would flow to Centra's net income or a liability account for future disposition.

RATIONALE FOR QUESTION:

To understand how the assumptions made by Centra with respect to the disposition of the excess FRP funding impact the 2019/20 proposed and future projected indicative rate increases toc customers as well as Centra's financial position.

RESPONSE:

d) The scenarios presented in this response include the additional $0.4 million in FRP funding to October 31, 2019 thereby increasing the proposed disposition from $17.3 million to $17.7 million in 2020/21.

Changing the timing of the proposed FRP disposal will change the amount assumed to be disposed due to the impacts of carrying costs on the outstanding balance of the liability. Advancing the disposition of the FRP excess funding to November 1, 2019 could reduce the amount of the assumed disposition by over $1 million.

The following table indicates the amounts that have assumed to be disposed from the FRP liability account under the various scenarios presented in this IR:

Disposition Assumption	Disposition Amount
(i) Over 1 year starting November 1, 2019	$16.6 million
(ii) Over 3 years starting November 1, 2019	$17.1 million
(iii) Over 5 years starting November 1, 2019	$17.7 million

The projected financial statements and ratios of the three scenarios above have been provided in the attachment to this response.

e) Funding for the Furnace Replacement Program is collected from Small General Service customers and initially recorded as revenue by Centra's customer billing system. It is then removed from revenue and recorded as a liability on Centra's Statement of Financial Position. Any additional amounts collected from customers as a result of the program continuing to be funded beyond July 31, 2019 would accrue to the liability account for future disposition.

GAS OPERATIONS (CGM18)
PROJECTED OPERATING STATEMENT
CGM18 - FRP Disbursed over 1 Year Starting Nov 1, 2019
(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	24	25	26	27	28	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	153	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	3	3	3	3	3	2	3	3	2
Net Income	3	2	4	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

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

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

GAS OPERATIONS (CGM18)
PROJECTED BALANCE SHEET
CGM18 - FRP Disbursed over 1 Year Starting Nov 1, 2019
(In Millions of Dollars)

For the year ended March 31	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
ASSETS										
Plant in Service	622	658	698	737	776	814	854	894	935	977
Accumulated Depreciation	(65)	(79)	(95)	(112)	(130)	(148)	(168)	(187)	(208)	(229)
Net Plant in Service	557	579	603	626	646	666	686	707	727	747
Construction in Progress	6	9	6	4	4	4	4	4	4	4
Current and Other Assets	92	92	92	92	92	92	92	92	92	92
Goodwill and Intangible Assets	10	9	9	9	9	9	9	9	9	9
Total Assets before Regulatory Deferral	665	689	710	730	751	771	791	812	832	853
Regulatory Deferral Balance	106	109	113	116	118	121	123	126	128	130
	771	798	823	846	869	891	914	937	960	983
LIABILITIES AND EQUITY										
Long-Term Debt	400	460	480	480	500	530	505	565	565	595
Current and Other Liabilities	112	83	83	98	92	76	115	70	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	81	85	92	99	106	112	120	127	134
Total Liabilities and Equity before Regulatory Deferral	759	794	818	842	864	887	910	933	957	979
Regulatory Deferral Balance	12	5	4	4	4	4	4	4	4	3
	771	798	823	846	869	891	914	937	960	983
Net Debt	452	489	510	527	543	560	576	592	607	622
Equity (PUB Approved Methodology)	31%	30%	29%	29%	29%	29%	29%	29%	29%	29%

GAS OPERATIONS (CGM18)
PROJECTED CASH FLOW STATEMENT
CGM18 - FRP Disbursed over 1 Year Starting Nov 1, 2019
(In Millions of Dollars)

For the year ended March 31	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
OPERATING ACTIVITIES										
Net Income	3	2	4	7	7	7	7	8	7	7
Add Back:										
Depreciation and Amortization	24	25	27	28	29	31	31	32	33	34
Finance Expense	22	24	25	26	27	28	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	(20)	(14)	(2)	(2)	(2)	(2)	(1)	(1)	(0)	(0)
Interest Paid	(33)	(36)	(37)	(38)	(39)	(40)	(42)	(43)	(44)	(45)
Cash Provided by Operating Activities	16	22	38	42	43	44	45	46	48	49
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	50	60	20	20	30	30	10	60	10	30
Retirement of Long-Term Debt	-	(20)	-	-	(20)	(10)	-	(35)	-	(10)
Cash Provided by Financing Activities	50	40	20	20	10	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	12	2	(0)	3	(6)	3	(7)	9	(5)	6
Cash at Beginning of Year	(44)	(32)	(30)	(30)	(27)	(33)	(30)	(36)	(27)	(32)
Cash at End of Year	(32)	(30)	(30)	(27)	(33)	(30)	(36)	(27)	(32)	(27)

GAS OPERATIONS (CGM18)
PROJECTED FINANCIAL RATIOS
CGM18 - FRP Disbursed over 1 Year Starting Nov 1, 2019

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	394.903	439.903	469.903	489.903	504.903	519.903	534.903	552.403	569.903	584.952
Average Due to Parent	37.967	30.727	29.759	28.397	29.919	31.402	33.052	31.850	29.897	29.594
Average Debt	**432.870**	**470.630**	**499.662**	**518.300**	**534.822**	**551.305**	**567.955**	**584.253**	**599.800**	**614.546**
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	77.206	79.889	83.119	88.772	95.592	102.335	109.012	116.071	123.287	130.146
Average Equity	**198.456**	**201.139**	**204.368**	**210.022**	**216.842**	**223.585**	**230.261**	**237.321**	**244.537**	**251.396**
Average Debt	432.870	470.630	499.662	518.300	534.822	551.305	567.955	584.253	599.800	614.546
Average Equity	198.456	201.139	204.368	210.022	216.842	223.585	230.261	237.321	244.537	251.396
Average Debt and Equity	631.326	671.769	704.030	728.322	751.663	774.889	798.217	821.574	844.337	865.942
PUB Approved Equity Ratio	**31.43%**	**29.94%**	**29.03%**	**28.84%**	**28.85%**	**28.85%**	**28.85%**	**28.89%**	**28.96%**	**29.03%**

GAS OPERATIONS (CGM18)
PROJECTED FINANCIAL RATIOS
CGM18 - FRP Disbursed over 1 Year Starting Nov 1, 2019

For the year ended March 31

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
INTEREST COVERAGE										
Net Income	3.230	2.135	4.324	6.983	6.657	6.829	6.524	7.595	6.837	6.880
Finance Expense	20.484	22.329	24.191	25.247	26.318	27.653	28.918	29.799	31.478	32.328
Capitalized Interest	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	23.885	24.702	28.765	32.362	33.010	34.518	35.478	37.431	38.353	39.247
Finance Expense	20.484	22.329	24.191	25.247	26.318	27.653	28.918	29.799	31.478	32.328
Capitalized Interest	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	20.655	22.566	24.441	25.379	26.353	27.689	28.954	29.836	31.515	32.366
Interest Coverage	**1.16**	**1.09**	**1.18**	**1.28**	**1.25**	**1.25**	**1.23**	**1.25**	**1.22**	**1.21**
Add: Depreciation and Amortization *	34.899	36.694	38.540	38.811	40.399	40.930	42.096	42.256	43.428	43.831
Total EBITDA	58.784	61.396	67.306	71.173	73.408	75.448	77.573	79.686	81.781	83.078
EBITDA Interest Coverage	**2.85**	**2.72**	**2.75**	**2.80**	**2.79**	**2.72**	**2.68**	**2.67**	**2.59**	**2.57**

* Includes amortization of deferred income tax

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
CAPITAL COVERAGE										
Internally Generated Funds	16.221	22.095	38.399	41.642	43.179	44.091	45.313	46.435	48.455	48.973
Capitalized Interest*	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	16.392	22.333	38.650	41.774	43.214	44.126	45.349	46.471	48.493	49.011
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	**0.46**	**0.56**	**1.01**	**1.07**	**1.09**	**1.09**	**1.10**	**1.10**	**1.13**	**1.12**

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

GAS OPERATIONS (CGM18)
PROJECTED OPERATING STATEMENT
CGM18 - FRP Disbursed over 3 Years Starting Nov 1, 2019
(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	28	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	3	3	3	3	3	2	3	3	2
Net Income	3	2	4	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

** 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%	30%	29%	29%	29%	29%	29%	29%	29%	29%

GAS OPERATIONS (CGM18)
PROJECTED BALANCE SHEET
CGM18 - FRP Disbursed over 3 Years Starting Nov 1, 2019
(In Millions of Dollars)

For the year ended March 31	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
ASSETS										
Plant in Service	622	658	698	737	776	814	854	894	935	977
Accumulated Depreciation	(65)	(79)	(95)	(112)	(130)	(148)	(168)	(187)	(208)	(229)
Net Plant in Service	557	579	603	626	646	666	686	707	727	747
Construction in Progress	6	9	6	4	4	4	4	4	4	4
Current and Other Assets	92	92	92	92	92	92	92	92	92	92
Goodwill and Intangible Assets	10	9	9	9	9	9	9	9	9	9
Total Assets before Regulatory Deferral	665	689	710	730	751	771	791	812	832	853
Regulatory Deferral Balance	106	109	113	116	118	121	123	126	128	130
	771	798	823	846	869	891	914	937	960	983
LIABILITIES AND EQUITY										
Long-Term Debt	390	450	480	470	500	530	505	565	565	585
Current and Other Liabilities	122	93	82	108	92	75	114	69	84	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	81	86	93	99	106	113	120	127	134
Total Liabilities and Equity before Regulatory Deferral	759	794	818	842	864	887	910	933	957	979
Regulatory Deferral Balance	12	5	4	4	4	4	4	4	4	3
	771	798	823	846	869	891	914	937	960	983
Net Debt	444	482	508	526	542	559	576	592	607	621
Equity (PUB Approved Methodology)	32%	30%	29%	29%	29%	29%	29%	29%	29%	29%

GAS OPERATIONS (CGM18)
PROJECTED CASH FLOW STATEMENT
CGM18 - FRP Disbursed over 3 Years Starting Nov 1, 2019
(In Millions of Dollars)

For the year ended March 31	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
OPERATING ACTIVITIES										
Net Income	3	2	4	7	7	7	7	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	28	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	(13)	(15)	(8)	(4)	(2)	(2)	(1)	(1)	(0)	(0)
Interest Paid	(33)	(35)	(37)	(38)	(39)	(40)	(41)	(43)	(44)	(45)
Cash Provided by Operating Activities	24	22	33	40	43	44	45	46	48	49
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	40	60	30	10	40	30	10	60	10	20
Retirement of Long-Term Debt	-	(20)	-	-	(20)	(10)	-	(35)	-	(10)
Cash Provided by Financing Activities	40	40	30	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	9	3	4	(9)	4	3	(7)	9	(5)	(4)
Cash at Beginning of Year	(44)	(35)	(32)	(28)	(36)	(33)	(29)	(36)	(27)	(32)
Cash at End of Year	(35)	(32)	(28)	(36)	(33)	(29)	(36)	(27)	(32)	(36)

GAS OPERATIONS (CGM18)
PROJECTED FINANCIAL RATIOS
CGM18 - FRP Disbursed over 3 Years Starting Nov 1, 2019

For the year ended March 31

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
PUB APPROVED DEBT TO EQUITY RATIO										
Average Long-Term Debt	389.903	429.903	464.903	484.903	499.903	519.903	534.903	552.403	569.903	579.952
Average Due to Parent	39.301	33.280	29.862	32.098	34.474	30.878	32.507	31.262	29.287	33.987
Average Debt	**429.204**	**463.183**	**494.765**	**517.001**	**534.377**	**550.781**	**567.410**	**583.665**	**599.190**	**613.938**
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	77.218	79.974	83.351	89.094	95.995	102.817	109.513	116.614	123.850	130.705
Average Equity	**198.468**	**201.223**	**204.601**	**210.344**	**217.245**	**224.066**	**230.762**	**237.864**	**245.100**	**251.954**
Average Debt	429.204	463.183	494.765	517.001	534.377	550.781	567.410	583.665	599.190	613.938
Average Equity	198.468	201.223	204.601	210.344	217.245	224.066	230.762	237.864	245.100	251.954
Average Debt and Equity	627.672	664.407	699.366	727.345	751.622	774.847	798.172	821.528	844.290	865.893
PUB Approved Equity Ratio	**31.62%**	**30.29%**	**29.26%**	**28.92%**	**28.90%**	**28.92%**	**28.91%**	**28.95%**	**29.03%**	**29.10%**

GAS OPERATIONS (CGM18)
PROJECTED FINANCIAL RATIOS
CGM18 - FRP Disbursed over 3 Years Starting Nov 1, 2019

For the year ended March 31

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
INTEREST COVERAGE										
Net Income	3.255	2.256	4.499	6.987	6.815	6.827	6.565	7.638	6.834	6.876
Finance Expense	20.496	22.245	24.025	25.243	26.160	27.656	28.877	29.756	31.482	32.332
Capitalized Interest	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	23.922	24.739	28.775	32.362	33.010	34.518	35.478	37.431	38.353	39.247
Finance Expense	20.496	22.245	24.025	25.243	26.160	27.656	28.877	29.756	31.482	32.332
Capitalized Interest	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	20.667	22.482	24.276	25.375	26.195	27.691	28.913	29.793	31.519	32.371
Interest Coverage	**1.16**	**1.10**	**1.19**	**1.28**	**1.26**	**1.25**	**1.23**	**1.26**	**1.22**	**1.21**
Add: Depreciation and Amortization *	34.899	36.694	38.540	38.811	40.399	40.930	42.096	42.256	43.428	43.831
Total EBITDA	58.821	61.433	67.315	71.173	73.409	75.448	77.574	79.686	81.781	83.078
EBITDA Interest Coverage	**2.85**	**2.73**	**2.77**	**2.80**	**2.80**	**2.72**	**2.68**	**2.67**	**2.59**	**2.57**

* Includes amortization of deferred income tax

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
CAPITAL COVERAGE										
Internally Generated Funds	23.554	22.323	33.070	39.774	43.339	44.090	45.356	46.479	48.453	48.971
Capitalized Interest*	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	23.725	22.561	33.321	39.906	43.374	44.126	45.392	46.516	48.490	49.009
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	**0.67**	**0.56**	**0.87**	**1.02**	**1.09**	**1.09**	**1.10**	**1.10**	**1.13**	**1.12**

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

GAS OPERATIONS (CGM18)
PROJECTED OPERATING STATEMENT
CGM18 - FRP Disbursed over 5 Years Starting Nov 1, 2019
(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	28	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	159	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	3	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

** 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%	30%	29%	29%	29%	29%	29%	29%	29%	29%

GAS OPERATIONS (CGM18)
PROJECTED BALANCE SHEET
CGM18 - FRP Disbursed over 5 Years Starting Nov 1, 2019
(In Millions of Dollars)

For the year ended March 31

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
ASSETS										
Plant in Service	622	658	698	737	776	814	854	894	935	977
Accumulated Depreciation	(65)	(79)	(95)	(112)	(130)	(148)	(168)	(187)	(208)	(229)
Net Plant in Service	557	579	603	626	646	666	686	707	727	747
Construction in Progress	6	9	6	4	4	4	4	4	4	4
Current and Other Assets	92	92	92	92	92	92	92	92	92	92
Goodwill and Intangible Assets	10	9	9	9	9	9	9	9	9	9
Total Assets before Regulatory Deferral	665	689	710	730	751	771	791	812	832	853
Regulatory Deferral Balance	106	109	113	116	118	121	123	126	128	130
	771	798	823	846	869	891	914	937	960	983
LIABILITIES AND EQUITY										
Long-Term Debt	390	450	470	470	500	530	505	555	565	585
Current and Other Liabilities	122	93	92	107	92	75	114	79	84	78
Deferred Revenue	47	49	49	50	52	55	57	58	59	60
Share Capital	121	121	121	121	121	121	121	121	121	121
Retained Earnings	79	81	86	93	100	106	113	121	128	135
Total Liabilities and Equity before Regulatory Deferral	759	794	818	842	864	887	910	933	957	979
Regulatory Deferral Balance	12	5	4	4	4	4	4	4	4	3
	771	798	823	846	869	891	914	937	960	983
Net Debt	443	478	502	522	541	559	576	591	606	621
Equity (PUB Approved Methodology)	32%	30%	29%	29%	29%	29%	29%	29%	29%	29%

GAS OPERATIONS (CGM18)
PROJECTED CASH FLOW STATEMENT
CGM18 - FRP Disbursed over 5 Years Starting Nov 1, 2019
(In Millions of Dollars)

For the year ended March 31	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
OPERATING ACTIVITIES										
Net Income	3	2	5	7	7	7	7	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	28	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	(11)	(12)	(6)	(6)	(5)	(3)	(1)	(1)	(0)	(0)
Interest Paid	(33)	(35)	(37)	(38)	(39)	(40)	(41)	(43)	(44)	(45)
Cash Provided by Operating Activities	25	25	35	38	40	43	45	46	49	49
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	40	60	20	20	40	30	10	50	20	20
Retirement of Long-Term Debt	-	(20)	-	-	(20)	(10)	-	(35)	-	(10)
Cash Provided by Financing Activities	40	40	20	20	20	20	10	15	20	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	11	5	(3)	0	1	2	(7)	(1)	5	(4)
Cash at Beginning of Year	(44)	(33)	(28)	(32)	(32)	(31)	(29)	(36)	(37)	(31)
Cash at End of Year	(33)	(28)	(32)	(32)	(31)	(29)	(36)	(37)	(31)	(36)

GAS OPERATIONS (CGM18)
PROJECTED FINANCIAL RATIOS
CGM18 - FRP Disbursed over 5 Years Starting Nov 1, 2019

For the year ended March 31

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
PUB APPROVED DEBT TO EQUITY RATIO										
Average Long-Term Debt	389.903	429.903	459.903	479.903	499.903	519.903	534.903	547.403	564.903	579.952
Average Due to Parent	38.574	30.707	30.000	31.727	31.464	30.143	32.344	36.092	34.038	33.654
Average Debt	**428.477**	**460.610**	**489.903**	**511.630**	**531.367**	**550.046**	**567.247**	**583.495**	**598.941**	**613.606**
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	77.221	79.984	83.378	89.189	96.159	102.999	109.705	116.814	124.131	131.070
Average Equity	**198.471**	**201.234**	**204.627**	**210.439**	**217.409**	**224.248**	**230.955**	**238.064**	**245.380**	**252.320**
Average Debt	428.477	460.610	489.903	511.630	531.367	550.046	567.247	583.495	598.941	613.606
Average Equity	198.471	201.234	204.627	210.439	217.409	224.248	230.955	238.064	245.380	252.320
Average Debt and Equity	626.948	661.844	694.530	722.069	748.776	774.294	798.202	821.559	844.321	865.925
PUB Approved Equity Ratio	**31.66%**	**30.41%**	**29.46%**	**29.14%**	**29.04%**	**28.96%**	**28.93%**	**28.98%**	**29.06%**	**29.14%**

GAS OPERATIONS (CGM18)
PROJECTED FINANCIAL RATIOS
CGM18 - FRP Disbursed over 5 Years Starting Nov 1, 2019

For the year ended March 31

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
INTEREST COVERAGE										
Net Income	3.259	2.267	4.521	7.102	6.837	6.841	6.572	7.645	6.989	6.890
Finance Expense	20.499	22.253	24.033	25.151	26.144	27.641	28.870	29.749	31.327	32.319
Capitalized Interest	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	23.929	24.757	28.805	32.385	33.016	34.518	35.478	37.431	38.353	39.247
Finance Expense	20.499	22.253	24.033	25.151	26.144	27.641	28.870	29.749	31.327	32.319
Capitalized Interest	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	20.670	22.490	24.284	25.283	26.178	27.677	28.906	29.786	31.364	32.357
Interest Coverage	**1.16**	**1.10**	**1.19**	**1.28**	**1.26**	**1.25**	**1.23**	**1.26**	**1.22**	**1.21**
Add: Depreciation and Amortization *	34.899	36.694	38.540	38.811	40.399	40.930	42.096	42.256	43.428	43.831
Total EBITDA	58.828	61.451	67.345	71.196	73.414	75.448	77.574	79.686	81.781	83.078
EBITDA Interest Coverage	**2.85**	**2.73**	**2.77**	**2.82**	**2.80**	**2.73**	**2.68**	**2.68**	**2.61**	**2.57**

* Includes amortization of deferred income tax

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
CAPITAL COVERAGE										
Internally Generated Funds	25.007	24.563	35.409	38.454	39.938	42.941	45.361	46.485	48.607	48.983
Capitalized Interest*	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	25.178	24.801	35.660	38.586	39.973	42.977	45.397	46.522	48.645	49.021
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	**0.71**	**0.62**	**0.93**	**0.99**	**1.00**	**1.06**	**1.10**	**1.10**	**1.13**	**1.12**

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

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.

REFERENCE:

Tab 3 – Section 3.1.5 Update to Centra's Return on Equity (pg 4-6), Appendix 3.5 – Evidence of Drazen Consulting Group Inc.

PREAMBLE TO IR (IF ANY):

On Page 4 of Tab 3, lines 17 to 19, Centra states that while return on equity is not an explicit assumption used in the preparation of CGM18, return on equity and the associated return on rate base inform the appropriate level of earnings under the cost of service determination of revenue requirement in CGM18.

On Page 5 of Tab 3, lines 4 to 7, Centra states that to respond to directive 8 from Order 85/13, for Centra to provide an update to the return on equity, Centra retained the regulatory expertise of Drazen Consulting Group Inc. (DCGI) to evaluate and recommend an appropriate return on equity and level of annual net earnings for Centra beyond the 2019/20 Test Year. DCGI's expert evidence is provided in Appendix 3.5 of the Application. On page 95 of Order 128/09, the PUB found the following with respect to the Corporate Allocation and Net Income:

"Consistent with the position of the Board presented in prior Orders, the Board will continue to restrict MH's return from Centra to $15 million, on a weather-normalized basis, with $12 million of that being paid to MH annually in the form of a Corporate Allocation and the other approximately $3 million being in the form of annual Net Income to be retained within Centra."

On page 27 of Order 85/13, the PUB found the following with respect to the fair return to Manitoba Hydro related to Centra Gas:

"The Board is not convinced that Centra requires a higher Net Income than has previously been approved, meaning $3 million per year. The Board has ruled that the Corporate Allocation forms part of the return to Centra and that a return of $14 to $16 million represents a fair return to Manitoba Hydro."

QUESTION:

a) Please confirm that the appropriate level of Net Income for Centra under a cost of service rate-setting framework has been previously determined by the PUB in a number of prior regulatory decisions to be $3 million.
b) Please also confirm that the PUB has also ruled in a number of prior regulatory decisions, that the $12 million Corporate Allocation also forms part of the return to Centra and that the total return to Centra of $14 to $16 million per year represents a fair return to Manitoba Hydro.
c) Please explain if Centra is requesting any approvals or direction from the PUB in the current regulatory proceeding with respect to the level of net earnings beyond the 2019/20 Test Year.

RATIONALE FOR QUESTION:

To obtain information to assess Mr. Drazen's qualifications to provide cost of capital and capital structure evidence and obtain further details to understand the information and analysis that he has relied on in order provide his recommendations with respect to the appropriate ROE and capital structure of Centra.

RESPONSE:

a) Confirmed. Centra notes that the PUB has also determined in past Orders that a 30% equity target is appropriate for Centra. Please see section 3.4 of Tab 3 of Centra's Application for a discussion on the application of the PUB established financial parameters for Centra beyond 2019/20.

b) Confirmed.

c) Centra is not requesting any approvals in the current Application for years beyond the 2019/20 Test Year.

REFERENCE:

Tab 3 – Section 3.1.5 Update to Centra's Return on Equity (pg 4-6), Appendix 3.5 – Evidence of Drazen Consulting Group Inc.

PREAMBLE TO IR (IF ANY):

On Page 4 of Tab 3, lines 17 to 19, Centra states that while return on equity is not an explicit assumption used in the preparation of CGM18, return on equity and the associated return on rate base inform the appropriate level of earnings under the cost of service determination of revenue requirement in CGM18.

On Page 5 of Tab 3, lines 4 to 7, Centra states that to respond to directive 8 from Order 85/13, for Centra to provide an update to the return on equity, Centra retained the regulatory expertise of Drazen Consulting Group Inc. (DCGI) to evaluate and recommend an appropriate return on equity and level of annual net earnings for Centra beyond the 2019/20 Test Year. DCGI's expert evidence is provided in Appendix 3.5 of the Application. On page 95 of Order 128/09, the PUB found the following with respect to the Corporate Allocation and Net Income:

"Consistent with the position of the Board presented in prior Orders, the Board will continue to restrict MH's return from Centra to $15 million, on a weather-normalized basis, with $12 million of that being paid to MH annually in the form of a Corporate Allocation and the other approximately $3 million being in the form of annual Net Income to be retained within Centra."

On page 27 of Order 85/13, the PUB found the following with respect to the fair return to Manitoba Hydro related to Centra Gas:

"The Board is not convinced that Centra requires a higher Net Income than has previously been approved, meaning $3 million per year. The Board has ruled that the Corporate Allocation forms part of the return to Centra and that a return of $14 to $16 million represents a fair return to Manitoba Hydro."

QUESTION:

d) Appendix A to the DCGI's evidence, Mr. Drazen's curriculum vitae, indicates that DCGI's work covers all aspects of utility regulation, including cost of capital. Appendix A does not outline Mr. Drazen's or DCGI's experience and qualifications with respect to providing expert evidence on cost of capital, rate of return on equity or capital structure issues. Please provide a detailed listing of (i) Mr. Drazen's and (ii) DCGI's engagements where he or his firm has provided expert evidence with respect to cost of capital, rate of return on equity or capital structure issues to regulatory tribunals, intervenors or applicant utilities, including a description of the nature of the engagement. Please also include (iii) the final determination of the regulatory tribunal with respect to cost of capital, rate of return on equity or capital structure matters.

e) With respect to Table 1 on Page 5 of Mr. Drazen's evidence, please provided the detailed calculations to support the Centra capital requirements for the next 5 and 10 years.

f) Mr. Drazen states on lines 3 to 5 of Page 6 of his evidence that "…net earnings of $3 million per year, which has been the authorized level for the last several years, will not be sufficient to finance the requisite portion of Centra's future and growing capital needs". Please explain if Mr. Drazen is aware that the $12 million Corporate Allocation forms part of the earnings to finance Centra's future capital needs and if this source of funding has been factored into his analysis and conclusions in Appendix 3.5.

g) Mr. Drazen states on lines 22 to 24 of Page 6 of his evidence that "In the case of Centra, the PUB in the past set the net earnings target for 2005/06 an 2006/07 based on pre-acquisition earnings. As time went on, this amount became less and less related to capital requirements." Please confirm that the overall return ($) is a function of two factors (i) the level of capital investment and (ii) the level of the overall rate of return. Please also confirm if Mr. Drazen is aware that the $14 to $16 million of overall return to Manitoba Hydro that is embedded in Centra's rates was determined by the PUB at a time (pre-acquisition) when interest rates and return on equity levels (ROE) were higher than current circumstances.

h) Please provide the detailed calculations to support Mr. Drazen's analysis with respect to Table 3 - Net Earnings and Table 4 - Equity Ratio on Page 13 of his evidence.

i) Please provide the detailed calculations to support Mr. Drazen's analysis (i) on lines 3 to 5 on Page 14 that "By 2023, Centra will require $20 million more borrowing in the "$3 million" case than in the "8.7% ROE" case. By 2028, the difference is $50 million." And (ii) on lines 12 to 15 on Page 14 that "This showed that calculating Centra's revenue requirement using a deemed 30% equity ratio and a 8.5% ROE would meet its financial needs and result in overall distribution cost increases of about one percentage point higher than the current $3 million earnings target."

j) On page 14, lines 10 to 11 of Mr. Drazen's evidence, he states that "Centra has higher risk than SaskEnergy because of greater income variability and a lower equity ratio." Please outline the evidence that Mr. Drazen is relying on to make this conclusion and explain if Mr. Drazen has undertaken a comprehensive review of the relative risks of Centra and SaskEnergy, as is commonly used by cost of capital experts to make recommendations to regulatory tribunals with respect to ROE and capital structure. Please indicate if Mr. Drazen is aware that in last full decision on cost of capital and capital structure that the PUB found that Centra's risks are on balance, below the average of risks of Canadian gas LDC's (Order 8/94, Section 9.5.6, Page 42).

k) On page 4, lines 27 to 29 of Mr. Drazen's evidence, he states that "a reasonable and effective approach over the next 5-10 years is to base net earnings on a deemed 30% equity ratio and a return on equity in the range of 8.3%-8.5%." Please explain if Mr. Drazen is relying solely on the one-year benchmarking of the approved ROE's of other Canadian Gas Distributors from Table 2, Page 8 of his evidence to come to this conclusion, or if he has performed any of the traditional cost of capital regulatory tests (CAPM, Risk Premium, DCF, Comparable Earnings) that are commonly used by cost of capital experts to recommend the appropriate range of ROE's to regulatory tribunals.

l) On page 17, lines 12 to 13 of Mr. Drazen's evidence, he states that "…Centra's equity ratio has been close to the 30% target equity ratio, so there should be no concern about "over-earning". Please provide the analysis that Mr. Drazen is relying on to make this conclusion about Centra's historical performance with respect to its equity ratio.

m) Please explain if Mr. Drazen has conducted any comparative risk analysis to reconcile a recommendation of a 30% equity ratio for Centra with Manitoba Hydro's consolidated equity ratio target of 25%.

RATIONALE FOR QUESTION:

To obtain information to assess Mr. Drazen's qualifications to provide cost of capital and capital structure evidence and obtain further details to understand the information and analysis that he has relied on in order provide his recommendations with respect to the appropriate ROE and capital structure of Centra.

RESPONSE:

Responses to parts d) through m) were provided by Mr. Drazen:

d) DCGI's engagements regarding these issues fall into two categories. For the most part, the evidence of Ms. Billie Sue LaConte ("BSL") dealt with return on equity issues for investor-owned utilities. The work by Mr. Drazen ("MD") involved "non-standard" issues, where conventional return on equity methods did not readily apply. Except for the work for Edmonton Drainage (the wastewater and stormwater utility in Edmonton, owned by the City), all engagements were to prepare evidence.

	Utility	**Year**	**Juris.**	**Case #**	**Issue**
MD	Citizens Electric Corp.	1979-80	Missouri	E80-24 E-81-78	Return for an electric cooperative
BSL	Interstate Power and Light	2002	Iowa	RPU-02-03	Return on equity
BSL	Metropolitan St. Louis Sewer District (MSD)	2002	MSD	(None)	Capital financing
MD, BSL	Entrega Gas Pipeline	2004	FERC	CP04-413-000	Rate of return
BSL	Nova Scotia Power Inc.	2004	Nova Scotia	P-881	Return on equity
MD, BSL	Edmonton Drainage	2006	Edmonton City Council	Report	Fiscal policy
BSL	AmerenUE	2007	Missouri	ER-2007-0002	Return on equity
MD, BSL	Metropolitan St. Louis Sewer District	2007	MSD	(None)	Long-term Financial Plan Capital Financing
BSL	AmerenUE	2008	Missouri	ER-2008-0318	Return on equity
MD	Nova Scotia Power Inc.	2009	Nova Scotia	M01737	Return on equity
BSL	Entergy Arkansas	2010	Arkansas	09-084-U	Return on equity
MD	Halifax Regional Water Commission	2010	Nova Scotia		Funding policy
BSL	AmerenUE	2011	Missouri	ER-2011-0028	Return on equity
BS	Missouri-American Water Company	2011	Missouri	WR-201-337, WR-201-0338	Return on equity
MD	Halifax Regional Water Comm.	2013	Nova Scotia	M05463	Funding Policy

Final determinations by the applicable tribunal, where available, may be located on the relevant tribunal website. Note that some of these proceedings ended with a settlement. The Metropolitan St. Louis Sewer District is self-regulating.

e) The year-by-year amounts are:

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
PP&E	$42.0	$47.1	$45.6	$46.5	$47.5	$48.5	$49.5	$50.5	$51.5	$52.5
Intan. & other	12.2	12.8	13.5	12.2	12.1	12.5	12.6	12.2	12.2	11.1
FRP	--	23.7	--	--	--	--	--	--	--	--
Debt	--	20.0	--		20.0	10.0		35.0	9.9	
Total	$54.1	$103.6	$59.1	$58.6	$79.6	$71.0	$62.1	$97.6	$63.7	$75.5

These are later figures than were used in the evidence. Updated Table 1 is below:

Table 1 (Updated)		
Centra Capital Requirements ($Millions)		
	5 Years	10 Years
Property, plant & equipment	$228.7	$481.1
Intangible assets & other	62.6	123.2
Furnace replacement plan disposition	23.7	23.7
Total	$355.0	$722.9

f) In Order No. 128/09 the Board said that the amount to be retained by Centra is $3 million:

> *Consistent with the position of the Board presented in prior Orders, the Board will continue to restrict* ***MH's return from Centra to $15 million****, on a weather-normalized basis, with* ***$12 million of that being paid to MH annuall****y in the form of a Corporate Allocation and the other* ***approximately $3 million being in the form of annual Net Income to be retained within Centra****.* (Page 95, emphasis added.)

g) In the last several years the overall return for Centra was set at a constant $3 million, not as the product of the capital investment (rate base) and rate of return.

Interest rates and RoE levels were higher at the time Manitoba Hydro acquired Centra. The net plant in service and forecast capital expenditures are also higher now than at the time of acquisition. In 1995 net plant in service was $238 million (as requested by Centra). In 2018/19 the net plant is about $520 million.

h) The numbers shown are outputs of Centra's financial model CGM18. Centra ran its model using different scenarios at DCGI's request. The results shown in the evidence were summaries of the scenario runs.

i) This was calculated by Centra's financial model. A comparison of the "8.7%" and "$3 million" scenarios is below:

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

Please see the attachment to this response, page 3 for the calculation that shows a 30% equity ratio.

j) The basis was as explained in the evidence. The observation in Order 8/94 that Centra's risks are below the average of other Canadian LDCs does not mean that Centra should have a RoE lower than the lowest other LDC.

k) The primary basis for recommending a RoE of 8.3%-8.5% was that a RoE in this range will enable Centra to maintain a 30% equity ratio.

The initial step of checking the returns of all other Canadian LDCs was to identify the range of results found appropriate for all other Canadian local distribution companies. Note that this explicitly represents a "comparable earnings" test. Then, Centra was requested to run various forecast scenarios with variations on financial parameters. These were:

- RoE of 8.3%
- RoE of 8.5%
- RoE of 8.7%
- Return at fixed $3 million annually

Centra also ran scenarios with higher interest rates as a test.

l) Centra's equity ratio in 2011/12 was 34%. Its equity ratio at the end of 2016/17 was 33%. Hence, the years of higher income due to colder weather did not materially increase Centra's equity ratio.

m) No. The focus was on Centra's needs.

SCENARIO:
CGM18 - 8.5% ROE starting in 2018/19

GAS OPERATIONS (CGM18)
PROJECTED FINANCIAL RATIOS

For the year ended March 31	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
PUB APPROVED DEBT TO EQUITY RATIO										
Opening Long-Term Debt	369.903	409.903	429.903	469.903	489.903	499.903	519.903	529.903	544.903	564.903
Long-Term Debt	409.903	429.903	469.903	489.903	499.903	519.903	529.903	544.903	564.903	575.000
Average Long-Term Debt	389.903	419.903	449.903	479.903	494.903	509.903	524.903	537.403	554.903	569.952
Opening Short-Term Debt	37.300	21.275	29.198	24.423	21.759	27.447	23.304	28.446	27.678	20.406
Opening Short-Term Investments	-	-	-	-	-	-	-	-	-	-
Opening Non-Interest Bearing Short-Term Debt	6.706	6.706	6.706	6.706	6.706	6.706	6.706	6.706	6.706	6.706
Short-Term Debt	21.275	29.198	24.423	21.759	27.447	23.304	28.446	27.678	20.406	21.745
Short-Term Investments	-	-	-	-	-	-	-	-	-	-
Non-Interest Bearing Short-Term Debt	6.706	6.706	6.706	6.706	6.706	6.706	6.706	6.706	6.706	6.706
Average Due to Parent	35.993	31.942	33.516	29.797	31.309	32.081	32.581	34.768	30.748	27.782
Average Debt	**425.896**	**451.845**	**483.419**	**509.700**	**526.212**	**541.984**	**557.484**	**572.171**	**585.651**	**597.733**
Opening Share Capital	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250
Share Capital	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250
Average Share Capital	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250
Opening Retained Earnings	75.591	81.607	87.821	94.120	100.595	107.782	115.485	123.430	132.816	141.989
Retained Earnings	81.607	87.821	94.120	100.595	107.782	115.485	123.430	132.816	141.989	151.849
Average Retained Earnings	78.599	84.714	90.971	97.357	104.188	111.633	119.458	128.123	137.403	146.919
Average Equity	**199.849**	**205.964**	**212.220**	**218.607**	**225.438**	**232.883**	**240.707**	**249.373**	**258.652**	**268.169**
Average Debt	425.896	451.845	483.419	509.700	526.212	541.984	557.484	572.171	585.651	597.733
Average Equity	199.849	205.964	212.220	218.607	225.438	232.883	240.707	249.373	258.652	268.169
Average Debt and Equity	625.745	657.809	695.640	728.307	751.650	774.867	798.191	821.544	844.304	865.902
PUB Approved Equity Ratio	**31.94%**	**31.31%**	**30.51%**	**30.02%**	**29.99%**	**30.05%**	**30.16%**	**30.35%**	**30.64%**	**30.97%**

REFERENCE:

Tab 3 – Section 3.1.5 Update to Centra's Return on Equity (pg 4-6) and Appendix 3.6 – CGM18 & Financial Ratios – Updated for 2018/19 & 2019/20

PREAMBLE TO IR (IF ANY):

On Page 1 of Appendix 3.6, Centra is projecting a 32% Equity ratio for the 2019/20 Test Year.

The PUB has previously ruled (Page 27 of Order 85/13) that a 30% Equity ratio is appropriate for rate-setting purposes.

QUESTION:

a) Please provide a CGM18 scenario (including the projected financial ratio calculations) assuming a non-gas revenue requirement change that would result in a projected Equity ratio (PUB Approved Methodology) of 30% for 2019/20.

RATIONALE FOR QUESTION:

To understand the impacts to the non-gas revenue requirement, rate impact calculations and rate base/rate of return calculations if Centra was to target the PUB approved Equity ratio of 30% in 2019/20 for rate-setting.

RESPONSE:

A 7.99% rate decrease (assuming August 1st implementation) would be required to precisely achieve the 30% equity ratio in 2019/20 using the Approved Budget as provided in Appendix 3.6 of the Application. This would result in a net loss of $20 million in the 2019/20 test year. A 7.99% rate decrease in 2019/20 will undoubtedly result in a net loss in the subsequent year that would require a rate increase greater than 7.99% simply to breakeven. The financial statements and financial ratios are provided below.

GAS OPERATIONS
PROJECTED OPERATING STATEMENT
Rate Increase to reach 30% Equity Ratio in 2019/20
(In Millions of Dollars)

For the year ended March 31	**Current 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***	-	(22)
	343	300
Weighted Average Cost of Gas Sold **	193	174
Gross Margin	150	127
Other	2	2
	152	129
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	2	(21)
Net Movement in Regulatory Deferral **	2	1
Net Income	4	(20)

* 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%	-7.99%
Cumulative Percent Increase	0.00%	-7.99%
Equity Ratio (PUB Approved Methodology)	32%	30%
EBITDA Interest Coverage	2.91	1.78
Capital Coverage	1.41	0.00

GAS OPERATIONS
PROJECTED BALANCE SHEET
Rate Increase to reach 30% Equity Ratio in 2019/20
(In Millions of Dollars)

For the year ended March 31	Current Outlook 2019	Approved Budget 2020
ASSETS		
Plant in Service	622	658
Accumulated Depreciation	(65)	(79)
Net Plant in Service	557	579
Construction in Progress	6	9
Current and Other Assets	86	85
Goodwill and Intangible Assets	10	9
Total Assets before Regulatory Deferral	659	682
Regulatory Deferral Balance	106	107
	765	789
LIABILITIES AND EQUITY		
Long-Term Debt	370	440
Current and Other Liabilities	120	106
Deferred Revenue	47	49
Share Capital	121	121
Retained Earnings	80	60
Total Liabilities and Equity before Regulatory Deferral	738	776
Regulatory Deferral Balance	26	12
	765	789
Net Debt	418	476
Equity (PUB Approved Methodology)	32%	30%

GAS OPERATIONS
PROJECTED CASH FLOW STATEMENT
Rate Increase to reach 30% Equity Ratio in 2019/20
(In Millions of Dollars)

For the year ended March 31	Current Outlook 2019	Approved Budget 2020
OPERATING ACTIVITIES		
Net Income	4	(20)
Add Back:		
Depreciation and Amortization	24	25
Finance Expense	22	23
Net Movement Impacts on Depreciation and Finance Expense	10	10
Adjustments for Non-Cash Items	11	11
Adjustments for Changes in Non-Cash Working Capital Accounts	12	(16)
Interest Paid	(33)	(34)
Cash Provided by Operating Activities	50	(0)
FINANCING ACTIVITIES		
Proceeds from Long-Term Debt	20	70
Retirement of Long-Term Debt	-	(20)
Cash Provided by Financing Activities	20	50
INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(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	(8)
Cash at Beginning of Year	(44)	(28)
Cash at End of Year	(28)	(36)

GAS OPERATIONS
PROJECTED FINANCIAL RATIOS
Rate Increase to reach 30% Equity Ratio in 2019/20

For the year ended March 31	**Current Outlook 2019**	**Proposed Budget 2020**
PUB APPROVED DEBT TO EQUITY RATIO		
Average Long-Term Debt	379.903	414.903
Average Due to Parent	36.019	31.940
Average Debt	**415.922**	**446.843**
Average Share Capital	121.250	121.250
Average Retained Earnings	77.808	70.254
Average Equity	**199.058**	**191.504**
Average Debt	415.922	446.843
Average Equity	199.058	191.504
Average Debt and Equity	614.979	638.346
PUB Approved Equity Ratio	**32.37%**	**30.00%**

GAS OPERATIONS
PROJECTED FINANCIAL RATIOS
Rate Increase to reach 30% Equity Ratio in 2019/20

For the year ended March 31	2019	2020
INTEREST COVERAGE		
Net Income	4.434	(19.541)
Finance Expense	20.408	21.713
Capitalized Interest	0.171	0.237
	25.013	2.409
Finance Expense	20.408	21.713
Capitalized Interest	0.171	0.237
	20.579	21.950
Interest Coverage	**1.22**	**0.11**
Add: Depreciation and Amortization *	34.893	36.672
Total EBITDA	59.906	39.081
EBITDA Interest Coverage	**2.91**	**1.78**

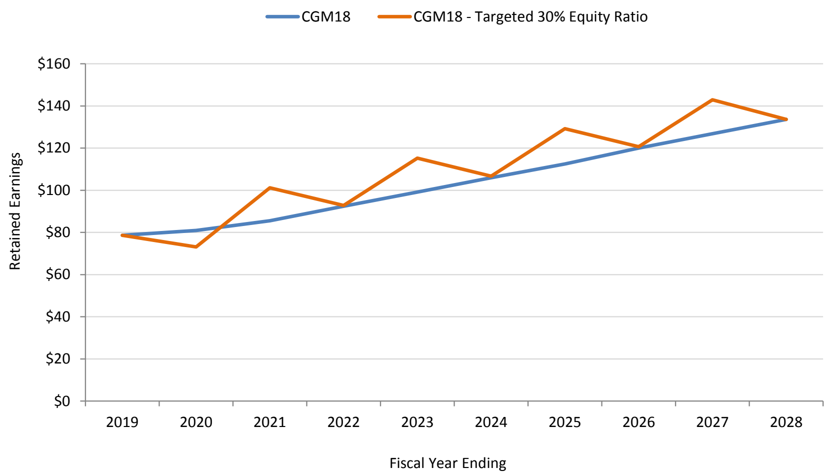
* Includes amortization of deferred income tax

	2019	2020
CAPITAL COVERAGE		
Internally Generated Funds	49.771	(0.112)
Capitalized Interest*	0.171	0.237
	49.942	0.126
Net Capital Construction Expenditures	35.404	40.075
Capital Coverage	**1.41**	**0.00**

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

Centra is not seeking a general revenue increase in 2019/20 and CGM18 (Appendix 3.1 of the Application) demonstrates a trend towards the 30% equity level target that the PUB has previously ruled sufficient for Centra. Adjusting rates in 2019/20 to precisely achieve the 30% PUB approved equity ratio has the potential to trigger "saw-tooth" like erratic rate increases and decreases in subsequent years to maintain the 30% ratio. The scenario presented below that precisely achieves the 30% equity ratio target in each and every year of the forecast is simply for demonstration purposes and does represent a realistic scenario for either the customer or for the utility.

CGM18 contains relatively smooth indicative rate increases over a 10-year period to remain at approximately the 30% equity ratio target level and results in a gradual growth to the retained earnings balance. The figure below compares the growth to the retained earnings balance contained in CGM18 with the scenario presented below that precisely achieves the 30% equity ratio target in each and every year of the forecast. The figure demonstrates the potential "saw-tooth" impact to annual earnings over the 10-year forecast period precisely targeting a 30% equity ratio, which ultimately arrives at the same retained earnings balance of $134 million by 2027/28 as in CGM18.



GAS OPERATIONS (CGM18)
PROJECTED OPERATING STATEMENT
CGM18 - Goal Seek rates to maintin 30% PUB Approved equity ratio
(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***	0	(8)	30	(6)	30	1	37	8	43	15
	308	300	346	311	346	317	353	323	358	329
Weighted Average Cost of Gas Sold **	159	158	166	166	165	165	164	163	162	163
Gross Margin	149	142	180	145	181	153	189	160	196	167
Other	2	2	2	2	2	2	2	2	2	2
	151	144	182	147	183	155	191	162	198	169
EXPENSES										
Operating and Administrative	63	61	62	63	64	65	66	68	69	70
Finance Expense	22	24	25	26	27	28	30	30	32	32
Depreciation and Amortization	24	25	27	28	29	31	31	32	33	34
Capital and Other Taxes	17	17	18	18	19	19	20	20	21	21
Other Expenses	12	13	13	12	12	12	12	12	12	11
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
	150	152	158	159	163	166	171	173	178	180
Net Income before Net Movement in Regulatory Deferral	1	(9)	25	(12)	20	(11)	20	(11)	20	(11)
Net Movement in Regulatory Deferral **	3	3	3	3	3	3	2	3	3	2
Net Income	3	(5)	28	(8)	22	(9)	23	(9)	22	(9)

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

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

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
******Additional Revenue Requirement***										
Percent Increase	0.00%	-2.85%	14.92%	-14.81%	17.76%	-12.88%	16.96%	-12.90%	16.78%	-12.51%
Cumulative Percent Increase	0.00%	-2.85%	11.65%	-4.88%	12.01%	-2.42%	14.13%	-0.59%	16.09%	1.57%
Financial Ratios										
Equity Ratio (PUB Approved Methodology)	32%	30%	30%	30%	30%	30%	30%	30%	30%	30%
EBITDA Interest Coverage	2.85	2.39	3.72	2.23	3.39	2.20	3.24	2.16	3.09	2.10
Capital Coverage	0.78	0.50	1.20	0.66	1.50	0.70	1.49	0.71	1.49	0.74

GAS OPERATIONS (CGM18)
PROJECTED BALANCE SHEET
CGM18 - Goal Seek rates to maintin 30% PUB Approved equity ratio
(In Millions of Dollars)

For the year ended March 31	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
ASSETS										
Plant in Service	622	658	698	737	776	814	854	894	935	977
Accumulated Depreciation	(65)	(79)	(95)	(112)	(130)	(148)	(168)	(187)	(208)	(229)
Net Plant in Service	557	579	603	626	646	666	686	707	727	747
Construction in Progress	6	9	6	4	4	4	4	4	4	4
Current and Other Assets	92	92	92	92	92	92	92	92	92	92
Goodwill and Intangible Assets	10	9	9	9	9	9	9	9	9	9
Total Assets before Regulatory Deferral	665	689	710	730	751	771	791	812	832	853
Regulatory Deferral Balance	106	109	113	116	118	121	123	126	128	130
	771	798	823	846	869	891	914	937	960	983
LIABILITIES AND EQUITY										
Long-Term Debt	390	450	460	470	480	530	495	555	545	585
Current and Other Liabilities	122	101	86	107	96	75	108	78	88	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	73	101	93	115	107	129	121	143	134
Total Liabilities and Equity before Regulatory Deferral	759	794	818	842	864	887	910	933	957	979
Regulatory Deferral Balance	12	5	4	4	4	4	4	4	4	3
	771	798	823	846	869	891	914	937	960	983
Net Debt	441	480	493	526	526	559	559	591	591	622
Equity (PUB Approved Methodology)	32%	30%	30%	30%	30%	30%	30%	30%	30%	30%

GAS OPERATIONS (CGM18)
PROJECTED CASH FLOW STATEMENT
CGM18 - Goal Seek rates to maintin 30% PUB Approved equity ratio
(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	(5)	28	(8)	22	(9)	23	(9)	22	(9)
Add Back:										
Depreciation and Amortization	24	25	27	28	29	31	31	32	33	34
Finance Expense	22	24	25	26	27	28	30	30	32	32
Net Movement Impacts on Depreciation and Finance Expense	10	10	11	10	10	9	10	10	10	9
Adjustments for Non-Cash Items	11	11	11	11	11	11	11	11	11	11
Adjustments for Changes in Non-Cash Working Capital Accounts	(9)	(9)	(19)	(3)	(1)	(2)	(1)	(2)	0	(0)
Interest Paid	(33)	(35)	(37)	(37)	(39)	(40)	(41)	(42)	(44)	(44)
Cash Provided by Operating Activities	27	20	46	26	59	28	62	30	64	32
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	40	60	10	30	20	50	-	60	-	40
Retirement of Long-Term Debt	-	(20)	-	-	(20)	(10)	-	(35)	-	(10)
Cash Provided by Financing Activities	40	40	10	30	-	40	-	25	-	30
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	0	(3)	(3)	0	7	(0)	(8)	1	(1)
Cash at Beginning of Year	(44)	(31)	(30)	(34)	(36)	(36)	(29)	(29)	(37)	(36)
Cash at End of Year	(31)	(30)	(34)	(36)	(36)	(29)	(29)	(37)	(36)	(37)

GAS OPERATIONS (CGM18)
PROJECTED FINANCIAL RATIOS
CGM18 - Goal Seek rates to maintin 30% PUB Approved equity ratio

For the year ended March 31	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
PUB APPROVED DEBT TO EQUITY RATIO										
Average Long-Term Debt	389.903	429.903	454.903	474.903	489.903	509.903	529.903	542.403	554.903	569.952
Average Due to Parent	37.383	30.618	31.988	34.897	36.255	32.508	28.836	32.689	36.125	36.199
Average Debt	**427.286**	**460.521**	**486.891**	**509.800**	**526.158**	**542.411**	**558.739**	**575.092**	**591.028**	**606.151**
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	76.117	87.418	97.236	104.246	111.212	118.210	125.218	132.048	138.529
Average Equity	**198.474**	**197.366**	**208.668**	**218.486**	**225.496**	**232.462**	**239.460**	**246.468**	**253.298**	**259.779**
Average Debt	427.286	460.521	486.891	509.800	526.158	542.411	558.739	575.092	591.028	606.151
Average Equity	198.474	197.366	208.668	218.486	225.496	232.462	239.460	246.468	253.298	259.779
Average Debt and Equity	625.761	657.887	695.558	728.286	751.654	774.873	798.199	821.560	844.326	865.929
PUB Approved Equity Ratio	**31.72%**	**30.00%**	**30.00%**	**30.00%**	**30.00%**	**30.00%**	**30.00%**	**30.00%**	**30.00%**	**30.00%**

GAS OPERATIONS (CGM18)
PROJECTED FINANCIAL RATIOS
CGM18 - Goal Seek rates to maintin 30% PUB Approved equity ratio

For the year ended March 31

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
INTEREST COVERAGE										
Net Income	3.267	(5.484)	28.087	(8.450)	22.471	(8.540)	22.536	(8.519)	22.179	(9.217)
Finance Expense	20.502	22.267	24.256	24.482	26.245	26.870	28.880	29.044	31.352	31.505
Capitalized Interest	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	23.941	17.021	52.594	16.163	48.750	18.366	51.451	20.562	53.568	22.327
Finance Expense	20.502	22.267	24.256	24.482	26.245	26.870	28.880	29.044	31.352	31.505
Capitalized Interest	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	20.674	22.505	24.507	24.614	26.279	26.906	28.916	29.081	31.389	31.543
Interest Coverage	**1.16**	**0.76**	**2.15**	**0.66**	**1.86**	**0.68**	**1.78**	**0.71**	**1.71**	**0.71**
Add: Depreciation and Amortization *	34.899	36.694	38.540	38.811	40.399	40.930	42.096	42.256	43.428	43.831
Total EBITDA	58.840	53.715	91.134	54.975	89.149	59.296	93.547	62.818	96.996	66.157
EBITDA Interest Coverage	**2.85**	**2.39**	**3.72**	**2.23**	**3.39**	**2.20**	**3.24**	**2.16**	**3.09**	**2.10**

* Includes amortization of deferred income tax

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
CAPITAL COVERAGE										
Internally Generated Funds	27.389	19.978	45.841	25.658	59.492	28.238	61.809	29.829	64.283	32.392
Capitalized Interest*	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	27.560	20.215	46.091	25.790	59.527	28.273	61.845	29.866	64.320	32.430
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**	**0.50**	**1.20**	**0.66**	**1.50**	**0.70**	**1.49**	**0.71**	**1.49**	**0.74**

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

REFERENCE:

Tab 3 – Section 3.1.5 Update to Centra's Return on Equity (pg 4-6) and Appendix 3.6 – CGM18 & Financial Ratios – Updated for 2018/19 & 2019/20

PREAMBLE TO IR (IF ANY):

On Page 1 of Appendix 3.6, Centra is projecting a 32% Equity ratio for the 2019/20 Test Year.

The PUB has previously ruled (Page 27 of Order 85/13) that a 30% Equity ratio is appropriate for rate-setting purposes.

QUESTION:

b) Please provide the base and billed rate impact calculations for 2019/20 consistent with the CGM18 scenario requested in part (a) of this question.

RATIONALE FOR QUESTION:

To understand the impacts to the non-gas revenue requirement, rate impact calculations and rate base/rate of return calculations if Centra was to target the PUB approved Equity ratio of 30% in 2019/20 for rate-setting.

RESPONSE:

Given that the scenario in CAC/CENTRA I-8a produces a 7.99% rate decrease in 2019/20 (and a large net loss of $20 million), only to be followed by the requirement for a large rate increase in 2020/21 would not be appropriate for customers or for Centra, customer bill impacts for this scenario have not been provided.

REFERENCE:

Tab 3 – Section 3.1.5 Update to Centra's Return on Equity (pg 4-6) and Appendix 3.6 – CGM18 & Financial Ratios – Updated for 2018/19 & 2019/20

PREAMBLE TO IR (IF ANY):

On Page 1 of Appendix 3.6, Centra is projecting a 32% Equity ratio for the 2019/20 Test Year.

The PUB has previously ruled (Page 27 of Order 85/13) that a 30% Equity ratio is appropriate for rate-setting purposes.

QUESTION:

c) Please provide a revised Schedule 6.0.0 – Summary of Rate Base Rate of Return, 6.8.8 – Overall Rate of Return and 6.10.8 – Return on Rate Base, assuming that the amount and weighting for Equity is fixed at 30%, the amount and weighting for Long-term debt remains as calculated and that the difference is added to the amount and weighting of Short-term debt.

RATIONALE FOR QUESTION:

To understand the impacts to the non-gas revenue requirement, rate impact calculations and rate base/rate of return calculations if Centra was to target the PUB approved Equity ratio of 30% in 2019/20 for rate-setting.

RESPONSE:

The revised schedules provided below assume the equity weighting is deemed at 30% and the difference between the actual PUB equity ratio of 31.76% and the 30% is added to the short-term debt weighting, increasing the short-term debt weighting from 8.26% to 10.0%.

CENTRA GAS MANITOBA INC. — **Schedule 6.0.0 (Update)**
Summary of Rate Base Rate of Return — **CAC-CENTRA-I-8c**
Revenue Requirement & Rate Base — **($000'S)**

		IFRS 2019/20 Test Year
1		
2		
3		IFRS
4		2019/20
5		Test Year
6		
7	Cost of Gas	173 667
8	Other Income	(2 366)
9	Furnace Replacement Program	545
10	Operating & Administration	60 550
11	Other Expenses	46
12	Depreciation & Amortization	33 480
13	Capital & Other Taxes	20 312
14	Return on Rate Base	39 011
16	Revenue Requirement from Gas Rates	325 244
17		
18		
19		
20	Gas Plant in Service (A)	868 266
21	Accumulated Depreciation (A)	(301 188)
22	Net Plant	567 078
23	Net Intangible Assets (A)	9 312
24	Regulatory Deferral Accounts (B)	26 603
25	Contributions in Aid of Construction (A)	(61 534)
26	Working Capital Allowance	104 095
27	Rate Base (Sum lines 22 to 26)	645 554

(A) Balances are calculated using 13-mo averages.
(B) Includes the regulatory deferral debit and credit 13-mo balances relating to: (i) change in depreciation method, (ii) deferred ineligible overhead, (iii) loss on disposal of assets, (iv) change in depreciation rate on meters, and (v) impact of 2014 depreciation study.

CENTRA GAS MANITOBA INC. **Schedule 6.8.8 (Update)**
Overall Rate of Return **CAC-CENTRA-I-8c**
2019/20 Test Year **($000'S)**

		Capital Structure	Weight	Cost Rate	Weighted Cost of Capital Col [2] * Col [3]
1		[1]	[2]	[3]	[4]
2					
3					
4	Long Term Debt	382 745	60.0%	5.04%	3.02%
5					
6	Short Term Debt	52 752	10.0%	3.20%	0.32%
7					
8	Equity	202 722	30.0%	8.30%	2.49%
9		638 218	100.0%		5.83%

CENTRA GAS MANITOBA INC. **Schedule 6.10.8 (Update)**
Return on Rate Base **CAC-CENTRA-I-8c**
2019/20 Test Year **($000'S)**

		Rate Base	Weight	Cost Rate	Return Col [1] * Col [2] * Col [3]
1		[1]	[2]	[3]	[4]
2					
3					
4	Long Term Debt	645 554	60.0%	5.04%	19 519
5					
6	Short Term Debt	645 554	10.0%	3.20%	2 072
7					
8	Equity	645 554	30.0%	8.30%	16 074
9			100.0%		37 665
10					
11	Interest on Common Assets and Inventory				1 346
12					
13	Total Return on Rate Base				39 011

REFERENCE:

Tab 3 – Section 3.5 Centra's Debt Portfolio and Interest Rate Risk (pg 15-16), Tab 5 – Section 5.2.5 – Finance Expense - Pages 20-24 and Appendix 5.13 – Tab 5 Figures Updated - Page 10

PREAMBLE TO IR (IF ANY):

The PUB approved Finance expense from the 2013/14 Test Year was $17,296. Centra is now forecasting Finance expense of $21,603 for the 2019/20 Test Year for rate-setting purposes including net movement in regulatory deferrals (Appendix 5.12 (Update), Page 4, Figure 3, line 52).

Centra states on page 15 of Tab 3, lines 22 to 24 "During the past few years, the interest rate risk on the existing debt portfolio has been mitigated by rebalancing the percentage of short term debt, floating rate long term debt and fixed rate long term debt with the existing debt portfolio."

Centra states on page 16 of Tab 3, lines 10 to 12 "Centra will continue to transition its debt portfolio to apply the principles of Manitoba Hydro's debt management strategy, including those to manage the interest rate risk within the debt portfolio."

Centra does not provide any analysis of the cost and rate-setting implications of rebalancing the Centra debt portfolio or of applying the debt management strategy and interest rate policy/guidelines for Manitoba Hydro's electric operations to gas operations.

QUESTION:

a) Further to the information requested in PUB/Centra I-47 (b) of this proceeding, please provide a more detailed explanation of how the Manitoba Hydro policy guidelines are being applied to Centra Gas and specifically, how the Centra debt portfolio has been rebalanced over the last few years.

b) Please provide detailed calculations of the Centra's projected performance for 2018/19 and 2019/20 as compared to each of the interest rate risk guidelines outlined on Pages 15 and 16 of Tab 3.

c) Please provide an assessment of the appropriateness of applying the debt management and interest rate risk policies/guidelines related to electric operations to natural gas operations, with reference to the current and expected operational circumstances of the two lines of business for the next 5 to 10 years (i.e., electric operations is currently in an era of record investment and borrowing for major capital projects) and current and expected financial market conditions.

d) Please explain the customer and rate-setting impacts and trade-offs of rebalancing Centra's debt portfolio for Centra's ratepayers. For instance, would application of the electric operations policies to gas operations result in an overly-conservative interest rate risk profile for Centra with a resulting higher cost to consumers.

e) Please explain the long-term goal and expected timeframe to continue to rebalance the Centra debt portfolio based on the electric operations debt management and interest rate risk policies and guidelines.

f) Please provide an update to the attachment to the response to CAC/Centra I-14 (e) from the 2013/14 Centra GRA (Centra long-term debt term to maturity analysis) for 2012/13 actual to 2019/20 forecast as well as any commentary that Centra believes is necessary to understand the updated attachment.

g) Please provide an update to the attachment to the response to CAC/Centra I-18 from the 2013/14 Centra GRA (Centra debt structure by quarter) for 2012/13 actual to 2019/20 forecast as well as any commentary that Centra believes is necessary to understand the updated attachment.

h) Please provide an update to charts 1 and 2 from the response to CAC/Centra I-19 from the 2013/14 Centra GRA for 2012/13 actual to 2019/20 forecast as well as any commentary that Centra believes is necessary to understand the updated charts. Please also confirm that Figure 3.7 from Tab 3 of the current Application is the update to chart 3 from CAC/Centra I-19 from the 2013/14 GRA.

i) Please provide an update to PUB/Centra I-43 (b) from the 2013/14 GRA (Centra term sheets related to existing debt issues), indicating how the interest rate was determined for the debt issues assigned from Manitoba Hydro to Centra. If there is any difference between the interest rate and terms of the debt issue assigned to Centra and the corresponding Manitoba Hydro debt issue, please provide the reasons for the differences.

j) Please provide an update to PUB/Centra I-43 (c) from the 2013/14 GRA (Centra long-term debt continuity schedule) for 2012/13 actual to 2019/20 forecast.

k) Please provide a comparison between the approved 2013/14 Finance expense of \$17,296 (CGAAP) and the 2019/20 projected Finance expense of \$21,603 and explain the key business drivers of the \$4,307 increase (asset growth, interest rate changes, debt structure changes etc.) on an overall basis, including the overall impacts of accounting changes from the transition to IFRS.

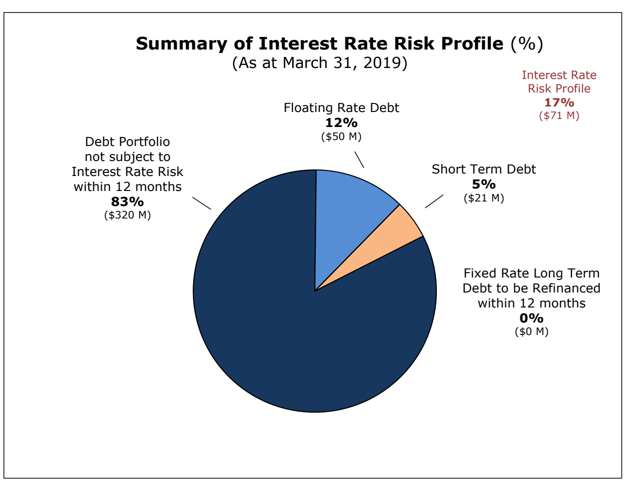
RATIONALE FOR QUESTION:

To understand the appropriateness and impact of applying the Manitoba Hydro debt management and interest rate risk policies and guidelines to Centra and the key business drivers for the changes in Finance expense since the 2013/14 GRA.

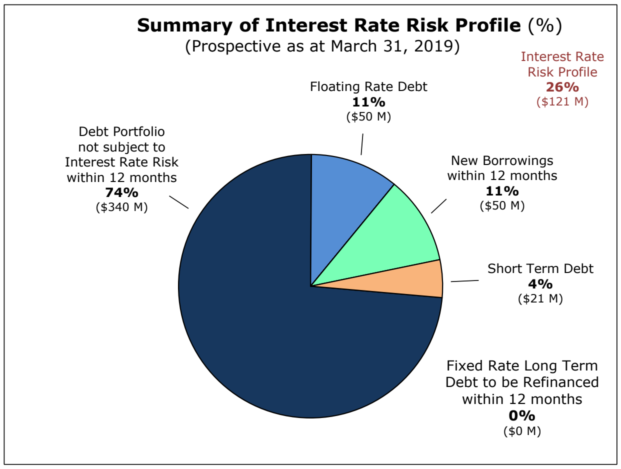
RESPONSE:

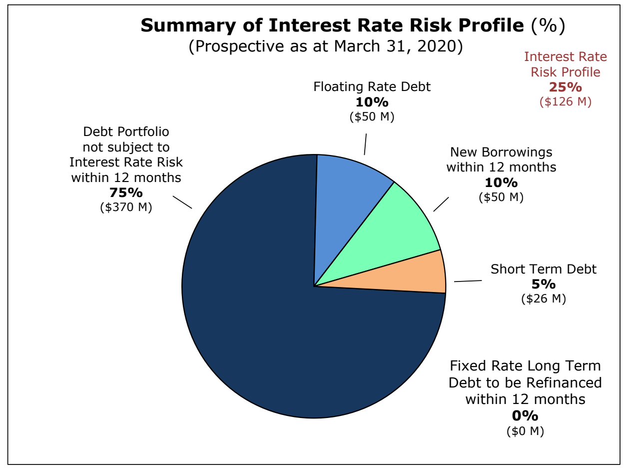
a) Please see part h) of this response.

b) To manage interest rate risk, Centra will maintain an aggregate of floating rate debt and short term debt within 15-25% of the total debt portfolio. The following chart illustrates Centra's compliance with this guideline at March 31, 2019.



New borrowings are subject to interest rate risk and have been included in the charts below to provide a more fulsome depiction of interest rate risk. The following charts illustrate Centra's prospective interest rate risk profile as of March 31, 2019 and March 31, 2020.

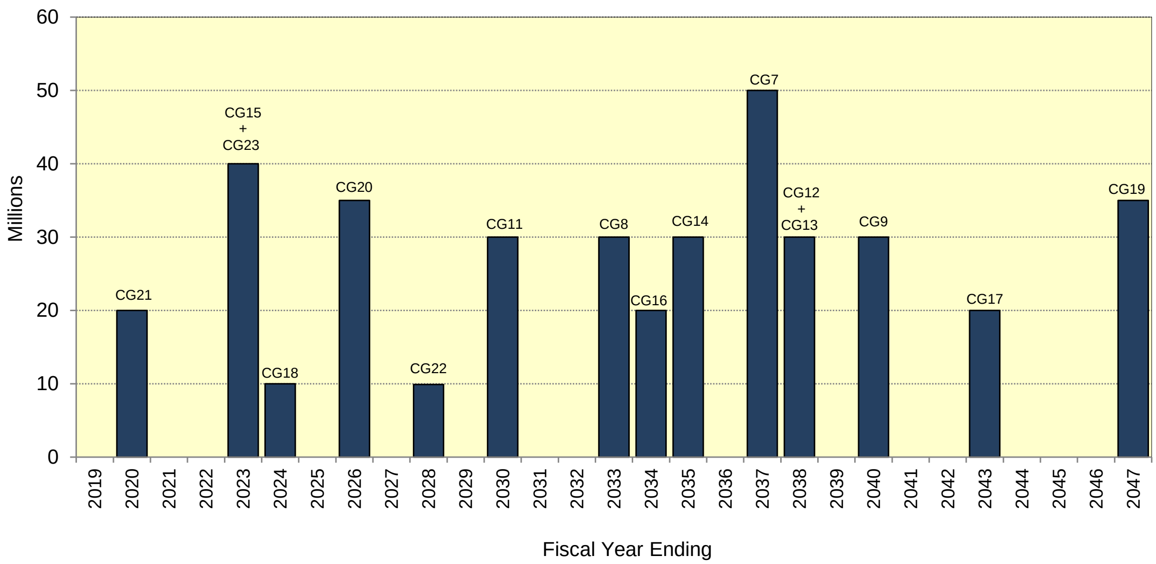




Manitoba Hydro advanced Series CG23, a $20 million floating rate debt issuance at 3 month BA + 0.175% maturing on December 15, 2022 to Centra on January 25, 2019. Centra is forecasting a total of $50 million of long term debt issuance in 2019/20. While the simplifying forecast assumption is for a 20 year term to maturity, actual issuances will vary from forecast. Debt maturities will be selected to smooth the debt maturity schedule and to reduce concentration risk such that the fixed rate long term debt to be refinanced within any particular 12 month period is targeted to be less than 15% of the total debt portfolio. The following chart shows Centra's debt maturity schedule with actuals at March 31, 2019.

Chart 3

Centra Existing Long Term Debt Maturities
As at March 31, 2019



Response to c), d) and e)

Manitoba Hydro's debt management and interest rate risk policies and guidelines related to Electric Operations apply equally as well to its Natural Gas Operations. These policies and guidelines are prudent and balance the costs and benefits to ratepayers. Manitoba Hydro's Electric Operations are currently in an era of record investment and borrowing for major capital projects which has necessitated changes in the management of Electric Operations borrowing and investing activities; however, the Natural Gas Operations have been managed to ensure compliance within the established financial guidelines.

The debt management and financial risk policies and guidelines under which Centra operates are not more conservative than some of its natural gas peers. For example, according to the debt maturity schedules available on Bloomberg as of November 2018, both Fortis BC Gas and Union Gas Ltd maintained a WATM of long term debt greater than Centra Gas (approximately 20 and 16 years respectively versus Centra's current 14.1 years).

In addition, according to their September 30, 2018 interim financials, Fortis BC Gas held only 7.1% of its debt exposed to short term rates while Union Gas Ltd held 12.2% exposed to short term rates versus Centra's current 17.2%.

Please see the response to PUB/Centra I-47b) for further information on Centra's Debt Management Strategy.

f) Please see the following schedules of Centra's long term debt weighted average term to maturity analysis for the years ending March 31, 2013 to March 31, 2020 as well as the comparable values for Manitoba Hydro's consolidated debt.

As At March 31, 2013 **MH Advances**	**Maturity Date**	**2013 Ending Balance**	**Maturing < 1 Year**	**Maturing 1 - 10 Years**	**Maturing 11 - 20 Years**	**Maturing > 20 Years**	**Total ($000's)**
CG 8 - CG 6 Extension	29-Oct-2032	30,000			30,000		30,000
CG 7 - Maturity	05-Mar-2037	50,000				50,000	50,000
CG 9 - Maturity	05-Mar-2040	30,000				30,000	30,000
CG 10 - Maturity	22-Feb-2015	35,000		35,000			35,000
CG 11 - Maturity	22-Feb-2030	30,000			30,000		30,000
CG 12 - Maturity	22-Aug-2037	10,000				10,000	10,000
CG 13 - Maturity	30-Sep-2037	20,000				20,000	20,000
CG 14 - Maturity	31-Mar-2035	30,000				30,000	30,000
CG 15 - Maturity	18-Sep-2022	20,000		20,000			20,000
CG 16 - Maturity	18-Sep-2033	20,000				20,000	20,000
CG 17 - Maturity	18-Sep-2042	20,000				20,000	20,000
Total		**295,000**	**-**	**55,000**	**60,000**	**180,000**	**295,000**
Centra Weighted Average Term to Maturity in Years		**19.5**					
Manitoba Hydro Weighted Average Term to Maturity in Years		14.8					
Percentage Maturing within Specific Time Period			0.0%	18.6%	20.3%	61.0%	
Largest Maturity Amount in Fiscal Year Ended 2036/37		**50,000**					
Percentage Maturing in Largest Maturity Year		**16.9%**					

As At March 31, 2014 **MH Advances**	**Maturity Date**	**2014 Ending Balance**	**Maturing < 1 Year**	**Maturing 1 - 10 Years**	**Maturing 11 - 20 Years**	**Maturing > 20 Years**	**Total ($000's)**
CG 8 - CG 6 Extension	29-Oct-2032	30,000			30,000		30,000
CG 7 - Maturity	05-Mar-2037	50,000				50,000	50,000
CG 9 - Maturity	05-Mar-2040	30,000				30,000	30,000
CG 10 - Maturity	22-Feb-2015	35,000	35,000				35,000
CG 11 - Maturity	22-Feb-2030	30,000			30,000		30,000
CG 12 - Maturity	22-Aug-2037	10,000				10,000	10,000
CG 13 - Maturity	30-Sep-2037	20,000				20,000	20,000
CG 14 - Maturity	31-Mar-2035	30,000				30,000	30,000
CG 15 - Maturity	18-Sep-2022	20,000		20,000			20,000
CG 16 - Maturity	18-Sep-2033	20,000			20,000		20,000
CG 17 - Maturity	18-Sep-2042	20,000				20,000	20,000
CG 18 - Maturity	02-Jun-2023	10,000		10,000			10,000
Total		**305,000**	**35,000**	**30,000**	**80,000**	**160,000**	**305,000**
Centra Weighted Average Term to Maturity in Years		**18.2**					
Manitoba Hydro Weighted Average Term to Maturity in Years		16.2					
Percentage Maturing within Specific Time Period			11.5%	9.8%	26.2%	52.5%	
Largest Maturity Amount in Fiscal Year Ended 2036/37		**50,000**					
Percentage Maturing in Largest Maturity Year		**16.4%**					

As At March 31, 2015		2015 Ending	Maturing	Maturing	Maturing	Maturing	Total
MH Advances	**Maturity Date**	**Balance**	**< 1 Year**	**1 - 10 Years**	**11 - 20 Years**	**> 20 Years**	**($000's)**
CG 8 - CG 6 Extension	29-Oct-2032	30,000			30,000		30,000
CG 7 - Maturity	05-Mar-2037	50,000				50,000	50,000
CG 9 - Maturity	05-Mar-2040	30,000				30,000	30,000
CG 11 - Maturity	22-Feb-2030	30,000			30,000		30,000
CG 12 - Maturity	22-Aug-2037	10,000				10,000	10,000
CG 13 - Maturity	30-Sep-2037	20,000				20,000	20,000
CG 14 - Maturity	31-Mar-2035	30,000			30,000		30,000
CG 15 - Maturity	18-Sep-2022	20,000		20,000			20,000
CG 16 - Maturity	18-Sep-2033	20,000			20,000		20,000
CG 17 - Maturity	18-Sep-2042	20,000				20,000	20,000
CG 18 - Maturity	02-Jun-2023	10,000		10,000			10,000
CG 19 - Maturity	05-Sep-2046	35,000				35,000	35,000
Total		**305,000**	**-**	**30,000**	**110,000**	**165,000**	**305,000**
Centra Weighted Average Term to Maturity in Years		**20.8**					
Manitoba Hydro Weighted Average Term to Maturity in Years		17.8					
Percentage Maturing within Specific Time Period			0.0%	9.8%	36.1%	54.1%	
Largest Maturity Amount in Fiscal Year Ended 2036/37		**50,000**					
Percentage Maturing in Largest Maturity Year		**16.4%**					

As At March 31, 2016		2016 Ending	Maturing	Maturing	Maturing	Maturing	Total
MH Advances	**Maturity Date**	**Balance**	**< 1 Year**	**1 - 10 Years**	**11 - 20 Years**	**> 20 Years**	**($000's)**
CG 8 - CG 6 Extension	29-Oct-2032	30,000			30,000		30,000
CG 7 - Maturity	05-Mar-2037	50,000				50,000	50,000
CG 9 - Maturity	05-Mar-2040	30,000				30,000	30,000
CG 11 - Maturity	22-Feb-2030	30,000			30,000		30,000
CG 12 - Maturity	22-Aug-2037	10,000				10,000	10,000
CG 13 - Maturity	30-Sep-2037	20,000				20,000	20,000
CG 14 - Maturity	31-Mar-2035	30,000			30,000		30,000
CG 15 - Maturity	18-Sep-2022	20,000		20,000			20,000
CG 16 - Maturity	18-Sep-2033	20,000			20,000		20,000
CG 17 - Maturity	18-Sep-2042	20,000				20,000	20,000
CG 18 - Maturity	02-Jun-2023	10,000		10,000			10,000
CG 19 - Maturity	05-Sep-2046	35,000				35,000	35,000
CG 20 - Maturity	02-Jun-2025	35,000		35,000			35,000
Total		**340,000**	**-**	**65,000**	**110,000**	**165,000**	**340,000**
Centra Weighted Average Term to Maturity in Years		**18.7**					
Manitoba Hydro Weighted Average Term to Maturity in Years		18.1					
Percentage Maturing within Specific Time Period			0.0%	19.1%	32.4%	48.5%	
Largest Maturity Amount in Fiscal Year Ended 2036/37		**50,000**					
Percentage Maturing in Largest Maturity Year		**14.7%**					

As At March 31, 2017		2017 Ending	Maturing	Maturing	Maturing	Maturing	Total
MH Advances	**Maturity Date**	**Balance**	**< 1 Year**	**1 - 10 Years**	**11 - 20 Years**	**> 20 Years**	**($000's)**
CG 8 - CG 6 Extension	29-Oct-2032	30,000			30,000		30,000
CG 7 - Maturity	05-Mar-2037	50,000			50,000		50,000
CG 9 - Maturity	05-Mar-2040	30,000				30,000	30,000
CG 11 - Maturity	22-Feb-2030	30,000			30,000		30,000
CG 12 - Maturity	22-Aug-2037	10,000				10,000	10,000
CG 13 - Maturity	30-Sep-2037	20,000				20,000	20,000
CG 14 - Maturity	31-Mar-2035	30,000			30,000		30,000
CG 15 - Maturity	18-Sep-2022	20,000		20,000			20,000
CG 16 - Maturity	18-Sep-2033	20,000			20,000		20,000
CG 17 - Maturity	18-Sep-2042	20,000				20,000	20,000
CG 18 - Maturity	02-Jun-2023	10,000		10,000			10,000
CG 19 - Maturity	05-Sep-2046	35,000				35,000	35,000
CG 20 - Maturity	02-Jun-2025	35,000		35,000			35,000
CG 21 - Maturity	21-Nov-2019	20,000		20,000			20,000
Total		**360,000**	**-**	**85,000**	**160,000**	**115,000**	**360,000**
Centra Weighted Average Term to Maturity in Years		**16.9**					
Manitoba Hydro Weighted Average Term to Maturity in Years		17.5					
Percentage Maturing within Specific Time Period			0.0%	23.6%	44.4%	31.9%	
Largest Maturity Amount in Fiscal Year Ended 2036/37		**50,000**					
Percentage Maturing in Largest Maturity Year		**13.9%**					

As At March 31, 2018 MH Advances	Maturity Date	2018 Ending Balance	Maturing < 1 Year	Maturing 1 - 10 Years	Maturing 11 - 20 Years	Maturing > 20 Years	Total ($000's)
CG 8 - CG 6 Extension	29-Oct-2032	30,000			30,000		30,000
CG 7 - Maturity	05-Mar-2037	50,000			50,000		50,000
CG 9 - Maturity	05-Mar-2040	30,000				30,000	30,000
CG 11 - Maturity	22-Feb-2030	30,000			30,000		30,000
CG 12 - Maturity	22-Aug-2037	10,000			10,000		10,000
CG 13 - Maturity	30-Sep-2037	20,000			20,000		20,000
CG 14 - Maturity	31-Mar-2035	30,000			30,000		30,000
CG 15 - Maturity	18-Sep-2022	20,000		20,000			20,000
CG 16 - Maturity	18-Sep-2033	20,000			20,000		20,000
CG 17 - Maturity	18-Sep-2042	20,000				20,000	20,000
CG 18 - Maturity	02-Jun-2023	10,000		10,000			10,000
CG 19 - Maturity	05-Sep-2046	35,000				35,000	35,000
CG 20 - Maturity	02-Jun-2025	35,000		35,000			35,000
CG 21 - Maturity	21-Nov-2019	20,000		20,000			20,000
CG 22 - Maturity	17-Aug-2027	9,903		9,903			9,903
Total		**369,903**	**-**	**94,903**	**190,000**	**85,000**	**369,903**

Centra Weighted Average Term to Maturity in Years	**15.7**				
Manitoba Hydro Weighted Average Term to Maturity in Years	17.2				
Percentage Maturing within Specific Time Period		0.0%	25.7%	51.4%	23.0%
Largest Maturity Amount in Fiscal Year Ended 2036/37	**50,000**				
Percentage Maturing in Largest Maturity Year	**13.5%**				

As At March 31, 2019 MH Advances	Maturity Date	2019 Ending Balance	Maturing < 1 Year	Maturing 1 - 10 Years	Maturing 11 - 20 Years	Maturing > 20 Years	Total ($000's)
CG 8 - CG 6 Extension	29-Oct-2032	30,000			30,000		30,000
CG 7 - Maturity	05-Mar-2037	50,000			50,000		50,000
CG 9 - Maturity	05-Mar-2040	30,000				30,000	30,000
CG 11 - Maturity	22-Feb-2030	30,000			30,000		30,000
CG 12 - Maturity	22-Aug-2037	10,000			10,000		10,000
CG 13 - Maturity	30-Sep-2037	20,000			20,000		20,000
CG 14 - Maturity	31-Mar-2035	30,000			30,000		30,000
CG 15 - Maturity	18-Sep-2022	20,000		20,000			20,000
CG 16 - Maturity	18-Sep-2033	20,000			20,000		20,000
CG 17 - Maturity	18-Sep-2042	20,000				20,000	20,000
CG 18 - Maturity	02-Jun-2023	10,000		10,000			10,000
CG 19 - Maturity	05-Sep-2046	35,000				35,000	35,000
CG 20 - Maturity	02-Jun-2025	35,000		35,000			35,000
CG 21 - Maturity	21-Nov-2019	20,000	20,000				20,000
CG 22 - Maturity	17-Aug-2027	9,903		9,903			9,903
CG 23 - Maturity	15-Dec-2022	20,000		20,000			20,000
Total		**389,903**	**20,000**	**94,903**	**190,000**	**85,000**	**389,903**

Centra Weighted Average Term to Maturity in Years	**14.1**				
Manitoba Hydro Weighted Average Term to Maturity in Years	17.8				
Percentage Maturing within Specific Time Period		5.1%	24.3%	48.7%	21.8%
Largest Maturity Amount in Fiscal Year Ended 2036/37	**50,000**				
Percentage Maturing in Largest Maturity Year	**12.8%**				

As At March 31, 2020 MH Advances	Maturity Date	2020 Ending Balance	Maturing < 1 Year	Maturing 1 - 10 Years	Maturing 11 - 20 Years	Maturing > 20 Years	Total ($000's)
CG 8 - CG 6 Extension	29-Oct-2032	30,000			30,000		30,000
CG 7 - Maturity	05-Mar-2037	50,000			50,000		50,000
CG 9 - Maturity	05-Mar-2040	30,000			30,000		30,000
CG 11 - Maturity	22-Feb-2030	30,000		30,000			30,000
CG 12 - Maturity	22-Aug-2037	10,000			10,000		10,000
CG 13 - Maturity	30-Sep-2037	20,000			20,000		20,000
CG 14 - Maturity	31-Mar-2035	30,000			30,000		30,000
CG 15 - Maturity	18-Sep-2022	20,000		20,000			20,000
CG 16 - Maturity	18-Sep-2033	20,000			20,000		20,000
CG 17 - Maturity	18-Sep-2042	20,000				20,000	20,000
CG 18 - Maturity	02-Jun-2023	10,000		10,000			10,000
CG 19 - Maturity	05-Sep-2046	35,000				35,000	35,000
CG 20 - Maturity	02-Jun-2025	35,000		35,000			35,000
CG 22 - Maturity	17-Aug-2027	9,903		9,903			9,903
CG 23 - Maturity	15-Dec-2022	20,000		20,000			20,000
New Issue March 2020- Maturity	31-Mar-2040	50,000			50,000		50,000
Total		**419,903**	**-**	**124,903**	**240,000**	**55,000**	**419,903**

Centra Weighted Average Term to Maturity in Years	**14.6**				
Manitoba Hydro Weighted Average Term to Maturity in Years	17.0				
Percentage Maturing within Specific Time Period		0.0%	29.7%	57.2%	13.1%
Largest Maturity Amount in Fiscal Year Ended 2036/37	**50,000**				
Percentage Maturing in Largest Maturity Year	**11.9%**				

g) Please see below for the Centra debt structure by quarter, updated for 2012/13 to 2018/19 actuals and 2019/20 forecast.

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Centra Debt Structure by Quarter ($000's)

	Quarter Ended Jun-12	Quarter Ended Sep-12	Quarter Ended Dec-12	Quarter Ended Mar-13	Quarter Ended Jun-13	Quarter Ended Sep-13	Quarter Ended Dec-13	Quarter Ended Mar-14	Quarter Ended Jun-14	Quarter Ended Sep-14	Quarter Ended Dec-14
Short Term Debt	5,271	37,455	42,410	19,262	34,326	52,420	43,808	27,669	82,908	113,486	120,644
Floating Rate Long Term Debt	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000
Total Short Term Debt and Floating Rate Long Term Debt (CAD)	**40,271**	**72,455**	**77,410**	**54,262**	**69,326**	**87,420**	**78,808**	**62,669**	**117,908**	**148,486**	**155,644**
Fixed Rate Long Term Debt	262,671	260,000	260,000	260,000	260,000	260,000	270,000	270,000	270,000	270,000	270,000
Total Fixed Rate Long Term Debt	262,671	260,000	260,000	260,000	260,000	260,000	270,000	270,000	270,000	270,000	270,000
Total Debt	**302,942**	**332,455**	**337,410**	**314,262**	**329,326**	**347,420**	**348,808**	**332,669**	**387,908**	**418,486**	**425,644**
Debt Portfolio Percentages:											
Short Term Debt	1.7%	11.3%	12.6%	6.1%	10.4%	15.1%	12.6%	8.3%	21.4%	27.1%	28.3%
Floating Rate Long Term Debt	11.6%	10.5%	10.4%	11.1%	10.6%	10.1%	10.0%	10.5%	9.0%	8.4%	8.2%
Short Term Debt & Floating Rate Long Term Debt	**13.3%**	**21.8%**	**22.9%**	**17.3%**	**21.1%**	**25.2%**	**22.6%**	**18.8%**	**30.4%**	**35.5%**	**36.6%**
Fixed Rate Long Term Debt	86.7%	78.2%	77.1%	82.7%	78.9%	74.8%	77.4%	81.2%	69.6%	64.5%	63.4%
Centra Rolling 5 Quarter Averages:											
Percentage Short Term Debt	6.0%	8.0%	8.0%	6.8%	8.4%	11.1%	11.4%	10.5%	13.6%	16.9%	19.5%
Percentage Floating Rate Long Term Debt	11.0%	10.8%	10.9%	11.0%	10.8%	10.5%	10.4%	10.5%	10.1%	9.6%	9.2%
Percentage Short Term Debt & Floating Rate Long Term Debt	**17.1%**	**18.8%**	**18.9%**	**17.8%**	**19.3%**	**21.6%**	**21.8%**	**21.0%**	**23.6%**	**26.5%**	**28.8%**
Percentage Fixed Rate Long Term Debt	82.9%	81.2%	81.1%	82.2%	80.7%	78.4%	78.2%	79.0%	76.4%	73.5%	71.2%
Centra Rolling 4 Quarter Averages:											
Percentage Short Term Debt & Floating Rate Long Term Debt	**18.1%**	**17.9%**	**18.0%**	**18.8%**	**20.8%**	**21.6%**	**21.5%**	**21.9%**	**24.2%**	**26.8%**	**30.3%**

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Centra Debt Structure by Quarter

($000's)

	Quarter Ended Mar-15	Quarter Ended Jun-15	Quarter Ended Sep-15	Quarter Ended Dec-15	Quarter Ended Mar-16	Quarter Ended Jun-16	Quarter Ended Sep-16	Quarter Ended Dec-16	Quarter Ended Mar-17	Quarter Ended Jun-17	Quarter Ended Sep-17
Short Term Debt	72,623	28,874	58,233	69,169	35,649	14,624	57,695	53,166	26,316	33,076	70,982
Floating Rate Long Term Debt	-	-	-	-	-	-	-	20,000	20,000	20,000	20,000
Total Short Term Debt and Floating Rate Long Term Debt (CAD)	**72,623**	**28,874**	**58,233**	**69,169**	**35,649**	**14,624**	**57,695**	**73,166**	**46,316**	**53,076**	**90,982**
Fixed Rate Long Term Debt	305,000	340,000	340,000	340,000	340,000	340,000	340,000	340,000	340,000	340,000	340,000
Total Fixed Rate Long Term Debt	305,000	340,000	340,000	340,000	340,000	340,000	340,000	340,000	340,000	340,000	340,000
Total Debt	**377,623**	**368,874**	**398,233**	**409,169**	**375,649**	**354,624**	**397,695**	**413,166**	**386,316**	**393,076**	**430,982**
Debt Portfolio Percentages:											
Short Term Debt	19.2%	7.8%	14.6%	16.9%	9.5%	4.1%	14.5%	12.9%	6.8%	8.4%	16.5%
Floating Rate Long Term Debt	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	4.8%	5.2%	5.1%	4.6%
Short Term Debt & Floating Rate Long Term Debt	**19.2%**	**7.8%**	**14.6%**	**16.9%**	**9.5%**	**4.1%**	**14.5%**	**17.7%**	**12.0%**	**13.5%**	**21.1%**
Fixed Rate Long Term Debt	80.8%	92.2%	85.4%	83.1%	90.5%	95.9%	85.5%	82.3%	88.0%	86.5%	78.9%
Centra Rolling 5 Quarter Averages:											
Percentage Short Term Debt	20.9%	20.8%	19.4%	17.4%	13.6%	10.6%	11.9%	11.6%	9.6%	9.3%	11.8%
Percentage Floating Rate Long Term Debt	7.2%	5.1%	3.3%	1.6%	0.0%	0.0%	0.0%	1.0%	2.0%	3.0%	3.9%
Percentage Short Term Debt & Floating Rate Long Term Debt	**28.1%**	**25.9%**	**22.7%**	**19.0%**	**13.6%**	**10.6%**	**11.9%**	**12.5%**	**11.6%**	**12.4%**	**15.8%**
Percentage Fixed Rate Long Term Debt	71.9%	74.1%	77.3%	81.0%	86.4%	89.4%	88.1%	87.5%	88.4%	87.6%	84.2%
Centra Rolling 4 Quarter Averages:											
Percentage Short Term Debt & Floating Rate Long Term Debt	**30.4%**	**24.8%**	**19.6%**	**14.6%**	**12.2%**	**11.3%**	**11.3%**	**11.5%**	**12.1%**	**14.4%**	**16.1%**

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Centra Debt Structure by Quarter

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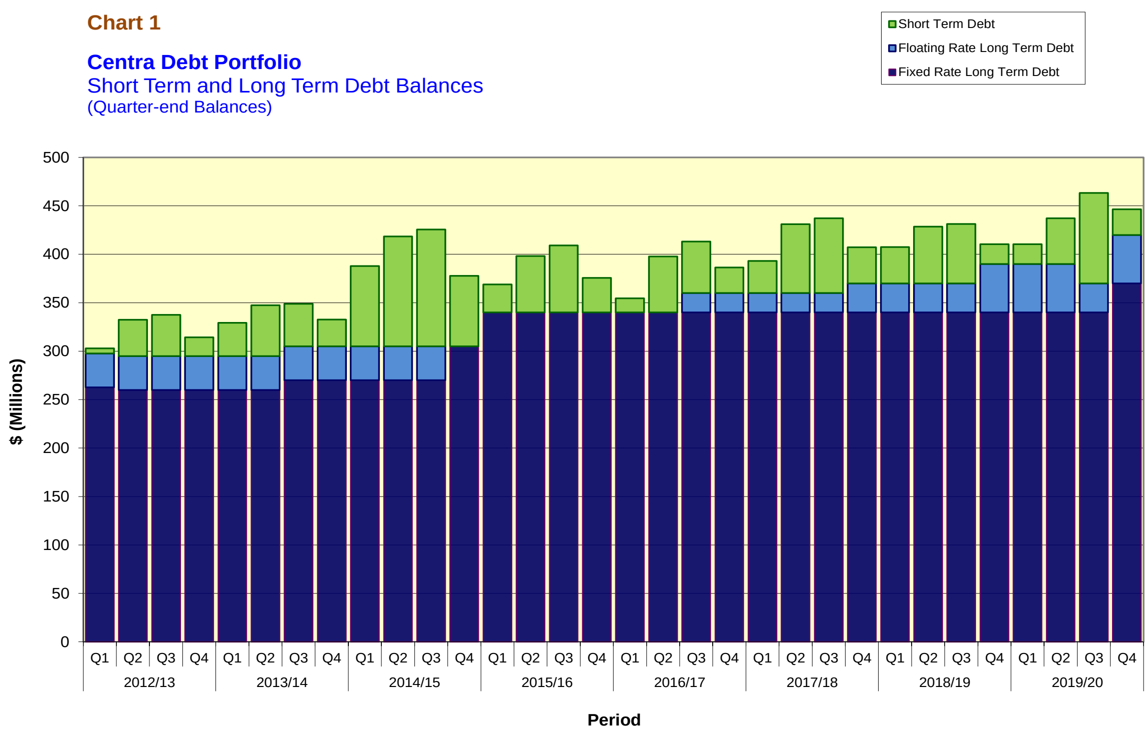
($000's)

	Quarter Ended Dec-17	Quarter Ended Mar-18	Quarter Ended Jun-18	Quarter Ended Sep-18	Quarter Ended Dec-18	Preliminary Quarter Ended Mar-19	Forecast Quarter Ended Jun-19	Quarter Ended Sep-19	Quarter Ended Dec-19	Quarter Ended Mar-20
Short Term Debt	77,117	37,300	37,625	58,586	61,444	20,492	20,447	47,278	93,421	26,449
Floating Rate Long Term Debt	20,000	29,903	29,903	29,903	29,903	49,903	49,903	49,903	29,903	49,903
Total Short Term Debt and Floating Rate Long Term Debt (CAD)	**97,117**	**67,203**	**67,528**	**88,489**	**91,347**	**70,395**	**70,350**	**97,181**	**123,324**	**76,352**
Fixed Rate Long Term Debt	340,000	340,000	340,000	340,000	340,000	340,000	340,000	340,000	340,000	370,000
Total Fixed Rate Long Term Debt	340,000	340,000	340,000	340,000	340,000	340,000	340,000	340,000	340,000	370,000
Total Debt	**437,117**	**407,203**	**407,528**	**428,489**	**431,347**	**410,395**	**410,350**	**437,181**	**463,324**	**446,352**
Debt Portfolio Percentages:										
Short Term Debt	17.6%	9.2%	9.2%	13.7%	14.2%	5.0%	5.0%	10.8%	20.2%	5.9%
Floating Rate Long Term Debt	4.6%	7.3%	7.3%	7.0%	6.9%	12.2%	12.2%	11.4%	6.5%	11.2%
Short Term Debt & Floating Rate Long Term Debt	**22.2%**	**16.5%**	**16.6%**	**20.7%**	**21.2%**	**17.2%**	**17.1%**	**22.2%**	**26.6%**	**17.1%**
Fixed Rate Long Term Debt	77.8%	83.5%	83.4%	79.3%	78.8%	82.8%	82.9%	77.8%	73.4%	82.9%
Centra Rolling 5 Quarter Averages:										
Percentage Short Term Debt	12.4%	11.7%	12.2%	13.2%	12.8%	10.3%	9.4%	9.7%	11.0%	9.4%
Percentage Floating Rate Long Term Debt	4.9%	5.4%	5.8%	6.2%	6.6%	8.2%	9.1%	9.9%	9.8%	10.7%
Percentage Short Term Debt & Floating Rate Long Term Debt	**17.3%**	**17.1%**	**18.0%**	**19.4%**	**19.4%**	**18.4%**	**18.5%**	**19.7%**	**20.9%**	**20.0%**
Percentage Fixed Rate Long Term Debt	82.7%	82.9%	82.0%	80.6%	80.6%	81.6%	81.5%	80.3%	79.1%	80.0%
Centra Rolling 4 Quarter Averages:										
Percentage Short Term Debt & Floating Rate Long Term Debt	**17.2%**	**18.3%**	**19.1%**	**19.0%**	**18.7%**	**18.9%**	**19.0%**	**19.4%**	**20.8%**	**20.8%**

h) The following chart depicts Centra's quarter ending short and long term debt balances from April 1, 2012 to March 31, 2020 (actuals, with forecasts for 2019/20).

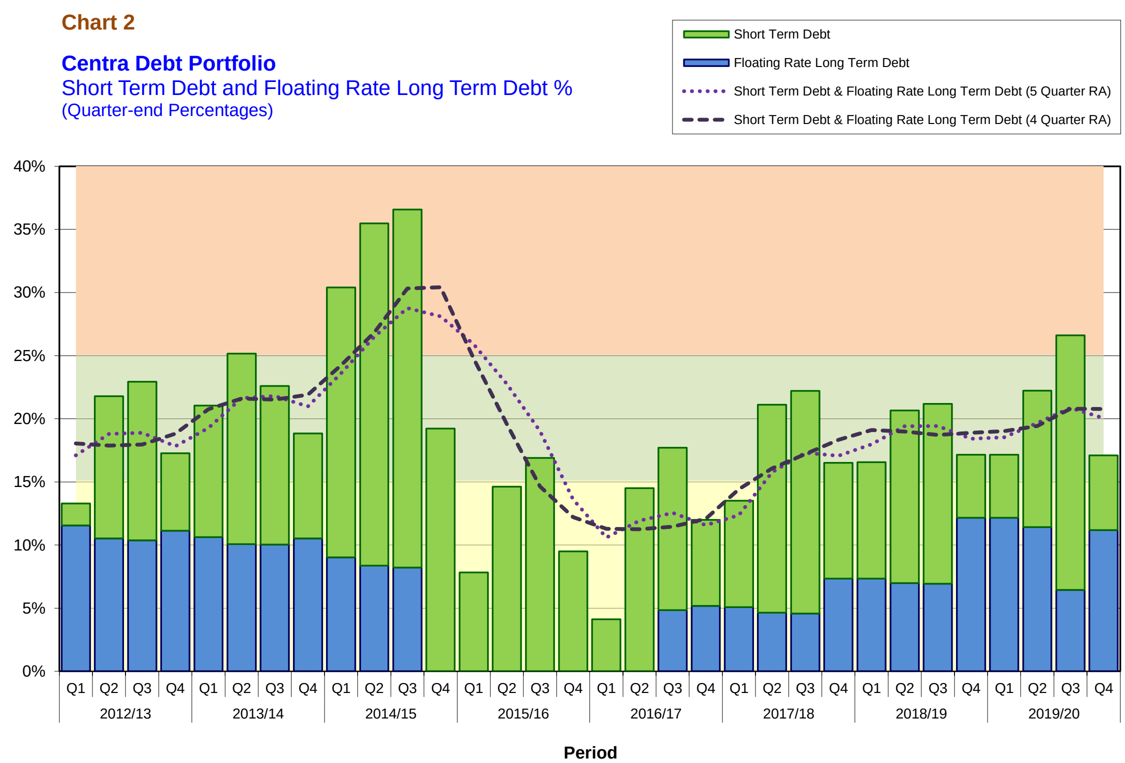


While there have been seasonal fluctuations, the average of the total debt balances has grown since the borrowing for the Winnipeg North West Upgrades Project which came into service on January 23, 2017.

In keeping with the Corporation's utilization of short term debt for temporary purposes, Centra converted cumulative amounts of its capital financing from short term debt to long term debt with debt series:

- CG18 ($10 million on November 26, 2013)
- CG20 ($35 million on June 11, 2015)
- CG21 ($20 million on November 21, 2016)
- CG22 ($9.9 million on February 20, 2018)
- CG23 ($20 million on January 25, 2019)

The following chart depicts Centra's quarter end percentages for short and long term debt balances from April 1, 2012 to March 31, 2020 (actuals, with forecasts for 2019/20).



The Corporation's debt management strategies and practices are not measured using rolling averages. However, this approach will smooth the seasonal variability inherent in Centra's short term working capital requirements.

On March 2, 2015, maturing floating rate series CG10 ($35 million) was refinanced with fixed rate series CG19 in order to reduce the interest rate risk exposure which had grown to not only exceed the top of the target range of 15 - 25%, but also the guideline limit of 35%. A further rebalancing with fixed rate financing in 2015/16 resulted in the short term and floating rate exposure dropping below 15%. Since this time, further long term advances to Centra have been issued at floating rates in an attempt to maintain Centra's interest rate exposure within the target range.

It is confirmed that Figure 3.7 from Tab 3 of the current Application is the update to chart 3 from CAC/Centra I-19 from the 2013/14 GRA. The most recent version of the chart is provided in part b) of this response and includes debt series CG23 ($20 million) issued on January 25, 2019 and maturing in fiscal 2023.

i) The following Centra term sheets relate to debt issued since the 2013/14 GRA. The interest rate for each was assigned based on an actual Manitoba Hydro debt issue with the same issue date, interest rate and term to maturity.

TERM SHEET

Series CG18

Intercompany Advance from the Manitoba Hydro-Electric Board (MHEB)

Principal	**$10,000,000 CAD**
Issue Date	November 26, 2013
Maturity Date	June 2, 2023
Term to Maturity	9.5 Years
Coupon Rate	3.398%
Yield Rate	3.398%
Interest Payable	June 2 & December 2

NOTE: Long term inter-company advance Series CG18 was issued to Centra Gas Manitoba by the MHEB in order to finance $10 million of cumulative new capital cash requirements at November 26, 2013. The interest rate was assigned based on MHEB Series GF which was issued on November 26, 2013. Interest will accrue from the date of issuance November 26, 2013 with the first interest payment occurring December 2, 2013.

TERM SHEET

Series CG19

Intercompany Advance from the Manitoba Hydro-Electric Board (MHEB)

Principal	**$35,000,000 CAD**
Issue Date	March 2, 2015
Maturity Date	September 5, 2046
Term to Maturity	30.5 Years
Coupon Rate	2.902%
Yield Rate	2.902%
Interest Payable	March 5 & September 5

NOTE: Long term inter-company advance Series CG19 was issued to Centra Gas Manitoba by the MHEB in order to refinance maturing debt series CG10 ($35 million). The interest rate was assigned based on MHEB Series GK which was issued on March 2, 2015. Interest will accrue from the date of issuance March 2, 2015 with the first interest payment occurring March 5, 2015.

TERM SHEET

Series CG20
Intercompany Advance from the Manitoba Hydro-Electric Board (MHEB)

Principal	**$35,000,000 CAD**
Issue Date	June 11, 2015
Maturity Date	June 2, 2025
Term to Maturity	10 Years
Coupon Rate	2.549%
Yield Rate	2.549%
Interest Payable	June 2 & December 2

NOTE: Long term inter-company advance Series CG20 was issued to Centra Gas Manitoba by the MHEB in order to finance new borrowing requirements. The interest rate was assigned based on MHEB Series GJ-3 which was issued on June 11, 2015. Interest will accrue from the date of issuance June 11, 2015 with the first interest payment occurring December 2, 2015.

TERM SHEET

Series CG21

Intercompany Advance from the Manitoba Hydro-Electric Board (MHEB)

Principal	**$20,000,000 CAD**
Issue Date	November 21, 2016
Maturity Date	November 21, 2019
Term to Maturity	3 Years
Coupon Rate	3BA + 0.1301227%
Yield Rate	3BA + 0.1301227%
Interest Payable	May & November 21

NOTE: Long term inter-company advance Series CG21 was issued to Centra Gas Manitoba by the MHEB in order to finance new borrowing requirements. The interest rate was assigned based on MHEB Series GQ-3 which was issued on November 21, 2016. Interest will accrue from the date of issuance November 21, 2016 with the first interest payment occurring May 21, 2017.

TERM SHEET

Series CG22
Intercompany Advance from the Manitoba Hydro-Electric Board (MHEB)

Principal	**$9,903,000 CAD**
Issue Date	February 20, 2018
Maturity Date	August 17, 2027
Term to Maturity	9.5 Years
Coupon Rate	3BA + 0.2958%
Yield Rate	3BA + 0.2958%
Interest Payable	February & August 17

NOTE: Long term inter-company advance Series CG22 was issued to Centra Gas Manitoba by the MHEB in order to finance new borrowing requirements. The interest rate was assigned based on MHEB Series C157-5B which was issued on February 20, 2018. Interest will accrue from the date of issuance February 20, 2018 with the first interest payment occurring August 17, 2018.

TERM SHEET

Series CG23

Intercompany Advance from the Manitoba Hydro-Electric Board (MHEB)

Principal	**$20,000,000 CAD**
Issue Date	January 25, 2019
Maturity Date	December 15, 2022
Term to Maturity	3.9 Years
Coupon Rate	3BA + 0.1750%
Yield Rate	3BA + 0.1750%
Interest Payable	June & December 15

NOTE: Long term inter-company advance Series CG23 was issued to Centra Gas Manitoba by the MHEB in order to finance new borrowing requirements. The interest rate was assigned based on MHEB Series C166-B which was issued on January 25, 2019. Interest will accrue from the date of issuance January 25, 2019 with the first interest payment occurring June 15, 2019.

j) Please find below a continuity schedule of long term debt from 2012/13 actual to 2019/20 forecast.

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Long Term Debt Continuity Schedule

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($000's)

	2012	2012/13			2013/14			2014/15			2015/16		
	Ending Balance	Maturities	New Advances	Ending Balance	Maturities	New Advances	Ending Balance	Maturities	New Advances	Ending Balance	Maturities	New Advances	Ending Balance
MH Advances													
CG1	62,671	(62,671)		-									
CG7	50,000			50,000			50,000			50,000			50,000
CG8	30,000			30,000			30,000			30,000			30,000
CG9	30,000			30,000			30,000			30,000			30,000
CG10	35,000			35,000			35,000	(35,000)		-			-
CG11	30,000			30,000			30,000			30,000			30,000
CG12	10,000			10,000			10,000			10,000			10,000
CG13	20,000			20,000			20,000			20,000			20,000
CG14	30,000			30,000			30,000			30,000			30,000
CG15			20,000	20,000			20,000			20,000			20,000
CG16			20,000	20,000			20,000			20,000			20,000
CG17			20,000	20,000			20,000			20,000			20,000
CG18						10,000	10,000			10,000			10,000
CG19									35,000	35,000			35,000
CG20												35,000	35,000
CG21													
CG22													
CG23													
New Debt - March 2020													
Total	**297,671**	**(62,671)**	**60,000**	**295,000**	**-**	**10,000**	**305,000**	**(35,000)**	**35,000**	**305,000**	**-**	**35,000**	**340,000**

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Long Term Debt Continuity Schedule

($000's)

	2016	2016/17			2017/18			2018/19			2019/20 Forecast		
	Ending Balance	Maturities	New Advances	Ending Balance	Maturities	New Advances	Ending Balance	Maturities	New Advances	Ending Balance	Maturities	New Advances	Ending Balance
MH Advances													
CG1													
CG7	50,000			50,000			50,000			50,000			50,000
CG8	30,000			30,000			30,000			30,000			30,000
CG9	30,000			30,000			30,000			30,000			30,000
CG10	-			-			-			-			-
CG11	30,000			30,000			30,000			30,000			30,000
CG12	10,000			10,000			10,000			10,000			10,000
CG13	20,000			20,000			20,000			20,000			20,000
CG14	30,000			30,000			30,000			30,000			30,000
CG15	20,000			20,000			20,000			20,000			20,000
CG16	20,000			20,000			20,000			20,000			20,000
CG17	20,000			20,000			20,000			20,000			20,000
CG18	10,000			10,000			10,000			10,000			10,000
CG19	35,000			35,000			35,000			35,000			35,000
CG20	35,000			35,000			35,000			35,000			35,000
CG21			20,000	20,000			20,000			20,000	(20,000)		-
CG22						9,903	9,903			9,903			9,903
CG23									20,000	20,000			20,000
New Debt - March 2020												50,000	50,000
Total	**340,000**	**-**	**20,000**	**360,000**	**-**	**9,903**	**369,903**	**-**	**20,000**	**389,903**	**(20,000)**	**50,000**	**419,903**

k) Following is a comparison between the approved 2013/14 Finance expense of $17,296 (CGAAP) and the 2019/20 projected Finance expense of $21,603.

CENTRA GAS MANITOBA INC.
Finance Expense
($000'S)

	Approved IFF12 2013/14	Approved Budget 2019/20	Difference
Interest on Long Term Debt/Advances	12,544	15,398	2,854
Provincial Guarantee Fee on Long Term Debt	2,950	3,899	949
Amortization of Debt Discounts	-	-	-
Interest on Short Term Debt	284	1,073	789
Provincial Guarantee Fee on Short Term Debt	25	213	188
Interest on Common Assets	3,020	1,220	(1,800)
Interest on Inventory	151	125	(26)
Interest Capitalized	(2,047)	(1,187)	860
Carrying Costs on Furnace Replacement Program	369	862	493
Other	-	-	-
Total Finance Expense under CGAAP	17,296	21,603	4,307

Finance expense is higher by $4.307 million in the Approved Budget for 2019/20 versus IFF12 for 2013/14. Higher interest on long term is due to higher debt balances as a result of asset growth. Interest on short term debt is higher due to both a higher volume of short term debt as well as a higher forecast interest rate. Consequently, the provincial guarantee fee on both long term and short term debt is higher due to the higher debt balances.

The carrying costs on deferred taxes, which is the driver of the interest capitalized variance, are lower in the Approved Budget for 2019/20 due to a lower unamortized balance of deferred taxes.

The carrying costs on the furnace replacement program have increased due to an increase in the forecast short term interest rate as well as an increase in the balance of the liability since 2013/14.

Partially offsetting these variances is lower interest on common assets due to a lower weighted average interest rate, a reduction in the cost allocation to Centra from 10% to 8%, and a lower net book value of assets.

REFERENCE:

Tab 3 – Section 3.5 Centra's Debt Portfolio and Interest Rate Risk (pg 15-16), Tab 5 – Section 5.2.5 – Finance Expense - Pages 20-24 and Appendix 5.13 – Tab 5 Figures Updated - Page 10

PREAMBLE TO IR (IF ANY):

The PUB approved Finance expense from the 2013/14 Test Year was $17,296. Centra is now forecasting Finance expense of $21,603 for the 2019/20 Test Year for rate-setting purposes including net movement in regulatory deferrals (Appendix 5.12 (Update), Page 4, Figure 3, line 52).

Centra states on page 15 of Tab 3, lines 22 to 24 "During the past few years, the interest rate risk on the existing debt portfolio has been mitigated by rebalancing the percentage of short term debt, floating rate long term debt and fixed rate long term debt with the existing debt portfolio."

Centra states on page 16 of Tab 3, lines 10 to 12 "Centra will continue to transition its debt portfolio to apply the principles of Manitoba Hydro's debt management strategy, including those to manage the interest rate risk within the debt portfolio."

Centra does not provide any analysis of the cost and rate-setting implications of rebalancing the Centra debt portfolio or of applying the debt management strategy and interest rate policy/guidelines for Manitoba Hydro's electric operations to gas operations.

QUESTION:

l) Please provide a CGM18 scenario (with adjusted proposed and indicative rate increases and projected financial ratio calculations) and revised Figure 5.12 from Appendix 5.13, assuming that interest rates are 0.5% lower than forecast in CGM18 for the entire term of the forecast.

RATIONALE FOR QUESTION:

To understand the appropriateness and impact of applying the Manitoba Hydro debt management and interest rate risk policies and guidelines to Centra and the key business drivers for the changes in Finance expense since the 2013/14 GRA.

RESPONSE:

The impact of a 50 basis point reduction in interest rates is approximately $630K in 2019/20 based on the Approved Budget. The finance expense details of this scenario can be found in the updated Figure 5.12 shown below.

The long-term impact of a 50 basis point decrease in interest rates is an increase of approximately $12 million in retained earnings by 2028. This can be found in the CGM18 scenario financial statements and detailed ratios provided below. Rate increases have not been adjusted in this scenario as the equity ratio remains in the 30% range.

CENTRA GAS MANITOBA INC.
Finance Expense
($000'S)

Figure 5.12
Updated for 2019/20 Approved Budget - Interest Rates Decreased by 50bp

	CGAAP				IFRS					
	2011/12	2012/13	2013/14	2014/15	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Forecast	Test Year
Interest on Long Term Debt/Advances	14 390	13 438	12 569	12 810	12 810	13 941	14 033	14 410	14 765	15 218
Provincial Guarantee Fee on Long Term Debt	2 977	2 977	2 950	3 050	3 050	3 050	3 400	3 600	3 699	3 899
Amortization of Debt Discounts	318	167	-	-	-	-	-	-	-	-
Interest on Short Term Debt	102	153	267	728	728	218	136	397	598	829
Provincial Guarantee Fee on Short Term Debt	126	71	193	277	277	726	356	263	373	213
Interest on Common Assets	2 703	2 823	1 993	1 977	1 977	1 840	1 419	1 687	1 505	1 220
Interest on Inventory	104	162	168	152	152	130	130	127	123	125
Interest Capitalized	(2 512)	(2 115)	(2 319)	(3 230)	(201)	(339)	(896)	(371)	(171)	(237)
Carrying Costs on Furnace Replacement Program	290	287	322	336	336	293	320	433	645	725
Other	(33)	(12)	(22)	89	89	(13)	31	34	-	-
Total Finance Expense	18 464	17 952	16 120	16 188	19 217	19 847	18 930	20 580	21 536	21 993
Year over year $ change		(513)	(1 831)	67	3 029	630	(917)	1 650	956	457
Year over year % change		-2.8%	-10.2%	0.4%	18.7%	3.3%	-4.6%	8.7%	4.6%	2.1%

GAS OPERATIONS (CGM18)
PROJECTED OPERATING STATEMENT
CGM18 - Interest Rates Decreased by 50bp
(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	24	26	26	27	28	29	30	31
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	156	159	162	166	169	172	176	179
Net Income before Net Movement in Regulatory Deferral	1	(0)	2	5	5	5	6	6	6	7
Net Movement in Regulatory Deferral **	3	3	3	3	3	3	2	3	3	2
Net Income	3	3	5	8	8	8	8	9	9	9

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

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

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
*****Additional Revenue Requirement**										
Percent Increase	0.00%	0.00%	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%
Financial Ratios										
Equity Ratio (PUB Approved Methodology)	32%	31%	30%	29%	29%	29%	30%	30%	30%	30%
EBITDA Interest Coverage	2.85	2.81	2.87	2.90	2.91	2.84	2.82	2.82	2.76	2.74
Capital Coverage	0.78	0.71	0.59	1.09	1.11	1.11	1.13	1.14	1.17	1.16

GAS OPERATIONS (CGM18)
PROJECTED BALANCE SHEET
CGM18 - Interest Rates Decreased by 50bp
(In Millions of Dollars)

For the year ended March 31	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
ASSETS										
Plant in Service	622	658	698	737	776	814	854	894	935	977
Accumulated Depreciation	(65)	(79)	(95)	(112)	(130)	(148)	(168)	(187)	(208)	(229)
Net Plant in Service	557	579	603	626	646	666	686	707	727	747
Construction in Progress	6	9	6	4	4	4	4	4	4	4
Current and Other Assets	92	92	92	92	92	92	92	92	92	92
Goodwill and Intangible Assets	10	9	9	9	9	9	9	9	9	9
Total Assets before Regulatory Deferral	665	689	710	730	751	771	791	812	832	853
Regulatory Deferral Balance	106	109	113	116	118	121	123	126	128	130
	771	798	823	846	869	891	914	937	960	983
LIABILITIES AND EQUITY										
Long-Term Debt	390	440	480	470	500	520	505	555	555	575
Current and Other Liabilities	122	102	81	105	89	81	108	72	85	78
Deferred Revenue	47	49	49	50	52	55	57	58	59	60
Share Capital	121	121	121	121	121	121	121	121	121	121
Retained Earnings	79	82	87	95	103	111	119	128	136	145
Total Liabilities and Equity before Regulatory Deferral	759	794	818	842	865	887	910	933	957	979
Regulatory Deferral Balance	12	5	4	4	4	4	4	4	4	3
	771	798	823	846	869	891	914	937	960	983
Net Debt	441	472	508	524	540	555	570	585	598	610
Equity (PUB Approved Methodology)	32%	31%	30%	29%	29%	29%	30%	30%	30%	30%

GAS OPERATIONS (CGM18)
PROJECTED CASH FLOW STATEMENT
CGM18 - Interest Rates Decreased by 50bp
(In Millions of Dollars)

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

GAS OPERATIONS (CGM18)
PROJECTED FINANCIAL RATIOS
CGM18 - Interest Rates Decreased by 50bp

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	514.903	529.903	547.403	559.903	569.952
Average Due to Parent	37.384	31.456	30.299	31.473	32.073	32.450	32.832	30.143	31.483	34.267
Average Debt	**427.287**	**456.359**	**490.202**	**516.376**	**531.976**	**547.353**	**562.735**	**577.546**	**591.386**	**604.218**
Average Share Capital	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250	121.250
Average Retained Earnings	77.225	80.317	84.442	91.001	98.781	106.662	114.633	123.200	132.138	140.922
Average Equity	**198.474**	**201.567**	**205.692**	**212.251**	**220.031**	**227.911**	**235.882**	**244.450**	**253.388**	**262.172**
Average Debt	427.287	456.359	490.202	516.376	531.976	547.353	562.735	577.546	591.386	604.218
Average Equity	198.474	201.567	205.692	212.251	220.031	227.911	235.882	244.450	253.388	262.172
Average Debt and Equity	625.761	657.926	695.894	728.627	752.007	775.265	798.618	821.995	844.774	866.390
PUB Approved Equity Ratio	**31.72%**	**30.64%**	**29.56%**	**29.13%**	**29.26%**	**29.40%**	**29.54%**	**29.74%**	**29.99%**	**30.26%**

GAS OPERATIONS (CGM18)
PROJECTED FINANCIAL RATIOS
CGM18 - Interest Rates Decreased by 50bp

For the year ended March 31	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
INTEREST COVERAGE										
Net Income	3.267	2.917	5.333	7.785	7.774	7.987	7.955	9.180	8.696	8.872
Finance Expense	20.502	21.630	23.180	24.444	25.199	26.493	27.485	28.211	29.617	30.334
Capitalized Interest	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	23.941	24.784	28.764	32.360	33.008	34.516	35.476	37.429	38.350	39.245
Finance Expense	20.502	21.630	23.180	24.444	25.199	26.493	27.485	28.211	29.617	30.334
Capitalized Interest	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	20.674	21.867	23.431	24.576	25.234	26.529	27.521	28.248	29.655	30.373
Interest Coverage	**1.16**	**1.13**	**1.23**	**1.32**	**1.31**	**1.30**	**1.29**	**1.32**	**1.29**	**1.29**
Add: Depreciation and Amortization *	34.899	36.694	38.540	38.811	40.399	40.930	42.096	42.256	43.428	43.831
Total EBITDA	58.840	61.478	67.304	71.172	73.407	75.446	77.571	79.684	81.778	83.075
EBITDA Interest Coverage	**2.85**	**2.81**	**2.87**	**2.90**	**2.91**	**2.84**	**2.82**	**2.82**	**2.76**	**2.74**

* Includes amortization of deferred income tax

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
CAPITAL COVERAGE										
Internally Generated Funds	27.389	28.303	22.569	42.402	44.262	45.220	46.720	48.003	50.299	50.956
Capitalized Interest*	0.171	0.237	0.251	0.132	0.035	0.035	0.036	0.037	0.037	0.038
	27.560	28.540	22.820	42.534	44.297	45.256	46.756	48.040	50.337	50.995
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**	**0.71**	**0.59**	**1.09**	**1.11**	**1.11**	**1.13**	**1.14**	**1.17**	**1.16**

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

REFERENCE:

Tab 3 – Section 3.1.3 Regulatory Deferral Accounts (pg 3-4), Appendix 3.4 – Regulatory Deferral Accounts & Accounting Estimates Update, Appendix 3.7 – Appendix 3.4 Updates and Appendix 5.13 – Tab 5 Figures Updated

PREAMBLE TO IR (IF ANY):

Centra is requesting PUB endorsement of a number of new regulatory deferral accounts associated with the transition to IFRS and depreciation account and rates as well as the associated amortization periods as outlined in Appendix 3.4 of the Application.

QUESTION:

a) On page 1 of Appendix 3.4, lines 8 to 10, Centra indicates that it continues to recognize regulatory deferral accounts under IFRS in accordance with IFRS standard, IFRS 14 Regulatory Deferral Accounts. Please provide an update on the International Accounting Standard's Board project with respect to a permanent accounting standard for Regulated Activities and any implications for Centra for rate-setting purposes.
b) Centra is requesting PUB endorsement to record ineligible overhead costs as a regulatory deferral account and to amortize the balance in this account over 34 years (Page 4, lines 7 to 11 of Appendix 3.4) consistent with the PUB approved period in Order 59/18. Please provide the projected weighted average (composite) depreciation rate and average remaining life for Centra's plant assets for 2019/20 and explain if the 34 years that was selected for the amortization period for electric operations is appropriate for gas operations.
c) Please summarize the reasons that support the proposed services lives and provide the impact on 2019/20 depreciation expense for each of the proposed three new depreciation accounts related to (i) gas meter testing/sampling (ii) cathodic protection – transmission and (iii) cathodic protection – distribution (Page 6, lines 14 to 34 and page 7, lines 1 to 5 of Appendix 3.4).
d) Please summarize the reasons that support the proposed service life for the updated gas meter depreciation rate (Page 9, lines 11 to 25 of Appendix 3.4).

e) Please summarize the reasons that support the proposed service life and provide the impact on 2019/20 depreciation expense for the new depreciation account to capture the costs associated with the implementation of the use of In-Line Inspection tools (Page 10, lines 9 to 14 of Appendix 3.4).

f) Please provide a breakdown of the additions to Regulatory Costs on line 9 of Figure 5.20, Appendix 5.13 for 2014/15 to 2019/20 by type of cost or regulatory proceeding, delineating between (i) Centra costs (ii) PUB and PUB advisor costs and (iii) Intervenor costs.

g) Please provide a breakdown of the amortization of Regulatory Costs on line 22 of Figure 5.20, Appendix 5.13 for 2014/15 to 2019/20 by type of cost or regulatory proceeding, delineating between (i) Centra costs, (ii) PUB and PUB advisor costs and (iii) Intervenor costs.

RESPONSE:

a) The International Accounting Standards Board (“IASB”) continues to have rate regulated accounting on its agenda. It is expected that a Discussion Paper or Exposure Draft will be issued in late 2019 or early 2020. At this time, Centra is unaware of any implications for rate setting purposes.

b) The last update to the probable remaining lives for Centra’s plant assets was determined as part of the 2014 Depreciation study. Based on the 2014 asset account balances and each account’s probable remaining service life (assuming ASL no salvage depreciation rates), the weighted average probable remaining life of Centra‘s assets is 42 years. The composite ASL (no salvage) depreciation rate for the 2014 study was 1.84% or 54 years.

Overall, the 34 year amortization period for ineligible overhead was chosen for the gas operations to be consistent with the period directed for the Electric operations in Order 59/18.

c) **Gas meter exchanges, testing/sampling:** The proposed 10 year amortization period is consistent with the 10-12 year seal life of new gas meters. In accordance with Measurement Canada requirements, meters must be tested prior to the expiration of their seal life. For the 2019/20 test year, Centra expects to capitalize $3.4 million (Schedule 6.1.8) of costs for gas meter exchanges and testing and recognize $0.154 million (Schedule 6.3.8) of depreciation expense.

Cathodic protection – transmission: The proposed 25 year life reflects the ratio of sacrificial anodes to rectifiers used for the cathodic protection of Centra's transmission system. Approximately 42% of the transmission system is protected by sacrificial anodes which have a service life of approximately 15 years for transmission lines and 58% of the line is protected by rectifier/ground beds which have an estimated service life of 25-35 years. On a pro-rated basis, the service life works out to be approximately 27 years. For the 2019/20 test year, Centra expects to capitalize $0.128 million (Schedule 6.1.8) of costs for transmission cathodic protection and recognize $0.044 million (Schedule 6.3.8) of depreciation expense.

Cathodic protection – distribution: The proposed 15 year life reflects the ratio of sacrificial anodes to rectifiers used for the cathodic protection of Centra's distribution system. Approximately 82% of the distribution system is protected by anodes which have a service life of approximately 10 years for distribution lines and 18% of the line is protected by rectifier/ground beds which have an estimated service life of 25-35 years. On a pro-rated basis, the service life works out to be approximately 15 years and as such, a 15 year depreciation period was chosen. For the 2019/20 test year, Centra expects to capitalize $0.317 million (Schedule 6.1.8) of costs for distribution cathodic protection and recognize $0.303 million (Schedule 6.3.8) of depreciation expense.

d) The estimated service life of gas meters was reduced from 25 to 20 years due to the exceptionally large retirement losses experienced for gas meters in 2014/15 and 2015/16 (approximating $1 million) following the completion of the 2014 Depreciation study. The losses were an indication that the meters were retiring several years prior to the previous 25 year service life estimate.

e) In 2015, Centra implemented the use of In-line Inspection ("ILI") tools to measure metal loss and deformation anomalies of the natural gas pipeline system. The use of ILI supports Centra's requirements for the inspection, defect assessment and remediation of its pipeline system. There are currently nine transmission pipeline systems that require inspection and the plan is to conduct an inspection of the pipelines every 5-10 years. As such, a 5 year depreciation period is proposed for this activity. For the 2019/20 test year, Centra expects to capitalize $1.66 million (Schedule 6.1.8) of costs for ILI and recognize $0.60 million (Schedule 6.3.8) of depreciation expense.

f) and g)

Please see the following schedule for a breakdown of the 2014/15 to 2019/20 additions to Regulatory Costs as per line 9 of Figure 5.20, Appendix 5.13, as well as the corresponding amortization amounts per line 22 of Figure 5.20, Appendix 5.13. The amounts have been broken down by regulatory proceeding, delineating between (i) Centra costs (ii) PUB and PUB advisor costs and (iii) Intervenor costs.

Centra Gas - Regulatory Deferrals

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

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

REFERENCE:

Tab 3 – Section 3.1.3 Regulatory Deferral Accounts (pg 3-4), Appendix 3.4 – Regulatory Deferral Accounts & Accounting Estimates Update, Appendix 3.7 – Appendix 3.4 Updates and Appendix 5.13 – Tab 5 Figures Updated

PREAMBLE TO IR (IF ANY):

Centra is requesting PUB endorsement of a number of new regulatory deferral accounts associated with the transition to IFRS and depreciation account and rates as well as the associated amortization periods as outlined in Appendix 3.4 of the Application.

QUESTION:

h) Please also provide a breakdown of the forecast costs associated with the 2019/20 GRA delineating between (i) Centra costs (ii) PUB and PUB advisor costs and (iii) Intervenor costs.
i) Please provide an estimate of the hours, hourly rates and projected costs for any external experts (Mr. Drazen etc.) and external legal counsel that Centra is planning to use for the 2019/20 GRA proceeding.

RATIONALE FOR QUESTION:

To understand the rate-setting impacts of the proposed new depreciation, deferral accounts and regulatory costs as well as the associated amortization periods.

RESPONSE:

h) Please see the following table for the requested information. The estimate of intervener costs was informed by the costs in previous natural gas proceedings and escalated to take into account the increase in hourly rates since these proceedings. Centra notes that the revised budgets provided by interveners for this proceeding and acknowledged by the PUB is $890 thousand.

	in ($000)	2019/20 GRA Budget
h)(i)	Centra Internal Costs	$ 1,170
h)(ii)	PUB Advisors	$ 750
h)(iii)	Interveners	$ 500
	Total	$ 2,420

Note: Centra internal costs include labour, consulting, printing, publication of Public Notices, and meals.

i) At the present time, Centra has not planned to retain external legal counsel for this proceeding. Centra will make a determination on its use of external legal counsel following the submission of intervener evidence.

The estimate number of hours and hourly rates of its external consultants is confidential information. The total projected costs for Centra's external consultants for this proceeding is $161 thousand.

REFERENCE:

Tab 3 – Section 3.1.3 Regulatory Deferral Accounts (pg 3-4), Appendix 3.4 – Regulatory Deferral Accounts & Accounting Estimates Update, Appendix 3.7 – Appendix 3.4 Updates and Appendix 5.13 – Tab 5 Figures Updated

PREAMBLE TO IR (IF ANY):

Centra is requesting PUB endorsement of a number of new regulatory deferral accounts associated with the transition to IFRS and depreciation account and rates as well as the associated amortization periods as outlined in Appendix 3.4 of the Application.

QUESTION:

j) Please provide a breakdown of the amortization of the projected costs associated with the 2019/20 GRA by year, including the proposed amortization period.

RATIONALE FOR QUESTION:

To understand the rate-setting impacts of the proposed new depreciation, deferral accounts and regulatory costs as well as the associated amortization periods.

RESPONSE:

j) Centra Gas is projecting to defer $1.7 million in costs associated with the 2019/20 GRA. Please see the response to CAC/Centra I-10 f) for a breakdown of the source (i.e. Centra, PUB, Intervenor) of the $1.7 million. Centra's Application assumed amortization would occur over a 24-month period commencing on August 1, 2019. The annual amortization expense is projected as follows:
   - 2019/20 - $566 667
   - 2020/21 - $850 000
   - 2021/22 - $283 333

REFERENCE:

Tab 6 – Section 6.6 Regulatory Deferrals (pg 8-11)

PREAMBLE TO IR (IF ANY):

On page 9 of Tab 6, Centra indicates that it has included most of the regulatory deferral balances in the Rate Base calculations, including (1) DSM (2) Regulatory hearing costs (3) Site restoration costs (4) Ineligible Overhead (5) Impact of 2014 Depreciation Study (6) Change in gas meters depreciation rate (6) Change in depreciation method and (7) Losses on disposal of assets.

Centra notes that the inclusion of DSM in rate base was accepted by the PUB in Order 128/09 but does not note that the other regulatory deferral accounts have not been approved by the PUB to be included in Rate Base.

Centra notes on page 10 of Tab 6, lines 1 to 3 that "The deferral accounts are proposed for inclusion in rate base in order to adjust the IFRS based financial statement values for plant and intangible assets to the PUB endorsed values for rate setting purposes." Centra had requested approval of the PUB to align the Overall Rate of Return and Return on Rate Base to consider the financing of regulatory deferral accounts in three separate regulatory hearings which have all been denied each time by the PUB in the following findings sections of regulatory decisions:
- Order 8/97 (1997 GRA) – Section 7.6, Page 27;
- Order 79/98 (1998 GRA) – Section 8.7, Page 67; and
- Order 118/03 (2013/14 GRA) – Section 13.7, Page 70.

QUESTION:

a) Please elaborate on Centra's reasons for the inclusion of all the regulatory deferral accounts listed in the preamble into Rate Base.
b) Please add an extra column to Schedule 6.5.8 (Update) which lists which of the specific regulatory deferral accounts have previously been approved by the PUB to be included

in Rate Base and which of the deferral accounts Centra is now requesting approval to include in Rate Base in the 2019/20 GRA.

c) For the 2019/20 Test Year, please provide the total requested increase in Rate Base for regulatory deferral accounts that have not been previously approved by the PUB to be included in Rate Base.

d) Please provide the following schedules that exclude the additional Rate Base related to regulatory deferral accounts that is calculated in part (b) of the question for the 2019/20 Test Year (i) Schedule 6.0.0 - Summary of Rate Base Rate of Return (Update) (ii) Schedule 6.5.8 – Regulated Deferrals Continuity Schedule – 2019/20 Test Year (Update) (iii) Schedule 6.7.8 – Working Capital Allowance – 2019/20 Test Year (Update) (iv) Schedule 6.8.8 – Overall Rate of Return – 2019/20 Test Year (Update) and (v) Schedule 6.10.8 – Return on Rate Base – 2019/20 Test Year (Update).

e) Please explain if the inclusion of the additional regulatory deferral balances in Rate Base that is calculated in part (b) of the question impacts the forecasted increase in net income requirements from the $3 million approved by the PUB to a forecast of around $7 million in 2021/22 to 2027/18 included in CGM18. If so, please provide a CGM18 scenario (including adjusted indicative rate increases and projected ratio calculations) that recalculates the forecast net income requirements and indicative rate increases from 2021/21 to 2027/18 excluding the additional Rate Base amount calculated in part (b).

RATIONALE FOR QUESTION:

To understand the reasons and implications of Centra's proposal to change the calculation of rate base to include most of its regulatory deferral accounts and if Centra's policy to use a COS framework to set rates in under review.

RESPONSE:

a) As outlined in the Application, Tab 6, Section 6.6, Centra has included DSM, site restoration and regulatory hearing costs in its working capital allowance.

   The PUB previously approved the inclusion of DSM in working capital. Similar to DSM programming, site restoration and regulatory hearing costs must be paid by Centra until reimbursement is obtained from customers. These items are working capital as they require cash to bridge the gap between the expenditures and the future receipt of payments from customers. The purpose of a working capital allowance is to reimburse the utility for the use of its funds. As such, these investments should be included in the working capital component of rate base.

As outlined in the Application, Tab 6, Section 6.6, Centra has included ineligible overhead, impact of 2014 depreciation study, change in depreciation rate for gas meters, change in depreciation method (difference between ELG and CGAAP ASL) and the loss on disposal of assets in rate base. The intent of this was to include costs that were previously part of rate base (in net property, plant & equipment) under CGAAP before Centra adopted IFRS.

Ineligible overhead amounts were previously capitalized. IFRS does not allow for capitalization of those costs; however the PUB has directed Manitoba Hydro to continue to capitalize these costs as regulatory deferrals. To be consistent with Manitoba Hydro, Centra adopted the same practice. If these costs were allowed as operating costs, they would form part of the determination of the working capital allowance, which as part of rate base earns a full rate of return.

Similarly, the regulatory account recording the difference between ASL and ELG deprecation rates should be included in rate base as the assets are recorded in property plant & equipment and rate base at a lower net book value (based on ELG depreciation). If the difference between ASL and ELG is not included in rate base, then revenue requirement would need to be adjusted to reflect ELG depreciation. The rationale for including the impact of the 2014 depreciation study and the change in depreciation rate for gas meters in rate base is similar.

Prior to the implementation of IFRS, the loss on disposal of assets was recorded as an adjustment to accumulated depreciation, effectively lowering net book value of the retired asset to zero. Under IFRS, the loss on disposal of assets is recorded through depreciation expense, and then removed from the income statement and deferred as a regulatory asset through net movement. The exclusion of the regulatory deferral for the loss on disposal of assets from rate base would result in an understatement of rate base as the full cost of the asset is removed but the net book value is not zero as the asset was not fully depreciated. The addition of the regulatory deferral to rate base results in a net book value of zero for the retired asset.

Including these costs in rate base provides a return to Centra that reflects the investment of cash prior to the collection of these costs from ratepayers. It should be noted that these deferrals should be recovered from ratepayers in future periods through the inclusion of amortization in revenue requirement.

b) Please see the following schedule (Schedule 6.5.8 (Update)) which provides the regulatory deferral accounts which Centra has requested PUB endorsement of in this Application.

CENTRA GAS MANITOBA INC. **Schedule 6.5.8 (Update)**
Regulated Deferrals Continuity Schedule
2019/20 Test Year **($000'S)**

	Balance Mar 31/19	Additions	Amortization /Recovery	Balance Mar 31/20	
	[1]	[2]	[3]	[4]	
Regulatory Deferral Debit Balance					
Included in Rate Base					
Investment in Demand Side Management	54 458	8 483	(9 946)	52 996	Approved
Site Restoration	1 765	-	(314)	1 452	Endorsement Requested
Regulatory Costs	2 325	2 145	(1 493)	2 977	Endorsement Requested
Total included in Working Capital	58 549	10 628	(11 753)	57 424	
Change in Depreciation Method	11 107	2 389	-	13 496	Endorsement Requested
Deferred Ineligible Overhead	3 335	700	(113)	3 922	Endorsement Requested
Change in Depreciation Rate - Meters	1 929	-	(96)	1 833	Endorsement Requested
Loss on Disposal of Assets	12 730	1 803	(374)	14 159	Endorsement Requested
DSM Deferral **(1)**	-	-	-	-	NA
Total included in Regulatory Deferrals	29 102	4 892	(584)	33 410	
Excluded from Rate Base					
Deferred Taxes	18 042	1 389	(3 193)	16 238	Excluded
Total Deferred Debit Balance	105 693	16 909	(15 529)	107 072	
Regulatory Deferral Credit Balance					
Included in Rate Base					
DSM Deferral **(1)**	-	-	-	-	NA
Impact of 2014 Depreciation Study	4 718	-	(139)	4 579	Endorsement Requested
Total included in Regulatory Deferrals	4 718	-	(139)	4 579	
Excluded from Rate Base					
PGVA	21 757	-	(14 031)	7 726	Excluded
Total Deferred Credit Balance	26 475	-	(14 170)	12 306	
Net Balance	**79 218**	**16 909**	**(1 360)**	**94 766**	

(1) The DSM deferral asset and corresponding liability have been assumed to be written-off on March 31, 2019 to comply with PUB Board Order 59/18 from the 2017/18 and 2018/19 Electric GRA

c) For the 2019/20 Test Year, Centra has included $31 million in regulatory deferrals into its rate base as follows:

Regulatory Deferrals Included in Rate Base ($000s)	IFRS 2019/20 Test Year
Regulatory Deferral Accounts (A)	26 603
Investment in Regulatory Costs (Working Capital)	2 847
Investment in Site Restoration (Working Capital)	1 608
	31 059

(A) Includes the regulatory deferral debit and credit 13-month balances relating to: (i) change in depreciation method, (ii) deferred ineligible overhead, (iii) loss on disposal of assets, (iv) change in depreciation rate on meters, and (v) impact of 2014 depreciation study.

d) The removal of the regulatory deferral accounts identified in part b) from rate base would require an increase to revenue requirement to reflect these as period costs. This would result in a disconnect between the costs included in rate base and the costs included in revenue requirement and is not aligned with the regulatory accounting treatment of these costs previously endorsed by the PUB for Manitoba Hydro. For example, the removal of the ineligible overhead deferral account from rate base would result in an increase in operating and administrative expense included in revenue requirement. As such, Centra is not providing the requested schedules.

e) The inclusion of regulatory balances in the rate base would increase the overall return on rate base. However, the indicative rate increases and resulting net income requirements set out in CGM18 for the years 2021/22 to 2027/28 were established in order to sustain the equity capitalization at or around the 30% level endorsed by the PUB as discussed in Tab 3 section 3.4 of the Application.

REFERENCE:

Tab 6 – Section 6.6 Regulatory Deferrals (pg 8-11)

PREAMBLE TO IR (IF ANY):

On page 9 of Tab 6, Centra indicates that it has included most of the regulatory deferral balances in the Rate Base calculations, including (1) DSM (2) Regulatory hearing costs (3) Site restoration costs (4) Ineligible Overhead (5) Impact of 2014 Depreciation Study (6) Change in gas meters depreciation rate (6) Change in depreciation method and (7) Losses on disposal of assets.

Centra notes that the inclusion of DSM in rate base was accepted by the PUB in Order 128/09 but does not note that the other regulatory deferral accounts have not been approved by the PUB to be included in Rate Base.

Centra notes on page 10 of Tab 6, lines 1 to 3 that “The deferral accounts are proposed for inclusion in rate base in order to adjust the IFRS based financial statement values for plant and intangible assets to the PUB endorsed values for rate setting purposes.”

Centra had requested approval of the PUB to align the Overall Rate of Return and Return on Rate Base to consider the financing of regulatory deferral accounts in three separate regulatory hearings which have all been denied each time by the PUB in the following findings sections of regulatory decisions:
- Order 8/97 (1997 GRA) – Section 7.6, Page 27;
- Order 79/98 (1998 GRA) – Section 8.7, Page 67; and
- Order 118/03 (2013/14 GRA) – Section 13.7, Page 70.

QUESTION:

f) Please confirm that Centra’s previous requests of the PUB to align the Overall Rate of Return and Return on Rate Base to consider the financing of regulatory deferral accounts in the 1997, 1998 and 2013/14 GRA’s all occurred when Centra’s rates were regulated under a Rate Base/Rate of Return (RBOR) rate-setting framework.

g) Please confirm that it was Centra that requested that it be regulated on a Cost of Service (COS) rate-setting framework in the 2005/06 & 2006/07 GRA, with part of the rationale for the change being that Manitoba Hydro did not require a return on equity from Centra.

RATIONALE FOR QUESTION:

To understand the reasons and implications of Centra's proposal to change the calculation of rate base to include most of its regulatory deferral accounts and if Centra's policy to use a COS framework to set rates in under review.

RESPONSE:

f) Centra assumes the reference to the 2013/14 General Rate Application should have been the 2003/04 General Rate Application given the reference to Order 118/03. Centra's rates were set on the basis of a Rate Base/Rate of Return methodology in each of the 1997/98, 1998/99 and 2003/04 General Rate Applications.

g) Not confirmed. Centra's understanding is that the discussion with respect to Centra moving toward setting rates based on a cost of service methodology similar to its parent company was raised at least as early as the Pre-Hearing Conference to Centra's 2004/05 COG application. As part of that proceeding, the PUB indicated that *"…given Centra's current status as a subsidiary of MH, the Board would initiate a discussion on the appropriateness of the current regulatory framework."*[1]

   As noted on page 84 of Order 131/04, issued following the 2004/05 COG application, the PUB encouraged Centra to file its next GRA on the basis of both rate base rate of return, and revenue requirement and cost of service, with emphasis on the latter, such to enable the PUB to take into account and compare revenue requirement and cost of service with the rate base, rate of return methodology in making future determinations.

[1] Page 81 of Order 131/04.

REFERENCE:

Tab 6 – Section 6.6 Regulatory Deferrals (pg 8-11)

PREAMBLE TO IR (IF ANY):

On page 9 of Tab 6, Centra indicates that it has included most of the regulatory deferral balances in the Rate Base calculations, including (1) DSM (2) Regulatory hearing costs (3) Site restoration costs (4) Ineligible Overhead (5) Impact of 2014 Depreciation Study (6) Change in gas meters depreciation rate (6) Change in depreciation method and (7) Losses on disposal of assets.

Centra notes that the inclusion of DSM in rate base was accepted by the PUB in Order 128/09 but does not note that the other regulatory deferral accounts have not been approved by the PUB to be included in Rate Base.

Centra notes on page 10 of Tab 6, lines 1 to 3 that “The deferral accounts are proposed for inclusion in rate base in order to adjust the IFRS based financial statement values for plant and intangible assets to the PUB endorsed values for rate setting purposes.”

Centra had requested approval of the PUB to align the Overall Rate of Return and Return on Rate Base to consider the financing of regulatory deferral accounts in three separate regulatory hearings which have all been denied each time by the PUB in the following findings sections of regulatory decisions:
- Order 8/97 (1997 GRA) – Section 7.6, Page 27;
- Order 79/98 (1998 GRA) – Section 8.7, Page 67; and
- Order 118/03 (2013/14 GRA) – Section 13.7, Page 70.

QUESTION:

h) Please provide Centra’s (i) understanding of the concept of working capital (ii) and explain why DSM expenditures would be considered to be part of a working capital allowance and (iii) if in Centra’s view, it continues to be appropriate to include DSM in working capital/rate base given the impending transition of natural gas DSM activities from Centra to Efficiency Manitoba.

i) Please provide the information in part (d) and (e), assuming that the additional requested deferral accounts and DSM are not included in Rate Base.

j) Please explain (i) why Centra has excluded Deferred Taxes and the PGVA from its proposed Rate Base calculation and (ii) what is different about these two regulatory deferral accounts from those for which Centra is now requesting approval to include in Rate Base.

k) Please confirm if it is Centra's understanding that if a cost is included in Rate Base, then it earns the overall rate of return under the RBROR rate-setting framework.

l) Further to the information requested in PUB/Centra I-60 (a) in the current proceeding, please explain if Centra is now requesting that it earn a full overall rate of return on most of its regulatory deferral accounts including accounts such as regulatory hearing costs.

RATIONALE FOR QUESTION:

To understand the reasons and implications of Centra's proposal to change the calculation of rate base to include most of its regulatory deferral accounts and if Centra's policy to use a COS framework to set rates in under review.

RESPONSE:

h) i) and ii) Please refer to the response to CAC/CENTRA I-11a.
iii) Centra's view is that it continues to be appropriate to include DSM in working capital regardless of who delivers the DSM programming.

i) Centra has not provided the requested schedules for the same reasons as outlined in CAC/CENTRA I-11d.

j) In Order 118/03 the PUB denied the inclusion of the unamortized balance of the one-time tax liability of $46 million in Rate Base, however allowed Centra to earn a full rate of return on the average unamortized balance which is included in revenue requirement. PGVA accounts may be either receivables or payables and attract carrying costs, reflecting the short-term nature of the account. As such, Centra has not included these amounts in rate base.

k) Confirmed. Centra understands that for purposes of the Rate Base/Rate of Return calculation, which is used a guideline by the PUB to assess the maximum revenue requirement allowed by Centra, it earns the overall rate of return for all costs included in its calculated rate base.

l) Centra has included regulatory deferral accounts in calculating the maximum allowed return under a RBROR methodology. Please see Centra's response to CAC/CENTRA I-11a for the reasons for inclusion of regulatory deferrals in rate base. Using the RBROR methodology, a 1.2% rate increase would be necessary to eliminate the shortfall in the revenue requirement, however Centra is not seeking a general revenue increase as part of this Application.

REFERENCE:

Tab 6 – Section 6.6 Regulatory Deferrals (pg 8-11)

PREAMBLE TO IR (IF ANY):

On page 9 of Tab 6, Centra indicates that it has included most of the regulatory deferral balances in the Rate Base calculations, including (1) DSM (2) Regulatory hearing costs (3) Site restoration costs (4) Ineligible Overhead (5) Impact of 2014 Depreciation Study (6) Change in gas meters depreciation rate (6) Change in depreciation method and (7) Losses on disposal of assets.

Centra notes that the inclusion of DSM in rate base was accepted by the PUB in Order 128/09 but does not note that the other regulatory deferral accounts have not been approved by the PUB to be included in Rate Base.

Centra notes on page 10 of Tab 6, lines 1 to 3 that "The deferral accounts are proposed for inclusion in rate base in order to adjust the IFRS based financial statement values for plant and intangible assets to the PUB endorsed values for rate setting purposes."

Centra had requested approval of the PUB to align the Overall Rate of Return and Return on Rate Base to consider the financing of regulatory deferral accounts in three separate regulatory hearings which have all been denied each time by the PUB in the following findings sections of regulatory decisions:
- Order 8/97 (1997 GRA) – Section 7.6, Page 27;
- Order 79/98 (1998 GRA) – Section 8.7, Page 67; and
- Order 118/03 (2013/14 GRA) – Section 13.7, Page 70.

QUESTION:

m) Please explain if based on Centra's overall commentary in Sections 3.2, 3.3.3 and 3.4 of the Application as well as Mr.Drazen's Evidence (Appendix 3.5, Page 14) that "calculating Centra's revenue requirement using a deemed 30% equity ratio and a 8.5% ROE would meet its financial needs and result in distribution cost increases of about one percentage point higher than the current $3 million earnings target", the policy of Centra or its Board of Directors has changed since the 2005/06 & 2006/07 and subsequent Centra GRA's, such that it now wants to move closer to setting Centra's rates based on a RBROR rate-setting framework.

RATIONALE FOR QUESTION:

To understand the reasons and implications of Centra's proposal to change the calculation of rate base to include most of its regulatory deferral accounts and if Centra's policy to use a COS framework to set rates in under review.

RESPONSE:

Centra is not proposing a change in its rate-setting framework at this time. While the financial forecast provided beyond the 2019/20 test year is provided for informational purposes only and subject to the review and approval of Centra's Board of Directors, the commentary contained in Tab 3 of Centra's Application noted in the question was provided to demonstrate that the $3 million net income level and 70:30 debt-to-equity ratio are mutually exclusive in that restricting net income to $3 million annually results in a steady decline in the equity ratio to 26% capitalization by the end of the forecast period.

REFERENCE:

Tab 6 – Section 6.6 Regulatory Deferrals (pg 8-11)

PREAMBLE TO IR (IF ANY):

On page 9 of Tab 6, Centra indicates that it has included most of the regulatory deferral balances in the Rate Base calculations, including (1) DSM (2) Regulatory hearing costs (3) Site restoration costs (4) Ineligible Overhead (5) Impact of 2014 Depreciation Study (6) Change in gas meters depreciation rate (6) Change in depreciation method and (7) Losses on disposal of assets.

Centra notes that the inclusion of DSM in rate base was accepted by the PUB in Order 128/09 but does not note that the other regulatory deferral accounts have not been approved by the PUB to be included in Rate Base.

Centra notes on page 10 of Tab 6, lines 1 to 3 that "The deferral accounts are proposed for inclusion in rate base in order to adjust the IFRS based financial statement values for plant and intangible assets to the PUB endorsed values for rate setting purposes."

Centra had requested approval of the PUB to align the Overall Rate of Return and Return on Rate Base to consider the financing of regulatory deferral accounts in three separate regulatory hearings which have all been denied each time by the PUB in the following findings sections of regulatory decisions:
- Order 8/97 (1997 GRA) – Section 7.6, Page 27;
- Order 79/98 (1998 GRA) – Section 8.7, Page 67; and
- Order 118/03 (2013/14 GRA) – Section 13.7, Page 70.

QUESTION:

n) Please also explain if the policy of proposing Centra's rates based on a COS rate-setting framework is under review by the Centra Board as a part of the comprehensive review of Manitoba Hydro's strategy, operations and finances by the recently appointed MHEB.

RATIONALE FOR QUESTION:

To understand the reasons and implications of Centra's proposal to change the calculation of rate base to include most of its regulatory deferral accounts and if Centra's policy to use a COS framework to set rates in under review.

RESPONSE:

Currently, Centra's use of a COS framework to set rates is not in scope as part of Manitoba Hydro's development of a 20 year Strategic Business Plan. It is premature to speculate if it will become part of any Centra Board review until the 20 year strategic planning process is complete.

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:

Tab 5 – Section 5.2.7 Capital & Other Taxes (pg 29-33), Appendix 5.13 – Tab 5 Figures - Page 14

PREAMBLE TO IR (IF ANY):

The PUB approved Capital & Other Taxes from the 2013/14 Test Year was $18,750. Centra is now forecasting Capital & Other Taxes of $20,312 for the 2019/20 Test Year for rate-setting purposes including net movement in regulatory deferrals (Appendix 5.12 (Update), Page 4, Figure 3, Line 45).

Centra provides the following variance analysis of year over year changes in Capital & Other Taxes in Tab 5, pages 31 to 33:

"2012/13 Actual vs. 2011/12 Actual (CGAAP)
The 2012/13 decrease in capital and other taxes is primarily due to a decrease in municipal taxes. These taxes declined as a result of the 2012 province-wide reassessment of property taxes. In general, the value of Centra's property did not increase to the same extent as the average increase of all other property in Manitoba and as a result Centra's property taxes decreased…

2016/17 Actual vs. 2015/16 Actual (IFRS)
The 2016/17 decrease in capital and other taxes is primarily due to lower municipal taxes. These taxes declined as a result of the 2016 province-wide reassessment of property values. In general, the value of Centra's property did not increase to the same extent as the average increase of all other property in Manitoba and as a result Centra's property taxes decreased…

2018/19 Forecast vs. 2017/18 Actual (IFRS)
The 2018/19 capital and other taxes are expected to increase primarily as a result of higher municipal taxes…Property taxes are expected to increase as a result of an increase in assessed values of property as well as an increase in rates…
2019/20 Forecast vs. 2018/19 Forecast (IFRS)

The 2019/20 capital and other taxes are expected to increase primarily as a result of expected increases in assessed values property and in rates…"

In the March 22, 2019 Supplement (pages 5 and 8), Centra indicates for 2018/19 and 2019/20 forecasts that "The decrease in capital and other taxes of $0.3 million is primarily a result of decreased property tax due to recent reassessments that evaluated Centra properties at a lower value."

QUESTION:

a) Please provide a comparison between the approved 2013/14 Capital & Other Taxes of $18,750 (CGAAP) and the 2019/20 Test Year forecast of Capital & Other Taxes of $20,312 (for rate-setting purposes) and explain the key business drivers (asset growth, mill rate changes, reassessments of value etc.) of the increase of $1,562 on an overall basis, including the overall impacts of accounting changes from the transition to IFRS.
b) For each of the 2012 and 2016 province-wide reassessment of property taxes, please provide (i) the escalation assumption (overall for the province) with respect to increased property taxes that was built into the forecast (ii) the actual percentage decline in property taxes (overall for the province) and (ii) the actual amount ($) of decline in property taxes (overall for the province);
c) Please explain if the $0.3 million reduction for reassessments in 2018/19 and 2019/20 in the Supplement to the Application is as a result of the next province-wide reassessment.
d) If the response to part (b) if yes, please indicate if this is Centra's estimate of the impact of the reassessment or it is based on reassessment notices already received by Centra. If this is based on Centra's estimate, please provide the assumptions and basis of the estimate and compare the estimate to the impacts of the last two reassessments noted above.
e) If the response to part (b) is no, please explain why Centra's properties are being assessed at a lower value and indicate (i) when the next province-wide reassessment of property taxes is excepted to occur in Manitoba, (ii) which Centra fiscal year(s) will be impacted by this reassessment and (iii) the expected increase or decrease in property taxes.

RATIONALE FOR QUESTION:

To understand the impacts of the next province-wide property tax reassessment for rate-setting purposes as well as the key drivers of the changes in Capital & Other Taxes since the 2013/14 GRA.

RESPONSE:

a) The increase in forecasted Capital & Other Taxes is primarily due to higher municipal and capital taxes, partially offset by lower deferred income taxes.
Municipal taxes accounted for $1.7 million of the increase. When forecasting municipal taxes Centra bases its forecast on overall historical property tax amounts as well as any information for the future if it is available. The increase in municipal tax is a result of a combination of asset growth and an increase in property assessment values partially offset by decreases in mill rates.

Capital taxes, which are driven by asset growth and an increase in retained earnings, accounted for $0.8 million of the increase.

As a result of IFRS 14 Regulatory Deferral Accounts, the amortization of deferred taxes was reclassified from Capital & Other Taxes to Net Movement in Regulatory Deferral Accounts.

For rate setting purposes, deferred income taxes decreased by $0.9 million as a result of the costs being amortized on a straight line basis over 30. Therefore each year the interest on the unamortized balance decreases.

b)

i. For 2012, the escalation rate used in the forecast for property taxes was 3% as no other information was available in regards to what the impact of the 2014 reassessment year would be. The average increase used in the past was 2%. Since the City of Winnipeg was no longer holding their rates steady, 3% was used as opposed to the 2%.

For 2016, the escalation rate used in the forecast for property taxes was similar to 2012 at 3% as it was assumed that Centra's portion of total tax burden in Manitoba would rise in line with inflationary impacts on mill rates.

ii and iii.

In fiscal 2013 (which encompasses most of calendar year 2012), Centra's municipal taxes decreased by \$0.9 million (7.6%) compared to fiscal 2012. In fiscal 2017, Centra's municipal taxes decreased by \$0.2 million (1.7%) compared to fiscal 2016.

c) The \$0.3 million reduction for reassessments in 2018/19 and 2019/2020 are not as a result of the next province-wide reassessment but rather as a result of the past reassessment which resulted in a decrease in property taxes.

d) Not applicable.

e) The increases in assessed values in farmland in comparison to Centra property were a contributing factor to Centra being assessed a smaller portion of the total property tax amounts needed by the Province. In addition, a consulting firm was engaged to analyze the assessment values of the properties of Manitoba Hydro of which many are shared with Centra. As a result, assessments have been disputed and adjusted downward which resulted in a decrease in property taxes. Centra benefited by this based on their portion of the allocation of property tax costs on these common assets.

   i. Province-wide reassessments happen every two years. The next province-wide reassessment period is 2020.
   ii. The 2020 reassessment period will impact fiscal 2021 and onward.
   iii. It is unknown in advance whether the reassessment period will increase or decrease property taxes. The main contributing factors that have driven the decrease in the past are the large increases in farmland values in comparison to the increase in the Centra property values as well as the reduction of the assessed values of the shared assets with Manitoba Hydro. Distribution assets are the largest portion of Centra property values, so it will depend on how they are assessed relative all other properties in Province, including farmland.

REFERENCE:

Tab 5 – Section 5.2.6 Depreciation & Amortization (pg 24-29), Appendix 5.13 – Page 12

PREAMBLE TO IR (IF ANY):

The PUB approved Depreciation & Amortization expense from the 2013/14 Test Year was $30,091. Centra is now forecasting Depreciation & Amortization of $33,480 for the 2019/20 Test Year for rate-setting purposes including net movement in regulatory deferrals (Appendix 5.12 (Update), Page 14, Figure 3, Line 39).

QUESTION:

Please provide a comparison between the 2013/14 approved Depreciation & Amortization expense of $30,091 (CGAAP) and the 2019/20 Test Year forecast of Depreciation of $33,480 (for rate-setting purposes) and explain the key business drivers (asset growth, change in composite depreciation rate etc.) of the increase of $3,389 on an overall basis, including the overall impacts of accounting changes from the transition to IFRS.

RATIONALE FOR QUESTION:

To understand the key drivers of the change in Depreciation & Amortization since the 2013/14 GRA.

RESPONSE:

Please see the following schedule that identifies the cumulative changes to depreciation and amortization from the 2013/14 actual balances to the 2019/20 approved forecast year. For comparison purposes the 2013/14 approved GRA amounts are also included in the schedule.

As provided in the schedule, the growth in depreciation and amortization expense from the $30.0 million 2013/14 GRA approved balance to the $33.5 million 2019/20 test year balance is due primarily to annual net plant asset and regulatory deferral (mainly DSM) additions which are partially offset by reductions in depreciation rates for the removal of net salvage and the impact of the 2014 Depreciation Study. Please see the responses to PUB/CENTRA I-7 and PUB/CENTRA I-41 for explanations and further details of the annual year over year changes.

CENTRA GAS MANITOBA INC. **Depreciation and Amortization Expense** **(In thousands of dollars)**		2013/14 - 2019/20 Cumulative Changes						Reclassifications for IFRS			Amortization of			Total	Rate
	CGAAP 2013/14 Approved	CGAAP 2013/14 Actual	Net Additions	2014 Dep'n Study Change in Life	Removal of Net Salvage	Loss on Disposal of Assets	Change in Depreciation Rate - Meters	Customer Contributions	Amort of Deferred Regulatory Expenditures	Loss on Disposal of Assets	Deferred Regulatory Expenditures	2014 Dep'n Study Change in Life	Change in Depreciation Rate - Meters	Change for Rate Setting	Setting 2019/20 Test Year
Intangible Assets															
Franchises & Consents	1	1	(0)	(0)	-		-	-	-	-	-	(0)	-	(0)	1
Land Rights	59	63	63	2	-		-	-	-	-	-	0	-	65	128
Computer System Development	530	530	(530)	-	-		-	-	-	-	-	-	-	(530)	-
Other Distribution Development (SCADA)	793	395	373	(255)	-		-	-	-	-	-	(33)	-	86	481
	1 384	990	(94)	(253)	-	-	-	-	-	-	-	(33)	-	(380)	610
Transmission Plant															
Land	-	-	-	-	-		-	-	-	-	-	-	-	-	-
Structures & Improvements - M&R	20	20	6	(9)	(2)		-	-	-	-	-	(1)	-	(5)	15
Structures & Improvements - Other	2	2	0	(1)	(0)		-	-	-	-	-	(0)	-	(1)	1
Mains - Transmission	1 668	1 696	874	39	(448)		-	-	-	-	-	1	-	465	2 161
Measuring & Regulating Equipment	149	149	127	43	(19)		-	-	-	-	-	4	-	154	303
Cath Prot/Rect/Sacr Anode, Groundbed	-	-	44	-	-		-	-	-	-	-	-	-	44	44
Gas Inline Inspections	-	-	595	-	-		-	-	-	-	-	-	-	595	595
Amort of Customer Contributions: Mains *	(502)	(410)	(37)	(49)	-		-	496	-	-	-	-	-	410	-
Amort of Customer Contributions: Measuring & Regulating Equip *	(5)	(21)	(11)	(25)	-		-	56	-	-	-	-	-	21	-
	1 333	1 437	1 598	(3)	(469)	-	-	552	-	-	-	4	-	1 682	3 118
Distribution Plant															
Land	-	-	-	-	-		-	-	-	-	-	-	-	-	-
Structures & Improvements	32	28	1	(4)	(5)		-	-	-	-	-	(1)	-	(9)	19
Structures & Improvements - M&R	70	66	22	16	2		-	-	-	-	-	3	-	43	109
Services	6 555	6 572	1 631	(1 203)	(3 195)		-	-	-	-	-	(120)	-	(2 887)	3 685
Regulators and Meter Installations	1 123	1 003	198	(153)	-		-	-	-	-	-	(21)	-	24	1 027
Mains - Distribution	3 259	3 321	629	7	(948)		-	-	-	-	-	2	-	(310)	3 011
Measuring & Reg. Equipment	1 171	1 198	503	(139)	(437)		-	-	-	-	-	(23)	-	(95)	1 103
Telemetry Equipment	203	202	70	(17)	-		-	-	-	-	-	(2)	-	51	252
Cath Prot/Rect/Sacr Anode, Groundbed	-	-	303	-	-		-	-	-	-	-	-	-	303	303
Meter Testing	-	-	154	-	-		-	-	-	-	-	-	-	154	154
Meters	1 999	1 765	202	329	-		505	-	-	-	-	59	96	1 191	2 957
Computer Equipment - Hardware	94	79	173	-	-		-	-	-	-	-	-	-	173	251
Amort of Customer Contributions: Services *	(171)	(175)	(2)	36	-		-	142	-	-	-	-	-	175	-
Amort of Customer Contributions: Regulators *	-	-	-	-	-		-	-	-	-	-	-	-	-	-
Amort of Customer Contributions: Mains *	(229)	(227)	11	9	-		-	207	-	-	-	-	-	227	-
Amort of Customer Contributions: Measuring & Regulating Equipment *	(91)	(91)	(1)	24	-		-	68	-	-	-	-	-	91	-
Amort of Customer Contributions: Meters *	(2)	(2)	0	(4)	-		-	6	-	-	-	-	-	2	-
	14 014	13 737	3 893	(1 100)	(4 582)	-	505	423	-	-	-	(102)	96	(868)	12 870
General Plant															
Land	-	-	-	-	-		-	-	-	-	-	-	-	-	-
Structures & Improvements	137	137	(8)	(25)	(3)		-	-	-	-	-	(8)	-	(43)	94
Office Furniture & Equipment	24	24	(24)	0	-		-	-	-	-	-	-	-	(24)	-
Transportation Equipment	26	46	(46)	-	-		-	-	-	-	-	-	-	(46)	(0)
Tools & Work Equipment	119	119	(119)	0	-		-	-	-	-	-	-	-	(119)	-
Deferred Ineligible Overhead		-	-	-	-		-	-	-	-	113	-	-	113	113
	306	326	(196)	(25)	(3)	-	-	-	-	-	113	(8)	-	(119)	207
Loss on Disposal of Property **	-	-	(978)	-	-	2 781	-	-	-	(1 803)	374	-	-	374	374
Depreciation on Common Assets	4 621	3 745	803	-	-	-	-	-	-	-	-	-	-	803	4 547
Other ***	1 235														
Regulatory Costs ***		437	144	-	-		-	-	(580)	-	1 493	-	-	1 056	1 493
Site Restoration ***		216	108	-	-		-	-	(324)	-	314	-	-	97	314
Investment in Demand Side Management ***	7 198	7 172	596	-	-		-	-	(7 768)	-	9 946	-	-	2 773	9 946
Deferred Asset Amortization	8 433	7 825	847	-	-	-	-	-	(8 673)	-	11 753	-	-	3 927	11 753
Depreciation & Amortization Expense	**30 091**	**28 060**	**5 837**	**(1 381)**	**(5 055)**	**2 781**	**505**	**975**	**(8 673)**	**(1 803)**	**12 240**	**(139)**	**96**	**5 419**	**33 480**

* Reclassified from Depreciation & Amortization to Other Income under IFRS
** Previously recorded in Accumulated Depreciation under CGAAP
*** Reclassified from Depreciation & Amortization to Net Movement under IFRS

REFERENCE:

Appendix 6.2 – Lead/Lag Analysis (pg 5-6)

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a table that compares the various non-cost of service tax collection leads and lags from the updated lead/lag analysis for the 2019/20 GRA to the prior lead/lag analysis from the 2005/06 & 2006/07 GRA.

RATIONALE FOR QUESTION:

To understand the proposed changes in the updated 2019/20 lead/lag analysis.

RESPONSE:

Please see the following table.

	2019/20 GRA	2005/06 & 2006/07 GRA
	Weighted Days	Weighted Days
City of Winnipeg Lead	(0.7)	(0.5)
Manitoba Provincial Tax Lead	(2.4)	(1.8)
GST - Revenue Lead	(6.3)	(6.9)
GST - Cost of Gas Lag	4.3	10.2
	(5.0)	**1.0**

REFERENCE:

Tab 13 – Public Utilities Board Directives & Other Matters

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide copies of the letters dated March 10, 2016 and April 4, 2016, related to natural gas accounting matters, noted on page 7 of Tab 13, lines 2 to 7,
b) Please further elaborate what Centra is requesting from the PUB with respect to the ICAM study from the 2019/20 GRA (ICAM is discussed on page 12 and 13 of Tab 13).

RATIONALE FOR QUESTION:

To understand the status of outstanding and on-going PUB directives to Centra.

RESPONSE:

a) Please see the Attachment to this response for copies of the letters dated March 10, 2016 and April 4, 2016 related to natural gas accounting matters.

b) Please see Centra's response to PUB/CENTRA I-37c).

Manitoba Hydro

PO Box 815 • Winnipeg, Manitoba Canada • R3C 2P4
Street Location for DELIVERY: 22nd floor 360 Portage Ave
Telephone / N° de téléphone : (204) 360-3633 • Fax / N° de télécopieur : (204) 360-6147 • ofernandes@hydro.mb.ca

March 10, 2016

Mr. D. Christle
Secretary and Executive Director
Public Utilities Board
400-330 Portage Avenue
Winnipeg, Manitoba
R3C 0C4

Dear Mr. Christle:

RE: CENTRA GAS MANITOBA INC. ("CENTRA") ACCOUNTING MATTERS

In advance of the closing of its financial statements for the 2015/16 fiscal year, Centra is requesting confirmation from the Public Utilities Board of Manitoba ("PUB") that the Corporation's proposed accounting treatment, as outlined below, of certain matters for its natural gas operations is consistent with the intent of the PUB's rate-setting objectives and previous findings. These include a change in accounting treatment for costs associated with meter testing and exchange activities, new depreciation rates for 2015/16 for rate-setting purposes, as well as overhead costs no longer eligible for capitalization.

1. Accounting for Meter Testing & Exchange Activities

Currently, Centra expenses the cost associated with natural gas meter testing and exchange activities in the year they are incurred. For Manitoba Hydro's electric operations, the cost of electric meter testing and exchange activities are capitalized and depreciated.

The Corporation transitioned to International Financial Reporting Standards ("IFRS") effective April 1, 2015 with restatement of the 2014/15 fiscal year for comparative reporting purposes. Under IFRS, there is a requirement to harmonize the accounting policies of a parent company and its subsidiaries.

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.

2. **Depreciation Rates**

As the PUB is aware, Centra periodically updates its asset life estimates and depreciation rates by way of comprehensive depreciation studies. Centra most recently completed a depreciation study in October 2014, based on plant assets as at March 31, 2014, to develop Canadian Generally Accepted Accounting Principles ("CGAAP") compliant depreciation rates (for fiscal 2014/15) based on the Average Service Life (ASL) method. In addition, this study also developed IFRS compliant depreciation rates (for fiscal 2015/16) using the Equal Life Group ("ELG") method. Please find the 2014 Depreciation Study prepared by Gannett Fleming Canada ULC ("Gannett Fleming") as Attachment 1 to this submission, which includes ELG depreciation rates effective for financial reporting purposes effective April 1, 2015, and Attachment 2 includes ASL depreciation rates including negative salvage effective April 1, 2014 and ASL depreciation rates excluding negative salvage for rate-setting purposes effective April 1, 2015.

Centra's depreciation rates were last updated April 1, 2011 and approved by the PUB in Order 85/13. In Order 85/13 at page 23, the PUB indicated that Centra is not to make any accounting changes related to depreciation for rate-setting purposes until it has received PUB approval.

For financial reporting purposes, Centra implemented the revised CGAAP ASL depreciation rates effective April 1, 2014 for fiscal 2014/15 and IFRS compliant ELG depreciation rates effective April 1, 2015 for fiscal 2015/16 with comparative year restatement.

On July 24, 2015, the PUB issued Order 73/15 with respect to Manitoba Hydro's 2015/16 & 2016/17 Electric General Rate Application ("GRA"). In that Order at page 46, the PUB found that Manitoba Hydro should retain its existing CGAAP ASL methodology for rate-setting purposes until Directives 8 and 9 from Order 43/13 have been complied with and the PUB has been provided with an IFRS-compliant depreciation study based on ASL. At page 45 of Order 73/15, the PUB accepted Manitoba Hydro's proposal to remove negative salvage from its depreciation rates effective April 1, 2015.

Consistent with the PUB's findings for the electric operations, Centra assumes that the CGAAP ASL methodology, excluding negative salvage costs, should also be applied to the natural gas operations for rate-setting purposes. Accordingly, Centra is seeking approval, on an interim basis, of CGAAP ASL depreciation rates excluding negative salvage costs for rate setting purposes.

In addition, Centra proposes to apply the same accounting treatment for the difference between depreciation expense calculated for financial reporting purposes (based on the IFRS compliant ELG method) and depreciation expense calculated for rate setting purposes (based on the CGAAP ASL method excluding negative salvage) as set out in Manitoba Hydro's letter to the PUB of February 25, 2016 with respect to its electric operations. In that letter, Manitoba Hydro proposes to record the difference between depreciation expense calculated for financial reporting purposes based on IFRS compliant ELG depreciation rates and depreciation expense calculated for rate-setting purposes based on CGAAP ASL depreciation rates (excluding negative salvage), as a regulated liability along with a corresponding regulated asset for the 2015/16 fiscal year.

Centra will seek final approval of the CGAAP ASL depreciation rates, as well as the disposition of the regulated liability and corresponding regulated asset at its next Gas GRA.

3. <u>Change in Service Life to Meter Account</u>

In addition to the change in depreciation rates outlined in the depreciation study, for 2015/16 the service life for the "meters" account will also be updated to 20 years from 25 years. While the Corporation's current practice is to undertake a depreciation study every 5 years, IFRS requires that the method of depreciation be reviewed at least annually with any changes being applied as a change in accounting estimate on a prospective basis. The change is based on an analysis of asset retirement gains and losses performed in fiscal 2015/16, and the annual impact of this change in depreciation rate is $0.6 million (assuming the ELG method). A letter from Gannett Fleming regarding this change is provided as Attachment 3 to this submission.

The change in service life for the meters account will apply to both the IFRS compliant ELG depreciation rates implemented effective April 1, 2015 for financial reporting purposes, as well as the CGAAP ASL no salvage depreciation rates that Centra is requesting interim approval of in this submission.

4. <u>Ineligible Overheads</u>

At page 15 of Order 85/13, the PUB noted that since 2010/11, Centra has expensed approximately $5 million of overhead costs that, previously, would have been capitalized. In addition, the PUB noted that Centra will expense a further $2 million in capitalized overhead when it implements IFRS in 2015/16.

At pages 35-36 of Order 73/15, the PUB noted that overheads no longer eligible for capitalization have increased since the 2012/13 & 2013/14 GRA and the PUB indicated that the additional ineligible overheads should continue to be capitalized for 2015/16 for rate-setting purposes.

Consistent with the PUB's findings for the electric operations, Centra assumes that the PUB's findings with respect to overhead should also be applied to the natural gas operations for rate-setting purposes. As indicated in the February 25, 2016 letter, Manitoba Hydro is proposing to record the difference between Operating & Administrative ("O&A") expense calculated for financial reporting purposes and O&A expense excluding the additional overheads to be capitalized, as a regulated liability along with a corresponding regulated asset for the 2015/16 fiscal year.

Centra is respectfully seeking the PUB's confirmation that its proposed accounting treatments are consistent with the intent of the PUB's rate-setting objectives and previous findings, which will allow Centra to close its financial statements for the 2015/16 fiscal year. A review of the disposition of the proposed regulated liability and asset balances can be considered at the next Gas GRA.

Given that the amounts in question are material to the financial statements and that the Corporation is preparing for its year-end audit process, Centra respectfully requests that confirmation be provided by the PUB by March 24, 2016.

Should you have any questions with respect to the forgoing, please do not hesitate to contact the writer at 204-360-3633 or Shannon Gregorashuk at 204-360-4270.

Yours truly,

MANITOBA HYDRO LAW DIVISION
Per:

ODETTE FERNANDES
Barrister & Solicitor

Att.

CENTRA GAS MANITOBA INC.

2014 DEPRECIATION STUDY

CALCULATION OF ANNUAL DEPRECIATION
ACCRUAL RATES RELATED TO
NATURAL GAS TRANSMISSION AND
DISTRIBUTION SERVICES FOR PLANT
IN SERVICE AS OF MARCH 31, 2014

Prepared by:

Gannett Fleming

*Excellence Delivered **As Promised***

CENTRA GAS MANITOBA INC.
Winnipeg, Manitoba

2014 DEPRECIATION STUDY

CALCULATION OF ANNUAL DEPRECIATION
ACCRUAL RATES RELATED TO
NATURAL GAS TRANMISSION AND DISTRIBUTION SERVICES
FOR PLANT IN SERVICE AS OF MARCH 31, 2014

GANNETT FLEMING CANADA ULC

Calgary, Alberta

June 3, 2015

Manitoba Hydro
360 Portage Avenue
Winnipeg, Manitoba
R3C 0G8

Attention: Mr. Darren Rainkie
Vice-President, Finance and Regulatory

Ladies and Gentlemen:

Pursuant to your request, we have conducted a depreciation study of the Centra Gas Manitoba Inc. ("Centra Gas" or the "Company") natural gas transmission, distribution and general plant assets as of March 31, 2014. The depreciation rates as developed in this report are applicable for use in the determination of the Centra Gas depreciation expense for financial reporting and regulatory purposes. Our report presents a description of the methods used in the determination of depreciation and the detailed tabulations of annual and accrued depreciation.

The calculated annual depreciation accrual rates presented in the report are based on the straight line method using the average service life ("ELG") procedure and were applied on a whole life basis, with any accumulated depreciation variances being amortized over the estimated remaining life of the assets.

Respectfully submitted,

GANNETT FLEMING CANADA ULC

DRAFT

LARRY E. KENNEDY
Vice President

LEK/hac
Project #058390.500

Gannett Fleming Canada ULC

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CENTRA GAS MANITOBA INC.
DEPRECIATION STUDY

EXECUTIVE SUMMARY

Pursuant to Manitoba Hydro's request, Gannett Fleming Canada ULC ("Gannett Fleming") conducted a depreciation study related to the natural gas transmission, distribution and general plant assets of Centra Gas Manitoba ("Centra Gas") as of March 31, 2014. The purpose of this study was to determine the annual depreciation accrual rates and amounts for book and ratemaking objectives. The results of the study are summarized on the attached Tables 1 and 2.

The attached depreciation rates are based on the straight line method using the equal life group ("ELG") procedure and were applied on a whole life basis based on attained ages and estimated average service lives. As discussed in the last review of depreciation rates, the use of the ELG procedure and the removal of net negative salvage from the depreciation rate calculations are consistent with Manitoba Hydro's planned implementation of the International Financial Reporting Standards ("IFRS"). Also consistent with prior studies conducted on behalf of Centra Gas, variances between the calculated accrued depreciation and the book accumulated depreciation as of March 31, 2014 are amortized over the remaining life of the assets.

Gannett Fleming recommends the annual depreciation accrual rates for the natural gas utility plant in service as of March 31, 2014 as presented in Tables 1 and 2. Gannett Fleming recommends the calculated annual depreciation accrual rates set forth herein apply specifically to gas plant in service as of March 31, 2014 as summarized by Tables 1 and 2 of the study by account detail. Supporting data and calculations are provided as well within the study.

The enclosed depreciation rates are effective for Centra Gas on April 1, 2015 upon its transition to IFRS.

The study results in an annual depreciation expense accrual of $14.8 million when applied to depreciable plant balances as of March 31, 2014. The report study results are summarized at an aggregate functional group level as follows:

SUMMARY OF ORIGINAL COSTS, ACCRUAL PERCENTAGES AND AMOUNTS

PLANT GROUP	ORIGINAL COST $'s	ANNUAL ACCRUAL %'s	ANNUAL ACCRUAL $'s
(1)	(2)	(3)	(4)
TRANSMISSION	115,233,145	1.70	1,959,272
DISTRIBUTION	562,922,127	2.13	12,007,670
GENERAL	16,747,069	4.69	784,601
TOTAL PLANT IN SERVICE	**694,902,341**	**2.12**	**14,751,543**

PART I. INTRODUCTION

CENTRA GAS MANITOBA INC.
DEPRECIATION STUDY
PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation study for Centra Gas Manitoba Inc. ("Centra Gas" or "the Company"), to determine the annual depreciation accrual rates and amounts for book purposes applicable to the original cost of the natural gas transmission, distribution and general plant assets at March 31, 2014. The rates and amounts are based on the straight line whole life method of depreciation with a separate amortization of the variance between the book depreciation reserve and the calculated accrued depreciation. This report also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates related to natural gas plant in service as of March 31, 2014.

The service life and net salvage estimates resulting from the study were based on: informed judgment which incorporated analyses of historical plant retirement data as recorded through March 31, 2014; a review of Company practice and outlook as they relate to plant operation and retirement; and consideration of current practice in the gas industry, including knowledge of service lives and net salvage estimates used for other natural gas utilities.

PLAN OF REPORT

Part I Introduction, contains statements with respect to the plan of the report, and the basis of the study. Part II Development of Depreciation Parameters, presents descriptions of the methods used in the service life and net salvage studies. Part III Calculation of Annual and Accrued Depreciation presents the methods and procedures used in the calculation of depreciation. Part IV Results of Study, presents summaries by depreciable group of annual and accrued depreciation. The Supporting Documents to this study include: Part V. Service Life Statistics, which presents the results of the retirement rate analysis and Part VI. Detailed Depreciation Calculations, which present the detailed tabulations of annual and accrued depreciation. An overview of Iowa curves and the Retirement Rate Analysis are set forth in Appendix A of this report.

BASIS OF THE STUDY

Depreciation

For most accounts, the annual and accrued depreciation were calculated by the straight line method using the equal life group (”ELG”) procedure. For certain General Plant accounts, the annual and accrued depreciation are based on amortization accounting. Both types of calculations were based on original cost, attained ages, and estimates of service lives and salvage. Variances between the calculated accrued depreciation or amortization and the book accumulated depreciation are amortized over the composite remaining life of each account.

Continued monitoring and maintenance of the accumulated depreciation reserve at the account level is recommended. Gannett Fleming has determined an amortization amount to correct the present variance with the calculated accrued depreciation, (“theoretical reserve”), over the composite remaining life of each account. Table 2 presented in Part IV of the report sets forth the amortization of the reserve variance at the account level. This adjustment mechanism, whether determined separately as an amortization amount or incorporated in the calculation of remaining life accruals, is widely-accepted. An explanation of the monitoring of the accumulated depreciation reserve and the calculation of the true-up provision is presented beginning on page III-5 of the report.

The straight line method, ELG procedure is a commonly used depreciation calculation procedure that has been widely accepted in jurisdictions throughout North America. Gannett Fleming recommends its continued use. Amortization accounting is used for certain General Plant accounts because of the disproportionate plant accounting effort required when compared to the minimal original cost of the large number of items in these accounts. Many gas utilities in North America have received approval to adopt amortization accounting for these accounts.

Service Life Estimates

The service life estimates used in the depreciation and amortization calculations were based on informed judgment which incorporated a review of management’s plans, policies and outlook, a general knowledge of the gas utility industry, and comparisons of the service life and net salvage estimates from our studies of other gas utilities. The use of survivor curves to reflect the expected dispersion of retirement provides a consistent method of estimating depreciation for gas plant. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts not subject to amortization accounting.

The procedure for estimating service lives consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data analyses and the probable future. The combination of the historical experience and the estimated future yielded estimated survivor curves from which the average service lives were derived.

The depreciation rates should be reviewed periodically to reflect the changes that result from plant and reserve account activity. A depreciation reserve deficiency or surplus will develop if future capital expenditures vary significantly from those anticipated in this study.

PART II. DEVELOPMENT OF DEPRECIATIONS PARAMETERS

PART II. DEVELOPMENT OF DEPRECIATION PARAMETERS

DEPRECIATION

Depreciation, in public utility regulation, is the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among causes to be given consideration are wear and tear, deterioration, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirements of public authorities.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing natural gas utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the straight-line method of depreciation.

The calculation of annual and accrued depreciation based on the straight line method requires the estimation of survivor curves and is described in the following sections of this report. The development of the proposed depreciation rates also requires the selection of group depreciation procedures, as discussed in Part III of this report.

ESTIMATION OF SURVIVOR CURVES

<u>Survivor Curves</u>

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units which survive at successive ages using the retirement rate method of analysis.

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements in relationship to the average life and relative height of the modes. The left-moded curves are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical-moded curves are those in which the greatest frequency of retirement occurs at average service life. The right-moded curves are those in which the greatest frequency occurs to the right of, or after, the average service life. The origin-moded curves are those in which the greatest frequency of retirement occurs at the origin, or immediately after age 0. The letter designation of each family of curves (L, S, R or O) represents the mode of the associated frequency curve with respect to the average service life. The numerical subscripts represent the relative heights of the modes of the frequency curves within each family.

A discussion of the general concept of survivor curves and retirement rate method is presented in Appendix A of this report.

Survivor Curve Judgments

The survivor curve estimates were based on judgment which considered a number of factors. The primary factors were the statistical analysis of data; current policies and outlook as determined during conversations with management personnel and on the knowledge Gannett Fleming developed through the completion of numerous natural gas utility studies.

The following discussion, dealing with a number of accounts which comprise the majority of the investment analyzed, presents an overview of the factors considered by Gannett Fleming in the determination of the average service life estimates. The survivor curve estimates for the remainder of the accounts not discussed in the following sections were based on similar considerations.

Account 465.00 – Transmission Mains - represents 14.7% of the depreciable plant studied. The plant additions for the period 1950 through 2014 were combined with retirement activity over the period of 1990 through 2014 for analysis using the retirement rate method. The original survivor curve as plotted on page V-8, results in a stubbed Iowa curve, however a material amount of retirement activity is observed over the period from 10.5 through to 21.5 years of age with minor amounts of retirement occurring thereafter. The level of retirement activity that is occurring early in the account's life provides indication that a mid-moded survivor curve is required for this account. The currently approved average service and Iowa curve for this account is the Iowa 65-R4, however as noted above the current indication is that a mid-moded curve is required. Typical average service life estimates for Canadian natural gas utilities for this account range from 62 through 66 years. Discussions with Centra Gas operational personnel indicated that they would anticipate future lives to be at least as long as historic indications which are indicating the 65-R3 Iowa curve. Gannett Fleming recommends a moderate decrease to the mode of the Iowa curve from a R4 to the R3, and the continued use of the 65 year average service life.

The Iowa 65-R3, selected in this study, accounts for the indication of early retirement activity, provides a reasonable interpretation of the retirement experience and is expected to provide a reasonable expectation of the future retirement trends.

<u>Account 467.00 - Transmission Plant - Measuring and Regulating Equipment</u> - represents 1.2% of the depreciable plant studied. The plant additions for the period 1956 through 2014 were combined with retirement activity over the period of 1990 through 2014 for analysis using the retirement rate method. The original survivor curve as plotted on page V-11, results in a sufficient amount of retirement experience for the analysis of historic retirement patterns, with material levels of retirement starting at age 9.5 and continuing thereafter. The currently approved average service and Iowa curve for this account is the Iowa 50-S2.5. Typical average service life estimates for Canadian natural gas utilities for this account range from 27 through 48 years. Given both the results of the retirement rate analysis and the lives used by other peer Canadian gas utilities, Gannett Fleming recommends a decrease to the life estimate of this account from 50 to 45 years and a change in the mode of the curve from the Iowa S2.5 to the Iowa R2.

The Iowa 45-R2, selected in this study, accounts for the indication of early retirement activity, provides a reasonable interpretation of the retirement experience and is expected to provide a reasonable expectation of the future retirement trends.

Account 473.00 – Distribution Services - represents 33.4% of the depreciable plant studied. The plant additions for the period 1953 through 2014 were combined with retirement activity over the period of 1990 through 2014 for analysis using the retirement rate method. The original survivor curve as plotted on page V-20, results in a sufficient amount of retirement experience for the analysis of historic retirement patterns, with material levels of retirement starting from the beginning years of the account and continuing at a steady pace thereafter, indicating a low-moded Iowa curve. The currently approved average service and Iowa curve for this account is the Iowa 55-R2.5.

Typical average service life estimates for Canadian natural gas utilities for this account ranges from 45 to 55 years. However, given the results of the retirement rate analysis and indications from management and operational staff that the future indications should be similar to the historic retirement trends, Gannett Fleming views that an increase to the life estimate of this account is required. Furthermore, operational staff has indicated that there is no early generation plastic pipe in this account of the type that has caused indications of early retirement experience in other provinces such as Alberta. As such, it is expected that the average service life indications for Centra Gas may be longer than that of the peers (specifically Alberta peers). Therefore, Gannett Fleming views that an increase in the average service life from 55 years to 62 years is reasonable. Additionally, as noted above, the early retirement experience leads to a lower-moded Iowa curve and, therefore, Gannett Fleming recommends a reduction in the Iowa curve shape from the Iowa R2.5 to the Iowa R2.

The Iowa 62-R2, selected in this study, accounts for the indication of early retirement activity, provides a reasonable interpretation of the retirement experience and is expected to provide a reasonable expectation of the future retirement trends.

Account 475.00 – Distribution Mains - represents 26.3% of the depreciable plant studied. The plant additions for the period 1953 through 2014 were combined with retirement activity over the period of 1990 through 2014 for analysis using the retirement rate method. While the original survivor curve as plotted on page V-26, results in a stubbed observed life curve, retirement indications are observed at almost all age intervals, which provides meaningful historic information. The currently approved average service and Iowa curve for this account is the Iowa 65-R4.

Typical average service life estimates for Canadian natural gas utilities for this account ranges from 62 to 66 years. However, given the results of the retirement rate analysis and indications from management and operational staff that the future indications should be similar to the historic retirement trends, Gannett Fleming views that an increase to the life estimate of this account is required. Furthermore, operational staff has indicated that there is no early generation plastic pipe in this account of the type that has caused indications of early retirement experience in other provinces such as Alberta. As such, it is expected that the average service life indications for Centra Gas may be longer than of the peers (specifically Alberta peers). Therefore, Gannett Fleming views that an increase in the average service life from 65 years to 68 years is reasonable. While the retirement rate analysis has indicated minor levels of retirement at most age intervals, the amounts plotted on the observed life table still provides for indications of a high-moded Iowa curve. Therefore, Gannett Fleming does not recommend any change to the currently used Iowa R4 curve shape.

The Iowa 68-R4, selected in this study, accounts for the observed retirement activity, provides a reasonable interpretation of the retirement experience and is expected to provide a reasonable expectation of the future retirement trends.

Account 477.00 – Distribution - Measuring and Regulating Equipment - represents 5.4% of the depreciable plant studied. The plant additions for the period 1954 through 2014 were combined with retirement activity over the period of 1990 through 2014 for analysis using the retirement rate method. The original survivor curve as plotted on page V-29, results in a sufficient amount of retirement experience for the analysis of historic retirement patterns, with material levels of retirement starting at age 7.5 and continuing thereafter. The currently approved average service and Iowa curve for this account is the Iowa 35-R2. Typical average service life estimates for Canadian natural gas utilities for this account range from 15 through 50 years, with an average of 36 years when the two extreme estimates are removed. Given both the results of the retirement rate analysis and the lives used by other peer Canadian gas utilities, Gannett Fleming recommends an increase to the life estimate of this account from 35 to 37 years and a change in the mode of the curve from the Iowa R2 to the Iowa R2.5.

The Iowa 37-R2.5, selected in this study, accounts for the observed retirement activity, provides a reasonable interpretation of the retirement experience and is expected to provide a reasonable expectation of the future retirement trends.

Account 478.00 – Distribution - Meters – represents 5.9% of the depreciable plant studied. The plant additions for the period 1962 through 2014 were combined with retirement activity over the period of 1990 through 2014 for analysis using the retirement rate method. The original survivor curve as plotted on page V-34, results in a full and complete observed life table of retirement experience for the analysis of historic retirement patterns. The currently approved average service and Iowa curve for this account is the Iowa 26-S1.5. Typical average service life estimates for Canadian natural gas utilities ranges for this account ranges from 15 through 32 years, with an average of 23 years. Given both the results of the retirement rate analysis and the lives used by other peer Canadian gas utilities, Gannett Fleming recommends a small decrease to the life estimate of this account from 26 to 25 years and a change in the mode of the curve from the Iowa S1.5 to the Iowa R1.5.

The Iowa 25-R1.5, selected in this study, accounts for the observed retirement activity, provides a reasonable interpretation of the retirement experience and is expected to provide a reasonable expectation of the future retirement trends.

PART III. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

PART III. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

Group Depreciation Procedures

When more than a single item of property is under consideration, a group procedure for depreciation is appropriate because normally all of the items within a group do not have identical service lives, but have lives that are dispersed over a range of time. There are two primary group procedures, namely, Average Service Life (ASL) and Equal Life Group (ELG).

In the ELG procedure, the property group is subdivided according to service life. That is, each equal life group includes that portion of the property which experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve. The calculated depreciation for the property group is the summation of the calculated depreciation based on the service life of each equal life group.

The table on the following page presents an illustration of the calculation of equal life group depreciation in a mass property account using the Iowa 10-R5 survivor curve, 0 percent net salvage and a December 31, 2014 calculation date. In the table, each equal life group is defined by the age interval shown in columns 1 and 2. These are the ages at which the first and last retirement of each group occurs, and the group's equal life, shown in column 3, is the midpoint of the interval. For purposes of the calculation, each vintage is divided into equal life groups arranged so that the midpoint of each one-year age interval coincides with the calculation date, e.g., December 31 in this case. This enables the calculation of annual accruals for a twelve-month period centered on the date of calculation.

The retirement during the age interval, shown in column 4, is the size of each equal life group and is derived from the Iowa 10-R5 survivor curve and 0 percent net salvage. It is the difference between the percents surviving at the beginning and end of the age interval. Each equal life group's annual accrual, shown in column 5, equals the group's size (column 4) divided by its life (column 3).

DETAILED COMPUTATION OF ANNUAL AND ACCRUED FACTORS USING THE EQUAL LIFE GROUP PROCEDURE

INPUT PARAMETERS:
CALCULATION DATE.. 12-31-2014
SURVIVOR CURVE.... 10-R5

AGE INTERVAL BEG (1)	END (2)	LIFE (3)	RETIREMENTS DURING INTERVAL (4)	GROUP ANNUAL ACCRUAL (5)=(4)/(3)	YEAR INST (6)	SUMMATION OF ANNUAL ACCRUALS (7)	AVERAGE PERCENT SURVIVING (8)	ANNUAL FACTOR (9)	ACCRUED FACTOR (10)
0.000	1.000	0.500	0.00000	0.00000000000	2014	10.21593609462	100.000000	0.1022	0.0511
1.000	2.000	1.500	0.00000	0.00000000000	2013	10.21593609462	100.000000	0.1022	0.1533
2.000	3.000	2.500	0.00000	0.00000000000	2012	10.21593609462	100.000000	0.1022	0.2555
3.000	4.000	3.500	0.00084	0.00024000000	2011	10.21581609462	99.999580	0.1022	0.3577
4.000	5.000	4.500	0.04802	0.01067111111	2010	10.21036053906	99.975150	0.1021	0.4595
5.000	6.000	5.500	0.45865	0.08339090909	2009	10.16332952896	99.721815	0.1019	0.5605
6.000	7.000	6.500	1.95737	0.30113384615	2008	9.97106715134	98.513805	0.1012	0.6578
7.000	8.000	7.500	5.58856	0.74514133333	2007	9.44792956160	94.740840	0.0997	0.7478
8.000	9.000	8.500	13.40588	1.57716235294	2006	8.28677771847	85.243620	0.0972	0.8262
9.000	10.000	9.500	24.92229	2.62339894737	2005	6.18649706831	66.079535	0.0936	0.8892
10.000	11.000	10.500	29.97992	2.85523047619	2004	3.44718235653	38.628430	0.0892	0.9366
11.000	12.000	11.500	18.68473	1.62475913043	2003	1.20718755322	14.296105	0.0844	0.9706
12.000	13.000	12.500	4.66098	0.37287840000	2002	0.20836878801	2.623250	0.0794	0.9925
13.000	13.700	13.350	0.29276	0.02192958801	2001	0.00767535580	0.102466	0.0749	1.0000
TOTAL			100.00000						

Columns 7 through 10 show the derivation of the annual and accrued factors for each vintage based on the information developed in the first five columns. The year installed is shown in column 6. For all vintages other than 2010, the summation of annual accruals for each year installed, shown in column 7, is calculated by adding one-half of the group annual accrual (column 5) for that vintage's current age interval plus the group annual accruals for all succeeding age intervals. For example, the figure 10.21593609462 for 2013 equals one-half of 0.00000000000 plus all of the succeeding figures in column 5. Only one-half of the annual accrual for the vintage's current age interval group is included in the summation because the equal life group for that interval has reached the year during which it is expected to be retired.

The summation of annual accruals (column 7) for installations during 2014 is calculated on the basis of an in-service date at the midpoint of the year, i.e., June 30. Inasmuch as the overall calculation is centered on December 31, 2014, the first figure in column 7, for vintage 2014, equals all of the group annual accrual for the first equal life group plus the accruals for all of the subsequent equal life groups.

The average percent surviving derived from the Iowa 10-R5 survivor curve and 0 percent net salvage, is shown in column 8 for each age interval. The annual factor, shown in column 9, is the result of dividing the summation of annual accruals (column 7) by the average percent surviving (column 8). The accrued factor, shown in column 10, equals the annual factor multiplied by the age of the group at December 31, 2014.

CALCULATION OF ANNUAL AND ACCRUED AMORTIZATION

Amortization is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. Normally, the distribution of the amount is in equal amounts to each year of the amortization period.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization period and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

For the purpose of calculating annual amortization amounts as of March 31, 2014, the book depreciation reserve for each plant account or subaccount is assigned or allocated to vintages. The book reserve assigned to vintages with an age greater than the amortization period is equal to the vintage's original cost. The remaining book reserve is allocated among vintages with an age less than the amortization period in proportion to the calculated accrued amortization. The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage's age to its amortization period. The annual amortization amount is determined by dividing the future amortizations (original cost less allocated book reserve) by the remaining period of amortization for the vintage.

Amortization accounting is proposed for a number of accounts that represent numerous units of property, but a very small portion of depreciable plant in service. The accounts and their amortization periods are as follows:

ACCOUNT	TITLE	AMORTIZATION PERIOD, YEARS
475.10	Cathodic Protection	20
478.10	AMR/ERT Modules	10
479.10	Computer Hardware Equipment – EMS/SCADA	5
479.30	Computer Hardware Development – EMS/SCADA	5
483.00	Office Furniture and Equipment	10
483.30	Computer system Development	10
486.00	Tools and Work Equipment	15
478.10	Meter Testing	10

A depreciation true-up is not calculated on these accounts where there is less than a 10 percent accumulated depreciation variance.

MONITORING OF BOOK ACCUMULATED DEPRECIATION

The calculated accrued depreciation or amortization represents that portion of the depreciable cost which will not be allocated to expense through future depreciation accruals, if current forecasts of service life characteristics and net salvage materialize and are used as a basis for depreciation accounting. Thus, the calculated accrued depreciation provides a measure of the book accumulated depreciation. The use of this measure is recommended in the amortization of book accumulated depreciation variances to insure complete recovery of capital over the life of the property.

The recommended amortization of the variance between the book accumulated depreciation and the calculated accrued depreciation is based on an amortization period equal to the composite remaining life for each property group where the variance exceeds five percent of the calculated accrued depreciation.

The composite remaining life for use in the calculation of accumulated depreciation variances is derived by developing the composite sum of the individual equal life group remaining lives in accordance with the following equation:

$$\text{Composite Remaining Life} = \frac{\sum\left(\frac{\text{Book Cost}}{\text{Life}} \text{ x Remaining Life}\right)}{\sum \frac{\text{Book Cost}}{\text{Life}}}.$$

The book costs and lives of the several equal life groups, which are summed in the foregoing equation, are defined by the estimated future survivor curve. Inasmuch as book cost divided by life equals the whole life annual accrual, the foregoing equation reduces to the following form:

$$\text{Composite Remaining Life} = \frac{\sum \text{Whole Life Future Accruals}}{\sum \text{Whole Life Annual Accruals}}$$

or

$$\text{Composite Remaining Life} = \frac{\sum \text{Book Cost - Calc. Reserve}}{\sum \text{Whole Life Annual Accrual}}.$$

PART IV. RESULTS OF STUDY

PART IV. RESULTS OF STUDY

QUALIFICATION OF RESULTS

The calculated annual and accrued depreciation are the principal results of the study. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and salvage and for the change of the composition of property in service. The annual accrual rates and the accrued depreciation were calculated in accordance with the straight line method, using the equal life group procedure based on estimates which reflect considerations of current historical evidence and expected future conditions.

DESCRIPTION OF DETAILED TABULATIONS

The service life estimates were based on judgment that incorporated statistical analysis of retirement data, discussions with management and consideration of estimates made for other electric utilities. The results of the statistical analysis of service life are presented in the section beginning on page V-3 of the Supporting Documents.

For each depreciable group analyzed by the retirement rate method, a chart depicting the original and estimated survivor curves followed by a tabular presentation of the original life table(s) plotted on the chart. The survivor curves estimated for the depreciable groups are shown as dark smooth curves on the charts. Each smooth survivor curve is denoted by a numeral followed by the curve type designation. The numeral used is the average life derived from the entire curve from 100 percent to zero percent surviving. The titles of the chart indicate the group, the symbol used to plot the points of the original life table, and the experience and placement bands of the life tables which where plotted. The experience band indicates the range of years for which retirements were used to develop the stub survivor curve. The placements indicate, for the related experience band, the range of years of installations which appear in the experience.

The tables of the calculated annual depreciation applicable to depreciable assets as of December 31, 2014 are presented in account sequence starting on page VI-2 of the Supporting Documents. The tables indicate the estimated average survivor curves used in the calculations. The tables set forth, for each installation year, the original cost, calculated accrued depreciation, and the calculated annual accrual.

CENTRA GAS MANITOBA INC.

TABLE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
AS OF MARCH 31, 2014

ACCOUNT	DEPRECIABLE GROUP	SURVIVOR CURVE	NET SALVAGE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)	ANNUAL PROVISION FOR TRUE-UP	TOTAL DEPRECIATION RELATED TO LIFE EXPENSE	TOTAL DEPRECIATION RELATED TO LIFE RATE (%)
	(1)	(2)	(3)	(4)	(5)	(6)=(5)/(4)	(7)	(8)=(5)+(7)	(9)=(8)/(4)
401.00	FRANCHISES AND CONSENTS	20-SQ	0	22,105	1,105	5.00	-	1,105 **	5.00
	TRANSMISSION								
461.00	LAND RIGHTS	75-SQ	0	3,932,416	52,301	1.33	(1,191)	51,110	1.30
463.00	STRUCTURES AND IMPROVEMENTS - MEASURING AND REGULATING	65-R4	0	1,035,535	16,373	1.58	(3,256)	13,117	1.27
464.00	STRUCTURES AND IMPROVEMENTS - OTHER	65-R4	0	76,421	1,178	1.54	(446)	732	0.96
465.00	MAINS	65-R3	0	101,865,455	1,719,725	1.69	(40,298)	1,679,427	1.65
465.10	CATHODIC PROTECTION	25-SQ	0	195,084	7,803	4.00	124	7,927	4.06
467.00	MEASURING AND REGULATING EQUIPMENT	45-R2	0	8,128,234	206,347	2.54	612	206,959	2.55
	TOTAL TRANSMISSION			**115,233,145**	**2,003,727**		**(44,455)**	**1,959,272**	
	DISTRIBUTION								
471.00	LAND RIGHTS	75-SQ	0	1,306,450	17,376	1.33	-	17,376	1.33
472.00	STRUCTURES AND IMPROVEMENTS	50-R3	0	1,335,428	27,512	2.06	(5,977)	21,535	1.61
472.10	STRUCTURES AND IMPROVEMENTS - MEASURING AND REGULATING	50-R3	0	4,232,659	90,869	2.15	6,959	97,828	2.31
473.00	SERVICES	62-R2	0	232,034,858	4,223,673	1.82	(321,263)	3,902,410	1.68
474.00	REGULATORS AND METER INSTALLATIONS	50-R5	0	52,825,017	1,070,082	2.03	(64,928)	1,005,154	1.90
475.00	MAINS	68-R4	0	182,842,390	2,802,187	1.53	(201,875)	2,600,312	1.42
475.10	CATHODIC PROTECTION	15-SQ	0	2,466,194	164,495	6.67	7,689	172,184	6.98
477.00	MEASURING AND REGULATING EQUIPMENT	37-R2.5	0	37,286,853	1,064,422	2.85	(131,049)	933,373	2.50
477.10	TELEMETRY EQUIPMENT	17-S6	0	4,046,541	230,472	5.70	(46,997)	183,475	4.53
478.00	METERS	25-R1.5	0	41,097,382	1,833,365	4.46	717,908	2,551,273	6.21
478.10	METER - TESTING	10-SQ	0	-	-	10.00	-	- *	10.00
479.10	COMPUTER HARDWARE EQUIPMENT - EMS/SCADA	5-SQ	0	441,769	88,354	20.00	-	88,354	20.00
479.30	COMPUTER SYSTEM DEVELOPMENT - EMS/SCADA	7-S3	0	3,006,585	461,812	15.36	(27,416)	434,396	14.45
	TOTAL DISTRIBUTION			**562,922,127**	**12,074,619**		**(66,949)**	**12,007,670**	
	GENERAL PLANT								
482.00	STRUCTURES AND IMPROVEMENTS	45-R3	0	8,983,418	192,975	2.15	(25,508)	167,467	1.86
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	0	265,592	5,050	1.90	28,672	33,722	12.70
483.30	COMPUTER SYSTEM DEVELOPMENT	10-SQ	0	5,304,028	530,403	10.00	-	530,403	10.00
484.00	TRANSPORTATION EQUIPMENT	10-R5	10	199,645	-	0.00	-	- ***	0.00
485.00	HEAVY WORK EQUIPMENT	20-R5	20	459,767	18,766	4.08	-	***	0.00
486.00	TOOLS AND WORK EQUIPMENT	15-SQ	0	1,512,515	51,904	3.43	-	51,904	3.43
	TOTAL GENERAL PLANT			**16,724,964**	**799,098**		**3,164**	**783,496**	
	TOTAL DEPRECIABLE PLANT			**694,902,341**	**14,878,549**		**(108,240)**	**14,751,543**	**2.12**

* Rate is provided for the use with future additions.
** Total depreciation expense calculated based upon length of lease term, with no provision for true-up.
*** Account is fully depreciated.

CENTRA GAS MANITOBA INC.

TABLE 2. CALCULATED ACCRUED DEPREICATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF ANNUAL PROVISION FOR TRUE-UP RELATED TO ORIGINAL COST AS OF MARCH 31, 2014

ACCT	DEPRECIABLE GROUP	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE AMOUNT	ACCUMULATED DEPRECIATION VARIANCE PERCENT	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP	TRUE-UP RATE (%)
	(1)	(2)	(3)	(4)	(5) = (3)-(4)	(6) = (5)/(3)	(7)	(8)=(5)/(7)	(9)=(8)/(2)
401.00	FRANCHISES AND CONSENTS	22,105	21,426	12,384	9,042	42.20	1.0	-	0.00
	TRANSMISSION								
461.00	LAND RIGHTS	3,932,416	650,054	725,696	(75,642)	(11.64)	63.5	(1,191)	(0.03)
463.00	STRUCTURES AND IMPROVEMENTS - MEASURING AND REGULATING	1,035,535	395,903	553,517	(157,614)	(39.81)	48.4	(3,256)	(0.31)
464.00	STRUCTURES AND IMPROVEMENTS - OTHER	76,421	45,609	59,420	(13,811)	(30.28)	31.0	(446)	(0.58)
465.00	MAINS	101,865,455	25,528,288	27,329,624	(1,801,336)	(7.06)	44.7	(40,298)	(0.04)
465.10	CATHODIC PROTECTION	195,084	3,876	844	3,032	78.23	24.5	124	0.06
467.00	MEASURING AND REGULATING EQUIPMENT	8,128,234	2,421,271	2,404,369	16,902	0.70	27.6	612	0.01
	TOTAL TRANSMISSION	**115,233,145**	**29,045,001**	**31,073,470**	**(2,028,469)**			**(44,455)**	
	DISTRIBUTION								
471.00	LAND RIGHTS	1,306,450	156,021	162,691	(6,670)	(4.27)	66.1 ***	-	0.00
472.00	STRUCTURES AND IMPROVEMENTS	1,335,428	644,625	797,038	(152,413)	(23.64)	25.5	(5,977)	(0.45)
472.10	STRUCTURES AND IMPROVEMENTS - MEASURING AND REGULATING	4,232,659	1,402,137	1,189,178	212,959	15.19	30.6	6,959	0.16
473.00	SERVICES	232,034,858	73,840,616	86,080,722	(12,240,106)	(16.58)	38.1	(321,263)	(0.14)
474.00	REGULATORS AND METER INSTALLATIONS	52,825,017	17,964,084	20,243,062	(2,278,978)	(12.69)	35.1	(64,928)	(0.12)
475.00	MAINS	182,842,390	54,694,912	64,364,739	(9,669,827)	(17.68)	47.9	(201,875)	(0.11)
475.10	CATHODIC PROTECTION	2,466,194	654,348	570,688	83,660	12.79	10.9	7,689	0.31
477.00	MEASURING AND REGULATING EQUIPMENT	37,286,853	15,272,917	18,129,793	(2,856,876)	(18.71)	21.8	(131,049)	(0.35)
477.10	TELEMETRY EQUIPMENT	4,046,541	3,025,826	3,486,399	(460,573)	(15.22)	9.8	(46,997)	(1.16)
478.00	METERS	41,097,382	15,064,697	6,306,218	8,758,479	58.14	12.2	717,908	1.75
478.10	METER TESTING								
479.10	COMPUTER HARDWARE EQUIPMENT - EMS/SCADA	441,769	215,567	202,210	13,358	6.20	2.5 ***	-	0.00
479.30	COMPUTER SYSTEM DEVELOPMENT - EMS/SCADA	3,006,585	230,906	395,400	(164,494)	(71.24)	6.0	(27,416)	(0.91)
	TOTAL DISTRIBUTION	**562,922,127**	**183,166,656**	**201,928,138**	**(18,761,482)**			**(66,949)**	
	GENERAL PLANT								
482.00	STRUCTURES AND IMPROVEMENTS	8,983,418	5,426,242	5,938,948	(512,706)	(9.45)	20.1	(25,508)	(0.28)
483.00	OFFICE FURNITURE AND EQUIPMENT	265,592	262,569	233,897	28,672	10.92	1.0 *	28,672	10.80
483.30	COMPUTER SYSTEM DEVELOPMENT	5,304,028	4,508,423	4,331,622	176,801	3.92	1.5 ***	-	0.00
484.00	TRANSPORTATION EQUIPMENT	199,645	199,645	199,645	0	0.00	0.0	-	0.00
485.00	HEAVY WORK EQUIPMENT	459,767	373,985	459,767	(85,782)	(22.94)	0.0 **	-	0.00
486.00	TOOLS AND WORK EQUIPMENT	1,512,515	1,435,293	1,331,160	104,133	7.26	1.5 ***	-	0.00
	TOTAL GENERAL PLANT	**16,724,964**	**12,206,157**	**12,495,039**	**(288,882)**			**3,164**	
	TOTAL DEPRECIABLE PLANT REVIEWED	**694,902,341**	**224,439,240**	**245,509,030**	**(21,069,790)**			**(108,240)**	

* No true-up is calculated as account will be amortized until fully depreciated.
** Fully amortized account, therefore true-up has been suspended.
*** True-up is not calculated on square accounts with less than 10% accumulated depreciation variance.

APPENDIX A

ESTIMATION OF SURIVOR CURVES

ESTIMATION OF SURVIVOR CURVES

Average Service Life

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units which survive at successive ages. A discussion of the general concept of survivor curves is presented. Also, the Iowa type survivor curves are reviewed.

SURVIVOR CURVES

The survivor curve graphically depicts the amount of property existing at each age throughout the life of an original group. From the survivor curve, the average life of the group, the remaining life expectancy, the probable life, and the frequency curve can be calculated. In Figure 1, a typical smooth survivor curve and the derived curves are illustrated. The average life is obtained by calculating the area under the survivor curve, from age zero to the maximum age, and dividing this area by the ordinate at age zero. The remaining life expectancy at any age can be calculated by obtaining the area under the curve, from the observation age to the maximum age, and dividing this area by the percent surviving at the observation age. For example, in Figure 1, the remaining life at age 30 is equal to the crosshatched area under the survivor curve divided by 29.5 percent surviving at age 30. The probable life at any age is developed by adding the age and remaining life. If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve presents the number of units retired in each age interval. It is derived by obtaining the differences between the amount of property surviving at the beginning and at the end of each interval.

Iowa Type Curves

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the

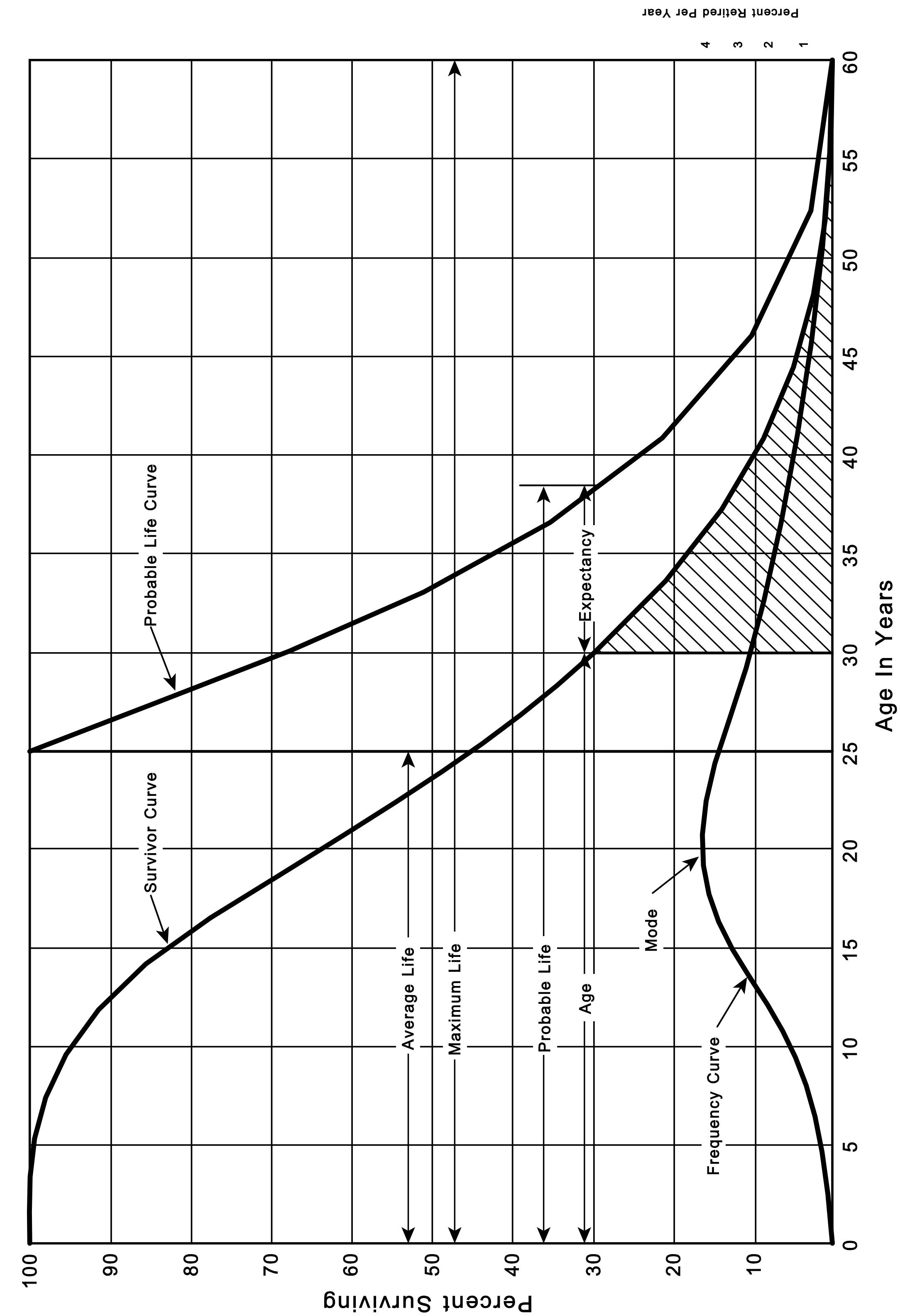


Figure 1. A Typical Survivor Curve and Derived Curves

Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements in relationship to the average life and the relative height of the modes. The left moded curves, presented in Figure 2, are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical moded curves, presented in Figure 3, are those in which the greatest frequency of retirement occurs at average service life. The right moded curves, presented in Figure 4, are those in which the greatest frequency occurs to the right of, or after, average service life. The origin moded curves, presented in Figure 5, are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero. The letter designation of each family of curves (L, S, R or O) represents the location of the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves within each family.

The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. A report of the study which resulted in the classification of property survivor characteristics into 18 type curves, which constitute three of the four families, was published in 1935 in the form of the Experiment Station's Bulletin 125.[1] These curve types have also been presented in subsequent Experiment Station bulletins and in the text, "Engineering Valuation and Depreciation."[2] In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis[3] presenting his development of the fourth family consisting of the four O type survivor curves.

[1] Winfrey, Robley. Statistical Analyses of Industrial Property Retirements. Iowa State College, Engineering Experiment Station, Bulletin 125. 1935.

[2] Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.

[3] Couch, Frank V. B., Jr. "Classification of Type O Retirement Characteristics of Industrial Property." Unpublished M.S. thesis (Engineering Valuation). Library, Iowa State College, Ames, Iowa. 1957.

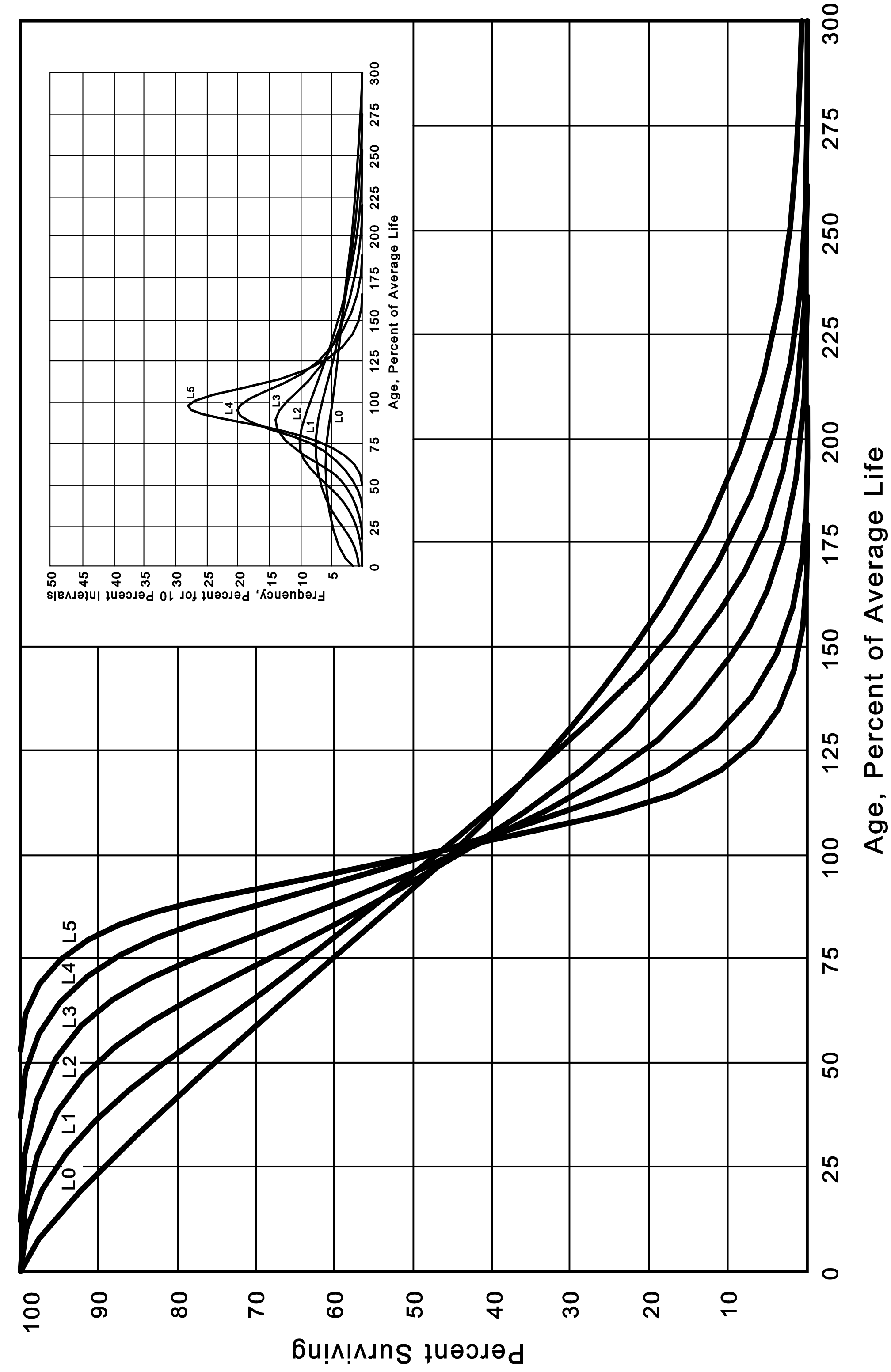


Figure 2. Left Modal or "L" Iowa Type Survivor Curves

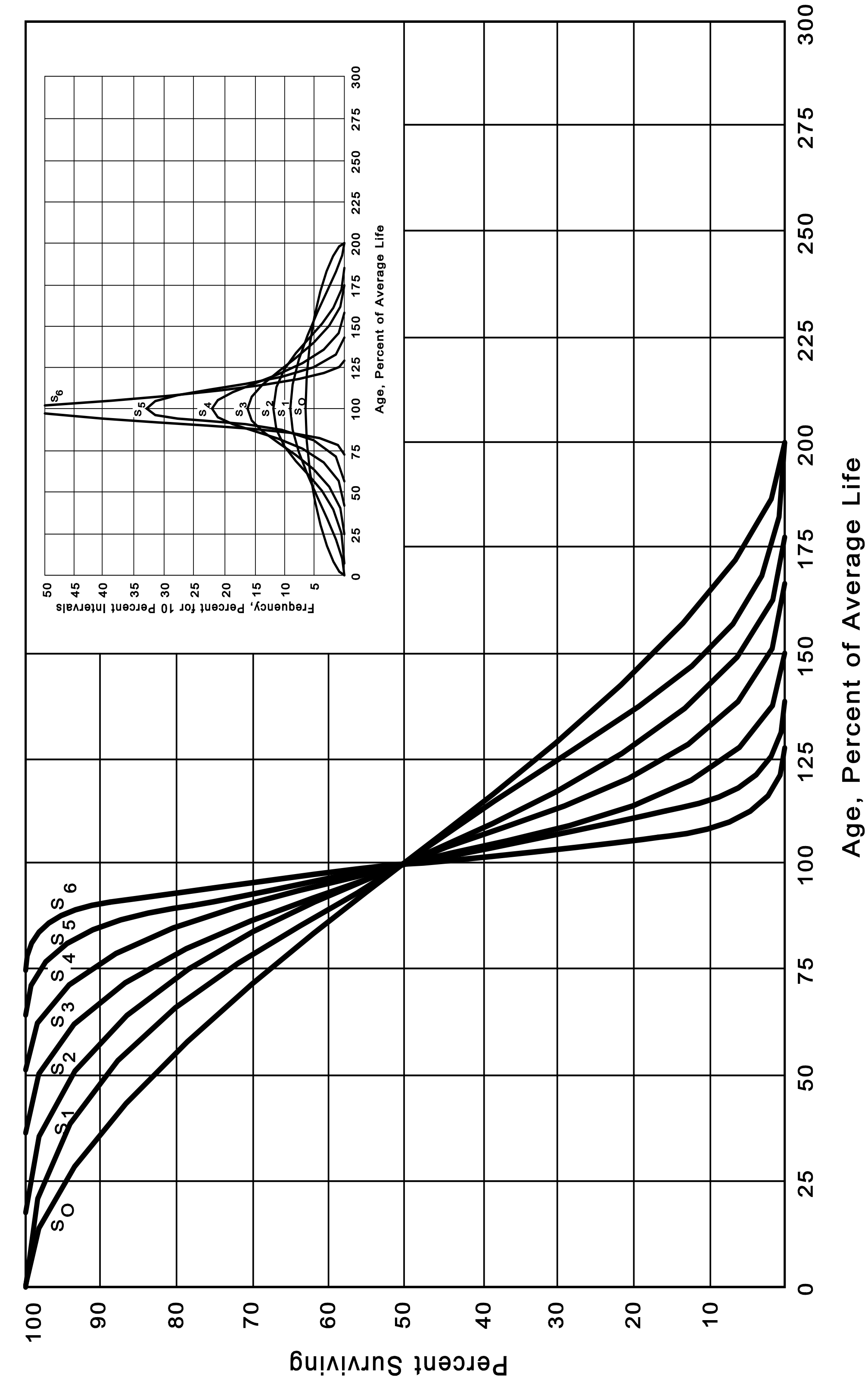


Figure 3. Symmetrical or "S" Iowa Type Survivor Curves

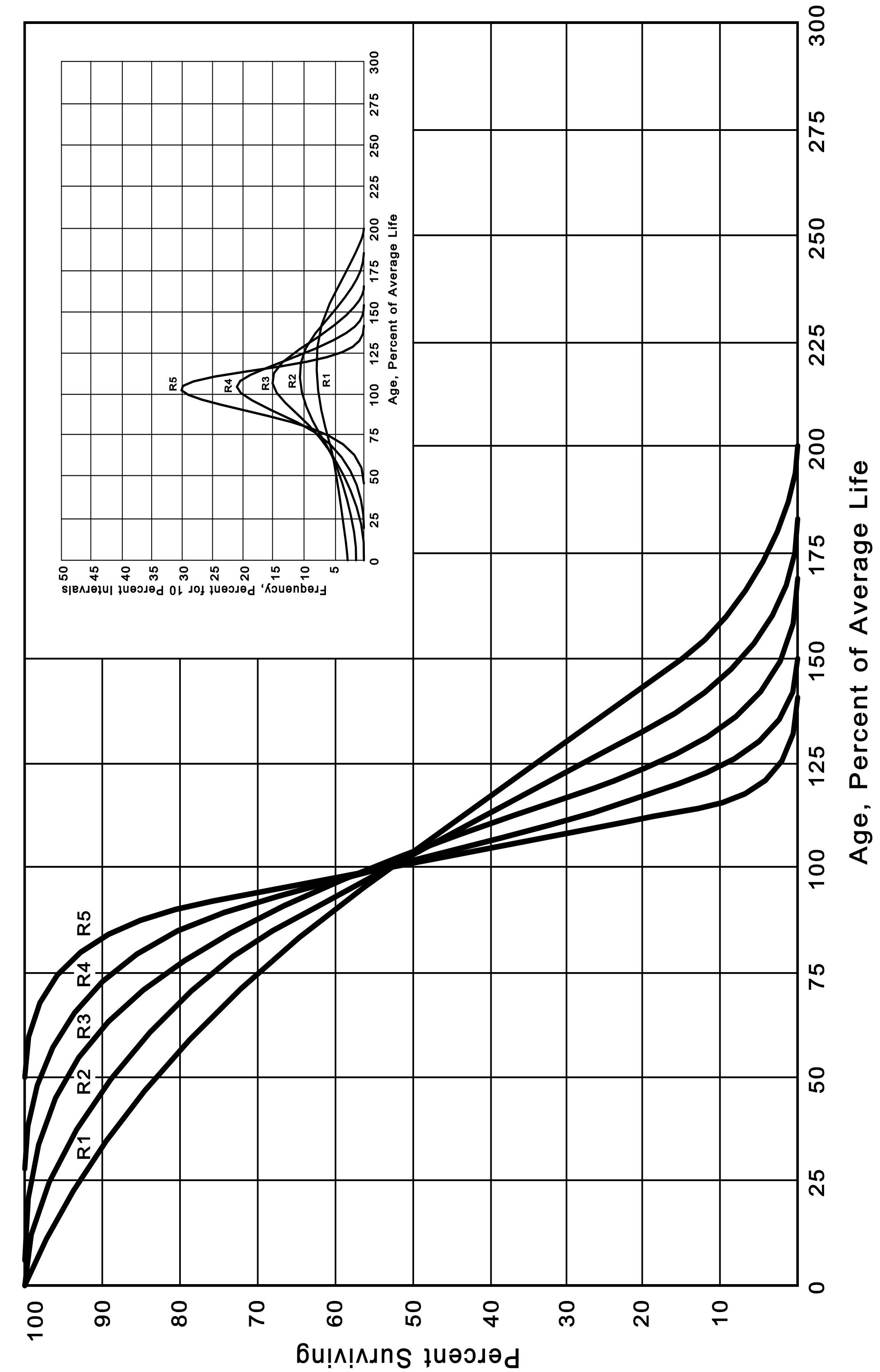


Figure 4. Right Modal or "R" Iowa Type Survivor Curves

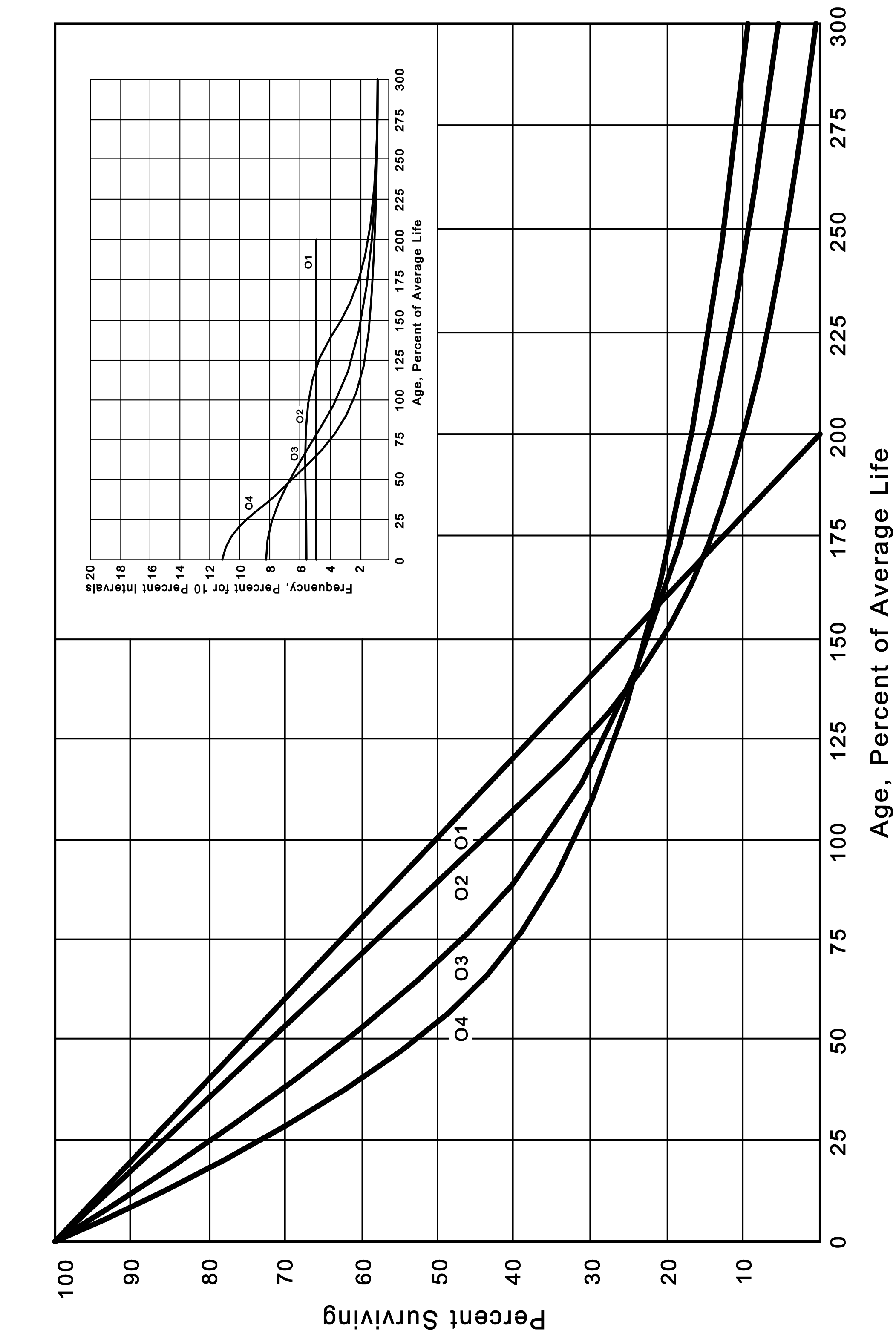


Figure 5. Origin Modal or "O" Iowa Type Survivor Curves

Retirement Rate Method of Analysis

The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each age group is retired. The method relates to property groups for which aged accounting experience is available and is the method used to develop the original stub survivor curves in this study. The method (also known as the annual rate method) is illustrated through the use of an example in the following text, and is also explained in several publications, including "Statistical Analyses of Industrial Property Retirements,"[4] "Engineering Valuation and Depreciation,"[5] and "Depreciation Systems."[6]

The average rate of retirement used in the calculation of the percent surviving for the survivor curve (life table) requires two sets of data: first, the property retired during a period of observation, identified by the property's age at retirement; and second, the property exposed to retirement at the beginning of the age intervals during the same period. The period of observation is referred to as the <u>experience band</u>, and the band of years which represent the installation dates of the property exposed to retirement during the experience band is referred to as the <u>placement band</u>. An example of the calculations used in the development of a life table follows. The example includes schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

Schedules of Annual Transactions in Plant Records

The property group used to illustrate the retirement rate method is observed for the experience band 2005-2014 during which there were placements during the years 2000-2014. In order to illustrate the summation of the aged data by age interval, the data were compiled in the manner presented in Schedules 1 and 2 on the following pages. In Schedule 1, the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, $10,000 of the dollars invested in 2000 were

[4]Winfrey, Robley, Supra Note 1.
[5]Marston, Anson, Robley Winfrey, and Jean C. Hempstead, Supra Note 2.
[6]Wolf, Frank K. and W. Chester Fitch. <u>Depreciation Systems</u>. Iowa State University Press. 1994.

SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2005-2014
SUMMARIZED BY AGE INTERVAL

Experience Band 2005-2014

Placement Band 2000-2014

Year Placed	Retirements, Thousands of Dollars During Year										Total During Age Interval	Age Interval
	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1999	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2000	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2001	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2002	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2003	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2004	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2005		5	11	12	13	14	15	16	18	20	113	7½-8½
2006			6	12	13	15	16	17	19	19	124	6½-7½
2007				6	13	15	16	17	19	19	131	5½-6½
2008					7	14	16	17	19	20	143	4½-5½
2009						8	18	20	22	23	146	3½-4½
2010							9	20	22	25	150	2½-3½
2011								11	23	25	151	1½-2½
2012									11	24	153	½-1½
2013										13	80	0-½
Total	53	68	86	106	128	157	196	231	273	308	1,606	

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2005-2014
SUMMARIZED BY AGE INTERVAL

Experience Band 2005-2014 | Placement Band 2000-2014

	Acquisitions, Transfers and Sales, Thousands of Dollars During Year											
Year Placed (1)	2005 (2)	2006 (3)	2007 (4)	2008 (5)	2009 (6)	2010 (7)	2011 (8)	2012 (9)	2013 (10)	2014 (11)	Total During Age Interval (12)	Age Interval (13)
1999	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
2000	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2001	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2002	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2003	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2004	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2005		-	-	-	-	-	-	-	-	-	-	7½-8½
2006			-	-	-	-	-	-	-	-	-	6½-7½
2007				-	-	-	-	(12)[b]	-	-	-	5½-6½
2008					-	-	-	-	22[a]	-	-	4½-5½
2009						-	-	(19)[b]	-	-	10	3½-4½
2010							-	-	-	-	-	2½-3½
2011								-	-	(102)[c]	(121)	1½-2½
2012									-	-	-	½-1½
2013												0-½
Total	-	-	-	-	-	-	60	(30)	22	(102)	(50)	

[a] Transfer Affecting Exposures at Beginning of Year
[b] Transfer Affecting Exposures at End of Year
[c] Sale with Continued Use
Parentheses Denote Credit Amount.

retired in 2005. The $10,000 retirement occurred during the age interval between 4½ and 5½ years on the basis that approximately one-half of the amount of property was installed prior to and subsequent to July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Schedule 1 immediately above the stair step line drawn on the table beginning with the 2005 retirements of 2000 installations and ending with the 2014 retirements of the 2009 installations. Thus, the total amount of 143 for age interval 4½-5½ equals the sum of:

$$10 + 12 + 13 + 11 + 13 + 13 + 15 + 17 + 19 + 20.$$

In Schedule 2, other transactions which affect the group are recorded in a similar manner. The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements, but are used in developing the exposures at the beginning of each age interval.

Schedule of Plant Exposed to Retirement

The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Schedule 3 on the following page. The surviving plant at the beginning of each year from 2005 through 2014 is recorded by year in the portion of the table headed "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Schedule 3 for each successive year following the beginning balance or addition, are obtained by adding or subtracting the net entries

SCHEDULE 3. PLANT EXPOSED TO RETIREMENT JANUARY 1
OF EACH YEAR 2005-2014
SUMMARIZED BY AGE INTERVAL

Experience Band 2005-2014 | Placement Band 2000-2014

	Exposures, Thousands of Dollars — Annual Survivors at the Beginning of the Year											
Year Placed (1)	2005 (2)	2006 (3)	2007 (4)	2008 (5)	2009 (6)	2010 (7)	2011 (8)	2012 (9)	2013 (10)	2014 (11)	Total at Beginning of Age Interval (12)	Age Interval (13)
1999	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2000	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2001	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2002	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2003	376	367	257	346	334	321	307	267	280	261	1,097	9½-10½
2004	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2005		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2006			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2007				580[a]	574	561	546	530	501	482	3,057	5½-6½
2008					660[a]	653	639	623	628	609	3,789	4½-5½
2009						750[a]	742	724	685	663	4,332	3½-4½
2010							850[a]	841	821	799	4,955	2½-3½
2011								960[a]	949	923	5,719	1½-2½
2012									1,080[a]	1,069	6,579	½-1½
2013										1,220[a]	7,490	0-½
Total	1,975	2,382	2,824	3,318	3,872	4,494	5,247	6,017	6,852	7,799	44,780	

[a] Additions during the year.

shown on Schedules 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2006 are calculated in the following manner:

Exposures at age 0	= amount of addition	= $750,000
Exposures at age ½	= $750,000 - $ 8,000	= $742,000
Exposures at age 1½	= $742,000 - $18,000	= $724,000
Exposures at age 2½	= $724,000 - $20,000 - $19,000	= $685,000
Exposures at age 3½	= $685,000 - $22,000	= $663,000

For the entire experience band 2005-2014, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Schedule 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

255 + 268 + 284 + 311 + 334 + 374 + 405 + 448 + 501 + 609.

Original Life Table

The original life table, illustrated in Schedule 4 on the following page, is developed from the totals shown on the schedules of retirements and exposures, Schedules 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100% at age zero and successively multiplying the percent

SCHEDULE 4. ORIGINAL LIFE TABLE

CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2005-2014 Placement Band 2000-2014

(Exposure and Retirement Amounts are in Thousands of Dollars)

Age at Beginning of Interval (1)	Exposures at Beginning of Age Interval (2)	Retirements During Age Interval (3)	Retirement Ratio (4)	Survivor Ratio (5)	Percent Surviving at Beginning of Age Interval (6)
0.0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.60
12.5	323	44	0.1362	0.8638	48.90
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	44,780	1,606			

Column 2 from Schedule 3, Column 12, Plant Exposed to Retirement.
Column 3 from Schedule 1, Column 12, Retirements for Each Year.
Column 4 = Column 3 divided by Column 2.
Column 5 = 1.0000 minus Column 4.
Column 6 = Column 5 multiplied by Column 6 as of the Preceding Age Interval.

surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15			
Exposures at age 4½	=	3,789,000			
Retirements from age 4½ to 5½	=	143,000			
Retirement Ratio	=	143,000 ÷	3,789,000	=	0.0377
Survivor Ratio	=	1.000 -	0.0377	=	0.9623
Percent surviving at age 5½	=	(88.15) x	(0.9623)	=	84.83

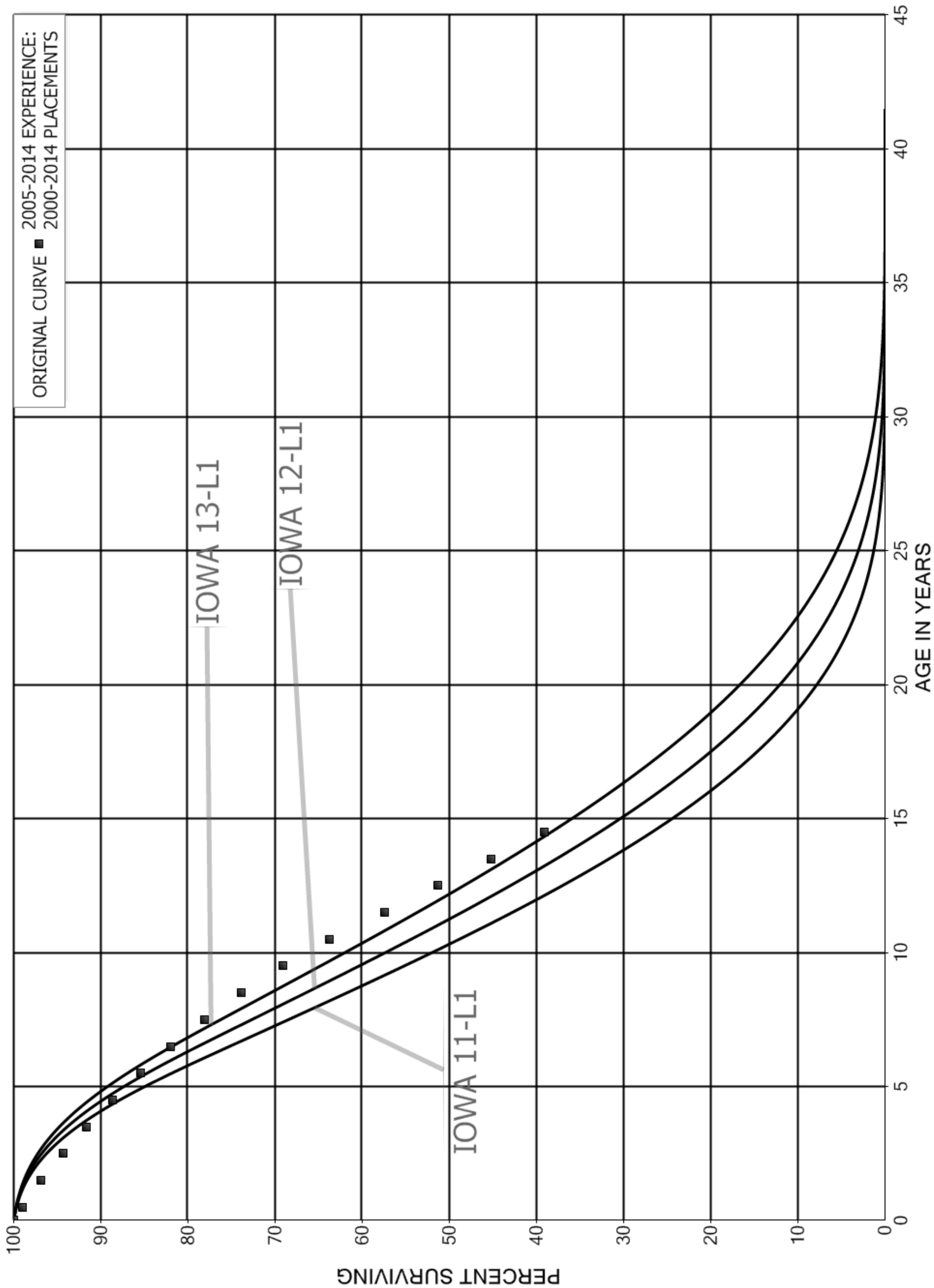
The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Schedules 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless. The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

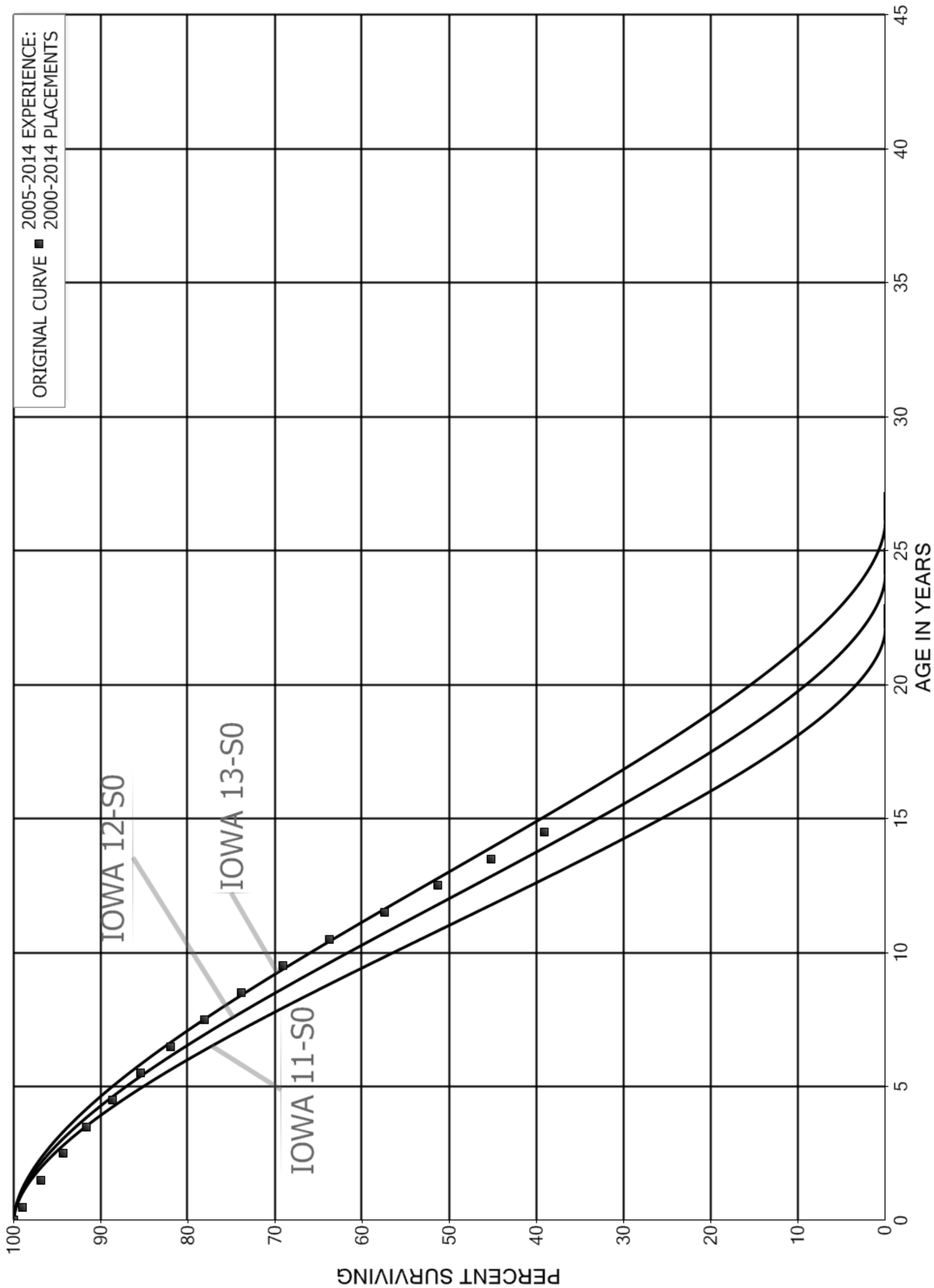
Smoothing the Original Survivor Curve

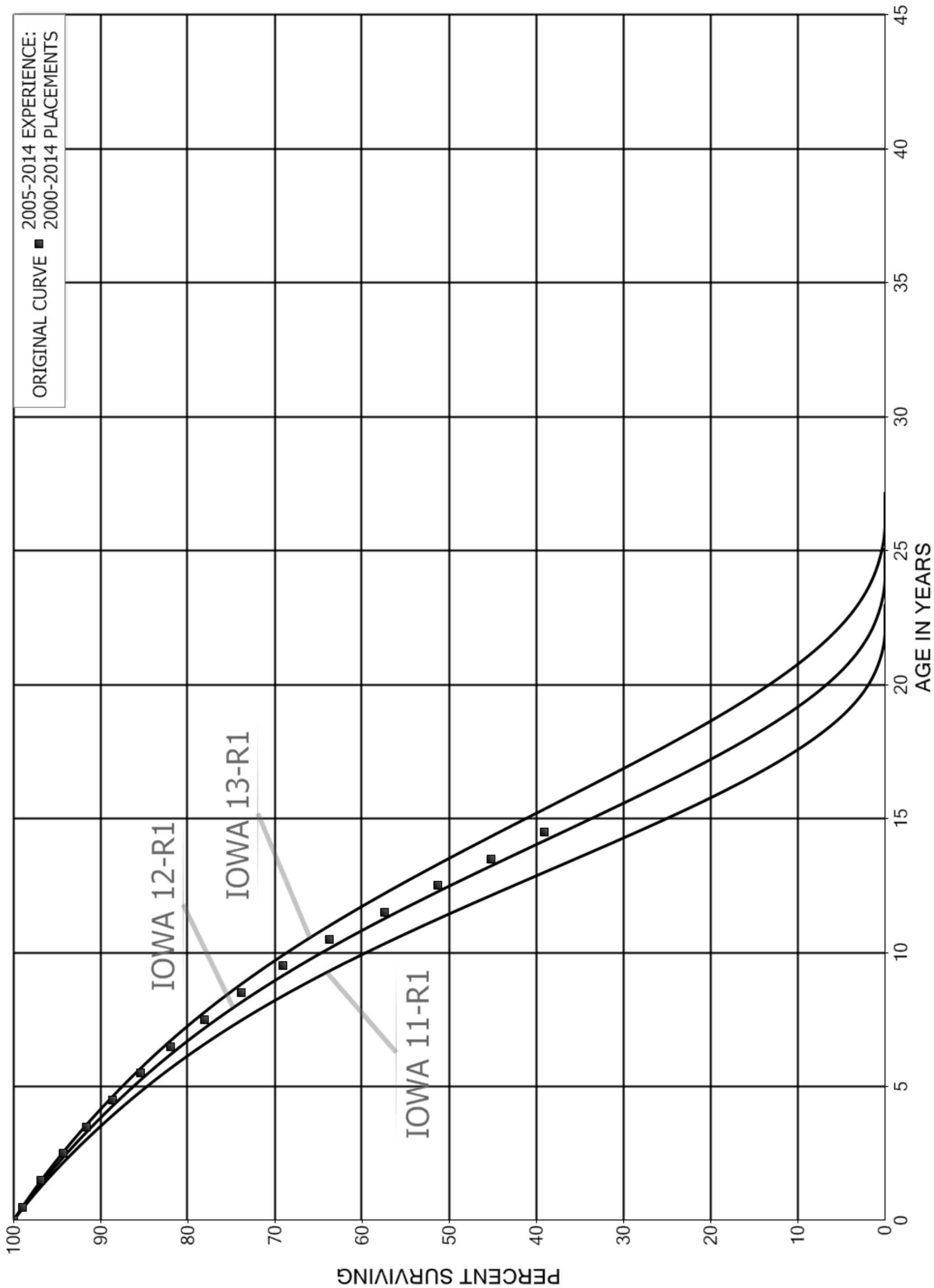
The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100% to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

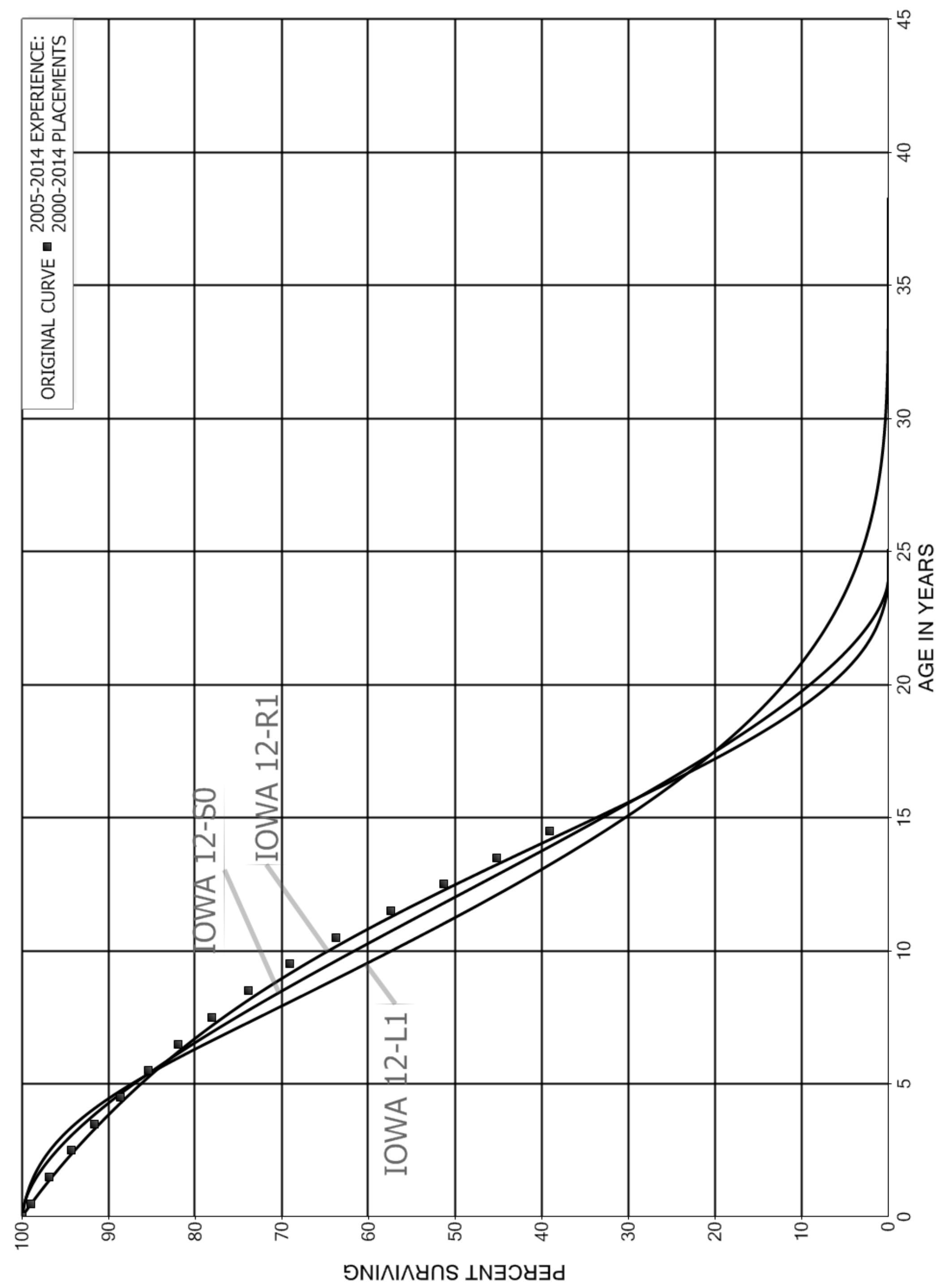
The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percents surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Schedule 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.


ORIGINAL CURVE ■ 2005-2014 EXPERIENCE:
2000-2014 PLACEMENTS
IOWA 13-L1
IOWA 12-L1
IOWA 11-L1
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
5
15
25
35
45


ORIGINAL CURVE ■ 2005-2014 EXPERIENCE:
2000-2014 PLACEMENTS
IOWA 12-S0
IOWA 13-S0
IOWA 11-S0
AGE IN YEARS
PERCENT SURVIVING
0
5
10
15
20
25
30
35
40
45
100
90
80
70
60
50
40
30
20
10
0


ORIGINAL CURVE ■ 2005-2014 EXPERIENCE:
2000-2014 PLACEMENTS
IOWA 12-R1
IOWA 13-R1
IOWA 11-R1
AGE IN YEARS
PERCENT SURVIVING


ORIGINAL CURVE ■ 2005-2014 EXPERIENCE:
2000-2014 PLACEMENTS
IOWA 12-S0
IOWA 12-R1
IOWA 12-L1
AGE IN YEARS
PERCENT SURVIVING
0
5
10
15
20
25
30
35
40
45
100
90
80
70
60
50
40
30
20
10
0

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February 25, 2016

Manitoba Hydro
360 Portage Avenue
Winnipeg, Manitoba
T3C 0G8

Attention: Mr. Darren Rainkie
Vice-President, Finance and Regulatory

Ladies and Gentlemen:

Pursuant to your request, we have calculated depreciation rates based on the original asset costs of Centra Gas Manitoba Inc. ("Centra Gas") as of March 31, 2014 using the depreciation calculation procedures that were approved in your last depreciation study, namely the use of the Average Service Life ("ASL") procedure and incorporation of estimated net salvage percentages. We have also prepared a schedule of depreciation rates incorporating the use of the ASL procedure, but without the incorporation of net salvage percentages. The attached schedules provide a summary of the depreciation rates for both with and without net salvage scenarios related to the transmission, distribution and general plant assets of Centra Gas of March 31, 2014.

The calculated annual depreciation accrual rates presented in the report are applicable to plant in service as of March 31, 2014. The depreciation rates are based on the average service life estimates and interim survivor curve determinations as recently completed in the full depreciation study report. The net salvage percentages used in the enclosed schedules of depreciation rates are consistent with the percentages used in the 2010 Depreciation Study.

Gannett Fleming has calculated and is providing these requested schedules of depreciation rates in order to provide continuity from the last depreciation study, through the transition to the depreciation rates as provided in the recently completed Gannett Fleming Depreciation Study report.

As the attached schedules are a work product of Gannett Fleming, we ask that this cover letter be provided any time that the attached schedules are distributed. Gannett Fleming does, however, authorize the distribution of the electronic version of the attached schedules.

Respectfully submitted,

GANNETT FLEMING CANADA ULC

LARRY E. KENNEDY
Vice President

LEK:hac
Project: 058390:500

/Attachments - 4

CENTRA GAS MANITOBA INC.

TABLE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
AS OF MARCH 31, 2014
ASL WITH SALVAGE

ACCOUNT	DEPRECIABLE GROUP	SURVIVOR CURVE	NET SALVAGE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)	ANNUAL PROVISION FOR TRUE-UP	TOTAL DEPRECIATION RELATED TO LIFE EXPENSE	TOTAL DEPRECIATION RELATED TO LIFE RATE (%)
	(1)	(2)	(3)	(4)	(5)	(6)=(5)/(4)	(7)	(8)=(5)+(7)	(9)=(8)/(4)
401.00	FRANCHISES AND CONSENTS	20-SQ	0	22,105	1,105	5.00	-	1,105 **	5.00
	TRANSMISSION								
461.00	LAND RIGHTS	75-SQ	0	3,932,416	52,301	1.33	(1,191)	51,110	1.30
463.00	STRUCTURES AND IMPROVEMENTS - MEASURING AND REGULATING	65-R4	(5)	1,035,535	16,745	1.62	(3,144)	13,601	1.31
464.00	STRUCTURES AND IMPROVEMENTS - OTHER	65-R4	(5)	76,421	1,236	1.62	(429)	807	1.06
465.00	MAINS	65-R3	(15)	101,865,455	1,804,037	1.77	(23,629)	1,780,408	1.75
465.10	CATHODIC PROTECTION	25-SQ	0	195,084	7,803	4.00	135	7,938	4.07
467.00	MEASURING AND REGULATING EQUIPMENT	45-R2	(5)	8,128,234	189,469	2.33	(8,374)	181,095	2.23
	TOTAL TRANSMISSION			**115,233,145**	**2,071,591**		**(36,632)**	**2,034,959**	
	DISTRIBUTION								
471.00	LAND RIGHTS	75-SQ	0	1,306,450	17,376	1.33	-	17,376	1.33
472.00	STRUCTURES AND IMPROVEMENTS	50-R3	(10)	1,335,428	29,379	2.20	(5,477)	23,902	1.79
472.10	STRUCTURES AND IMPROVEMENTS - MEASURING AND REGULATING	50-R3	5	4,232,659	80,420	1.90	163	80,583	1.90
473.00	SERVICES	62-R2	(50)	232,034,858	5,603,642	2.41	82,448	5,686,090	2.45
474.00	REGULATORS AND METER INSTALLATIONS	50-R5	0	52,825,017	1,056,500	2.00	(72,608)	983,892	1.86
475.00	MAINS	68-R4	(20)	182,842,390	3,225,340	1.76	(42,705)	3,182,635	1.74
475.10	CATHODIC PROTECTION	15-SQ	0	2,466,194	164,495	6.67	7,689	172,184	6.98
477.00	MEASURING AND REGULATING EQUIPMENT	37-R2.5	(20)	37,286,853	1,208,094	3.24	(87,294)	1,120,800	3.01
477.10	TELEMETRY EQUIPMENT	17-S6	0	4,046,541	237,937	5.88	(48,404)	189,533	4.68
478.00	METERS	25-R1.5	0	41,097,382	1,641,170	3.99	356,362	1,997,532	4.86
478.10	METER - TESTING	10-SQ	0	0	0	10.00	-	- *	10.00
479.10	COMPUTER HARDWARE EQUIPMENT - EMS/SCADA	5-SQ	0	441,769	88,354	20.00	-	88,354	20.00
479.30	COMPUTER SYSTEM DEVELOPMENT - EMS/SCADA	7-S3	0	3,006,585	429,641	14.29	(27,791)	401,850	13.37
	TOTAL DISTRIBUTION			**562,922,127**	**13,782,349**		**162,383**	**13,944,732**	
	GENERAL PLANT								
482.00	STRUCTURES AND IMPROVEMENTS	45-R3	15	8,983,418	169,517	1.89	(63,108)	106,409	1.18
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	0	265,592	5,050	1.90	28,672	33,722	12.70
483.30	COMPUTER SYSTEM DEVELOPMENT	10-SQ	0	5,304,028	530,403	10.00	-	530,403	10.00
484.00	TRANSPORTATION EQUIPMENT	10-R5	10	199,645	0	0.00	-	- ***	0.00
485.00	HEAVY WORK EQUIPMENT	20-R5	20	459,767	0	3.38	-	***	0.00
486.00	TOOLS AND WORK EQUIPMENT	15-SQ	0	1,512,515	51,904	3.43	-	51,904	3.43
	TOTAL GENERAL PLANT			**16,724,964**	**756,874**		**(34,436)**	**722,438**	
	TOTAL DEPRECIABLE PLANT			**694,902,341**	**16,611,918**		**91,315**	**16,703,233**	**2.40**

* Rate is provided for the use with future additions.
** Total depreciation expense calculated based upon length of lease term, with no provision for true-up.
*** Account is fully depreciated.

CENTRA GAS MANITOBA INC.

TABLE 2. CALCULATED ACCRUED DEPREICATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF ANNUAL PROVISION FOR TRUE-UP RELATED TO ORIGINAL COST AS OF MARCH 31, 2014
ASL WITH SALVAGE

ACCT	DEPRECIABLE GROUP	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE AMOUNT	ACCUMULATED DEPRECIATION VARIANCE PERCENT	PROBABLE REMAINING LIFE		ANNUAL PROVISION FOR TRUE-UP	TRUE-UP RATE (%)
	(1)	(2)	(3)	(4)	(5) = (3)-(4)	(6) = (5)/(3)	(7)		(8)=(5)/(7)	(9)=(8)/(2)
401.00	FRANCHISES AND CONSENTS	22,105	21,426	12,384	9,042	42.20	1.0		-	0.00
	TRANSMISSION									
461.00	LAND RIGHTS	3,932,416	650,054	725,696	(75,642)	(11.64)	63.5		(1,191)	(0.03)
463.00	STRUCTURES AND IMPROVEMENTS - MEASURING AND REGULATING	1,035,535	395,737	553,517	(157,780)	(39.87)	50.2		(3,144)	(0.30)
464.00	STRUCTURES AND IMPROVEMENTS - OTHER	76,421	45,667	59,420	(13,753)	(30.12)	32.0		(429)	(0.56)
465.00	MAINS	101,865,455	26,132,115	27,329,624	(1,197,509)	(4.58)	50.7		(23,629)	(0.02)
465.10	CATHODIC PROTECTION	195,084	4,153	844	3,309	79.68	24.5		135	0.07
467.00	MEASURING AND REGULATING EQUIPMENT	8,128,234	2,082,993	2,404,369	(321,376)	(15.43)	38.4		(8,374)	(0.10)
	TOTAL TRANSMISSION	**115,233,145**	**29,310,719**	**31,073,470**	**(1,762,751)**				**(36,632)**	
	DISTRIBUTION									
471.00	LAND RIGHTS	1,306,450	156,021	162,691	(6,670)	(4.27)	66.1	***	-	0.00
472.00	STRUCTURES AND IMPROVEMENTS	1,335,428	640,233	797,038	(156,805)	(24.49)	28.6		(5,477)	(0.41)
472.10	STRUCTURES AND IMPROVEMENTS - MEASURING AND REGULATING	4,232,659	1,194,905	1,189,178	5,727	0.48	35.1		163	0.00
473.00	SERVICES	232,034,858	89,858,471	86,080,722	3,777,749	4.20	45.8		82,448	0.04
474.00	REGULATORS AND METER INSTALLATIONS	52,825,017	17,619,738	20,243,062	(2,623,324)	(14.89)	36.1		(72,608)	(0.14)
475.00	MAINS	182,842,390	62,269,632	64,364,739	(2,095,107)	(3.36)	49.1		(42,705)	(0.02)
475.10	CATHODIC PROTECTION	2,466,194	654,348	570,688	83,660	12.79	10.9		7,689	0.31
477.00	MEASURING AND REGULATING EQUIPMENT	37,286,853	15,986,724	18,129,793	(2,143,069)	(13.41)	24.6		(87,294)	(0.23)
477.10	TELEMETRY EQUIPMENT	4,046,541	3,004,778	3,486,399	(481,621)	(16.03)	10.0		(48,404)	(1.20)
478.00	METERS	41,097,382	11,829,826	6,306,218	5,523,608	46.69	15.5		356,362	0.87
479.10	COMPUTER HARDWARE EQUIPMENT - EMS/SCADA	441,769	215,567	202,210	13,358	6.20	2.5	***	-	0.00
479.30	COMPUTER SYSTEM DEVELOPMENT - EMS/SCADA	3,006,585	214,760	395,400	(180,640)	(84.11)	6.5		(27,791)	(0.92)
	TOTAL DISTRIBUTION	**562,922,127**	**203,645,003**	**201,928,138**	**1,716,865**				**162,383**	
	GENERAL PLANT									
482.00	STRUCTURES AND IMPROVEMENTS	8,983,418	4,261,535	5,938,948	(1,677,413)	(39.36)	26.6		(63,108)	(0.70)
483.00	OFFICE FURNITURE AND EQUIPMENT	265,592	262,569	233,897	28,672	10.92	1.0	*	28,672	10.80
483.30	COMPUTER SYSTEM DEVELOPMENT	5,304,028	4,508,423	4,331,622	176,801	3.92	1.5	***	-	0.00
484.00	TRANSPORTATION EQUIPMENT	199,645	179,680	199,645	(19,965)	(11.11)	0.0	**	-	0.00
485.00	HEAVY WORK EQUIPMENT	459,767	295,009	459,767	(164,758)	(55.85)	0.0	**	-	0.00
486.00	TOOLS AND WORK EQUIPMENT	1,512,515	1,435,308	1,331,160	104,148	7.26	1.5	***	-	0.00
	TOTAL GENERAL PLANT	**16,724,964**	**10,942,524**	**12,495,039**	**(1,552,515)**				**(34,436)**	
	TOTAL DEPRECIABLE PLANT	**694,902,341**	**243,919,672**	**245,509,030**	**(1,589,358)**				**91,315**	

* No true-up is calculated as account will be amortized until fully depreciated.
** Fully amortized account, therefore true-up has been suspended.
*** True-up is not calculated on square accounts with less than 10% accumulated depreciation variance.

CENTRA GAS MANITOBA INC.

TABLE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
AS OF MARCH 31, 2014
ASL WITHOUT SALVAGE

ACCOUNT	DEPRECIABLE GROUP	SURVIVOR CURVE	NET SALVAGE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)	ANNUAL PROVISION FOR TRUE-UP	TOTAL DEPRECIATION RELATED TO LIFE EXPENSE	TOTAL DEPRECIATION RELATED TO LIFE RATE (%)
	(1)	(2)	(3)	(4)	(5)	(6)=(5)/(4)	(7)	(8)=(5)+(7)	(9)=(8)/(4)
401.00	FRANCHISES AND CONSENTS	20-SQ	0	22,105	1,105	5.00	-	1,105 **	5.00
	TRANSMISSION								
461.00	LAND RIGHTS	75-SQ	0	3,932,416	52,301	1.33	(1,191)	51,110	1.30
463.00	STRUCTURES AND IMPROVEMENTS - MEASURING AND REGULATING	65-R4	0	1,035,535	15,947	1.54	(3,518)	12,429	1.20
464.00	STRUCTURES AND IMPROVEMENTS - OTHER	65-R4	0	76,421	1,177	1.54	(497)	680	0.89
465.00	MAINS	65-R3	0	101,865,455	1,568,728	1.54	(90,811)	1,477,917	1.45
465.10	CATHODIC PROTECTION	25-SQ	0	195,084	7,803	4.00	135	7,938	4.07
467.00	MEASURING AND REGULATING EQUIPMENT	45-R2	0	8,128,234	180,447	2.22	(10,917)	169,530	2.09
	TOTAL TRANSMISSION			**115,233,145**	**1,826,403**		**(106,799)**	**1,719,604**	
	DISTRIBUTION								
471.00	LAND RIGHTS	75-SQ	0	1,306,450	17,376	1.33	-	17,376	1.33
472.00	STRUCTURES AND IMPROVEMENTS	50-R3	0	1,335,428	26,709	2.00	(7,510)	19,199	1.44
472.10	STRUCTURES AND IMPROVEMENTS - MEASURING AND REGULATING	50-R3	5	4,232,659	80,420	1.90	163	80,583	1.90
473.00	SERVICES	62-R2	0	232,034,858	3,735,761	1.61	(571,259)	3,164,502	1.36
474.00	REGULATORS AND METER INSTALLATIONS	50-R5	0	52,825,017	1,056,500	2.00	(72,608)	983,892	1.86
475.00	MAINS	68-R4	0	182,842,390	2,687,783	1.47	(254,248)	2,433,535	1.33
475.10	CATHODIC PROTECTION	15-SQ	0	2,466,194	164,495	6.67	7,703	172,198	6.98
477.00	MEASURING AND REGULATING EQUIPMENT	37-R2.5	0	37,286,853	1,006,745	2.70	(195,826)	810,919	2.17
477.10	TELEMETRY EQUIPMENT	17-S6	0	4,046,541	237,937	5.88	(48,404)	189,533	4.68
478.00	METERS	25-R1.5	0	41,097,382	1,641,170	3.99	356,362	1,997,532	4.86
478.10	METER - TESTING	10-SQ	0	0	0	10.00	-	- *	10.00
479.10	COMPUTER HARDWARE EQUIPMENT - EMS/SCADA	5-SQ	0	441,769	88,354	20.00	-	88,354	20.00
479.30	COMPUTER SYSTEM DEVELOPMENT - EMS/SCADA	7-S3	0	3,006,585	429,641	14.29	(27,791)	401,850	13.37
	TOTAL DISTRIBUTION			**562,922,127**	**11,172,891**		**(813,418)**	**10,359,473**	
	GENERAL PLANT								
482.00	STRUCTURES AND IMPROVEMENTS	45-R3	15	8,983,418	169,517	1.89	(63,108)	106,409	1.18
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	0	265,592	5,050	1.90	28,672	33,722	12.70
483.30	COMPUTER SYSTEM DEVELOPMENT	10-SQ	0	5,304,028	530,403	10.00	-	530,403	10.00
484.00	TRANSPORTATION EQUIPMENT	10-R5	10	199,645	0	0.00	-	- ***	0.00
485.00	HEAVY WORK EQUIPMENT	20-R5	20	459,767	0	3.38	-	***	0.00
486.00	TOOLS AND WORK EQUIPMENT	15-SQ	0	1,512,515	51,904	3.43	-	51,904	3.43
	TOTAL GENERAL PLANT			**16,724,964**	**756,874**		**(34,436)**	**722,438**	
	TOTAL DEPRECIABLE PLANT			**694,902,341**	**13,757,273**		**(954,653)**	**12,802,620**	**1.84**

* Rate is provided for the use with future additions.
** Total depreciation expense calculated based upon length of lease term, with no provision for true-up.
*** Account is fully depreciated.

CENTRA GAS MANITOBA INC.

TABLE 2. CALCULATED ACCRUED DEPREICATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF ANNUAL PROVISION FOR TRUE-UP RELATED TO ORIGINAL COST AS OF MARCH 31, 2014
ASL WITHOUT SALVAGE

ACCT	DEPRECIABLE GROUP	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE AMOUNT	ACCUMULATED DEPRECIATION VARIANCE PERCENT	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP	TRUE-UP RATE (%)
	(1)	(2)	(3)	(4)	(5) = (3)-(4)	(6) = (5)/(3)	(7)	(8)=(5)/(7)	(9)=(8)/(2)
401.00	FRANCHISES AND CONSENTS	22,105	21,426	12,384	9,042	42.20	1.0	-	0.00
	TRANSMISSION								
461.00	LAND RIGHTS	3,932,416	650,054	725,696	(75,642)	(11.64)	63.5	(1,191)	(0.03)
463.00	STRUCTURES AND IMPROVEMENTS - MEASURING AND REGULATING	1,035,535	376,927	553,517	(176,590)	(46.85)	50.2	(3,518)	(0.34)
464.00	STRUCTURES AND IMPROVEMENTS - OTHER	76,421	43,493	59,420	(15,927)	(36.62)	32.0	(497)	(0.65)
465.00	MAINS	101,865,455	22,727,306	27,329,624	(4,602,318)	(20.25)	50.7	(90,811)	(0.09)
465.10	CATHODIC PROTECTION	195,084	4,153	844	3,309	79.68	24.5	135	0.07
467.00	MEASURING AND REGULATING EQUIPMENT	8,128,234	1,985,423	2,404,369	(418,946)	(21.10)	38.4	(10,917)	(0.13)
	TOTAL TRANSMISSION	**115,233,145**	**25,787,356**	**31,073,470**	**(5,286,114)**			**(106,799)**	
	DISTRIBUTION								
471.00	LAND RIGHTS	1,306,450	156,021	162,691	(6,670)	(4.27)	66.1 ***	-	0.00
472.00	STRUCTURES AND IMPROVEMENTS	1,335,428	582,032	797,038	(215,006)	(36.94)	28.6	(7,510)	(0.56)
472.10	STRUCTURES AND IMPROVEMENTS - MEASURING AND REGULATING	4,232,659	1,194,905	1,189,178	5,727	0.48	35.1	163	0.00
473.00	SERVICES	232,034,858	59,905,649	86,080,722	(26,175,073)	(43.69)	45.8	(571,259)	(0.25)
474.00	REGULATORS AND METER INSTALLATIONS	52,825,017	17,619,738	20,243,062	(2,623,324)	(14.89)	36.1	(72,608)	(0.14)
475.00	MAINS	182,842,390	51,891,356	64,364,739	(12,473,383)	(24.04)	49.1	(254,248)	(0.14)
475.10	CATHODIC PROTECTION	2,466,194	654,348	570,688	83,660	12.79	10.9	7,703	0.31
477.00	MEASURING AND REGULATING EQUIPMENT	37,286,853	13,322,271	18,129,793	(4,807,522)	(36.09)	24.6	(195,826)	(0.53)
477.10	TELEMETRY EQUIPMENT	4,046,541	3,004,778	3,486,399	(481,621)	(16.03)	10.0	(48,404)	(1.20)
478.00	METERS	41,097,382	11,829,826	6,306,218	5,523,608	46.69	15.5	356,362	0.87
479.10	COMPUTER HARDWARE EQUIPMENT - EMS/SCADA	441,769	215,567	202,210	13,358	6.20	2.5 ***	-	0.00
479.30	COMPUTER SYSTEM DEVELOPMENT - EMS/SCADA	3,006,585	214,760	395,400	(180,640)	(84.11)	6.5	(27,791)	(0.92)
	TOTAL DISTRIBUTION	**562,922,127**	**160,591,251**	**201,928,138**	**(41,336,887)**			**(813,418)**	
	GENERAL PLANT								
482.00	STRUCTURES AND IMPROVEMENTS	8,983,418	4,261,535	5,938,948	(1,677,413)	(39.36)	26.6	(63,108)	(0.70)
483.00	OFFICE FURNITURE AND EQUIPMENT	265,592	262,569	233,897	28,672	10.92	1.0 *	28,672	10.80
483.30	COMPUTER SYSTEM DEVELOPMENT	5,304,028	4,508,423	4,331,622	176,801	3.92	1.5 ***	-	0.00
484.00	TRANSPORTATION EQUIPMENT	199,645	179,680	199,645	(19,965)	(11.11)	0.0 **	-	0.00
485.00	HEAVY WORK EQUIPMENT	459,767	295,009	459,767	(164,758)	(55.85)	0.0 **	-	0.00
486.00	TOOLS AND WORK EQUIPMENT	1,512,515	1,435,308	1,331,160	104,148	7.26	1.5 ***	-	0.00
	TOTAL GENERAL PLANT	**16,724,964**	**10,942,524**	**12,495,039**	**(1,552,515)**			**(34,436)**	
	TOTAL DEPRECIABLE PLANT	**694,902,341**	**197,342,557**	**245,509,030**	**(48,166,473)**			**(954,653)**	

* No true-up is calculated as account will be amortized until fully depreciated.
** Fully amortized account, therefore true-up has been suspended.
*** True-up is not calculated on square accounts with less than 10% accumulated depreciation variance.

February 26, 2016

Manitoba Hydro
360 Portage Avenue
Winnipeg, Manitoba
T3C 0G8

Attention: Mr. Darren Rainkie
Vice-President, Finance and Regulatory

Ladies and Gentlemen:

Based on my review of the loss as projected in the gains/loss model for the year ending March 31, 2015 related to the Centra Gas Account 478 – Meters, I determined that the average service life and Iowa curve requires a change to better reflect the life expectancy of the assets in this account. As such, we included the retirement data related to the year 2015 to our historic retirement data bases and prepared a new actuarial analysis of Account 478.

Based on our additional analysis, I have concluded that a revision for the average service life to the Iowa 20-L1.5 is reasonable at this time. In order to provide the impact of this change on the Centra Gas depreciation rate, we have prepared a depreciation calculation based on this change in the Iowa curve. I have attached revised versions of the Tables 1 and 2 from the last depreciation study which now incorporate this change. The attached tables reflect the changed rate on both an Equal Life Group procedure and separately for the use of the Average Service Life procedure. Both of the attached scenarios exclude any provision for net negative salvage.

As the attached schedules are a work product of Gannett Fleming, we ask that this cover letter be provided any time that the attached schedules are distributed. Gannett Fleming does, however, authorize the distribution of the electronic version of the attached schedules.

Respectfully submitted,

GANNETT FLEMING CANADA ULC

LARRY E. KENNEDY
Vice President

LEK:hac
Project: 058390:500

/Attachments - 4

CENTRA GAS MANITOBA INC.

TABLE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
AS OF MARCH 31, 2015
ELG

ACCOUNT	DEPRECIABLE GROUP	SURVIVOR CURVE	NET SALVAGE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2015	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)	ANNUAL PROVISION FOR TRUE-UP	TOTAL DEPRECIATION RELATED TO LIFE EXPENSE	TOTAL DEPRECIATION RELATED TO LIFE RATE (%)
	(1)	(2)	(3)	(4)	(5)	(6)=(5)/(4)	(7)	(8)=(5)+(7)	(9)=(8)/(4)
478.00	METERS	20-L1.5	0	42,641,151	2,298,403	5.39	813,661	3,112,064	7.30

CENTRA GAS MANITOBA INC.

TABLE 2. CALCULATED ACCRUED DEPREICATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF ANNUAL PROVISION FOR TRUE-UP RELATED TO ORIGINAL COST AS OF MARCH 31, 2015
ELG

ACCT	DEPRECIABLE GROUP	SURVIVING ORIGINAL COST AS OF MARCH 31, 2015	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE AMOUNT	ACCUMULATED DEPRECIATION VARIANCE PERCENT	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP	TRUE-UP RATE (%)
	(1)	(2)	(3)	(4)	(5) = (3)-(4)	(6) = (5)/(3)	(7)	(8)=(5)/(7)	(9)=(8)/(2)
478.00	METERS	42,641,151	18,107,475	8,018,075	10,089,400	55.72	12.4	813,661	1.91

CENTRA GAS MANITOBA INC.

TABLE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
AS OF MARCH 31, 2015
ASL

ACCOUNT	DEPRECIABLE GROUP	SURVIVOR CURVE	NET SALVAGE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2015	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)	ANNUAL PROVISION FOR TRUE-UP	TOTAL DEPRECIATION RELATED TO LIFE EXPENSE	TOTAL DEPRECIATION RELATED TO LIFE RATE (%)
	(1)	(2)	(3)	(4)	(5)	(6)=(5)/(4)	(7)	(8)=(5)+(7)	(9)=(8)/(4)
478.00	METERS	20-L1.5	0	42,641,151	2,132,058	5.00	559,409	2,691,467	6.31

CENTRA GAS MANITOBA INC.

TABLE 2. CALCULATED ACCRUED DEPREICATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF ANNUAL PROVISION FOR TRUE-UP RELATED TO ORIGINAL COST AS OF MARCH 31, 2015
ASL

ACCT	DEPRECIABLE GROUP	SURVIVING ORIGINAL COST AS OF MARCH 31, 2015	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE AMOUNT	ACCUMULATED DEPRECIATION VARIANCE PERCENT	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP	TRUE-UP RATE (%)
	(1)	(2)	(3)	(4)	(5) = (3)-(4)	(6) = (5)/(3)	(7)	(8)=(5)/(7)	(9)=(8)/(2)
478.00	METERS	42,641,151	13,894,104	6,957,435	6,936,669	49.93	12.4	559,409	1.31

Public Utilities Board — Régie des services publics

April 4, 2016

Manitoba Hydro
Legal Department
22nd Floor, 360 Portage Avenue
Winnipeg, MB R3C 2P4

Attention: Odette Fernandes

VIA EMAIL

Dear Madam:

Re: Centra Gas Manitoba Inc.
March 10, 2016 Request for Accounting Clarification

The Board is in receipt of Centra Gas Manitoba Inc.'s ("Centra") attached correspondence of March 10, 2016 seeking the Public Utilities Board's ("Board") clarification with respect to the 2015/16 fiscal year treatment of various accounting matters in light of Centra's implementation of International Financial Reporting Standards ("IFRS"). In particular, Centra seeks the following:

1. Confirmation from the Board that capitalizing expenditures related to meter testing and exchange activities is appropriate for rate-setting purposes.
2. Confirmation that, similar to the Directive to Manitoba Hydro in Order 73/15 to continue to determine depreciation for rate-setting purposes based on the Average Service Life ("ASL") methodology without net salvage, Centra should utilize ASL without net salvage for rate-setting purposes. In addition, Centra proposes to apply the same accounting treatment for the difference between depreciation expense calculated for financial reporting purposes and rate-setting purposes as set out in Manitoba Hydro's letter to the PUB dated February 25, 2016, a copy of which is also attached.
3. Approval of a service life change to the Meter account.
4. Confirmation that with respect to the capitalization of overhead, Centra should apply the same rationale as the Board set out for Manitoba Hydro in Order 73/15. As indicated in its February 25, 2016 letter, Manitoba Hydro is proposing to record the difference between Operating and Administrative (O&A) expense calculated for financial reporting purposes and O&A expense excluding the additional overheads to be capitalized, as a regulated liability along with a corresponding regulated asset for the 2015/16 fiscal year.

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.

The Board stated as follows in Order 85/13, emanating from the hearing of Centra's last General Rate Application:

> The Board understands that Centra has been making changes to its accounting practices to be consistent with International Financial Reporting Standards. These changes reflect a consistent approach with its parent Manitoba Hydro to address capitalization policies. In the Board's view, Centra's proposed accounting changes are appropriate for the test year. 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 the 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.

Among other things, Order 85/13 requires Centra to continue to use the Average Service Life (ASL) methodology of depreciation for rate-setting purposes, which is the same methodology the Board directed Manitoba Hydro to use in Order 73/15. The Board notes that this means the depreciation methodology is currently consistent between Centra and its parent company Manitoba Hydro. However, the Board accepts that with respect to the other issues raised in Centra's March 10, 2016 letter, there could be inconsistency between Manitoba Hydro and Centra.

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.

In the meantime, the Board expects Centra to seek such advice as it considers appropriate in preparation of its financial statements.

Yours truly,

"Original Signed By"

Kurt Simonsen
Associate Secretary

Attachment

cc: Interveners of Record

REFERENCE:

Tab 13 – Public Utilities Board Directives & Other Matters

PREAMBLE TO IR (IF ANY):

QUESTION:

c) Please provide an update to PUB/Centra I-73 (a) and (b) (Status Update on AMI Plans) from the 2013/14 GRA (AMI is discussed on page 13 of Tab 13, lines 12 to 19).

RATIONALE FOR QUESTION:

To understand the status of outstanding and on-going PUB directives to Centra.

RESPONSE:

Manitoba Hydro continues to assess the merits and timing of a potential Advanced Metering Infrastructure ("AMI") initiative. Electric metering capabilities continue to evolve as do the communications technologies that form an important part any AMI deployment.

While AMI technology offers a number of operational and customer benefits, a full-scale AMI deployment represents a significant investment for Manitoba Hydro at a time when the utility also faces numerous other investments including addressing aging infrastructure. Manitoba Hydro's most recent work has focused on the impact of a prolonged roll-out of AMI on both the investment requirements and the achievement of benefits.

Manitoba Hydro and Centra continue to be mindful of direction issued by PUB in relation to AMI and will file information with the PUB and seek required approvals prior to proceeding with any project.

REFERENCE:

Tab 13 – Public Utilities Board Directives & Other Matters

PREAMBLE TO IR (IF ANY):

QUESTION:

d) With respect to on-going directives from Order 118/03 on page 14 of Tab 13 and Appendix 13.4, please explain why Centra has not included the PUB directive from page 84 of Order 118/03 that "…the Board will require Centra establish a more regular schedule, not to exceeding three years, for periodic rate reviews. This regular schedule should improve the efficiency, effectiveness and timeliness of the regulatory process, even if no rate changes are requested." If Centra views this directive has been satisfied or rescinded by the PUB, then please provide the documentation that Centra is relying on to form this view.

RATIONALE FOR QUESTION:

To understand the status of outstanding and on-going PUB directives to Centra.

RESPONSE:

Centra views this directive to be ongoing. The Corporation expects to engage with the Public Utilities Board of Manitoba following this hearing with respect to the efficiency, effectiveness and timeliness of the regulatory process for all matters.

REFERENCE:

Updated Application, March 22, 2019 (pg 12, 14 & 15)

PREAMBLE TO IR (IF ANY):

In Order 108/15, the PUB directed Centra to file a full General Rate Application by January 20, 2017 and in the event it did not, it directed that non-gas components embedded in Centra's rates would revert back to levels approved on an interim basis in Order 66/11 effective August 1, 2017. As part of Centra's August 1, 2017 Primary Gas Application, Centra rolled back rates as directed by the PUB which were approved through Order 79/17. Currently approved rates thus combine the 2010/11 GRA non-gas costs and billing determinants with the 2015/16 non-primary Gas Costs approved in Order 108/15, but for the Special Contract and Power Station classes. Non-gas costs flowing from Centra's 2013/14 GRA are no longer a relevant basis of comparison for cost allocation and rate design purposes as they are no longer embedded in current rates.

QUESTION:

a) Please file all Cost Allocation Schedules similar to Schedules 10.1.0 – 10.1.6 of this Application that underpin Centra's August 1, 2017 rate rollback determinations not otherwise included as part of the August 1, 2017 Primary Gas Application (CAC/Centra 3).
b) Please re-file Figures 7, 8, 9 & 10 as per the March 22, 2019 Supplemental Filing to compare non-gas and gas costs currently approved and embedded in rates to the i) November 30, 2018 filing and ii) the March 22, 2019 filing. Please also provide and explain the top 3 or 4 most material drivers of the differences for each row. For reference, similar tables were filed as part of Centra's 2013/14 GRA, Tab 11, pages 10 and 13.
c) Please provide a schedule similar to Schedule 10.1.1 that:
    i. Provides the difference between what is currently approved and embedded in rates and proposed (based on Centra's March 22, 2019 Update).

ii. Provides the difference between what is currently approved and embedded in rates and proposed (based on Centra's March 22, 2019 Update) as per (i) above but each value represented on a percentage basis.

d) Please file a similar table to Figure 9 (March 22, 2019 Filing, page 14) for both the Primary Gas Overhead Rate and the Fixed Rate Primary Gas Overhead Rate that compares currently approved and embedded in rates to proposed.
e) Please file Figures 7, 8, 9, & 10 that reflect a comparison between currently approved and embedded in rates and the gas cost update as part of Centra's Pre-hearing Update in July 2019.

RATIONALE FOR QUESTION:

To understand the changes in costs and load by class proposed compared to currently approved and embedded in rates.

RESPONSE:

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

b) In the current 2019/20 GRA Centra has chosen the last approved 2013/14 Cost Allocation Study as the most appropriate comparison due to there being no single Cost Allocation Study that supports the currently approved base rates. The currently approved base rates approved by in Order 79/17 are a combination of:
   i. Non-gas costs for SGS and LGS classes rates were reversed (August 2017) to the non-gas rates approved in Order 66/11 which are based on 2008/09 Approved Test Year as per Order 128/09, page 16.
   ii. Non-gas costs for HVF, Mainline, Co-op and Interruptible classes were reversed (August 2017) to non-gas rates approved in Order 66/11 and are based on 2010/11 Approved Test Year.
   iii. Non-gas for the Special Contract (SC) and Power Station (PS) classes were exempted from August 2017 rate reversion and are based on the 2013/14 approved Test Year.

iv. Non-Primary gas costs were approved in Order 108/15 flowing from the 2015/16 Cost of Gas.

To assist in better understanding of the effect of the reversion of the August 1, 2017 non-gas rate changes, Centra has isolated the Customer Bill Impacts that relates to the reversion of the August 2017 non-gas rate changes from Customer Bill Impact due to changes proposed in the current Application (see the attachment to Centra's response to PUB/CENTRA I-143).

c) See the response to part a) and b) above.

d) The comparison of the proposed and currently approved Fixed Rate Primary Gas Service ("FRPGS") Program Cost Rate ("PCR") is provided in Figure 1.

Figure 1: Calculation of FRPGS Program Cost

	2013/14 GRA Currently Approved	2019/20 GRA March 22 Update
Fixed Rate Primary Gas OH rate		
Non-gas allocated ($)	242,196	21,155
Volumes (10^3m^3)	7,720	562
Rate/10^3m^3	31.37 *	37.67
rate/m^3	0.0314	0.0377

* The FRPG Overhead Rate was not reversed in August 2017 .

The calculation of the proposed Primary Gas Overhead of $0.91/$10^3m^3$ is provided in Figure 2. The currently approved Primary Gas Overhead rate of $1.64/$10^3m^3$ reflects the reversion of non-gas components implemented in August 2017 to the rate that was established by the PUB in Order 128/09 (different from the rate that Centra had applied for in the 2009/10 GRA as such Centra could not provide the underling calculation).

Figure 2: Calculation of Primary Gas Overhead Rate

	Currently Approved	2019/20 GRA March 22 Update
<u>Primary Gas OH rate</u>		
Non-gas allocated ($)		[redacted]
Volumes (10^3m^3)		[redacted]
Rate/10^3m^3	1.64 *	0.91
rate/m^3	0 0016	0.0009

1d, 1e

*As per Order 79/17 the Primary Gas Overhead Rate was reversed to $1.64/103/m3 effective August 1, 2017.
The $1.64 103m3 Primary Gas Overhead Rate was established By PUB Order 128/09 to be effective May 1, 2010.

e) Centra will provide the requested information with its pre-hearing update in July 2019.

REFERENCE:

Tab 10 (pg 5, 14) and Christensen Associates Energy Consulting Report

PREAMBLE TO IR (IF ANY):

Centra states that it has not made substantial changes to its Cost Allocation approach or Rate Design since the 2013/14 GRA.

In Order 65/11 (page 28), the PUB found that Centra's overall rate structure should be reviewed and considered in relation to the Cost of Service Study Methodology Review. As part of the completeness filing dated December 12, 2018, Centra filed the Christensen Associates Energy Consulting ("CA") Report on Cost of Service Methods as Attachment 10.

QUESTION:

a) Please provide Centra's intention to undertake a comprehensive review of its cost allocation and rate design methodology given the significant passage of time and PUB direction.
b) Please provide how often a comprehensive review of cost allocation and rate design is undertaken at other Canadian gas LDCs.
c) Please provide Centra's perspective on how long is a reasonable length of time between cost allocation and rate design reviews?
d) Provide discuss Centra's ratemaking objectives and the relative priority placed upon them as reflected in the 2019/20 Cost Allocation and Rate Design Study.

RATIONALE FOR QUESTION:

To understand Centra's intention regarding a full review of its cost allocation and rate design methodology given the prior findings of the PUB and that it has been nearly 25 years since its last review.

RESPONSE:

a) Centra views that its current cost allocation methodology continues to function in a reasonable manner and that the outputs of that study give appropriate information for the determination of just and reasonable rates

b) Centra has not undertaken research specifically investigating how often a comprehensive review of cost allocation and rate design is undertaken at other Canadian gas LDCs.

c) Centra is of the view that there is not a generally accepted "length of time" or duration between cost allocation reviews.

d) Two rate design goals that are prominent in the design of the cost allocation study are:
   - Rates should be reflective of the costs incurred to provide the service (cost based), and;
   - Rates should be fair and equitable.

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:

a) As part of MH's 2017/18 GRA, MH stated that it considered rate shock to be a double-digit rate increase. Please discuss Centra's view of the magnitude of a rate increase and related bill impacts that constitutes rate shock.

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:

a) Manitoba Hydro's position at its 2017/18 General Rate Application was that a proposed overall increase of 7.9% across all customer classes did not constitute rate shock.

During the public hearing for that Application, Manitoba Hydro noted that the PUB had previously approved rate increases for Centra as large as approximately 25%.

Natural gas rates have far more inherent volatility than electricity rates, and by definition, volatility means that both decreases and increases occur. Electric utility rates in Manitoba tend to exhibit greater stability. The volatility in natural gas rates is due to volatility of natural gas prices in the upstream natural gas market and other contributing factors.

Natural gas billed rates include applicable rate riders which may be either collecting from customers or refunding to customers. The expiry of those rate riders and the application of new rate riders, for example, may amplify the volatility of billed rates. Similarly, a reversion to past rates followed by the introduction of rates based on a current revenue requirement and cost of service study may result in additional bill impact volatility, as is the case in this rate Application.

The reversion of natural gas rates on August 1, 2017 caused significant rate decreases for certain customer classes. For example, the annual bill for a Mainline class T-service customer using 44,000 10^3m^3 at a 75% load factor shows a reduction of approximately $176,600 (or -31%) on August 1, 2017 (Please see Figure 2 of the response to PUB/CENTRA I-143a in this GRA). The same customer could experience a corresponding increase of approximately $176,600 when the rate reversion is removed. That same dollar amount, however, translates into a 43% increase when compared to the annual bill on August 1, 2017. The customer would experience a 31% decrease followed by a 43% increase to return it to the same revenue level prior to August 1, 2017.

It is therefore difficult to strictly define rate shock for natural gas utility rates, due to the inherent volatility in natural gas utility rates compared to electric utility rates.

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.

REFERENCE:

Tab 10 (pg 5)

PREAMBLE TO IR (IF ANY):

Centra states that it has not made substantial changes to its Cost Allocation approach since the 2013/14 GRA.

In Order 164/16 flowing from Manitoba Hydro's electric Cost of Service Methodology Review, the PUB directed MH to change its COS treatment of DSM costs from an assignment based on class participation to one that treats DSM as a system resource. The PUB stated that that DSM investments reduce customer energy consumption and, in most instances, the peak demand of the Manitoba Hydro system providing system benefits by delaying investment in generation, transmission or distribution. The PUB also stated that within the customer classes, there are non-participants in DSM programs which support this approach over Manitoba Hydro's direct assignment of the costs.

QUESTION:

a) Please explain and provide the rationale of Centra's current Cost Allocation treatment of DSM costs.
b) Please provide Centra's perspective on the appropriateness of a system charge (through transmission, distribution investment or both) vs. a direct assignment approach.
c) Please provide a sensitivity analysis with supporting assumptions that quantify the differences by class between the methodologies identified in the preamble.

RATIONALE FOR QUESTION:

To understand Centra's view of the appropriateness of treating the cost of DSM as a system resource for gas operations recoverable from all customer classes.

RESPONSE:

a) There are primarily two benefits to natural gas DSM. First, a reduction in natural gas consumption by customers' results in a reduction in the carbon released to the atmosphere and therefore this is a positive effect on levels of greenhouse gas emissions. Second, participating customers that achieve lower consumption will enjoy lower monthly bills, all else equal.

Centra began natural gas DSM programs in the mid-2000s and since inception has taken the approach of directly assigning the amortized amounts for DSM to customer classes based upon each customer classes participation in the respective DSM programs. Natural gas DSM programs are targeted at specific markets and therefore the costs can be identified for assignment to the appropriate customer classes. Customer classes which did not receive DSM programs (Special Contract and Power Station, for example) did not receive any assignment of DSM costs. As natural gas DSM programs are intended to reduce customer greenhouse gas emissions and to lower consumption (and resulting bills) for participants, it was considered appropriate to directly assign DSM costs to customer classes on that basis.

Centra functionalized gas DSM costs as on-site for cost allocation purposes. This was done with regard for the unbundled nature of natural gas service offerings, where certain customer classes may elect to receive Sales Service or Transportation Service. Functionalizing the assigned DSM costs to on-site ensured cost recovery from all customers in a class, regardless of whether they were Sales Service or T-Service customers.

Centra classified DSM costs as customer-related and allocated them by the number of customers in the class. Therefore DSM costs were notionally recovered in the Basic Monthly Charge, although the existing level of the Basic Monthly Charge for the SGS and LGS classes ($14/month and $77/month respectively) remained unchanged and therefore those costs were essentially being recovered through the volumetric charge.

In the 2013/14 GRA, Centra proposed to change the functionalization of DSM costs from on-site to transmission. The assigned DSM costs were then classified as energy-related instead of customer-related. The DSM cost for each customer class is then recovered by the volumetric charge and not the Basic Monthly Charge. This proposed change was examined in the course of Centra's 2013/14 GRA and was approved by the PUB in Order 85/13.

The change was done to better align the cost with its driver. While the assignment of the total DSM amortization expense to each class was not impacted, the change has shifted the costs from being recovered through BMC to the Volumetric Charge (Distribution to Customer). As the larger volume customers within each class stand to benefit to a greater extent from DSM opportunities therefore DSM costs recovered volumetrically align more directly with its costs driver.

b) Centra offers the following perspective on the treatment of natural gas DSM costs by way of a system benefit charge versus the direct assignment to participating customer classes.

The preamble references Order 164/16 which was issued with respect to the Review of the Cost of Service Study Methodology for Manitoba Hydro's electric operations. It is useful to recognize the differences between vertically integrated hydro-electric utilities and natural gas distribution utilities with regard to DSM, in order to evaluate differences in the treatment of DSM program costs for rate setting purposes.

In addition to lowering participating customer's consumption and bills, electric DSM also provides potential benefits from the deferral of expensive new generation resources and an increase in extra-provincial sales revenues to assist in offsetting costs for domestic electric customers. In that regard, it may be appropriate to treat DSM costs as a system benefit charge for a vertically integrated electric utility.

However, natural gas DSM does not achieve the same result as there is no deferral of local energy production investment and no increase in off-system revenues to help offset total costs. Therefore, a system benefit charge may not be as rational a basis to recover natural gas DSM costs as it is for electric DSM costs, and the direct assignment approach is valid for natural gas DSM cost recovery.

c) The attachment to this response compares the cost allocation treatment of DSM amortization costs proposed in the 2019/20 GRA and the treatment proposed in this question.

Comparison of the cost allocation treatment of DSM costs in the 2019/20 GRA (based on the forecasted customer classes participation) to DSM allocation based on the system volumes:

						Allocation to classes								
1														
2		Function	Classify	Allocation Method	Total Amount ($)	SGS	LGS	HVF	CO-OP	MLF	SC	PS	INT	
3	2019/20 GRA	Transmission	Energy	based on the forecasted	9,945,608	5,768,452	3,779,331	298,368	0	99,456	0	0	0	
4				participation in DSM										
5														
6	CAC-Centra I-20	Transmission	Energy	allocated based on the	9,945,608	[redacted]								1d,1e,2d
7				total system volume (COM-T)										
8	Change in costs/class					[redacted]								
9	compared to 2019/20 GRA													
10														
11	CAC-Centra I-20	Transmission	Energy	allocated based on the system	9,945,608	[redacted]								1d,1e
12				volume excluding SC & PS (COM-TBS)										
13	Change in costs/class					[redacted]								
14	compared to 2019/20 GRA													

REFERENCE:

Tab 10 (pg 5)

PREAMBLE TO IR (IF ANY):

Centra states that it has not made substantial changes to its Cost Allocation approach since the 2013/14 GRA.

QUESTION:

a) What factors were considered to conclude asset investment is transmission-related or distribution-related?
b) What asset investment, if any, reflected in the 2019/20 Cost Allocation Study has been functionalized differently than how it is reflected in the accounting records of Centra? Why or Why not?
c) How have the costs associated with the replacement of SCADA been functionalized, classified and allocated in the 2019/20 Cost Allocation Study. Provide the rationale.

RATIONALE FOR QUESTION:

To understand the appropriateness of the functionalization of transmission and distribution-related costs.

RESPONSE:

a) Please refer to the response to IGU/CENTRA I-4 a) for a description of the types of assets included in transmission versus distribution plant accounts.

b) In the 2019/20 Cost Allocation Study, asset investments were assigned to the transmission or distribution plant categories according to the plant accounting classification. All transmission plant investments were functionalized to the Transmission function and all distribution plant investments were functionalized to the

Distribution and Onsite functions consistent with the approved cost allocation methodology.

c) According to the accounting plant records, the asset investment for the Gas SCADA Replacement project was capitalized to the Distribution Plant (Computer Equipment Hardware) and the Intangible Plant (Other Distribution Development-SCADA) as shown in Figure 26 of Appendix 6.1.

In the 2019/20 Cost Allocation Study, the cost of replacement of SCADA system was assigned to the Distribution Plant and Intangible Plant categories according to the plant accounting classification.

The portion of SCADA replacement cost that was included in Distribution Plant (Computer Equipment Hardware) was functionalized partly to the Distribution function and partly to the Onsite function. Then, the portion of costs functionalized to Distribution was classified partly as demand-related and partly as customer-related, and the portion functionalized as Onsite was classified as customer-related, recognizing the fact that distribution plant serves both. The allocation to various customer classes is done in the same proportion as that plant costs were assigned in the distribution-demand, distribution-customer and onsite-customer phases respectively using allocators such as (DISTPT-D, DISTPT-Cu and ONSITEPT-Cu) as provided in Schedule 10.1.4.

The portion of SCADA replacement cost that was capitalized to Intangible Plant (Other Distribution Development-SCADA) was functionalized to the Transmission, Distribution and Onsite functions. The portion of SCADA investment functionalized to the Transmission function was then classified as demand-related, the portion of the investment functionalized to the Distribution function was classified partly as demand and partly as customer, and the portion of the investment functionalized to the Onsite function was classified as customer-related. The allocation to various customer classes is done in the same proportion as that plant costs were allocated in each functionalized and classified phase using allocators such as (TRANSPT-D, DISTPT-D, DISTPT-Cu and ONSITEPT-Cu) as provided in Schedule 10.1.4.

REFERENCE:

Tab 4 (pg 4)

PREAMBLE TO IR (IF ANY):

Centra states that it has not made substantial changes to its Cost Allocation approach since the 2013/14 GRA.

QUESTION:

a) Please explain how pressure reducing stations (primary gate stations, gate stations, regulation stations, farm taps) are each functionalized, classified and allocated in Centra's 2019/20 Cost Allocation Study.
b) Are any pressure reducing stations functionalized as both transmission-related and distribution-related? If not, why not? If yes, please describe how this split is determined?
c) Are any of the Brandon Primary Gas Station costs related to the refurbishment of the adjacent TCPL station? If yes, provide how the costs have been treated for purposes of the cost allocation study.

RATIONALE FOR QUESTION:

To understand Centra's assertion that it has not made any substantial changes to its Cost Allocation approach.

RESPONSE:

a) and b)

In the 2019/20 Cost Allocation Study, the investment in pressure reducing stations was functionalized according to the plant accounting classification. The investment in pressure reducing stations is included in Rate Base in the Measuring & Regulating Equipment, Structures & Improvements – M&R, and Land plant accounts within the Transmission Plant and Distribution Plant categories. Please refer to the response to

IGU/CENTRA I-4 a) for a description of the types of assets included in each plant account.

Pressure reducing stations are accounted for as either transmission or distribution assets based on the source of the natural gas. All pressure reducing stations with direct interconnection to the TCPL mainline are accounted for as transmission assets. All other pressure reducing stations are accounted for as distribution assets.

In the 2019/20 Cost Allocation Study, the plant accounts containing investment in pressure regulating station assets were functionalized, classified and allocated as follows:

- The Transmission – Measuring & Regulating Equipment and the Transmission – Structures & Improvements – M&R plant accounts were functionalized to the Transmission function, classified as Demand related and then allocated to customer classes based on the Peak & Average allocator. Please refer to Schedule 10.1.4 for the allocation of this plant account to the various customer classes.

- The Transmission – Land plant account was functionalized to the Transmission function, classified as Demand related and then allocated to customer classes based the allocation of total demand related transmission plant in service. Please refer to Schedule 10.1.4 for the allocation of this plant account to the various customer classes.

- The Distribution – Measuring & Regulating Equipment plant account was primarily functionalized to the Distribution function, classified as Demand related and then allocated to customer classes based on a Peak & Average allocator. Please refer to Schedule 10.1.4 for the allocation of this plant account to the various customer classes.

- The Distribution – Structures & Improvements – M&R plant account was functionalized to the Distribution function, classified as Demand related and then allocated to customer classes based on the Peak & Average allocator.

Please refer to Schedule 10.1.4 for the allocation of this plant account to the various customer classes.

- The Distribution – Land plant account was functionalized, classified and allocated based on total distribution plant in service. The investment was first functionalized to the Distribution and Onsite functions. The portion of investment attributed to the Distribution function was then classified as Demand related and Customer related, and the portion of the investment attributed to the Onsite function was classified as Customer related. The classified investment was then allocated to customer classes. Please refer to Schedule 10.1.4 for the allocation of this plant account to the various customer classes.

c) The Brandon Primary Gate Station Re-construction project does not include any costs to refurbish the adjacent TCPL station.

REFERENCE:

Tab 2 (pg 5), Tab 12, Appendix 12.1, page 27

PREAMBLE TO IR (IF ANY):

At Tab 2, page 5, of Centra's Application, Centra states "Centra's system has proven to be highly reliable with customer outages being exceedingly rare and normally confined to a single customer or a small group of customers in a localized area"

It also states at line 13 "Centra has since developed its own local CNG compression facility with two CNG tube trailers and a pressure reducing decant system to permit the use of CNG to supply a limited number of customers during an outage"

QUESTION:

Further to PUB/Centra 92:

a) Please explain how the costs of the CNG investment were functionalized, classified and allocated in the 2019/20 Cost Allocation Study. Provide the rationale.

RATIONALE FOR QUESTION:

To understand how the capital and ongoing operating expenses related to the CNG facility have been treated for purposes of the Cost Allocation Study.

RESPONSE:

a) According to the accounting plant records, the Compressed Natural Gas Investment (Tube Trailers and Trailer Filing Station) was capitalized to Transmission Plant (Mains) and Distribution Plant (Measuring & Regulating Equipment and Structures & Improvements M&R) as provided in Figures 34 and 36 of Appendix 6.1.

   In 2019/20 Cost Allocation Study, the CNG investment was assigned to transmission and distribution plant categories according to the plant accounting classification. The CNG

Tube Trailers were functionalized to the Distribution function (within Measuring & Regulatory Equipment plant category). The CNG Trailer Filling Station was functionalized to both the Distribution function (within Measuring & Regulatory Equipment and Structures & Improvements- M&R plant categories) and to the Transmission function (within Mains plant category).

Then, the CNG investments were classified (consistent with each plant category) as demand-related and allocated to each customer class on the basis of the peak and average allocator as provided in Schedule 10.1.4.

REFERENCE:

Tab 2 (pg 5), Tab 12, Appendix 12.1, page 27

PREAMBLE TO IR (IF ANY):

At Tab 2, page 5, of Centra's Application, Centra states "Centra's system has proven to be highly reliable with customer outages being exceedingly rare and normally confined to a single customer or a small group of customers in a localized area"

It also states at line 13 "Centra has since developed its own local CNG compression facility with two CNG tube trailers and a pressure reducing decant system to permit the use of CNG to supply a limited number of customers during an outage"

QUESTION:

Further to PUB/Centra 92:

b) Provide the estimated annual costs to operate and maintain the facility and how those costs are functionalized, classified and allocated for purposes of Centra's Cost Allocation Study.

RATIONALE FOR QUESTION:

To understand how the capital and ongoing operating expenses related to the CNG facility have been treated for purposes of the Cost Allocation Study.

RESPONSE:

b) The estimated annual costs to operate and maintain the CNG compression facility are approximately $91,000 and are captured under the Regulating Station Maintenance program.

For the 2019/20 Cost Allocation Study, the costs to operate and maintain the CNG compression facility were functionalized to the Distribution function and classified as

Demand and Customer related based on the distribution plant classification allocator ("DISTPT"). Demand related costs were allocated to customer classes on the basis of the peak & average allocator. Customer related costs were allocated to customer classes on the basis of the number of customers.

REFERENCE:

Tab 2 (pg 5), Tab 12, Appendix 12.1, page 27

PREAMBLE TO IR (IF ANY):

At Tab 2, page 5, of Centra's Application, Centra states "Centra's system has proven to be highly reliable with customer outages being exceedingly rare and normally confined to a single customer or a small group of customers in a localized area"

It also states at line 13 "Centra has since developed its own local CNG compression facility with two CNG tube trailers and a pressure reducing decant system to permit the use of CNG to supply a limited number of customers during an outage"

QUESTION:

c) Please explain if the rupture on the TCPL Mainline in January 2014 was considered by Centra as a failure under the act of "Force Majeure". Why or why not?

RATIONALE FOR QUESTION:

To understand how the capital and ongoing operating expenses related to the CNG facility have been treated for purposes of the Cost Allocation Study.

RESPONSE:

No, Centra did not consider the rupture on the TCPL Mainline in January 2014 a "force majeure" event. Both TCPL and the Transportation Safety Board of Canada determined that the line rupture was caused by a circumferential brittle fracture initiated at a pre-existing crack at a weld between a bypass tee and a short section of the pipe.

REFERENCE:

Tab 10, Schedule 10.1.1 and Tab 11

PREAMBLE TO IR (IF ANY):

Centra states that it has not made substantial changes to its Cost Allocation approach since the 2013/14 GRA.

QUESTION:

Further to PUB/Centra 110:

a) Please provide and discuss the reasons for the number of days Interruptible customers were curtailed for downstream-related reasons (that is, on Centra's system) over the past twenty years.
b) In light of part a) please discuss Centra's view on whether there is merit in reviewing of the cost allocation methodology associated with the Interruptible Class?

RATIONALE FOR QUESTION:

To understand the appropriateness of Centra's Cost of Service results and whether there is a requirement to assess the reasonableness of interruptible service and class cost responsibility.

RESPONSE:

a) Centra's Interruptible customers have not been curtailed for downstream-related (i.e., system reliability) reasons over the past twenty years.

b) The number of customers electing to use Centra's Interruptible Service is down by 57% over the past 10 years from a total of 46 customers ten years ago to 20 customers today. Today, the customers using Interruptible Service are comprised almost entirely of public institutions such as health care facilities (that Centra understands maintain dual fuel capability regardless of whether they use Centra's Interruptible Service) or summer seasonal customers such as asphalt plants. In addition, Centra has not been permitting any new customers to take Interruptible service.

Given the current small size of the Interruptible class and the fact that there is no forecast growth in the size of the class, combined with the nature of the customers currently in the class, Centra does not believe that there is merit in undertaking a review of the currently approved cost allocation methodology for the Interruptible class.

REFERENCE:

Tab 10, Schedule 10.1.1 and Tab 11

PREAMBLE TO IR (IF ANY):

Centra states that it has not made substantial changes to its Cost Allocation approach since the 2013/14 GRA.

QUESTION:

Further to PUB/Centra 110:

c) Please file the Value of Interruptible Report prepared by Navigant for Centra in approximately 2002.

RATIONALE FOR QUESTION:

To understand the appropriateness of Centra's Cost of Service results and whether there is a requirement to assess the reasonableness of interruptible service and class cost responsibility.

RESPONSE:

Please see the attachment to this response for the report on the Value of Interruptible Class.

Value of Interruptible Class:
A Follow-up Analysis and Report

Prepared for Centra Gas Manitoba, Inc.

Navigant™
CONSULTING, INC.

Centra Gas Manitoba, Inc.
Value of Interruptible Class

Updated Statement of Findings

The results of this follow-up study confirm the findings of the original study. Centra's rates for interruptible service reasonably reflect the value that interruptible customers bring to firm customers. Rates to the existing firm customers would be reduced by only one quarter of one percent (0.25%) if Centra were to "firm up" the interruptible service. This indicates that there is effectively no subsidy (in either direction) between firm and interruptible customers based on the current cost allocation approach. Furthermore, the updated study demonstrates that terminating interruptible service (with the resulting loss of the interruptible load) would impose substantially higher costs on the existing firm customers. Looked at either way, it is in the best interests of both firm and interruptible customers to continue the current level of discount for interruptible service.

Report Background and Highlights

Centra Gas Manitoba Inc. (Centra) offers Interruptible Sales Service and Interruptible Delivery Service to approximately 67 customers. Interruptible service is priced lower than the comparable firm service to reflect the fact that these customers are subject to interruption of their natural gas service for any reason with sufficient notice. At issue is whether the lower rates for interruptible service reflect all of the value that these customers provide to the Centra system, and the firm customers.

Terms Used in the Report

The study discusses concepts such as value, discount, benefit and subsidy. In the context of this report, those terms have the following meanings:

Value: Interruptible customers provide *value* to the extent that they reduce the costs incurred by Centra or the revenues that need to be collected from the firm customers.

Discount: Rates for Interruptible service reflect a *discount* from the rates paid by the firm service customers. The level of rates for interruptible service are determined in the Cost of Service study using a methodology that recognizes interruptible service does not contribute to peak day demand on the system. Accordingly, the rates for interruptible service are both "cost based" (from the perspective of the cost study) and discounted relative to firm rates.

Benefit: In this study, *benefit* is measured as a reduction in the revenues that need to be recovered from firm service. Benefits can occur either because overall costs to be recovered have been reduced, or because the interruptible service contributes revenues that reduce the amount to be recovered from firm service.

Subsidy: A *subsidy* occurs when a class imposes some of its costs on another class. In a situation where a large amount of costs are shared among classes according to an allocation methodology, a subsidy occurs whenever a class is required to pay more under the cost allocation scheme than they would have to pay as a stand-alone entity, for the same level of service.

Original Study Findings

To address this issue, Centra filed a study with the Manitoba Public Utilities Board (PUB) that separated the supply and delivery aspects of interruptible service. The study involved a review of tariffs from other natural gas LDCs, discussions with gas supply and marketing personnel at Centra, meeting with

Centra's interruptible customers, and analyses using Centra's system planning and cost allocation studies. The two conclusions from that study were:

- Centra's rates for interruptible service reasonably reflect the value that interruptible customers bring to firm customers.
- Customers and Centra disagree on the fundamental justification for, and operational requirements of, Interruptible Service.

The following recommendations were also included:

- The extensive costs incurred by customers to provide alternate fuel capabilities should not be reflected in Centra's rates.
- Additional subclasses of interruptible service should not be introduced.
- The Summer Delivery Option should be terminated at the end of the 2000-2001 winter season.

The PUB, acting on the original study and other evidence filed by Centra, has terminated the Summer Delivery Option.

Follow-up Study Findings

The PUB has ordered Centra to study further the gas supply issues related to interruptible customers. This follow-up study addresses additional gas supply issues, and reaffirms the non-gas-supply issues from the previous review. This study produces the following results:

- "Firming up" the existing interruptible customers would increase Centra's costs by at least $2 million per year, and possibly substantially more than that. (see table on page 23)

- "Firming up" the existing interruptible customers would decrease the costs to be recovered from firm customers by approximately $1 million, since the firmed-up interruptible customers would be required to pay for a greater share of the total costs than they are currently responsible for.
- Disconnecting service to the existing interruptible customers would increase the costs to be recovered from firm customers by approximately $4 million.

These results indicate that Centra's current service offerings and cost allocation approach does not provide a subsidy (in either direction) between firm and interruptible service.

Gas Supply Issues

The fundamental gas supply issue is whether the gas supply to firm customers is less expensive and/or more reliable because of the existence of interruptible customers on the system. To address this fundamental issue, it is necessary to consider a number of related questions;

- Does interruptible service reduce the cost of pipeline transportation (deliverability) for firm customers?
- Does interruptible service reduce the cost of storage service for firm customers?
- Does interruptible service reduce the cost of gas supply for firm customers?

The follow-up study finds that interruptible service does provide benefits to firm customers. However, those benefits are commensurate with the discounts already received by the interruptible customers. The net result is that firm customers are somewhere between $4 million better off and $1 million worse off now than they would be if interruptible service were terminated, on firm service revenues of approximately $400 million. This confirms the findings of the original study. In the original study, it was determined that the discount received by interruptible customers was approximately equal to the savings received by firm customers. In this study, it is determined that migrating the interruptible customers to firm service would not substantially increase the weighted average cost of gas (WACOG) at the system level, but that significant additional cost burdens would land on the interruptible class. This impact is both unnecessary and potentially harmful to the customers that receive interruptible service. At the same time, if all the existing interruptible customers were disconnected from the system, the responsibility for costs that would devolve onto the remaining firm customers would substantially impact firm service in a negative way. The conclusion is that the discount provided for interruptible service is balanced by the benefit received by firm customers. It would seem inappropriate to move that balance in either direction.

The study recognizes that the gas supply portfolio would need to change if interruptible service were terminated. The most economical way to firm up the interruptible service would be to rely more heavily on supplemental (delivered) supplies. If interruptible customers were disconnected, the types of changes required to maintain the current level of costs to firm customers include:

- Reduced transportation capacity (deliverability) from Western Canada.
- Reduced deliverability during all seasons from the United States.
- Greater reliance on supplemental supplies during colder than normal winters.
- Greater balances left in storage (to be disposed of in the wholesale market) during warmer than normal winters.

Discussions with Centra's gas supply staff indicate that these changes are manageable using present resources and generally available market opportunities.

Non Gas Supply Issues

The non-gas-supply issues relate to the delivery service on Centra's transmission and distribution system. Centra provides delivery service from the TransCanada city gate stations to the customer's home or business (meter). The fundamental conclusion discussed in the original report was that firming up the delivery service to interruptible customers would result in essentially the same costs being allocated to existing firm customers. This result supported the conclusion that the rates paid for interruptible service were reasonable, since the cost impact of not offering interruptible service is roughly equal to the revenues contributed by interruptible customers.

The costs associated with firming up the T&D system to serve the interruptible load was estimated by Centra's engineering department. The study first determined what investment upgrades would be necessary to serve anticipated growth in firm load over the next ten years in each area. Then the requirements to provide firm service to the existing interruptible customers were added on top of the firm growth requirements. The results are shown in the table below.

Investment Cost to Provide Firm Service
to Existing Interruptible Customers

Service Area	Pressure Classification	Investment Cost
Portage La Prairie	Intermediate	$15,800
Shilo	-	-
Minnell	-	-
Brandon	Transmission	$481,000
Ste. Anne/Steinbach	Transmission	$77,700
South Loop	Transmission	$345,000
Winnipeg	Medium	$120,000
Winnipeg	High	-
Wpg. (Ile Des Chenes)	Transmission	$4,617,000
Winnipeg (La Salle)	Transmission	$565,000
Winnipeg (Oakbluff)	Transmission	-
	TOTAL	$6,221,500

The results show that, in some areas, no additional costs would be required to "firm up" the existing interruptible customers. In other areas like Winnipeg, the additional costs could be several million dollars. Overall, the investment cost would amount to approximately $6.2 million.

To measure the impact that $6.2 million would have on existing rates to customers, the investment cost was converted to annual revenue requirements using factors derived from the latest cost of service study. The estimated first year cost of "firming up" the interruptible load is $1.4 million. To gauge the impact of these costs on each of the existing rate classes, the costs were added to the appropriate account, and the peak day allocator for the interruptible class was modified to reflect firm service. The table below compares the allocated costs to each class from this analysis with the results from Centra's last cost of service study.

Impact on Revenue Requirements of Firm Delivery Service to All Classes

	Base Case ($)	All Firm ($)	Increase ($)	Percent Increase
Small General	115,330,881	115,033,251	(297,630)	-0.3%
Large General	39,800,409	39,670,968	(129,441)	-0.3%
High Volume	5,761,383	5,734,541	(26,843)	-0.5%
Main Line	2,556,575	2,574,878	18,303	0.7%
Interruptible	5,575,464	7,135,231	1,559,767	28.0%
Special Contract	1,320,213	1,465,419	145,206	11.0%
Primary Gas	154,234,253	154,372,665	138,412	0.1%
Firm Storage/Peaking	7,535,846	7,508,309	(27,536)	-0.4%
Interruptible Storage/Peaking	1,946,006	1,938,954	(7,052)	-0.4%
	334,061,031	335,434,216	1,373,185	0.4%

The results generally indicate that the discount provided to the Interruptible Class is approximately equal to the costs that are saved from offering interruptible service. Centra saves approximately $1.4 million per year by offering interruptible service, and the Interruptible Class saves approximately $1.6 million compared to the rates that they would pay for firm service. This result is somewhat coincidental, since there is no necessary linkage between the incremental costs of firm service to the cost allocation methodology. At the same time, it establishes that the discount is reasonable, based on the costs that the Interruptible Class would have to pay for firm service.

Overall Impact on Firm Customers

The cost of service results shown above incorporate two key assumptions:

- All existing interruptible load would be converted to firm load.
- No change in gas costs as a result of the conversion.

These two assumptions are reasonable for performing what-if analyses that isolate the impact on delivery service rates, but they may not capture the total impact on firm customers. In this follow-up study, two complete cases were considered:

1. Firming up both delivery and gas supply to serve interruptible load.
2. Discontinue both delivery and gas service to existing interruptible load.

Compared to the base case, the following results can be seen:

- The increased cost responsibility for the interruptible customers if they were required to take firm service is approximately $3 million per year. In addition to the $1.6 million in delivery costs identified in the previous study, the class' share of the Upstream Transportation costs would increase by more than $1 million as well.
- Discontinuing service to interruptible customers would have a substantial negative impact on all customers. The interruptible customers would lose the economic benefits of natural gas service and firm customers would have to bear a significantly higher cost burden for several years, as the Centra T&D system "grows into" it's currently available capacity.

Fairness of the Existing Rate to the Interruptible Class

The quantitative analyses provided in this report indicate that the existing cost allocation approach provides a reasonable discount for interruptible service. The current discount reflects two key concessions in the rates for interruptible service:

- Rates for delivery service are reduced to reflect the fact that service may be interrupted at any time.
- Rates for supplemental gas supply are reduced to reflect the fact that service from supplemental supplies can be interrupted, with alternative supplies offered at market prices.

The "fairness" of these discounts can be evaluated from two different perspectives: firm customers and interruptible customers.

This report has emphasized the firm customer perspective. This perspective is recommended for a number of reasons:

- The system is built primarily for the firm service customers. All other services are considered options or alternatives from that service.
- Firm service customers have fewer options available to them, and therefore provide the standard for measuring regulatory impacts and protections.
- Firm service rates offer a convenient standard for measuring discounts.

From the perspective of the firm customers, the current level of discount for interruptible service is fair because there is no apparent subsidy in either direction between firm and interruptible customers. Firm customers should not be required to subsidize the more discretionary types of service, and in this situation the analyses have shown that they do not.

The interruptible customers, understandably, have emphasized their perspective in measuring fairness. As evidenced in comments collected for this study, as well as comments presented to the PUB, interruptible customers wish to emphasize the difficulties they experience in being interrupted, as well as the costs they incur to maintain their interruptible capability (equipment, fuel supplies, operating changes, etc.). These burdens can be significant for the interruptible customer, and from their perspective deserving of significant compensation or consideration from Centra.

The firm customer perspective is most suitable for public policy, not the interruptible customer perspective. There are several reasons for this:

- Interruptible customers have more options available to them than most customers, and therefore require less "protection" from a regulatory perspective.
- Interruptible customers vary widely among themselves, and do not offer a reasonably uniform standard for service requirements, performance or public need.
- Interruptible customers are often required to have dual fuel equipment by law or government action. Those other regulatory requirements should not entitle them to "compensation" from the PUB.

Interruptible customers are essentially offering a supply alternative to Centra. As such, they should be compared to other supply options and provided compensation for their impact on gas supply costs. For policy considerations, however, it is more appropriate to measure their impact on gas supply costs to firm customers rather than provide them whatever rate or payment is necessary to make them "whole".

Gas Supply Issues

Centra's gas supply incorporates three upstream functions: production, transportation and storage. All three functions occur before the natural gas commodity reaches Centra's system in Manitoba (hence "upstream" of the Centra Manitoba receipt point). Production involves the extraction and processing of the commodity in Western Canada (Alberta) or the United States (the Louisiana or the Oklahoma basin). Storage, located in Michigan, injects commodity in the summer (April through October) and withdraws it to meet customer demand in the winter (November through March). Transportation moves the commodity across provincial and state borders along several paths:

1. Western Canada to Manitoba (all year)

2. Western Canada to Michigan (summer only).
3. Louisiana to Michigan (summer only).
4. Oklahoma to Michigan (all year).
5. Michigan to Manitoba (winter only).

Routes 1 and 5, as characterized above, are used to meet the demand in Manitoba. Routes 1 and 2 combined are referred to as flowing supply, since together they flow all year at approximately the same daily volume. Route 5 is often referred to as a backhaul, since it moves opposite the traditional direction of flow in Canada, which is west to east (Alberta to Quebec). Routes 2, 3 and 4 above serve to fill the storage field in the summer, although route 4 is available to provide additional commodity during the winter.

Centra's gas supply fundamentals are essentially simple. Enough commodity is required to serve the total load in Manitoba (aside from curtailment of interruptible customers) on each day of the year. Flowing supplies from Western Canada travel along "route 1 and 2" above. Most of that supply is "base load" that must be utilized at an 85% or better load factor annually (and 100% load factor from November through March) to avoid penalties from TransCanada Energy Services. Additional flowing supplies from Western Canada are designated "swing supplies" that have no minimum requirements or penalties. Flowing supply is also available from the United States. Most of the US flowing supplies are used to fill storage in the summer along "routes 3 and 4", but a small amount is also available for delivery directly to Manitoba in the winter. Storage withdrawals are used during the winter months to serve the load that is in excess of the flowing supply.

Delivered Services are also available to meet demand in the winter months. Delivered services are short term arrangements that Centra makes when available and as needed. They are generally used to meet excess load situations such as unusually cold weather in the winter months or to fill small gaps in the supply portfolio during the months when storage service is not available (April and October). Delivered services may also be obtained for economic reasons. Delivered services are different from Centra's other supplies in that the seller (not Centra) is responsible for transporting the gas to Manitoba.

Effects of Interruptible Service on Gas Supply

Centra obtains its gas supply (production) under a combination of long term contracts and spot market purchases. Generally speaking, Centra can obtain enough commodity from its Western Canadian and US suppliers to meet the demand of both firm and interruptible customers under the expected range of demand conditions. Therefore, gas supply is not a big factor in justifying the existing interruptible service or its associated price discounts. Additionally, the gas commodity is a variable cost to Centra. Without any fixed costs to share on the commodity, there is no particular benefit to Centra or the firm customers from serving or curtailing interruptible load.

Effects of Interruptible Load on Storage

Centra has a long term contract for storage service in Michigan. That contract allows Centra to store approximately 15 million gigajoules (GJs) during the summer for withdrawal in the winter. Under normal weather conditions, Centra expects to use 12 million GJs, leaving three million GJs to carry over into the following year or to sell in the wholesale markets. The ability to carryover unused gas in storage often requires a special arrangement, since technically the storage volume is supposed to be emptied by the end of each winter season.

In a colder than normal winter, Centra may withdraw all of its gas in storage to meet customer load. In a warmer than normal winter, the balance remaining in storage may exceed 3 million GJs. Interruptible load affects storage in two ways. Under warmer than normal conditions, interruptible load acts like a sponge to absorb some of the gas in storage that would otherwise be sold off-system (wholesale). Under colder than normal conditions, the interruptible load is curtailed, conserving the commodity for firm customers. Interruptible load is not a perfect counterweight to weather-related variations in load, however. Interruptible load itself is pro-cyclical. In warm winters, demand by interruptible customers is also reduced, meaning their ability to absorb the excess commodity is reduced. Similarly, in cold winters, demand by interruptible customers increases, putting more pressure on the gas supply, and requiring even greater amounts of interruption than normal weather conditions would have suggested.

The greater issue is that weather conditions are not predictable in advance. In deciding whether to release gas in storage to serve interruptible load, the gas planners cannot know in December whether the winter will be colder or warmer than average. Therefore, the prudent strategy is to assume that conditions are normal through the early part of the winter, allow for the possibility that a late winter cold spell could occur, and reassess the situation in the January/February time frame. Unfortunately, by this time in the winter, the remaining ability of interruptible load to absorb excess commodity in storage is severely compromised. There is only a limited amount of interruptible load that is demanded in February and March, meaning that Centra would still have to turn to the wholesale market to manage its remaining storage inventory.

Effect of Interruptible Service on Transportation Contracts

Centra's existing transportation contracts create significant fixed costs based predominantly on maximum daily demand. 85% of the costs of transportation are fixed and only 15% of the total transportation costs are variable in a normal weather year. Interruptible load has its greatest impact on transportation costs. Interruptible load allows the transportation costs to be spread over a larger volume than just firm load yet does not increase the maximum daily demand.

Transportation contracts also define Centra's ability to meet peak daily loads. To reliably meet its peak day requirements, sufficient capacity must be provided from flowing supplies (Western Canada to Manitoba) or backhaul (Michigan to Manitoba). Transportation service for either of these routes is expensive, relative to the ability to interrupt load on the highest demand days of the year. However, Centra has another option that provides peak day capacity: delivered services. Due to Centra's fortunate location midway between the Western Canadian production areas and the large Eastern Canadian consuming areas, a lot of capacity is available in Manitoba that can be creatively negotiated with other market participants. For Centra, more so than for LDCs located at the end of the transportation pipeline, delivered services are more readily available even under cold weather conditions. While delivered services are priced at a premium over conventional supplies, the fact that no fixed transportation commitments are required make them competitive with interruptible load for meeting daily load requirements under high demand conditions.

Analysis of Supply Options

To assess the benefits of interruptible load on gas supply costs, an analysis of several supply strategies was performed. The base case for the analysis incorporates Centra's 2002-2003 cost of gas budget (subject to change). The key assumptions in this budget include:

- The most recent load projections by class, and on a daily basis.
- The latest commodity price forecasts based on the strip price from September 1, 2001.
- The current transportation contract prices and demand levels.

All of these assumptions were maintained throughout the analysis.

To estimate the benefits provided by interruptible service, the base case was compared to two alternate cases: firming up the interruptible load and discontinuing the interruptible load. Each of these cases highlights the impact on firm rates from the elimination of interruptible service. To firm up the interruptible load, the following assumptions were made:

- Storage service would be maintained at its current level.
- The gas supply must be adequate to meet winter load that is 10% greater than normal weather load.

Firming up the interruptible load requires significant additional capacity to meet the design conditions. The additional capacity requirements could be obtained through either delivered services (option A) or increased reliance on US supplies (option B). Obtaining the additional capacity from TransCanada Pipeline was also explored, and produced cost impacts that were comparable to the US supply option.

Option A means that 13% of the peak day requirements would come from delivered services on the extreme peak day (10% higher than the normal weather peak day). Option B means that 8% of the peak day requirements would come from delivered services, which is the same level of reliance found on an extreme peak day in the base case supply portfolio. As the results below show, Option B is estimated to be much more expensive than Option A.

Discontinuing the interruptible service creates an excess supply situation, and the opportunity to reduce costs. The most effective way to reduce costs under this scenario is to reduce the daily deliverability of flowing supplies from Western Canada by approximately 8% (option C). Option C results in a situation where delivered services provide 12% of daily requirements under extreme peak day conditions (essentially the same target reliability achieved under option A).

The results of the analysis are summarized in the table below, estimated under normal weather conditions. The results indicate that while the interruptible load could be firmed up using delivered services at essentially no extra cost to firm customers (option A), both of the other options would impose additional costs on the existing firm customers.

		Base Case	Firm Up Option A	Firm Up Option B	Firm Only Option C
Annual Requirements	GJs	62,676,538	62,764,789	62,764,789	57,752,618
Curtailed Load	GJs	88,250	0	0	-
TCPL Flowing Supply	GJ/day	200,952	200,952	200,952	184,841
GLGT Backhaul	GJ/day	237,388	237,388	260,384	237,388
Transport Capability	GJ/day	438,340	438,340	461,336	422,229
Primary Gas WACOG	$/GJ	$4.673	$4.673	$4.673	$4.688
Supplemental WACOG	$/GJ	$4.564	$4.575	$4.728	$4.575
Transportation WACOG	$/GJ	$0.962	$0.960	$0.982	$1.005

The conclusion from this analysis is that discontinuing service to interruptible customers (option C) would increase the transportation WACOG by approximately 4.5%, which is undesirable and unnecessary. Firming up the service to the existing interruptible customers would increase the transportation WACOG between 0% and 2.1%, and also increase the cost of Supplemental Gas service slightly. It should be noted, however, that Centra uses a class-specific transportation WACOG to determine its rates for firm and interruptible customers. The system average increases shown above do not include any inter-class considerations, which could make the impact on firm customers even greater.

The conclusion from this analysis can be summarized in the following points:

- Continuing the existing interruptible service is preferable to firming up the interruptible load, since firming up the gas supply would incur additional and unwanted costs to be borne by interruptible customers.
- Using delivered supplies would be the most economical supply option for firming up the interruptible load.
- Firming up the interruptible load using Option A provides no significant benefit or disbenefit to firm customers.

A further comment on the "all firm" option is also warranted. This option appears to indicate that interruptible customers contribute more to paying the transportation WACOG than could be saved if they left the system. That conclusion is not entirely correct, however. The statement is based on the average transportation WACOG for all customers, which is very sensitive to load factor. The interruptible customers have a better than average load factor. If any group of high load factor customers left the system, a similar result would occur. To understand the full meaning of the analysis, it is necessary to consider the allocation of the transportation WACOG, along with all other costs, to the rate classes.

Cost Allocation to Firm and Interruptible Classes

Revenue Impact of "Firming Up" the Interruptible Load

Interruptible customers currently pay rates that are specifically designed to recover their calculated cost of service. The most immediate, short term, method of firming up the service to interruptible customers would be to charge them the same rates paid by firm customers. While there is no strictly comparable firm service classification, it is most likely that the High Volume Firm (HVF) rate class would be most appropriate. Centra would realize an immediate windfall in revenues of approximately $3.5 million per year from the higher rates, as the annual charges to interruptible customers would increase from approximately $27.7 million to $31.1 million, based on currently approved base rates (effective November 1, 2001).

This revenue impact would not be permanent, however. The windfall would exist only so long as Centra does not apply for a general rate increase. As part of the GRA, rates for the different customer classes would be recalculated in accordance with the accepted cost allocation methods. The result would be an adjustment to the rates applicable to customer classes, as discussed below.

Revisions to Cost Allocation Study

Centra has a well-established approach to cost allocation. Centra's costs are assigned to one of three upstream or three downstream functions. The functions are:

- Upstream
  - Production - acquiring the commodity from producers in Western Canada or the US.
  - Pipeline – Fixed and variable charges to TransCanada Pipeline to move the flowing supply from the production areas to Manitoba.

  - Storage – Fixed and variable charges for rental of the storage field in Michigan, as well as transportation of commodity from the US producing areas to storage and transportation on TransCanada Pipelines between Manitoba and Michigan.
- Downstream
  - Transmission – movement of commodity from the TransCanada Pipeline gate stations on Centra's higher pressure system.
  - Distribution – movement of commodity on Centra's lower pressure system to the customer's location.
  - Customer – services provided directly to customers or at customer locations.

Costs in each function are then classified as demand-related, commodity related, or customer-related. Finally each cost is allocated among the customer classes using an appropriate allocator. Generally speaking, the demand-related costs are allocated using a Peak and Average factor, commodity-related costs are allocated using annual consumption, and customer-related costs are allocated using a weighted customer factor.

Peak and Average is an allocator that considers both the customer's peak day demand on the system and the customer's annual use of the system. Peak day demand reflects the costs incurred to meet the highest demand on the system. Average day demand (annual demand divided by 365) reflects the usage of the system by each class. The combined allocator assigns cost responsibility for using the system, which would not be reflected in a purely peak demand allocator.

The weighted customer allocators spread costs based on the number of customers in each class, but includes specific weights for each class because some customers are more expensive to serve than others. For example, the meter allocator weights each customer by the average cost of a meter for that class, since meters for large customers are much more expensive than meters for small customers. Similarly, the meter reading allocator reflects the fact that small general service (SGS) customers are read bi-monthly, while larger customers are read monthly.

The major difference between firm and interruptible customers in the cost allocation study is that interruptible customers are assigned on peak day responsibility. This reflects the fact that the design of the supply portfolio and the T&D system assume that interruptible customers will not be served on the peak day. Interruptible customers do consume energy throughout the year, however, so they bear some responsibility for demand-related costs under the Peak and Average allocator.

To evaluate the overall impact on customers from firming up or discontinuing service to interruptible customers, three scenarios were established:

- Base case – continue with the existing mix of firm and interruptible service.
- Firmup - provide firm service to the existing interruptible customers, with delivered services representing 13% of the design day supply. This is the more economical of the two options considered above.
- Firm only – discontinue service to interruptible customers. Gas supply costs that cannot be shed, and all T&D system costs, will be recovered from the existing firm customers.

Three types of changes were incorporated into the cost allocation model:

- Gas supply costs were revised to reflect the costs of the four scenarios: base case, firm-up option A, firm-up option B, and firm only. These different gas cost scenarios were discussed above.
- Plant costs and related expenses were revised to reflect the costs of upgrading the Centra T&D system to provide firm service. These additional costs were the topic of the original report, as mentioned above.
- Peak day gas supply responsibility is assigned to interruptible customers under the firm-up scenario, while all allocation responsibilities are "zeroed-out" under the firm only scenario.

Allocation Results

The table below contains the allocation results under the three scenarios: base case, firm up (option A) and firm only. Firm up option B was excluded since it was similar to, but more expensive than, Option A. It also shows each scenario's difference from the base case for each rate class.

Centra Gas Manitoba, Inc.
Value of Interruptible Class

Cost Allocation Results

	Base Case	Firm-up	Firm Only
Small General	119,214,395	118,262,841	121,783,520
Large General	42,437,025	41,842,031	44,105,263
High Volume	6,161,563	6,057,899	6,576,961
Main Line	2,773,551	2,721,526	2,859,215
Interruptible	7,614,189	10,501,900	0
Special Contract	1,396,078	1,595,035	1,475,706
Firm Gas	232,730,801	233,225,031	231,785,990
Interr. Gas	19,597,586	19,602,477	0
Total	431,925,186	433,808,741	408,586,654
Total Firm	404,713,411	403,704,364	408,586,654
Total Interruptible	27,211,775	30,104,377	0

Difference from the Base Case

	Firm-up	Firm Only
Small General	-951,554	2,569,125
Large General	-594,993	1,668,238
High Volume	-103,664	415,398
Main Line	-52,025	85,664
Interruptible	2,887,710	-7,614,189
Special Contract	198,958	79,628
Firm Gas	494,231	-944,811
Interr. Gas	4,892	-19,597,586
Total	1,883,555	-23,338,532
Total Firm	-1,009,047	3,873,243
Total Interruptible	2,892,602	-27,211,775

The results indicate that existing firm customers would get a benefit of approximately $1 million from firming up the interruptible class (negative cost impact). While firming up the interruptible class requires additional costs of approximately $1.9 million that must be shared by all classes, the interruptible customers themselves would be required to pick up more costs than would be added to the system. The extra burden of firm service on the current interruptible class would be approximately $2.9 million per year. Additional costs of firm Supplemental Gas as contemplated under firm-up option B would add to the burden.

The firm-only alternative demonstrates the opposite impact. Discontinuing service to interruptible service would require the remaining firm customers to pick up all of the costs that were previously covered by the interruptible customers. This extra cost responsibility more than offsets the gas supply cost reductions under this scenario. Overall, the firm only scenario reduces total costs by approximately \$23.3 million. Of that amount, \$20.5 million is gas supply cost and \$2.8 million is upstream transportation costs. However, interruptible customers contribute approximately \$7.6 million to cover upstream transportation and all downstream costs. They also contribute approximately \$19.5 million to gas supply costs. The net impact on firm customers would be an increase of \$3.9 million, which is the difference between the \$23.3 million saved from discontinuing service to interruptible customers and the \$27.2 million that they contribute in revenue.

In the final two rows on the table above, the Firm Gas rate class is a combination of Primary Gas to the current firm customers and Firm Supplemental. The Interruptible Gas rate class is Primary Gas to existing interruptible customers and and Interruptible Supplemental supply. The impact of firming up or discontinuing service to interruptible customers was discussed earlier in the report. To summarize those impacts:

- The rate for Primary Gas is relatively unaffected by the various alternative scenarios.
- The rate for Supplemental Gas increases in the firm-up scenario, but remains relatively constant in the other scenarios.

The overall conclusions from the cost allocation results are that firming up the interruptible customers would generate a windfall benefit of no more than approximately $1 million for the existing firm customers, but that discontinuing service to interruptible customers would harm the existing firm customers by at least $3.8 million. This harm is apparent in the first year, but would dwindle over time as demand from firm customers grows into the capacity that was previously paid for by interruptible customers. That is a long term process, however, that could take five or ten years at current growth rates.

REFERENCE:

Tab 10 (pg 1)

PREAMBLE TO IR (IF ANY):

Centra states that it has not made substantial changes to its Cost Allocation approach since the 2013/14 GRA.

QUESTION:

a) Please explain whether Centra updated its meter investment study to support the allocation of meter costs for the 2019/20 Cost Allocation Study? If not, why not?
b) Please explain any material differences in the allocation of meter investment to customer classes compared to class cost responsibility currently embedded in rates.

RATIONALE FOR QUESTION:

To understand the impact of meter investment cost on class cost responsibility.

RESPONSE:

a) Centra did not update its meter investment study for the 2019/20 Cost Allocation Study and considers the meter investment study prepared in 2010 to be appropriate to use at this time given that there was not a significant change between the 2004 and the 2010 studies.

b) The table below provides an allocation of meter investment to customer classes in Centra's 2009/10 & 2010/11 GRA, the 2013/14 GRA and the current Application.

Comparing Allocation of Meter Investment to customer classes:

	Account Description	Total Allocated Dollars	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	Main Line ML	Interruptible INT
2019/20	Meters	46,179,936	28,916,978	16,142,761	864,382	78,281	177,534
GRA		100.0%	62.6%	35.0%	1.9%	0.2%	0.4%
2013/14	Meters	42,745,268	26,878,444	14,755,339	697,846	67,779	345,860
GRA		100.0%	62.9%	34.5%	1.6%	0.2%	0.8%
2010/11	Meters	41,092,142	26,013,194	13,684,892	859,574	94,120	440,361
GRA		100.0%	63.3%	33.3%	2.1%	0.2%	1.1%

REFERENCE:

Tab 5 Appendix 5.9, pages 12-20, Tab 10 Schedule 10.1.5

PREAMBLE TO IR (IF ANY):

Centra states that it has not made substantial changes to its Cost Allocation approach since the 2013/14 GRA.

QUESTION:

a) Schedule 10.1.5 (Update) provides the allocation by class of O&M costs of $60.6 million based on the new cost categories discussed in Tab 5, Appendix 5.9 of Centra's Application. Please provide a table by category as reflected in Appendix 5.9 and Schedule 10.1.5 that identifies Centra's cost allocation treatment (functionalization, classification and allocation). If multiple allocators were used please provide.
b) Please provide a table that identifies the major changes, with reasons, in class responsibility for O&M costs compared with class responsibility for O&M embedded in current rates.

RATIONALE FOR QUESTION:

To understand Centra's assertion that no substantial changes in its cost allocation approach have been made.

RESPONSE:

a) Please see the schedules attached to this response.

b) There is not a single cost allocation study that encompasses all components. Please see the response to CAC/CENTRA I-17a.

   The following table compares the class responsibility for O&M between the 2019/20 proposed Test Year to the 2013/14 and 2010/11 approved Test Years.

Total Operating & Administrative Expenses														
Test Year	**Total**	**SGS**	**LGS**	**HVF**	**CO-OP**	**ML**	**SC**	**GS**	**INT**	**PG**	**FSP**	**ISP**	**FPO**	
2019/20	60,550,000	44,487,044	10,097,453	2,775,022	4,273	913,884	782,447	79,038	347,217	[redacted]			19,168	1e
2019/20%	100 0%	73.5%	16.7%	4.6%	0.0%	1.5%	1.3%	0.1%	0.6%	[redacted]			0.0%	
2013/14	68,800,000	52,682,600	10,588,496	2,347,294	4,477	728,291	603,614	108,116	885,596	611,723	102,428	9,177	128,188	
2013/14%	100 0%	76.6%	15.4%	3.4%	0.0%	1.1%	0.9%	0.2%	1.3%	0.9%	0.1%	0.0%	0.2%	
2010/11	60,343,473	46,070,064	9,171,425	1,806,352	3,340	564,099	650,404	204,099	748,146	804,522	9,551	18,050	293,421	
2010/11%	100 0%	76.3%	15.2%	3.0%	0.0%	0.9%	1.1%	0.3%	1.2%	1.3%	0 0%	0.0%	0.5%	

The increased investment in transmission plant has shifted the costs of programs such as Distribution Maintenance from the Onsite function to the Transmission function (via the MAIN/SCV functionalizing factor). The costs functionalized to transmission are allocated to customer classes using the Peak and Average allocator.

The major reasons for the shift in class responsibility for O&M costs are:

- SGS: The SGS load growth has remained relatively modest in the past several years and as a result the SGS class's share of total volumes and share of the coincident peak has declined when compared to other classes.

- LGS: The increase in load growth for the LGS class. The LGS class assumes a higher share of total volumes and a higher share of Centra's coincident peak day volumes, resulting in an increased share of Peak and Average allocators.

- HVF & INT: The shift of customers from the Interruptible class to the High Volume Firm class has resulted in a shift of volumes and a share of Centra's coincident peak to the HVF class and corresponding decrease in the INT share of total volumes and share of Centra's coincident peak.

- ML: an increase in load growth for the Mainline class has driven an increase in ML share of the Peak and Average allocators.

1			Functionalization							
2	III. OPERATING & ADMINISTRATIVE EXPENSES		Direct	Function						
3			Factor	Factor	Production	Pipeline	Storage	Transmission	Distribution	OnSite
4	A. CUSTOMER SERVICE & CORPORATE RELATIONS									
5	Back/Middle Office Services	294,425		GASCOST	186,065	72,448	33,128	2,785	-	-
6	Billing & Collections	7,705,172		ONSITE	-	-	-	-	-	7,705,172
7	Customer & Public Relations	4,008,554		ONSITE	-	-	-	-	-	4,008,554
8	Customer Information Systems (Banner)	533,983		ONSITE	-	-	-	-	-	533,983
9	Customer Inspections	7,151,177	LLOCATE	ONSITE	-	-	-	552,385	826,327	5,772,464
10	Customer Safety Services	1,285,355		ONSITE	-	-	-	-	-	1,285,355
11	Dispatch	2,306,190		ONSITE	-	-	-	-	-	2,306,190
12	Energy Supply, Planning & Support	2,869,025	PROCURE	PROCGAS	594,424	729,153	729,153	816,296	-	-
13	Environment	398,798		MAINS	-	-	-	159,780	239,019	-
14	Meter Reading	2,511,105		ONSITE	-	-	-	-	-	2,511,105
15	Rate and Regulatory Affairs	943,878		OPEXP	16,288	16,728	15,908	84,138	220,366	590,450
16	Research & Development	-		DIST	-	-	-	-	-	-
17	Sub-total	30,007,662			796,776	818,329	778,189	1,615,383	1,285,712	24,713,273
18										
19	B. OPERATIONS AND MAINTENANCE									
20	Communication System	135,343		SCADA	0	0	0	13,534	44,663	77,145
21	Distribution Maintenance	6,758,662	CUSTSERV	MAIN/SVC	0	0	0	1,379,630	2,416,672	2,962,360
22	Load Forecast	70,288		ONSITE	0	0	0	0	0	70,288
23	Metering	573,718		ONSITE	0	0	0	0	0	573,718
24	Plant Failures & Emergencies	302,792		ONSITE	0	0	0	0	0	302,792
25	Quality Assessment	434,989		MAIN/SVC	0	0	0	100,468	150,293	184,229
26	Regulating Station Maintenance	5,376,364		DIST	0	0	0	0	5,376,364	0
27	System Performance & Reliability	2,513,109		MAINS	0	0	0	1,006,884	1,506,225	0
28	IT - Distribution/Metering	-		OPEXP	0	0	0	0	0	0
29	Treasury	-		OPEXP	0	0	0	0	0	0
30	Sub-total	16,165,264			0	0	0	2,500,516	9,494,217	4,170,532
31										
32	C. ORGANIZATIONAL SUPPORT									
33	Corporate Governance	2,156,541		OPEXP	37,214	38,221	36,346	192,236	503,485	1,349,039
34	Corporate Infrastructure	4,581,302		OPEXP	79,057	81,195	77,212	408,382	1,069,590	2,865,866
35	Corporate Services	1,864,893		OPEXP	32,181	33,052	31,431	166,238	435,394	1,166,597
36	Departmental Support	5,446,970		OPEXP	93,995	96,537	91,802	485,548	1,271,696	3,407,391
37	Operational Management	1,657,966		OPEXP	28,610	29,384	27,943	147,793	387,083	1,037,153
38	Customer Relations	-			-	-	-	-	-	-
39	Sub-total	15,707,672			271,057	278,389	264,734	1,400,197	3,667,248	9,826,046
40										
41	D. ADJUSTMENTS TO INCOME									
42	Corporate Alloc. & Adj.	852,395		OPEXP	14,709	15,107	14,366	75,983	199,007	533,222
43	Depreciation, Interest, Taxes	- 2,182,994		OPEXP	- 37,671	- 38,689	- 36,792	- 194,594	- 509,660	- 1,365,587
44	Sub-total	- 1,330,599			- 22,961	- 23,582	- 22,426	- 118,611	- 310,653	- 832,365
45										
46	**Total Operating & Administrative Expenses**	**60,550,000**			**1,044,872**	**1,073,136**	**1,020,497**	**5,397,486**	**14,136,524**	**37,877,485**

1		Production		Pipeline		Storage				Transmission				Distribution				OnSite	
2		Classif.		Classif.		Total	Classif.			Total	Classif.			Total	Classif.			Classif.	
3		Factor	Energy	Factor	Demand	Costs	Factor	Demand	Energy	Costs	Factor	Demand	Energy	Costs	Factor	Demand	Customer	Factor	Customer
4	A. CUSTOMER SERVICE & CORPORATE RELATIONS																		
5	Back/Middle Office Services	PRODGAS	186,065	PIPEGAS	72,448	33,128	STORGAS	29,929	3,199	2,785	TRANGAS	330	2,455	-	DISTO&M	-	-	ONSITEO&M	-
6	Billing & Collections	PRODO&M	-	PIPEO&M	-	-	STORO&M	-	-	-	TRANO&M	-	-	-	DISTO&M	-	-	CUST	7,705,172
7	Customer & Public Relations	PRODO&M	-	PIPEO&M	-	-	STORO&M	-	-	-	TRANO&M	-	-	-	DISTO&M	-	-	CUST	4,008,554
8	Customer Information Systems (Banner)	PRODO&M	-	PIPEO&M	-	-	STORO&M	-	-	-	TRANO&M	-	-	-	DISTO&M	-	-	CUST	533,983
9	Customer Inspections	PRODO&M	-	DEMAND	-	-	DEMAND	-	-	552,385	DEMAND	552,385	-	826,327	CUST	-	826,327	CUST	5,772,464
10	Customer Safety Services	PRODO&M	-	DEMAND	-	-	DEMAND	-	-	-	DEMAND	-	-	-	DISTPT	-	-	CUST	1,285,355
11	Dispatch	PRODO&M	-	DEMAND	-	-	DEMAND	-	-	-	DEMAND	-	-	-	DISTPT	-	-	CUST	2,306,190
12	Energy Supply, Planning & Support	PRODGAS	594,424	PIPEGAS	729,153	729,153	STORGAS	658,742	70,411	816,296	DEMAND	816,296	-	-	DISTO&M	-	-	ONSITEO&M	-
13	Environment	PRODO&M	-	PIPEO&M	-	-	STORO&M	-	-	159,780	DEMAND	159,780	-	239,019	MINPLANT	159,346	79,673	ONSITEO&M	-
14	Meter Reading	PRODO&M	-	DEMAND	-	-	DEMAND	-	-	-	DEMAND	-	-	-	DISTPT	-	-	CUST	2,511,105
15	Rate and Regulatory Affairs	PRODO&M	16,288	PIPEO&M	16,728	15,908	STORO&M	14,372	1,536	84,138	TRANO&M	84,087	51	220,366	DISTO&M	147,457	72,909	ONSITEO&M	590,450
16	Research & Development	PRODO&M	-	DEMAND	-	-	DEMAND	-	-	-	DEMAND	-	-	-	DISTPT	-	-	ONSITEPT	-
17	Sub-total		796,776		818,329	778,189		703,042	75,146	1,615,383		1,612,877	2,506	1,285,712		306,803	978,909		24,713,273
18																			
19	B. OPERATIONS AND MAINTENANCE																		
20	Communication System	PRODO&M	0	DEMAND	0	0	DEMAND	0	0	13,534	DEMAND	13,534	0	44,663	DEMAND	44,663	0	CUST	77,145
21	Distribution Maintenance	PRODO&M	0	DEMAND	0	0	DEMAND	0	0	1,379,630	DEMAND	1,379,630	0	2,416,672	DISTPT	1,782,158	634,515	CUST	2,962,360
22	Load Forecast	PRODO&M	0	PIPEO&M	0	0	STORO&M	0	0	0	TRANO&M	0	0	0	DISTPT	0	0	CUST	70,288
23	Metering	PRODO&M	0	PIPEO&M	0	0	STORO&M	0	0	0	TRANO&M	0	0	0	DISTO&M	0	0	CUST	573,718
24	Plant Failures & Emergencies	PRODO&M	0	DEMAND	0	0	DEMAND	0	0	0	DEMAND	0	0	0	DISTPT	0	0	CUST	302,792
25	Quality Assessment	PRODO&M	0	PIPEO&M	0	0	STORO&M	0	0	100,468	DEMAND	100,468	0	150,293	DISTPT	110,832	39,460	CUST	184,229
26	Regulating Station Maintenance	PRODO&M	0	DEMAND	0	0	DEMAND	0	0	0	DEMAND	0	0	5,376,364	DISTPT	3,964,761	1,411,603	ONSITEPT	0
27	System Performance & Reliability	PRODO&M	0	DEMAND	0	0	DEMAND	0	0	1,006,884	DEMAND	1,006,884	0	1,506,225	MINPLANT	1,004,150	502,075	ONSITEPT	0
28	IT - Distribution/Metering	PRODO&M	0	PIPEO&M	0	0	STORO&M	0	0	0	TRANO&M	0	0	0	DISTO&M	0	0	ONSITEO&M	0
29	Treasury	PRODO&M	0	PIPEO&M	0	0	STORO&M	0	0	0	TRANO&M	0	0	0	DISTO&M	0	0	ONSITEO&M	0
30	Sub-total		0		0	0		0	0	2,500,516		2,500,516	0	9,494,217		6,906,564	2,587,653		4,170,532
31																			
32	C. ORGANIZATIONAL SUPPORT																		
33	Corporate Governance	PRODO&M	37,214	PIPEO&M	38,221	36,346	STORO&M	32,836	3,510	192,236	TRANO&M	192,119	117	503,485	DISTO&M	336,906	166,579	ONSITEO&M	1,349,039
34	Corporate Infrastructure	PRODO&M	79,057	PIPEO&M	81,195	77,212	STORO&M	69,756	7,456	408,382	TRANO&M	408,133	249	1,069,590	DISTO&M	715,714	353,876	ONSITEO&M	2,865,866
35	Corporate Services	PRODO&M	32,181	PIPEO&M	33,052	31,431	STORO&M	28,395	3,035	166,238	TRANO&M	166,137	101	435,394	DISTO&M	291,343	144,051	ONSITEO&M	1,166,597
36	Departmental Support	PRODO&M	93,995	PIPEO&M	96,537	91,802	STORO&M	82,937	8,865	485,548	TRANO&M	485,253	296	1,271,696	DISTO&M	850,953	420,743	ONSITEO&M	3,407,391
37	Operational Management	PRODO&M	28,610	PIPEO&M	29,384	27,943	STORO&M	25,245	2,698	147,793	TRANO&M	147,703	90	387,083	DISTO&M	259,016	128,067	ONSITEO&M	1,037,153
38	Customer Relations	PRODO&M	-	DEMAND	-	-	DEMAND	-	-	-	DEMAND	-	-	-	DISTPT	-	-	CUST	-
39	Sub-total		271,057		278,389	264,734		239,170	25,564	1,400,197		1,399,345	853	3,667,248		2,453,932	1,213,317		9,826,046
40																			
41	D. ADJUSTMENTS TO INCOME																		
42	Corporate Alloc. & Adj.	PRODO&M	14,709	PIPEO&M	15,107	14,366	STORO&M	12,979	1,387	75,983	TRANO&M	75,937	46	199,007	DISTO&M	133,165	65,842	ONSITEO&M	533,222
43	Depreciation, Interest, Taxes	PRODO&M	- 37,671	PIPEO&M	- 38,689	- 36,792	STORO&M	- 33,239	- 3,553	- 194,594	TRANO&M	- 194,476	- 118	- 509,660	DISTO&M	- 341,038	- 168,622	ONSITEO&M	- 1,365,587
44	Sub-total		- 22,961		- 23,582	- 22,426		- 20,260	- 2,166	- 118,611		- 118,539	- 72	- 310,653		- 207,873	- 102,780		- 832,365
45																			
46	Total Operating & Administrative Expenses		1,044,872		1,073,136	1,020,497		921,952	98,545	5,397,486		5,394,199	3,287	14,136,524		9,459,426	4,677,098		37,877,485

1		Total	Direct	Allocation	Production - Energy												
2	III. OPERATING & ADMINISTRATIVE EXPENSES	Costs	Assignment	Factor	SGS	LGS	HVF	CO-OP	ML	SC	PS	INT	PG	FSP	ISP	FPO	
3	A. CUSTOMER SERVICE & CORPORATE RELATIONS												[redacted]				
4	Back/Middle Office Services	186,065		PRODGAS-E	-	-	-	-	-	-	-	-	[redacted]			75	
5	Billing & Collections	-		PRODO&M-E	-	-	-	-	-	-	-	-	[redacted]			-	
6	Customer & Public Relations	-		PRODO&M-E	-	-	-	-	-	-	-	-	[redacted]			-	
7	Customer Information Systems (Banner)	-		PRODO&M-E	-	-	-	-	-	-	-	-	[redacted]			-	
8	Customer Inspections	-		COMCOST	-	-	-	-	-	-	-	-	[redacted]			-	1e
9	Customer Safety Services	-		COMCOST	-	-	-	-	-	-	-	-	[redacted]			-	
10	Dispatch	-		COMCOST	-	-	-	-	-	-	-	-	[redacted]			-	
11	Energy Supply, Planning & Support	594,424		PRODGAS-E	-	-	-	-	-	-	-	-	[redacted]			238	
12	Environment	-		PRODO&M-E	-	-	-	-	-	-	-	-	[redacted]			-	
13	Meter Reading	-		COMCOST	-	-	-	-	-	-	-	-	[redacted]			-	
14	Rate and Regulatory Affairs	16,288		PRODO&M-E	-	-	-	-	-	-	-	-	[redacted]			7	
15	Research & Development	-		COMCOST	-	-	-	-	-	-	-	-	[redacted]			-	
16	Sub-total	796,776			-	-	-	-	-	-	-	-	[redacted]			319	
17													[redacted]				
18	B. OPERATIONS AND MAINTENANCE												[redacted]				
19	Communication System	0		COMCOST	-	-	-	-	-	-	-	-	[redacted]			-	
20	Distribution Maintenance	0		COMCOST	-	-	-	-	-	-	-	-	[redacted]			-	
21	Load Forecast	0		COMCOST	-	-	-	-	-	-	-	-	[redacted]			-	
22	Metering	0		PRODO&M-E	-	-	-	-	-	-	-	-	[redacted]			-	1e
23	Plant Failures & Emergencies	0		COMCOST	-	-	-	-	-	-	-	-	[redacted]			-	
24	Quality Assessment	0		COMCOST	-	-	-	-	-	-	-	-	[redacted]			-	
25	Regulating Station Maintenance	0		COMCOST	-	-	-	-	-	-	-	-	[redacted]			-	
26	System Performance & Reliability	0		COMCOST	-	-	-	-	-	-	-	-	[redacted]			-	
27	IT - Distribution/Metering	0		PRODO&M-E	-	-	-	-	-	-	-	-	[redacted]			-	
28	Treasury	0		PRODO&M-E	-	-	-	-	-	-	-	-	[redacted]			-	
29	Sub-total	0			-	-	-	-	-	-	-	-	[redacted]			-	
30													[redacted]				
31	C. ORGANIZATIONAL SUPPORT												[redacted]				
32	Corporate Governance	37,214		PRODO&M-E	-	-	-	-	-	-	-	-	[redacted]			15	
33	Corporate Infrastructure	79,057		PRODO&M-E	-	-	-	-	-	-	-	-	[redacted]			32	
34	Corporate Services	32,181		PRODO&M-E	-	-	-	-	-	-	-	-	[redacted]			13	1e
35	Departmental Support	93,995		PRODO&M-E	-	-	-	-	-	-	-	-	[redacted]			38	
36	Operational Management	28,610		PRODO&M-E	-	-	-	-	-	-	-	-	[redacted]			11	
37	Customer Relations	-		COMCOST	-	-	-	-	-	-	-	-	[redacted]			-	
38	Sub-total	271,057			-	-	-	-	-	-	-	-	[redacted]			109	
39													[redacted]				
40	D. ADJUSTMENTS TO INCOME												[redacted]				
41	Corporate Alloc. & Adj.	14,709		PRODO&M-E	-	-	-	-	-	-	-	-	[redacted]			6	
42	Depreciation, Interest, Taxes	- 37,671		PRODO&M-E	-	-	-	-	-	-	-	-	[redacted]			15	1e
43	Sub-total	- 22,961			-	-	-	-	-	-	-	-	[redacted]			9	
44													[redacted]				
45	Total Operating & Administrative Expenses	1,044,872			-	-	-	-	-	-	-	-	[redacted]			419	1e

1		Total	Direct	Allocation	Pipeline - Demand											
2		Costs	Assignment	Factor	SGS	LGS	HVF	CO-OP	ML	SC	PS	INT	PG	FSP	ISP	FPO
3	A. CUSTOMER SERVICE & CORPORATE RELATIONS															
4	Back/Middle Office Services	72,448		PIPEGAS-D	36,150	27,640	7,716	14	119	-	-	809				
5	Billing & Collections	-		PAVG	-	-	-	-	-	-	-	-				
6	Customer & Public Relations	-		PAVG	-	-	-	-	-	-	-	-				
7	Customer Information Systems (Banner)	-		PAVG	-	-	-	-	-	-	-	-				
8	Customer Inspections	-		PAVG	-	-	-	-	-	-	-	-				
9	Customer Safety Services	-		PAVG	-	-	-	-	-	-	-	-				
10	Dispatch	-		PAVG	-	-	-	-	-	-	-	-				
11	Energy Supply, Planning & Support	729,153		PIPEGAS-D	363,836	278,180	77,660	136	1,196	-	-	8,146				
12	Environment	-		PAVG	-	-	-	-	-	-	-	-				
13	Meter Reading	-		PAVG	-	-	-	-	-	-	-	-				
14	Rate and Regulatory Affairs	16,728		PAVG	8,347	6,382	1,782	3	27	-	-	187				
15	Research & Development	-		PAVG	-	-	-	-	-	-	-	-				
16	Sub-total	818,329			408,333	312,202	87,158	153	1,342	-	-	9,142				
17																
18	B. OPERATIONS AND MAINTENANCE															
19	Communication System	0		PAVG	-	-	-	-	-	-	-	-				
20	Distribution Maintenance	0		PAVG	-	-	-	-	-	-	-	-				
21	Load Forecast	0		PAVG	-	-	-	-	-	-	-	-				
22	Metering	0		PAVG	-	-	-	-	-	-	-	-				
23	Plant Failures & Emergencies	0		PAVG	-	-	-	-	-	-	-	-				
24	Quality Assessment	0		PAVG	-	-	-	-	-	-	-	-				
25	Regulating Station Maintenance	0		PAVG	-	-	-	-	-	-	-	-				
26	System Performance & Reliability	0		PAVG	-	-	-	-	-	-	-	-				
27	IT - Distribution/Metering	0		PAVG	-	-	-	-	-	-	-	-				
28	Treasury	0		PAVG	-	-	-	-	-	-	-	-				
29	Sub-total	0			-	-	-	-	-	-	-	-				
30																
31	C. ORGANIZATIONAL SUPPORT															
32	Corporate Governance	38,221		PAVG	19,071	14,582	4,071	7	63	-	-	427				
33	Corporate Infrastructure	81,195		PIPEO&M-D	40,515	30,977	8,648	15	133	-	-	907				
34	Corporate Services	33,052		PIPEO&M-D	16,492	12,610	3,520	6	54	-	-	369				
35	Departmental Support	96,537		PIPEO&M-D	48,171	36,830	10,282	18	158	-	-	1,078				
36	Operational Management	29,384		PIPEO&M-D	14,662	11,210	3,130	5	48	-	-	328				
37	Customer Relations	-		PAVG	-	-	-	-	-	-	-	-				
38	Sub-total	278,389			138,912	106,209	29,650	52	457	-	-	3,110				
39																
40	D. ADJUSTMENTS TO INCOME															
41	Corporate Alloc. & Adj.	15,107		PIPEO&M-D	7,538	5,764	1,609	3	25	-	-	169				
42	Depreciation, Interest, Taxes	- 38,689		PIPEO&M-D	- 19,305	- 14,760	- 4,121	- 7	- 63	-	-	- 432				
43	Sub-total	- 23,582			- 11,767	- 8,997	- 2,512	- 4	- 39	-	-	- 263				
44																
45	Total Operating & Administrative Expenses	**1,073,136**			**535,477**	**409,413**	**114,297**	**200**	**1,760**	**-**	**-**	**11,988**				

1		Total	Direct	Allocation	Storage - Demand											
2		Costs	Assignment	Factor	SGS	LGS	HVF	CO-OP	ML	SC	PS	INT	PG	FSP	ISP	FPO
3	A. CUSTOMER SERVICE & CORPORATE RELATIONS															
4	Back/Middle Office Services	29,929		STORGAS-D	14,934	11,418	3,188	6	49	-	-	334				
5	Billing & Collections	-		PAVG	-	-	-	-	-	-	-	-				
6	Customer & Public Relations	-		PAVG	-	-	-	-	-	-	-	-				
7	Customer Information Systems (Banner)	-		PAVG	-	-	-	-	-	-	-	-				
8	Customer Inspections	-		PAVG	-	-	-	-	-	-	-	-				
9	Customer Safety Services	-		PAVG	-	-	-	-	-	-	-	-				
10	Dispatch	-		PAVG	-	-	-	-	-	-	-	-				
11	Energy Supply, Planning & Support	658,742		STORGAS-D	328,701	251,317	70,161	123	1,080	-	-	7,359				
12	Environment	-		STORO&M-D	-	-	-	-	-	-	-	-				
13	Meter Reading	-		PAVG	-	-	-	-	-	-	-	-				
14	Rate and Regulatory Affairs	14,372		PAVG	7,171	5,483	1,531	3	24	-	-	161				
15	Research & Development	-		PAVG	-	-	-	-	-	-	-	-				
16	Sub-total	703,042			350,807	268,219	74,879	131	1,153	-	-	7,854				
17																
18	B. OPERATIONS AND MAINTENANCE															
19	Communication System	0		PAVG	-	-	-	-	-	-	-	-				
20	Distribution Maintenance	0		PAVG	-	-	-	-	-	-	-	-				
21	Load Forecast	0		PAVG	-	-	-	-	-	-	-	-				
22	Metering	0		PAVG	-	-	-	-	-	-	-	-				
23	Plant Failures & Emergencies	0		PAVG	-	-	-	-	-	-	-	-				
24	Quality Assessment	0		PAVG	-	-	-	-	-	-	-	-				
25	Regulating Station Maintenance	0		PAVG	-	-	-	-	-	-	-	-				
26	System Performance & Reliability	0		PAVG	-	-	-	-	-	-	-	-				
27	IT - Distribution/Metering	0		PAVG	-	-	-	-	-	-	-	-				
28	Treasury	0		PAVG	-	-	-	-	-	-	-	-				
29	Sub-total	0			-	-	-	-	-	-	-	-				
30																
31	C. ORGANIZATIONAL SUPPORT															
32	Corporate Governance	32,836		STORO&M-D	16,385	12,527	3,497	6	54	-	-	367				
33	Corporate Infrastructure	69,756		STORO&M-D	34,807	26,613	7,430	13	114	-	-	779				
34	Corporate Services	28,395		STORO&M-D	14,169	10,833	3,024	5	47	-	-	317				
35	Departmental Support	82,937		STORO&M-D	41,384	31,641	8,833	15	136	-	-	927				
36	Operational Management	25,245		STORO&M-D	12,597	9,631	2,689	5	41	-	-	282				
37	Customer Relations	-		PAVG	-	-	-	-	-	-	-	-				
38	Sub-total	239,170			119,342	91,246	25,473	45	392	-	-	2,672				
39																
40	D. ADJUSTMENTS TO INCOME															
41	Corporate Alloc. & Adj.	12,979		STORO&M-D	6,476	4,952	1,382	2	21	-	-	145				
42	Depreciation, Interest, Taxes	- 33,239		STORO&M-D	- 16,586	- 12,681	- 3,540	- 6	- 55	-	-	- 371				
43	Sub-total	- 20,260			- 10,109	- 7,729	- 2,158	- 4	- 33	-	-	- 226				
44																
45	Total Operating & Administrative Expenses	**921,952**			**460,039**	**351,735**	**98,194**	**172**	**1,512**	**-**	**-**	**10,299**				

1		Total	Direct	Allocation	Storage - Energy											
2		Costs	Assignment	Factor	SGS	LGS	HVF	CO-OP	ML	SC	PS	INT	PG	FSP	ISP	FPO
3	A. CUSTOMER SERVICE & CORPORATE RELATIONS															
4	Back/Middle Office Services	3,199		STORGAS-E	1,563	1,194	356	0	7	-	-	79				
5	Billing & Collections	-		STORO&M-E	-	-	-	-	-	-	-	-				
6	Customer & Public Relations	-		STORO&M-E	-	-	-	-	-	-	-	-				
7	Customer Information Systems (Banner)	-		STORO&M-E	-	-	-	-	-	-	-	-				
8	Customer Inspections	-		STORPT-E	-	-	-	-	-	-	-	-				
9	Customer Safety Services	-		STORPT-E	-	-	-	-	-	-	-	-				
10	Dispatch	-		STORPT-E	-	-	-	-	-	-	-	-				
11	Energy Supply, Planning & Support	70,411		STORGAS-E	34,411	26,290	7,828	7	146	-	-	1,729				
12	Environment	-		STORPT-E	-	-	-	-	-	-	-	-				
13	Meter Reading	-		STORPT-E	-	-	-	-	-	-	-	-				
14	Rate and Regulatory Affairs	1,536		STORO&M-E	751	574	171	0	3	-	-	38				
15	Research & Development	-		STORPT-E	-	-	-	-	-	-	-	-				
16	Sub-total	75,146			36,725	28,058	8,354	8	156	-	-	1,845				
17																
18	B. OPERATIONS AND MAINTENANCE															
19	Communication System	0		STORPT-E	-	-	-	-	-	-	-	-				
20	Distribution Maintenance	0		STORPT-E	-	-	-	-	-	-	-	-				
21	Load Forecast	0		STORPT-E	-	-	-	-	-	-	-	-				
22	Metering	0		STORO&M-E	-	-	-	-	-	-	-	-				
23	Plant Failures & Emergencies	0		STORPT-E	-	-	-	-	-	-	-	-				
24	Quality Assessment	0		STORPT-E	-	-	-	-	-	-	-	-				
25	Regulating Station Maintenance	0		STORPT-E	-	-	-	-	-	-	-	-				
26	System Performance & Reliability	0		STORPT-E	-	-	-	-	-	-	-	-				
27	IT - Distribution/Metering	0		STORO&M-E	-	-	-	-	-	-	-	-				
28	Treasury	0		STORO&M-E	-	-	-	-	-	-	-	-				
29	Sub-total	0			-	-	-	-	-	-	-	-				
30																
31	C. ORGANIZATIONAL SUPPORT															
32	Corporate Governance	3,510		STORO&M-E	1,715	1,310	390	0	7	-	-	86				
33	Corporate Infrastructure	7,456		STORO&M-E	3,644	2,784	829	1	15	-	-	183				
34	Corporate Services	3,035		STORO&M-E	1,483	1,133	337	0	6	-	-	75				
35	Departmental Support	8,865		STORO&M-E	4,332	3,310	986	1	18	-	-	218				
36	Operational Management	2,698		STORO&M-E	1,319	1,008	300	0	6	-	-	66				
37	Customer Relations	-		STORPT-E	-	-	-	-	-	-	-	-				
38	Sub-total	25,564			12,494	9,545	2,842	3	53	-	-	628				
39																
40	D. ADJUSTMENTS TO INCOME															
41	Corporate Alloc. & Adj.	1,387		STORO&M-E	678	518	154	0	3	-	-	34				
42	Depreciation, Interest, Taxes	- 3,553		STORO&M-E	- 1,736	- 1,327	- 395	- 0	- 7	-	-	- 87				
43	Sub-total	- 2,166			- 1,058	- 809	- 241	- 0	- 4	-	-	- 53				
44																
45	**Total Operating & Administrative Expenses**	**98,545**			**48,160**	**36,795**	**10,955**	**10**	**205**	**-**	**-**	**2,420**				

1		Total	Direct	Allocation	Transmiision - Demand											
2		Costs	Assignment	Factor	SGS	LGS	HVF	CO-OP	ML	SC	PS	INT	PG	FSP	ISP	FPO
3	A. CUSTOMER SERVICE & CORPORATE RELATIONS															
4	Back/Middle Office Services	330		TRANGAS-D	129	99	30	0	19	49	1	3				
5	Billing & Collections	-		TRANO&M-D	-	-	-	-	-	-	-	-				
6	Customer & Public Relations	-		TRANO&M-D	-	-	-	-	-	-	-	-				
7	Customer Information Systems (Banner)	-		TRANO&M-D	-	-	-	-	-	-	-	-				
8	Customer Inspections	552,385		PAVG-T	215,877	165,291	50,756	81	31,027	81,673	2,457	5,223				
9	Customer Safety Services	-		PAVG-T	-	-	-	-	-	-	-	-				
10	Dispatch	-		PAVG-T	-	-	-	-	-	-	-	-				
11	Energy Supply, Planning & Support	816,296	TRANS-GASSUPPLY	TRANGAS-D	233,554	178,826	113,227	88	150,196	102,939	31,816	5,650				
12	Environment	159,780		PAVG-T	62,443	47,811	14,682	23	8,975	23,624	711	1,511				
13	Meter Reading	-		PAVG-T	-	-	-	-	-	-	-	-				
14	Rate and Regulatory Affairs	84,087		TRANO&M-D	31,078	23,796	8,524	12	6,901	12,062	962	752				
15	Research & Development	-		PAVG-T	-	-	-	-	-	-	-	-				
16	Sub-total	1,612,877			543,081	415,824	187,219	204	197,116	220,348	35,947	13,138				
17																
18	B. OPERATIONS AND MAINTENANCE															
19	Communication System	13,534		PAVG-T	5,289	4,050	1,244	2	760	2,001	60	128				
20	Distribution Maintenance	1,379,630		PAVG-T	539,171	412,830	126,769	202	77,492	203,986	6,137	13,044				
21	Load Forecast	0		PAVG-T	0	0	0	0	0	0	0	0				
22	Metering	0		TRANO&M-D	0	0	0	0	0	0	0	0				
23	Plant Failures & Emergencies	0		PAVG-T	0	0	0	0	0	0	0	0				
24	Quality Assessment	100,468		PAVG-T	39,264	30,063	9,232	15	5,643	14,855	447	950				
25	Regulating Station Maintenance	0		PAVG-T	0	0	0	0	0	0	0	0				
26	System Performance & Reliability	1,006,884		PAVG-T	393,499	301,292	92,519	148	56,555	148,873	4,479	9,520				
27	IT - Distribution/Metering	0		TRANO&M-D	0	0	0	0	0	0	0	0				
28	Treasury	0		TRANO&M-D	0	0	0	0	0	0	0	0				
29	Sub-total	2,500,516			977,223	748,235	229,762	366	140,450	369,715	11,124	23,641				
30																
31	C. ORGANIZATIONAL SUPPORT															
32	Corporate Governance	192,119		TRANO&M-D	71,007	54,368	19,475	27	15,766	27,559	2,198	1,718				
33	Corporate Infrastructure	408,133		TRANO&M-D	150,845	115,499	41,373	57	33,494	58,546	4,670	3,649				
34	Corporate Services	166,137		TRANO&M-D	61,404	47,016	16,842	23	13,634	23,832	1,901	1,486				
35	Departmental Support	485,253		TRANO&M-D	179,349	137,323	49,191	67	39,822	69,609	5,553	4,339				
36	Operational Management	147,703		TRANO&M-D	54,591	41,799	14,973	20	12,121	21,188	1,690	1,321				
37	Customer Relations	-		PAVG-T	-	-	-	-	-	-	-	-				
38	Sub-total	1,399,345			517,195	396,004	141,854	194	114,837	200,735	16,013	12,512				
39																
40	D. ADJUSTMENTS TO INCOME															
41	Corporate Alloc. & Adj.	75,937		TRANO&M-D	28,066	21,490	7,698	11	6,232	10,893	869	679				
42	Depreciation, Interest, Taxes	- 194,476		TRANO&M-D	- 71,878	- 55,035	- 19,714	- 27	- 15,960	- 27,897	- 2,225	- 1,739				
43	Sub-total	- 118,539			- 43,812	- 33,546	- 12,016	- 16	- 9,728	- 17,004	- 1,356	- 1,060				
44																
45	Total Operating & Administrative Expenses	**5,394,199**			**1,993,687**	**1,526,517**	**546,819**	**748**	**442,676**	**773,792**	**61,728**	**48,232**				

Line		Total	Direct	Allocation	Transmission - Energy											
2		Costs	Assignment	Factor	SGS	LGS	HVF	CO-OP	ML	SC	PS	INT	PG	FSP	ISP	FPO
3	A. CUSTOMER SERVICE & CORPORATE RELATIONS															
4	Back/Middle Office Services	2,455		TRANGAS-E	943	675	216	-	179	69	135	238				
5	Billing & Collections	-		TRANO&M-E	-	-	-	-	-	-	-	-				
6	Customer & Public Relations	-		TRANO&M-E	-	-	-	-	-	-	-	-				
7	Customer Information Systems (Banner)	-		TRANO&M-E	-	-	-	-	-	-	-	-				
8	Customer Inspections	-		TRANPT-E	-	-	-	-	-	-	-	-				
9	Customer Safety Services	-		TRANPT-E	-	-	-	-	-	-	-	-				
10	Dispatch	-		TRANPT-E	-	-	-	-	-	-	-	-				
11	Energy Supply, Planning & Support	-		TRANGAS-E	-	-	-	-	-	-	-	-				
12	Environment	-		TRANPT-E	-	-	-	-	-	-	-	-				
13	Meter Reading	-		TRANPT-E	-	-	-	-	-	-	-	-				
14	Rate and Regulatory Affairs	51		TRANO&M-E	20	14	5	-	4	1	3	5				
15	Research & Development	-		TRANPT-E	-	-	-	-	-	-	-	-				
16	Sub-total	2,506			962	689	221	-	183	70	138	243				
17																
18	B. OPERATIONS AND MAINTENANCE															
19	Communication System	0		TRANPT-E	-	-	-	-	-	-	-	-				
20	Distribution Maintenance	0		TRANPT-E	-	-	-	-	-	-	-	-				
21	Load Forecast	0		TRANPT-E	-	-	-	-	-	-	-	-				
22	Metering	0		TRANO&M-E	-	-	-	-	-	-	-	-				
23	Plant Failures & Emergencies	0		TRANPT-E	-	-	-	-	-	-	-	-				
24	Quality Assessment	0		TRANPT-E	-	-	-	-	-	-	-	-				
25	Regulating Station Maintenance	0		TRANPT-E	-	-	-	-	-	-	-	-				
26	System Performance & Reliability	0		TRANPT-E	-	-	-	-	-	-	-	-				
27	IT - Distribution/Metering	0		TRANO&M-E	-	-	-	-	-	-	-	-				
28	Treasury	0		TRANO&M-E	-	-	-	-	-	-	-	-				
29	Sub-total	0			-	-	-	-	-	-	-	-				
30																
31	C. ORGANIZATIONAL SUPPORT															
32	Corporate Governance	117		TRANO&M-E	45	32	10	-	9	3	6	11				
33	Corporate Infrastructure	249		TRANO&M-E	95	68	22	-	18	7	14	24				
34	Corporate Services	101		TRANO&M-E	39	28	9	-	7	3	6	10				
35	Departmental Support	296		TRANO&M-E	114	81	26	-	22	8	16	29				
36	Operational Management	90		TRANO&M-E	35	25	8	-	7	3	5	9				
37	Customer Relations	-		TRANPT-E	-	-	-	-	-	-	-	-				
38	Sub-total	853			327	234	75	-	62	24	47	83				
39																
40	D. ADJUSTMENTS TO INCOME															
41	Corporate Alloc. & Adj.	46		TRANO&M-E	18	13	4	-	3	1	3	4				
42	Depreciation, Interest, Taxes	- 118		TRANO&M-E	- 46	- 33	- 10	-	- 9	- 3	- 7	- 11				
43	Sub-total	- 72			- 28	- 20	- 6	-	- 5	- 2	- 4	- 7				
44																
45	Total Operating & Administrative Expenses	**3,287**			**1,262**	**904**	**289**	**-**	**240**	**92**	**181**	**319**				

1		Total	Direct	Allocation	Distribution - Demand											
2		Costs	Assignment	Factor	SGS	LGS	HVF	CO-OP	ML	SC	PS	INT	PG	FSP	ISP	FPO
3	A. CUSTOMER SERVICE & CORPORATE RELATIONS															
4	Back/Middle Office Services	-		DISTPT-D	-	-	-	-	-	-	-	-				
5	Billing & Collections	-		DISTPT-D	-	-	-	-	-	-	-	-				
6	Customer & Public Relations	-		DISTPT-D	-	-	-	-	-	-	-	-				
7	Customer Information Systems (Banner)	-		DISTPT-D	-	-	-	-	-	-	-	-				
8	Customer Inspections	-		PAVG-D	-	-	-	-	-	-	-	-				
9	Customer Safety Services	-		DISTPT-D	-	-	-	-	-	-	-	-				
10	Dispatch	-		DISTPT-D	-	-	-	-	-	-	-	-				
11	Energy Supply, Planning & Support	-		DISTPT-D	-	-	-	-	-	-	-	-				
12	Environment	159,346		PAVG-D	78,921	60,344	18,310	-	-	-	-	1,771				
13	Meter Reading	-		DISTPT-D	-	-	-	-	-	-	-	-				
14	Rate and Regulatory Affairs	147,457		DISTO&M-D	70,005	53,539	16,279	16	6,026	-	-	1,592				
15	Research & Development	-		PAVG-D	-	-	-	-	-	-	-	-				
16	Sub-total	306,803			148,926	113,883	34,589	16	6,026	-	-	3,364				
17																
18	B. OPERATIONS AND MAINTENANCE															
19	Communication System	44,663		PAVG-TBS	20,657	15,800	4,811	8	2,914	0	0	474				
20	Distribution Maintenance	1,782,158		DISTPT-D	866,217	662,389	201,171	87	32,737	0	0	19,557				
21	Load Forecast	0		DISTPT-D	0	0	0	0	0	0	0	0				
22	Metering	0		DISTPT-D	0	0	0	0	0	0	0	0				
23	Plant Failures & Emergencies	0		DISTPT-D	0	0	0	0	0	0	0	0				
24	Quality Assessment	110,832		DISTPT-D	53,870	41,194	12,511	5	2,036	0	0	1,216				
25	Regulating Station Maintenance	3,964,761		PAVG-TBS	1,833,689	1,402,616	427,055	686	258,643	0	0	42,072				
26	System Performance & Reliability	1,004,150		PAVG-D	497,337	380,268	115,383	0	0	0	0	11,162				
27	IT - Distribution/Metering	0		DISTO&M-D	0	0	0	0	0	0	0	0				
28	Treasury	0		DISTO&M-D	0	0	0	0	0	0	0	0				
29	Sub-total	6,906,564		0	3,271,770	2,502,267	760,932	786	296,329	0	0	74,480				
30																
31	C. ORGANIZATIONAL SUPPORT															
32	Corporate Governance	336,906		DISTPT-D	163,753	125,220	38,030	16	6,189	-	-	3,697				
33	Corporate Infrastructure	715,714		DISTO&M-D	339,781	259,863	79,015	78	29,248	-	-	7,729				
34	Corporate Services	291,343		DISTO&M-D	138,313	105,782	32,164	32	11,906	-	-	3,146				
35	Departmental Support	850,953		DISTO&M-D	403,985	308,966	93,945	92	34,774	-	-	9,190				
36	Operational Management	259,016		DISTO&M-D	122,966	94,044	28,595	28	10,585	-	-	2,797				
37	Customer Relations	-		DISTPT-D	-	-	-	-	-	-	-	-				
38	Sub-total	2,453,932			1,168,799	893,875	271,750	246	92,701	-	-	26,560				
39																
40	D. ADJUSTMENTS TO INCOME															
41	Corporate Alloc. & Adj.	133,165		DISTO&M-D	63,220	48,350	14,701	14	5,442	-	-	1,438				
42	Depreciation, Interest, Taxes	- 341,038		DISTO&M-D	- 161,906	- 123,825	- 37,651	- 37	- 13,937	-	-	- 3,683				
43	Sub-total	- 207,873			- 98,686	- 75,475	- 22,949	- 23	- 8,495	-	-	- 2,245				
44																
45	**Total Operating & Administrative Expenses**	**9,459,426**			**4,490,808**	**3,434,550**	**1,044,322**	**1,026**	**386,561**	**-**	**-**	**102,159**				

1		Total	Direct	Allocation	Distribution - Customer											
2		Costs	Assignment	Factor	SGS	LGS	HVF	CO-OP	ML	SC	PS	INT	PG	FSP	ISP	FPO
3	A. CUSTOMER SERVICE & CORPORATE RELATIONS															
4	Back/Middle Office Services	-		DISTO&M-C	-	-	-	-	-	-	-	-				
5	Billing & Collections	-		DISTO&M-C	-	-	-	-	-	-	-	-				
6	Customer & Public Relations															
7	Customer Information Systems (Banner)	-		DISTO&M-C	-	-	-	-	-	-	-	-				
8	Customer Inspections	826,327		CUST-D	802,088	23,863	319	-	-	-	-	57				
9	Customer Safety Services	-		CUST-D	-	-	-	-	-	-	-	-				
10	Dispatch	-		CUST-D	-	-	-	-	-	-	-	-				
11	Energy Supply, Planning & Support	-		DISTO&M-C	-	-	-	-	-	-	-	-				
12	Environment	79,673		CUST-D	77,336	2,301	31	-	-	-	-	6				
13	Meter Reading	-		CUST-D	-	-	-	-	-	-	-	-				
14	Rate and Regulatory Affairs	72,909		DISTO&M-C	70,769	2,105	28	0	0	-	0	5				
15	Research & Development	-		DISTPT-C	-	-	-	-	-	-	-	-				
16	Sub-total	978,909			950,193	28,270	378	0	0	-	0	68				
17																
18	B. OPERATIONS AND MAINTENANCE															
19	Communication System	0		CUST-D	0	0	0	0	0	0	0	0				
20	Distribution Maintenance	634,515		CUST-D	615,902	18,324	245	0	0	0	0	44				
21	Load Forecast	0		CUST-D	0	0	0	0	0	0	0	0				
22	Metering	0		CUST-D	0	0	0	0	0	0	0	0				
23	Plant Failures & Emergencies	0		CUST-D	0	0	0	0	0	0	0	0				
24	Quality Assessment	39,460		CUST-D	38,303	1,140	15	0	0	0	0	3				
25	Regulating Station Maintenance	1,411,603	ODOR	DISTPT-C	1,370,178	40,765	545	1	13	0	3	98				
26	System Performance & Reliability	502,075		CUST-D	487,347	14,499	194	0	0	0	0	35				
27	IT - Distribution/Metering	0		DISTO&M-C	0	0	0	0	0	0	0	0				
28	Treasury	0		DISTO&M-C	0	0	0	0	0	0	0	0				
29	Sub-total	2,587,653		0	2,511,729	74,728	998	1	13	0	3	180				
30																
31	C. ORGANIZATIONAL SUPPORT															
32	Corporate Governance	166,579		DISTO&M-C	161,692	4,811	64	0	1	-	0	12				
33	Corporate Infrastructure	353,876		DISTO&M-C	343,494	10,219	137	0	1	-	0	25				
34	Corporate Services	144,051		DISTO&M-C	139,825	4,160	56	0	1	-	0	10				
35	Departmental Support	420,743		DISTO&M-C	408,399	12,150	162	0	2	-	0	29				
36	Operational Management	128,067		DISTO&M-C	124,310	3,698	49	0	0	-	0	9				
37	Customer Relations	-		CUST-D	-	-	-	-	-	-	-	-				
38	Sub-total	1,213,317			1,177,719	35,039	468	1	5	-	1	84				
39																
40	D. ADJUSTMENTS TO INCOME															
41	Corporate Alloc. & Adj.	65,842		DISTO&M-C	63,910	1,901	25	0	0	-	0	5				
42	Depreciation, Interest, Taxes	- 168,622		DISTO&M-C	- 163,675	- 4,870	- 65	- 0	- 1	-	- 0	- 12				
43	Sub-total	- 102,780			- 99,765	- 2,968	- 40	- 0	- 0	-	- 0	- 7				
44																
45		**4,677,098**			**4,539,877**	**135,068**	**1,804**	**2**	**18**	**-**	**4**	**325**				

1		Total	Direct	Allocation	OnSite - Customer											
2		Costs	Assignment	Factor	SGS	LGS	HVF	CO-OP	ML	SC	PS	INT	PG	FSP	ISP	FPO
3	A. CUSTOMER SERVICE & CORPORATE RELATIONS															
4	Back/Middle Office Services	-		ONSITEO&M-C	-	-	-	-	-	-	-	-	-	-	-	-
5	Billing & Collections	7,705,172	CNTCTCNTR	BILLCOLL	6,769,871	780,447	119,366	1,075	9,678	1,075	2,151	21,507	-	-	-	-
6	Customer & Public Relations	4,008,554		CUSTREL	2,778,077	660,256	431,167	-	35,014	4,002	8,003	78,030	-	-	-	14,005
7	Customer Information Systems (Banner)	533,983		BILLCUST-D	518,319	15,421	206	-	-	-	-	37	-	-	-	-
8	Customer Inspections	5,772,464	LLOCATES	CUSTINSP	5,651,802	118,607	1,584	14	128	14	29	285	-	-	-	-
9	Customer Safety Services	1,285,355		CUSTSAFE	901,517	377,325	5,021	45	407	45	90	905	-	-	-	-
10	Dispatch	2,306,190		WORKCOORD	2,048,703	247,197	7,868	-	1,405	-	-	1,017	-	-	-	-
11	Energy Supply, Planning & Support	-		ONSITEO&M-C	-	-	-	-	-	-	-	-	-	-	-	-
12	Environment	-		ONSITEO&M-C	-	-	-	-	-	-	-	-	-	-	-	-
13	Meter Reading	2,511,105		METERREAD	2,176,187	316,691	13,997	-	1,380	153	307	2,390	-	-	-	-
14	Rate and Regulatory Affairs	590,450		ONSITEO&M-C	505,341	65,510	14,939	33	1,261	133	267	2,673	-	-	-	292
15	Research & Development	-		ONSITEO&M-C	-	-	-	-	-	-	-	-	-	-	-	-
16	Sub-total	24,713,273			21,349,817	2,581,453	594,149	1,168	49,273	5,423	10,847	106,845	-	-	-	14,298
17																
18	B. OPERATIONS AND MAINTENANCE															
19	Communication System	77,145		CUST-IND	-	-	59,882	-	4,855	539	1,079	10,790	-	-	-	-
20	Distribution Maintenance	2,962,360		CUSTSERV	2,536,037	409,287	13,028	-	2,325	-	-	1,683	-	-	-	-
21	Load Forecast	70,288		LOADFORE	35,144	17,694	13,545	-	1,098	122	244	2,441	-	-	-	-
22	Metering	573,718		METERREPAIR	429,339	81,856	48,194	434	3,908	434	868	8,684	-	-	-	-
23	Plant Failures & Emergencies	302,792		CUSTSAFE	212,371	88,887	1,183	11	96	11	21	213	-	-	-	-
24	Quality Assessment	184,229		CUSTSERV	157,716	25,454	810	-	145	-	-	105	-	-	-	-
25	Regulating Station Maintenance	0		ONSITEO&M-C	-	-	-	-	-	-	-	-	-	-	-	-
26	System Performance & Reliability	0		ONSITEO&M-C	-	-	-	-	-	-	-	-	-	-	-	-
27	IT - Distribution/Metering	0		ONSITEO&M-C	-	-	-	-	-	-	-	-	-	-	-	-
28	Treasury	0		ONSITEO&M-C	-	-	-	-	-	-	-	-	-	-	-	-
29	Sub-total	4,170,532			3,370,606	623,177	136,643	445	12,427	1,106	2,213	23,915	-	-	-	-
30																
31	C. ORGANIZATIONAL SUPPORT															
32	Corporate Governance	1,349,039		ONSITEO&M-C	1,154,586	149,675	34,132	75	2,882	305	610	6,107	-	-	-	668
33	Corporate Infrastructure	2,865,866		ONSITEO&M-C	2,452,773	317,965	72,510	160	6,122	648	1,296	12,974	-	-	-	1,419
34	Corporate Services	1,166,597		ONSITEO&M-C	998,441	129,433	29,516	65	2,492	264	527	5,281	-	-	-	577
35	Departmental Support	3,407,391		ONSITEO&M-C	2,916,242	378,047	86,211	190	7,279	770	1,541	15,426	-	-	-	1,687
36	Operational Management	1,037,153		ONSITEO&M-C	887,655	115,071	26,241	58	2,216	234	469	4,695	-	-	-	513
37	Customer Relations	-		CUSTREL-CSD	-	-	-	-	-	-	-	-	-	-	-	-
38	Sub-total	9,826,046			8,409,696	1,090,190	248,610	549	20,990	2,221	4,443	44,483	-	-	-	4,864
39																
40	D. ADJUSTMENTS TO INCOME															
41	Corporate Alloc. & Adj.	533,222		ONSITEO&M-C	456,362	59,160	13,491	30	1,139	121	241	2,414	-	-	-	264
42	Depreciation, Interest, Taxes	- 1,365,587		ONSITEO&M-C	- 1,168,748	- 151,511	- 34,551	- 76	- 2,917	- 309	- 617	- 6,182	-	-	-	- 676
43	Sub-total	- 832,365			- 712,386	- 92,350	- 21,060	- 46	- 1,778	- 188	- 376	- 3,768	-	-	-	- 412
44																
45		**37,877,485**			**32,417,733**	**4,202,471**	**958,341**	**2,115**	**80,913**	**8,563**	**17,126**	**171,475**	**-**	**-**	**-**	**18,750**

REFERENCE:

Supplement, Section 5.0 (pg 15-16)

PREAMBLE TO IR (IF ANY):

Centra states (Tab 11, page 3) that "base rate impacts are driven by a decrease in non-gas costs, and a decrease in non-Primary Gas costs, which results in an overall decrease in customer bills for most sales service customer classes"

Centra also states (Tab 10, page 12) that the proportion of rate base that is transmission-related versus distribution-related has increased as a result of significant transmission investments since Centra's last GRA.

QUESTION:

a) Please provide Schedule 10.1.3 (if not already provided as part of CAC/Centra 3) based on what is currently approved and embedded in rates as well as the percentage difference with Centra's proposal as per the March 22, 2019 Update.
b) Given the significant increase in transmission investment that is allocated to all customers, please provide and discuss what cost or costs (or load changes) have declined significantly enough to offset the increase in transmission investment to drive an overall reduction for the SGS customers?
c) Please provide the percentage comparison of transmission investment to distribution investment embedded in current rates compared to that reflected in the 2019/20 Cost Allocation Study overall and by customer class. Please explain the major drivers of the changes (for example investment increases, customer class load increases or decreases, the rollback of rates pursuant to 79/17).

RATIONALE FOR QUESTION:
To understand the how the substantial transmission investment increase impacts the SGS class, the changes of other allocated cost and loads resulting in the overall reduction to the SGS class.

RESPONSE:

a) Please see Centra's response to CAC/Centra I-17 a).

b) While Centra cannot provide a schedule of non-gas allocated to all customer classes embedded in current rates, Centra can provide data showing total non-gas cost components and non-gas costs allocated to the SGS class for the 2010/11 approved test year, the 2013/14 test year, and the 2019/20 proposed test year. Please see the following schedule.

	Test Year	Non-Gas Costs	All Classes	SGS Only	SGS% of Total
1	2019/20	OTHER REVENUE	-1,189,728	-1,039,977	87.4%
2	2019/20	OPERATING EXPENSES	60,550,000	44,487,044	73.5%
3	2019/20	DEPRECIATION & AMORTIZATION	32,349,802	21,371,879	66.1%
4	2019/20	CAPITAL & OTHER TAXES	20,311,504	13,572,900	66.8%
5	2019/20	FINANCE EXPENSE	21,603,263	14,348,335	66.4%
6	2019/20	CORPORATE ALLOCATION	12,000,000	7,970,093	66.4%
7	2019/20	NET INCOME	2,894,415	1,922,396	66.4%
8	2019/20	Total Non-Gas Costs	148,519,256	102,632,670	69.1%
9					
10					
11	2013/14	OTHER REVENUE	-1,865,560	-1,719,974	92.2%
12	2013/14	OPERATING EXPENSES	68,800,000	52,682,600	76.6%
13	2013/14	DEPRECIATION & AMORTIZATION	33,890,579	24,995,263	73.8%
14	2013/14	CAPITAL & OTHER TAXES	18,750,000	12,800,808	68.3%
15	2013/14	FINANCE EXPENSE	16,945,000	11,445,423	67.5%
16	2013/14	CORPORATE ALLOCATION	12,000,000	8,105,346	67.5%
17	2013/14	NET INCOME	3,000,000	2,026,336	67.5%
18	2013/14	Total Non-Gas Costs	151,520,019	110,335,803	72.8%
19					
20					
21	2010/11	OTHER REVENUE	-2,025,790	-2,002,958	98.9%
22	2010/11	OPERATING EXPENSES	60,343,473	46,070,064	76.3%
23	2010/11	DEPRECIATION & AMORTIZATION	31,167,487	24,420,570	78.4%
24	2010/11	CAPITAL & OTHER TAXES	23,940,053	16,198,171	67.7%
25	2010/11	FINANCE EXPENSE	19,257,379	12,747,369	66.2%
26	2010/11	CORPORATE ALLOCATION	12,000,000	7,943,367	66.2%
27	2010/11	NET INCOME	2,353,000	1,557,562	66.2%
28	2010/11	Total Non-Gas Costs	147,035,602	106,934,144	72.7%

The major costs changes resulting in a rate decrease for the SGS class are:

- The discontinuance of the Furnace Replacement Program (FRP) proposed in the 2019/20 Test Year. The FRP added a total of $3.8 million to depreciation and amortization expense for the SGS class in both the 2010/11 and 2013/14 approved test years.
- The SGS class' share of operating expenses has declined in the 2019/20 Proposed Test Year compared to 2010/11 and 2013/14 Test Years.

c) Please see the following table.

	Test Year	Description	Total T&D Rbase	SGS	LGS	HVF	CO-OP	ML	SC	PS	INT
1	2019/20	Transmission Rate Base	22.2%	13.1%	28.8%	40.5%	61.0%	75.2%	99.1%	35.7%	38.8%
2	2019/20	Distribution Rate Base	77.8%	86.9%	71.2%	59.5%	39.0%	24.8%	0.9%	64.3%	61.2%
3											
4	2013/14	Transmission Rate Base	17.8%	10.3%	22.7%	34.1%	55.8%	73.4%	98.7%	55.7%	33.5%
5	2013/14	Distribution Rate Base	82.2%	89.7%	77.3%	65.9%	44.2%	26.6%	1.3%	44.3%	66.5%
6											
7	2010/11	Transmission Rate Base	19.7%	11.4%	24.6%	35.0%	53.0%	71.5%	98.5%	74.0%	34.6%
8	2010/11	Distribution Rate Base	80.3%	88.6%	75.4%	65.0%	47.0%	28.5%	1.5%	26.0%	65.4%

The share of transmission rate base compared to distribution rate base has increased for all customer classes except Power Stations. The major driver for the increased transmission to distribution ratio is the large investment in transmission plant. Load changes impacted the Peak & Average allocator which resulted in minor changes of the allocation transmission and distribution rate base as the SGS class is allocated a slightly lower share of T&D rate base while the LGS and HVF are allocated a slightly larger share of T&D rate base. The reduction in coincident peak associated with the Power Station class has resulted in the reduced allocation of Transmission rate base.

REFERENCE:

Tab 10 Schedule 10.1.1 and Tab 11 Pages 9-14

PREAMBLE TO IR (IF ANY):

It is noted that approximately 40% of Tab 11 which focuses on Proposed Rates & Bill Impacts is devoted to a discussion of the Fixed Rate Primary Gas Service and that based on Schedule 10.1.1, few customers are subscribed to Centra's FRPGS.

QUESTION:

Please provide Centra's view on whether the offering of this service continues to be customer value added, cost justified, and a reasonable benchmark/comparator against other market offerings in light of 1) investment requirements to address aging infrastructure and increased load and 2) cost constraint initiatives including the VDP?

RATIONALE FOR QUESTION:

To understand Centra's view on the continuation of this program considering its current operational environment and cost (both accounting and opportunity cost).

RESPONSE:

Centra continues to believe that there is value in providing customers with choice as to both their Primary Gas supplier (please also see the response to PUB/Centra I-155 c)), as well as the pricing terms under which they purchase their Primary Gas. This is true regardless of whether or not customers actively exercise that choice or not.

In Order 160/07, issued following the PUB's 2007 Competitive Landscape Review Proceeding, wherein Centra was directed to apply to introduce what ultimately became the FRPGS, one of the PUB's key stated rationales for doing so was so that *"…new and better priced competitive offerings will soon be made available, particularly to small volume customers."*

Centra's observance of Western Transportation Service ("WTS") marketer pricing of Primary Gas products before and after the introduction of the FRPGS implies that the introduction of the FRPGS has been successful in achieving the PUB's objective of achieving more competitively priced fixed rate Primary Gas products for small volume customers in Manitoba as was the goal set out in Order 160/07. Given this success and the minimal ongoing cost to administer the FRPGS (approximately $20,000 annually) Centra believes that continuation of the FRPGS is warranted.

REFERENCE:

Tab 10 (pg 14)

PREAMBLE TO IR (IF ANY):

Centra states that it has not made substantial changes to its Cost Allocation approach or rate design in this Application.

QUESTION:

Further to PUB/Centra 138:

a) Please discuss why Centra elected a three-part rate design for the Power Stations in 2003.
b) Please discuss whether any changes in the Power Station contractual arrangements or clause expirations since 2003 necessitates a review and possible restructure of its current three-part rate?

RATIONALE FOR QUESTION:

To understand the impact to Centra's financial position of the Power Stations current three-part rate structure in the absence of any further financial feasibility true-ups provisions and a three-part rate structure without any upper limits.

RESPONSE:

a) Centra prefers a three part rate design for its large volume customer classes as it provides transparency with regard to the level of customer, demand and variable costs incurred, and provides a rate structure that is reflective, on a customer by customer basis, of the costs they impose on the system.

   Centra introduced the three part rate design for large volume customer classes in the 1996 Cost of Service and Rate Design Methodology Review, and implemented this rate design in subsequent GRAs.

Centra applied for approval of the Power Station class in the 2003/04 GRA, with a three part rate design consistent with that found in its other large volume customer classes.

b) Centra views that the three part rate remains appropriate for the Power Station class, as the basic charge and demand charge components enable Centra to recover 100% of the allocated fixed costs for those customers.

REFERENCE:

Tab 10 Schedules 10.1.4

PREAMBLE TO IR (IF ANY):

Centra states that it has not made substantial changes to its Cost Allocation approach or rate design in this Application.

QUESTION:

a) Please explain and file the relevant materials on the background of the allocation treatment associated with Ex-Franchise Customers.
b) Based on Schedules 10.1.4, no cost appears to have been allocated to this group. Please explain.
c) Please explain what the "Broker Class" is as per Schedules 10.1.5.

RATIONALE FOR QUESTION:

To understand the reasonableness of the results of Centra's 2019/20 Cost Allocation Study results. To understand what is intended by the Broker Class.

RESPONSE:

a) to c)

Centra has not allocated any costs to the "Ex-franchise Customers" or "Broker Class" classes as these two classes are not used in 2019/20 Cost Allocation Study. These two columns should have been removed from schedules 10.1.4 and 10.1.5.

REFERENCE:

Tab 10 (pg 14)

PREAMBLE TO IR (IF ANY):

Centra states that it has not made substantial changes to its Cost Allocation approach or rate design in this Application.

QUESTION:

a) Please provide a comparison of the customer-related costs flowing from the 2019/20 Cost Allocation Study and the $14 per customer per month Basic Monthly Charge for SGS customers. Please provide the dollar difference and the percentage of customer-related costs recovered through the BMC. Please provide the same comparison for MH electric operations related to its current Residential Monthly Basic Charge of $8.71.

RATIONALE FOR QUESTION:

To understand Centra's view of the benefits or drawbacks of harmonizing for rate-setting purposes the residential basic monthly charge between MH electric and natural gas operations and its intentions in this regard.

RESPONSE:

Please see Table 1 below which provides the customer-related costs flowing from the 2019/20 Cost Allocation Study and the percentage of customer costs recovered by the SGS class from the BMC and the distribution rate.

Table 1

Centra Gas Customer Costs & BMC		2019/20 TY	% of Total
Residential (SGS) Customer Costs	Sch 10.1.3 line 40	72,756,175	
residential Basic Monthly Charge Revenue	Sch. 10.1.6 line 6	46,925,172	64.5%
SGS Customer Costs in Distribution Rate		25,831,003	35.5%

Table 2 below provides Manitoba Hydro customer-related costs flowing from PCOSS18 and the percentages recovered in the Residential Monthly Basic Charge and the energy rate. Centra notes that Manitoba Hydro's current Residential Basic Monthly Charge is $8.41/month and not $8.71 as stated in the preamble.

Table 2

Manitoba Hydro Customer Costs & BMC		**PCOSS18**	**% of Total**
Residential Customer Costs	Schedule 1.2, Appendix 8.1, MH 2017/18 & 2018/19 GRA	77,814,000	
Residential Basic Charge Revenue	Figure 5, MIPUG MFR 6, MH 2017/18 & 2018/19 GRA	47,912,971	61.6%
Customer Costs in Energy Rate		29,901,029	38.4%

REFERENCE:

Tab 10 (pg 14)

PREAMBLE TO IR (IF ANY):

Centra states that it has not made substantial changes to its Cost Allocation approach or rate design in this Application.

QUESTION:

b) Please discuss whether the substantial difference in the residential basic monthly charges between MH electric and natural gas operations is reasonable.
c) Please provide Centra's/MH's intention regarding the Basic Monthly Charge.

RATIONALE FOR QUESTION:

To understand Centra's view of the benefits or drawbacks of harmonizing for rate-setting purposes the residential basic monthly charge between MH electric and natural gas operations and its intentions in this regard.

RESPONSE:

b) While there is a difference between the electric BMC ($8.41/month) approved June 1, 2018 and the currently approved Centra BMC of $14/month, each BMC is recovering a similar percentage of their respective allocated customer costs.

   As identified in part a) to this response, Centra's BMC of $14 recovers approximately 64.5% of the allocated customer-related costs. Manitoba Hydro's Basic Charge of $8.41/month recovers approximately 61.6% of the allocated customer costs as found in PCOSS18. By that measure, both basic charges appear to be relatively consistent.

c) Centra and Manitoba Hydro do not, at this time, have specific intentions with regard to the levels of basic charges.

REFERENCE:

Tab 12 (pg 7)

PREAMBLE TO IR (IF ANY):

QUESTION:

Further to PUB 141:

a) Please explain the incremental impact to overdue accounts and bad debt expense as a result of the implementation of the Federal Carbon Tax.

b) Who is responsible for customer unpaid Federal Carbon Tax? If Centra is responsible, please explain how that cost will be allocated to customer classes.

c) Further to PUB 153, please confirm that it is Centra's intention to continue to apply the LPC at the time of the issuance of the customers next bill rather than from the payment due date.

d) Further to PUB 151, please provide a breakdown between reconnection revenue collected on account of a customer's request for disconnection versus the reconnection revenue collected on account of disconnections for non-payment.

    i. Manitoba Hydro states, Tab 12, page 11, that it "has placed increased emphasis on having its Credit Representatives identify low income customers and apply discretion in waiving LPCs to assist these customers in bringing their accounts back to current status". Does MH apply the same discretion in waiving Reconnect Fees for low income customers to assist in keeping their accounts current? If not, why not?

RATIONALE FOR QUESTION:

To understand Centra's intentions regarding the application of the LPC, the EPP and Reconnect Fees.

RESPONSE:

a) The incremental impact to overdue accounts and bad debt expense is expected to be directly proportional to the increase in energy charges as a result of the Federal carbon charge. The value of accounts written off will be greater by the amount of the Federal carbon charge at the time of write off.

b) For accounts that Centra writes off for uncollectability, the Federal carbon charge becomes part of the bad debt expense of Centra. As such, it becomes a cost to Centra and will be allocated to customer classes as part of bad debt expense. Unlike PST or GST, for which Centra is able to recover uncollected taxes, the Federal carbon charge is not a "tax," but is treated like a charge, similar to the commodity charge.

c) Confirmed.

d) Please see the response to PUB/Centra I-151d.
   i. Manitoba Hydro applies the same discretion in waiving Reconnect Fees as it does for LPCs for low income customers on a case-by-case basis.

REFERENCE:

Tab 12 (pg 7)

PREAMBLE TO IR (IF ANY):

QUESTION:

Further to PUB 141:

e) Further to PUB 154 – Centra states that it is not proposing any changes to the Equipment Problem Program (EPP) and its 40-page document has been filed for information purposes only despite the large emphasis placed on the complications associated with the EPP. Please explain what the purpose of this report is, what Centra's intention is regarding the EPP, and what its expectations are of the PUB.

RATIONALE FOR QUESTION:

To understand Centra's intentions regarding the application of the LPC, the EPP and Reconnect Fees.

RESPONSE:

Centra is not requesting changes to the program, however, technological changes are making it increasingly challenging to provide the service in the manner which it was originally envisioned.

Centra is making the PUB aware of these trends and the underlying causes. For example, CEPP calls have dropped by 42% from 2006 to 2017 as seen in Table 2 page 7 in Appendix 12.4. Dealer referrals have also increased to 12% of the total calls as seen in Table 11 page 17 in Appendix 12.4.

REFERENCE:

Tab 9, Tab 10 (pg 2-5)

PREAMBLE TO IR (IF ANY):

Centra states that it has not made substantial changes to its Cost Allocation approach since the 2013/14 GRA.

QUESTION:

[redacted]

RATIONALE FOR QUESTION:

[redacted]

RESPONSE:

a) Please see the response to PUB/Centra I-137.

b) through d)

[redacted]

[redacted]

REFERENCE:

Tab 10 (pg 1)

PREAMBLE TO IR (IF ANY):

Centra states that it has not made substantial changes to its Cost Allocation approach since the 2013/14 GRA.

QUESTION:

a) Further to PUB/Centra 145, please explain and provide the rationale of any Centra changes made to its cost allocation methodology to accommodate its proposed approach to T-Service Balancing Fees.
b) Please explain whether the current forecast of balancing fees of $250,000 (Schedules 8.9.3 and 10.1.5) is only related to sales service system imbalances?
c) Please provide a forecast of the anticipated revenue to be generated by Centra's proposed approach to T-Service Balancing Fees.
d) How has the revenue associated with T-Service imbalances been treated from a cost allocation perspective in the current and past years?
e) How has the anticipated revenue to be generated by Centra's proposed approach to T-Service Balancing Fees reflected in the current GRA?
f) How have the anticipated revenues to be generated by Centra's proposed approach to T-Service Balancing Fees been treated for cost allocation purposes?

RATIONALE FOR QUESTION:

To understand class cost responsibility related to balancing fees and associated revenue.

RESPONSE:

a) Centra's cost allocation methodology will be unaffected by the new balancing fee structure. As is the case today, balancing fees collected from T-Service customers 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.

b) The 2018/19 Gas Year forecast of balancing fees of $250,000 (Schedule 8.9.3 b)) represents a forecast of the net of balancing fees collected from T-Service customers and balancing fees paid to TCPL. Please note that the new balancing fee structure is proposed to come into effect November 1, 2019 for the 2019/20 Gas Year.

c) Please see the response to PUB/CENTRA I-147b.

d) In both the current and past years, any amounts recovered from T-Service customers are netted against Centra's balancing fees paid to TCPL. These recoveries function in a manner similar to Capacity Management revenues, with both serving as offsets to the upstream transportation and storage costs paid by Centra's Sales Service customers.

e) Please see the responses to PUB/CENTRA I-147b and IGU/CENTRA I-1a through c.

f) Please see the response to part a) above.

REFERENCE:

Tab 4, p. 2 of 22, lines 5-10

PREAMBLE TO IR (IF ANY):

In describing the differences between Projects and Programs in the referenced passage, Centra states that Programs are “a collection of similar investments that are managed in a coordinated way to obtain benefits which may not be achieved when managed individually” (emphasis added).

QUESTION:

a) Please describe the types of benefits that Centra sees as not being attainable when managing projects individually as opposed to as a part of a program.
b) Please articulate the differences (if any) in the scope, nature and volume of information collected, reviewed and analysed to develop the near-term (e.g. 1-year) and longer-term (longer-than 1 year) forecasts related to programs and projects respectively.
c) Please describe the internal review / governance processes that Centra has in place to justify the continued need / relevance of a particular program year-over-year?

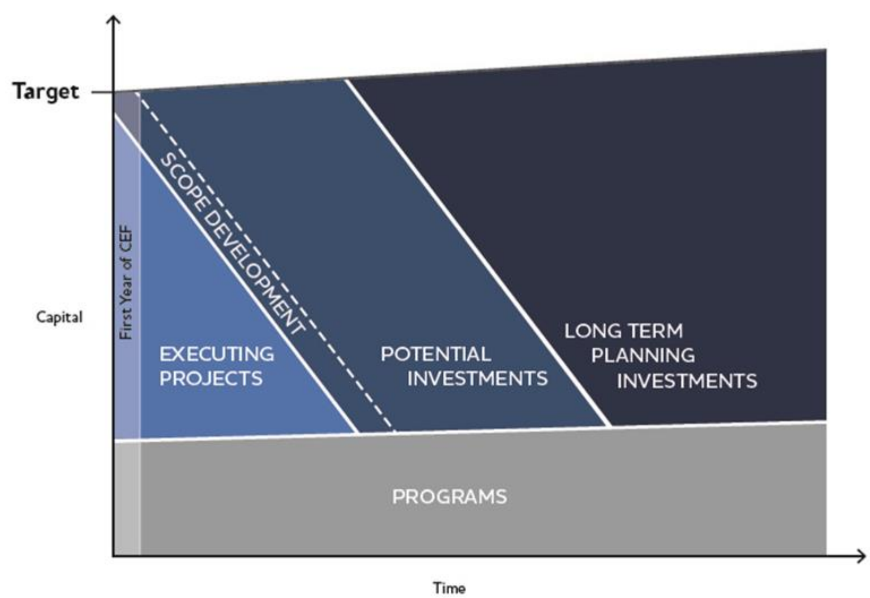
RESPONSE:

a) For programs, the annual expenditure varies from year to year often based on external drivers. Using the New Business program as an example, the external driver would be customer requests for gas. Individual investments (program items) are often not known when fiscal planning is done and annual forecasts are prepared and having a program facilitates budgeting within the overall gas capital portfolio. At the program level, expenditures on an annual basis can be estimated without having specifics at a program item level. It would be difficult to estimate at a program item level where there may be over a hundred program items that are identified, designed and constructed within a one year period. The use of programs also suits the base business contracting methodology that has been used by Centra for many years. This contracting method with defined rates for specified work is very flexible in accommodating the performance of many similar projects.

b) 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. Centra projects are generally in excess of $1 million dollars. Certainty in the capital plan is highest in year one due to the defined scope, schedule and budget, as well as the start date.

Programs are a collection of asset classes that are generally not planned on a specific asset basis, but rather as a group. The majority of program forecasts reflect historic spending levels which are escalated with time.

Forecasts become more uncertain and more likely to change the further they are out in time. Portfolio adjustments are used to smooth the forecast in the longer term to achieve target levels of spending over multiple years to reflect capital investment requirements that are expected to be fluid. The following diagram provides a graphical depiction of the capital planning process at Centra.



c) The internal review / governance processes that Centra has in place to justify the continued need / relevance of a particular program year-over-year includes:

1. During the annual budgeting process programs are reviewed to understand changes in historical spending and also to plan for any emerging issues that may result from ongoing reviews of operations. Program budgets are submitted by each operating group as part of the annual corporate budgeting process. Once submitted, program budgets along with individual project budgets are assembled into an investment portfolio submitted for approval to the operating group's governance committee and Vice-President. Additional approvals may also be required as outlined in PUB/CENTRA I-64, based upon the annual program spend levels. To assist with portfolio governance, the corporation is also in the process of transitioning to the use of a Corporate Value Framework for evaluating programs and project investments; this evaluation process will help assess the various investments within the context of an operating group's portfolio to help determine the appropriate mix of investments required to achieve overall objectives for the group and the corporation.

2. During the year, individual investments within each program are initiated following a structured review and approval processes. For example, in the New Business program, investments determined to be feasible through analysis, or by the receipt of a required customer contribution, proceed to construction. In asset sustainment related programs, investments are generally initiated following regular surveys or site investigations of issues identified through pipeline integrity activities.

3. Program expenditures are monitored throughout the year as part of the ongoing portfolio performance review, changes in requirements are highlighted and communicated through normal variance analysis processes. Significant changes in program requirements require approval in accordance with corporate policies.

REFERENCE:

Tab 4, p. 2 of 22, lines 5-10

PREAMBLE TO IR (IF ANY):

In describing the differences between Projects and Programs in the referenced passage, Centra states that Programs are "a collection of similar investments that are managed in a coordinated way to obtain benefits which may not be achieved when managed individually" (emphasis added).

QUESTION:

d) Please describe the steps Centra takes to evaluate the forecasted-to-actual cost variances for Programs and Projects, and the subsequent process steps (if any) to reduce the risk of variances in the future.

RATIONALE FOR QUESTION:

RESPONSE:

d) In addition to continuous project monitoring through the Finance Centre, as discussed in PUB/CENTRA I-47b, monthly meetings are conducted to discuss and review the status of all current projects and program items. Representatives from Engineering, Operations, Construction and Finance are in attendance at these meetings. All active projects and program items are reviewed and discussed amongst the group to identify if the project or program item is on schedule and if the in-service date, cashflow, budget or other information requires revision.

   Management reviews are also conducted on a monthly basis by Directors and Department Managers responsible for gas investments. These reviews include a comparison of the current outlook to approved, as well as the current year actuals to approved forecast, along with explanations for significant variances. These reviews and discussions are part of the continuous capital planning and portfolio management process. If departures from approved forecast are experienced, discussions occur to identify ways to mitigate a continued variance as well as reduce the risk of similar variances occurring on future projects and programs.

In addition, the CFO reviews the financial performance of the company with the Executive Committee on a monthly basis; this review includes an overview of the capital performance. Explanations for material variances are shared on a quarterly basis.

REFERENCE:

Tab 4, p. 2 of 22, lines 27-30

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please articulate the key differences in scope, function and underlying approval and information collection and analysis processes between the Capital Investment Justification ("CIJ") and Capital Project Justification ("CPJ") documents.
b) If verbal and/or graphic descriptions of preparation, approval and/or other manners of utilization of the CIJ vs. the CPJ documents are available, please provide them in support of your answer under sub (a).

RATIONALE FOR QUESTION:

RESPONSE:

a) The Capital Investment Justification ("CIJ") replaced the Capital Project Justification ("CPJ") as part of Manitoba Hydro's Capital Asset Management initiative in 2016 (discussed in Section 4.2 of the Application). The CIJ (and previously the CPJ) is used to request approval for a capital investment. The document ensures the investment meets the corporation's capital requirements and is aligned with the strategic direction of the corporation.

   The primary difference between the two documents is the CIJ incorporates a Corporate Value Framework (CVF) assessment and score which supports value-based investment decision making, as well as online workflows reflecting approvals.

b) No verbal and/or graphic depictions of preparation, approval and other manners of utilization of the CIJ vs. the CPJ documents are available.

REFERENCE:

Tab 4, p. 2 of 22, lines 12-19, Figure 4.1, p. 4 of 22.

PREAMBLE TO IR (IF ANY):

In the referenced passage, Centra describes the "variance from target" line item present in its capital forecasts, while the referenced table shows "Target Variance" as a line item below the "Projects" subsection of the forecast.

QUESTION:

a) Please articulate the rationale (e.g. from the perspective of financial forecasting, project management, governance or others) of including "Target Variance" as an explicit line item in capital forecasts.
b) Is Centra Gas aware of any other natural gas or electric utilities other than Manitoba Hydro that incorporate Target Variance as a budgetary line item in regulatory applications in particular?
c) Please clarify whether the Target Variance line item, included in Table 4.1 on p. 4 is applicable to both Projects and Programs, or just Projects (i.e. the section of the forecasts it appears immediately next to).
d) Please describe the methodology applied to the calculation of the Target Variances related to each of the 2018/19, 2019/20, 2018/19-2027/28 forecasts.
e) Is Centra Gas taking any steps to reduce the risk of forecast to actual project / program cost variances so as to eliminate the need for explicitly forecasting the "targeted" variances? If Centra Gas does not believe that reducing the value of or eliminating an explicit forecast of project variances in business plans and/or regulatory submissions is a worthwhile endeavour, please explain why.

RESPONSE:

a) to e)

The Target Variance line item included in Figure 4.1 of Tab 4 is applicable to the Business Operations Capital portfolio for Centra, including both projects and programs. It is representative of the difference between annual capital spend targets and detailed project and program forecasts. As discussed in Tab 4, the target variance (or variance to target) in the short term is recognition of anticipated variances in the accumulation of program spending and recognition that external factors such as contractor availability and external approvals can affect the total spending in a given year. In the longer term, the Target Variance includes future investment requirements that are in the early stages of identification or development, as well as considering historical experience and ongoing trends. As it is unlikely that the aggregations of the project and program annual forecasts could match exactly to the established targets, which are set to ensure the operability and sustainability of the system, the inclusion of a Target Variance is required.

Manitoba Hydro also uses a Target Variance as a budgetary line in regulatory proceedings. The Corporation is not aware if any other natural gas or electric utilities also incorporate a target variance as a budgetary line item.

REFERENCE:

Tab 4, p. 5 of 22, Figure 4.2

PREAMBLE TO IR (IF ANY):

QUESTION:

Please quantify the dollar value of cost forecast changes between CEF 16 and CEF 18 for each of the 2018/19, 2019/20 and 2018/19-2027/28 Business Operations Capital forecasts driven primarily by insights obtained from the Natural Gas System Asset Condition Assessment (Appendix 4.4), and the Report of Pipeline Risk Methodology (Completeness Filing Attachment 3).

For clarity, please identify any project or program changes in excess of $250,000 that would not occur between CEF 16 and CEF 18 but for the insights from the Asset Condition Assessment and/or the 2017 Pipeline Risk Assessment Results.

RESPONSE:

The dollar value of the forecast changes from CEF 16 and CEF 18, attributable to the 2017 Pipeline Risk Assessment Results report are:

Fiscal Year or Range	Forecast Change from CEF 16 to CEF 18 Driven by 2017 Pipeline Risk Assessment Results
2018/19	2.55 million
2019/20	1.64 million
2018/19- 2027/28	6.42 million (not defined past 2021/22)

All costs identified to date are associated with the pipeline in-line inspection project which was initiated in response to information gaps identified in the Natural Gas System Asset Condition Assessment report.

REFERENCE:

Tab 4, p. 7 of 22, lines 13-20

PREAMBLE TO IR (IF ANY):

In the referenced passage, Centra describes the policy statements it has recently established to foster continuous improvement of its asset management and investment planning activities, including the commitment for the investment plans to be "regularly reviewed and benchmarked appropriately."

QUESTION:

a) Please provide any internal and/or external benchmarking studies, reports, presentations, surveys or other analytical and/or comparative undertaking performed by Centra, Manitoba Hydro, or the external advisors procured by either entity in relation to planning and analysis of natural gas asset management or investment planning work.
b) If benchmarking studies are currently ongoing or are planned over the next two years, please provide the details of these studies, including their scopes and timelines.

RESPONSE:

a) The development of the natural gas asset management system is a work in progress and is not complete. No work on benchmarking the asset management system has yet been done.

b) No benchmarking studies are currently underway or scheduled.

REFERENCE:

Tab 4, Figures 4.4 and 4.8, (pp. 9 and 15 of 22).

PREAMBLE TO IR (IF ANY):

Figure 4.4. showcases the data requirements for each level of Asset Maintenance Maturity, while Figure 4.8 lists the Critical Asset and Sub-Asset Groups comprising Centra's system.

QUESTION:

a) Please amend the Figure 4.4 to showcase the current state of Centra's data requirement repositories for each of the six asset maintenance maturity thresholds as related to each of the Critical Asset and Sub-Asset groups included in Figure 4.8.

   As an example of the requested modifications to the table, please see the below table prepared for the Applicant's convenience. Should a different format be more preferable, please feel free to submit it instead, provided that it covers the requested information. CAC also notes that it is aware that a similar, albeit significantly consolidated view is offered in Figure 4.9. However, in requesting the data presentation in this more detailed format, we seek to obtain a more nuanced and quantitative view of information than that provided in Figure 4.9.

	Percentage of assets for which each type of data is currently available, or capabilities are in place to capture the data as it becomes available.														
Asset Types and Maintenance Data	Notification of Failure	Unique Identifier	GIS Data	Expected End of Life	Asset Classes	Physical Properties	Maintenance Properties	Environmental Conditions	Asset Condition Assessments	Operational Properties	Financial Data	Legal Properties	Stores Data	Additional Financial Data	Additional Asset Condition Assessment
Primary Stations															
Gate Stations															
Regulation Stations															
Farm Taps															
Valves															
Transmission Pressure															
High Pressure															
Medium Pressure															
Residential Services															
Commercial / Industrial Services															

b) For each of the types of information (horizontal columns in Centra's Figure 4.4) please provide a definition as used and understood by Centra, including the specific types and sources of data relevant in the context of Centra's operations.

RESPONSE:

a) Please see the following table, which provides the information Centra has available at this time.

	Percentage of assets for which each type of data is currently available, or capabilities are in place to capture the data as it becomes available.														
Asset Types and Maintenance Data	**Notification of Failure**	**Unique Identifier**	**GIS Data**	**Expected End of Life**	**Asset Classes**	**Physical Properties**	**Maintenance Properties**	**Environmental Conditions**	**Asset Condition Assessments**	**Operational Properties**	**Financial Data**	**Legal Properties**	**Stores Data**	**Additional Financial Data**	**Additional Asset Condition Assessment**
Primary Stations	100	100	100	(2)	100	90 (3)	100	100	100	100	100	100	100 (8)	80	N/A
Gate Stations	100	100	100	(2)	100	90 (3)	100	100	100	100	100	100	100 (8)	80	N/A
Regulation Stations	100	100	100	(2)	100	90 (3)	100	100	100	100	100	100	100 (8)	80	N/A
Farm Taps	100	100	100	(2)	100	90 (3)	100	100	100	100	100	100	100 (8)	80	N/A
Valves	100	100 (1)	100	(2)	100	90 (3)	100	100	100	100	100	100	100 (8)	80	N/A
Transmission Pressure	100	100	100	(2)	100	95 (4)	100	100	10	100	100	100	N/A (9)	50	75 (10)
High Pressure	100	100	100	(2)	100	95 (4)	100	100	0	100	100	100	N/A (9)	50	75 (10)
Medium Pressure	100	100	100	(2)	100	55 (5)	100	100	0	100	100	100	100	50	60 (10)
Residential Services	100	100	100	(2)	100	80 (6)	100	80 (7)	15	100	100	100	100	50	60 (10)
Commercial / Industrial Services	100	100	100	(2)	100	80 (6)	100	80 (7)	15	100	100	100	100	50	60 (10)

Notes:

1. All pipeline valves and valves controlling gas flow at stations have unique identification numbers. Needle valves, isolation valves on pressure relief valves, valves at farm taps and at individual services are not individually numbered but are identified as part of the overall assembly. There is no intent to provide further identification of these valves.
2. Expected end of life for individual assets is not considered to be known.
3. A station by station drawing review is required to confirm availability of information on non-structured data (pipe, fittings, etc.)

4. Pipe data (grade, wall thickness, coating) is primarily known. Fitting information needs to be reviewed.
5. There are gaps in pipe wall thickness/pipe SDR and grade or resin information.
6. Meter information is at or near 100%, regulator and pressure relief valve information is very good but there is reduced availability of information on service valves, fittings and service pipe.
7. Information on suitable physical protection of meter sets is not known.
8. For new construction, station materials can be supplied from Central Stores, the contractor or specifically ordered for the project. For maintenance purposes, materials are obtained through Central Stores or specifically stocked by the operations group responsible for stations maintenance.
9. Only short lengths of steel pipe are typically stocked with materials ordered specifically for projects.
10. Estimate of additional information available.

b) Please see below for definitions as used and understood by Centra, including the specific types and sources of data relevant in the context of Centra's operations:

Term	**Definition**	**Sources of data**
Notification of Failure	Notification of unusual event that required a response and action.	• SCADA • Dispatch/Public notification • Banner work order • Third party damage report • Below grade leak report • Service order associated with failures
Unique identifier	An item specific alphanumeric or numeric identifier that can be used to identify and record item specific information.	• Premise number • Meter number • Facility number • Farm tap number • Valve number • Pipeline segment • Station number
GIS data	System information and properties geographically identified	• eGIS • SFM • Banner

		• GSA
Expected end of life	The economic optimum time to replace an asset considering total business impact of failure, increasing operating costs and cost of asset replacement.	• Banner work orders • Asset Condition Assessment • Estimated asset replacement and maintenance costs
Asset Classes	Grouping of similar individual assets to permit evaluation, risk assessment, and management as a group.	• As defined in the Asset Condition Assessment
Physical Properties	Asset specific characteristics that include the size, wall thickness, material and grade, the pressure rating, the operating characteristics, etc.	• eGIS • SFM • Banner • RMS • EDMS • Manufacturers' information
Maintenance Properties	Established scope of work associated with the maintenance of an asset. Includes requirements for annual maintenance of valves, cathodic property checks, leak inspections, recommended manufacturer's maintenance cycles.	• RMS • Banner • Manufacturers' information • Operating procedures
Environmental conditions	Environmental conditions include information on the asset physical location and exposures including: • Natural gas quality • Above/below grade exposure • Soil conditions • Local geotechnical information (river crossing, slope) • CSA Z662 Class location • Road/rail crossing • Available physical protection	• eGIS • Gas supply tariff • Geotechnical reports and database • Depth of cover reports • Class location reviews • Surveys • GSA
Asset Condition Assessment	Condition information and assessment of a specific asset.	• In-line inspection reports • Station condition assessments • Integrity excavation findings and analyzes • Below grade leaks

		• Service riser audit
Operational Properties	Defined operating characteristics that define an assets performance including pressure ratings, capacity/flow ratings, maximum operating pressure and seasonal operating pressures.	• eGIS • SCADA • Pressure set point documents • Manufacturers' information • RMS
Financial Data	Information on the installed cost of the assets.	• SAP • C55
Legal Properties	Properties that are governed by provincial legislation or contracts between Centra and third parties. This includes information on easements, company owned property, franchise agreements, crossing agreements with foreign pipelines and rail companies.	• eGIS • Property & Legal Files • Regulatory
Stores Data	Stores data includes the information on the pipe, fittings and other materials required to construct and maintain the natural gas system.	• SAP- Central Stores Catalogue • CSO Gas Outage Response Manual • Gas Apparatus Maintenance & Control
Additional Financial Data	Additional financial data includes information on the repair costs of assets and asset replacement costs	• RMS • Banner
Additional Asset Condition Assessment	Additional asset condition assessment information includes indirect information on an asset including information such as depth of cover, coating integrity, close interval survey, cathodic information, etc.	• Program files

REFERENCE:

Tab 4, p. 10 of 22, lines 22-29.

PREAMBLE TO IR (IF ANY):

In the referenced passage Centra discusses the sources of assets' expected End of Life ("EOL") as being asset manufacturers or industry best practices.

QUESTION:

a) Has Centra, its contractors or any other party acting on its behalf, attempted to evaluate the expected EOL of Centra's system assets using the data obtained in the course of its own operations?
b) If no EOL analysis has been conducted using Centra's own data (e.g. asset failure post-mortems, etc.), does Centra think that it is in a position to perform such analysis? If so, over what timeframe and what assets could such analysis cover?
c) If Centra has performed statistical failure analysis using its own data, such as generation of asset failure curves, please provide the results of this analysis along with the original input data and the methodologies used to perform the calculation. If spreadsheet software was used, please provide the spreadsheets with all formulas intact.

RESPONSE:

a) Yes, Centra has provided preliminary estimates of the EOL of Centra's system assets using data obtained in the course of its operations. Further work (such as pipeline in-line inspections) to support the estimates is being performed. Centra is evaluating the application of pipeline industry software that can assist in determining when to replace existing assets.

b) Please see the response to part a).

c) Centra has not performed statistical failure analysis, such as generation of asset failure curves. The estimated EOLs in the form of asset life expectancy ranges were documented in Appendix 4.4. Centra's asset life expectancies ranges in the asset condition assessment were estimated by subject matter expert interpretation of condition based information including:

- station inspections and maintenance,
- valve inspections and maintenance history,
- coating condition and type on steel pipelines,
- cathodic protection information on steel pipelines,
- visual pipe condition information on pipelines,
- leaks on pipelines and service metersets
- service regulator sample testing and,
- observed condition of service metersets during maintenance and replacement.

On average for the natural gas assets, Centra considers the estimated asset life expectancies ranges to be conservative, while recognizing that very few assets or 'outliers' reach end of life prior to these ranges. Centra does not consider the asset life expectancy ranges alone as a robust enough justification to conduct asset replacement.

REFERENCE:

Tab 4, p. 14 of 22, Figure 4.7

PREAMBLE TO IR (IF ANY):

Figure 4.7 showcases 25 Inspection and Maintenance programs that Centra currently undertakes as a part of its natural gas system asset management.

QUESTION:

a) Please quantify the O&A expenditures for each of the programs showcased, for the past three calendar years, along with expenditures forecasted for the 2018/19 and 2019/2020 timeframe. If certain percentage of any program's maintenance work is capitalized, please indicate so accordingly.

b) For each program mentioned in Figure 4.7 please describe the types of assets it is applicable to, along with the description of the percentage of eligible assets inspected / maintained in an average year. If any of the programs are not cyclical in nature but are rather triggered by a particular event (such as asset failure) please provide this information.

c) Please describe the types of quantitative data gathered through each of the programs by Centra's employees and/or contractors.

RESPONSE:

a) Operating and Administrative ("O&A") expenditures associated with the Inspections and Maintenance Programs of the Natural Gas System, as shown in Figure 4.7 of Tab 4 of the Application, from 2015/16 through 2019/20 are presented in the table below. Centra does not discretely capture costs for all of the programs identified as some of them are grouped and costed with other functions that cannot be easily apportioned with confidence. The programs not discretely costed have been highlighted and noted in the table. Other exceptions have also been noted in the table.

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

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

*As per Section2 of Appendix 5.9, meter sampling, testing & exchange costs are proposed for capitalization in 2019/20.

b) Please see table below for a description of the types of assets Figure 4.7 is applicable to, along with the description of the percentage of eligible assets inspected / maintained in an average year.

No.	Inspection and Maintenance Program	Type of Asset	% Inspected / Maintained in an Average Year	If the Program is Not Cyclical in Nature but Triggered by an Event, please explain
1	Cathodic Protection System Monitoring	Pipelines	100%	Cyclical
2	Close Interval Potential Survey	Pipelines	15%	Cyclical
3	Coating Shielding Corrosion	Pipelines	5%	Future inspection frequency TBD
4	External Corrosion Direct Assessment	Pipelines	5%	Future inspection frequency TBD
5	Monitoring of Steel Risers on Plastic Services	Services	20%	Cyclical
6	Depth of Cover Surveys	Pipelines	10%	Cyclical
7	Geotechnical Monitoring of Pipelines in Slopes	Pipelines	10%	Cyclical
8	Hydro Geotechnical Monitoring of Pipelines in Water courses	Pipelines	5%	Cyclical
9	In-line Inspection	Pipelines	2%	Future inspection frequency TBD
10	Aerial Pipeline Inspection	Pipelines	33%	Cyclical
11	Leak Inspection	Not "unique" program - See 15, 17, 18, 19 & 20.		
12	Strained Service Failure Reporting	Services	0%	Event initiated when a meterset cracks or snaps
13	Customer Meter Set Maintenance Survey	Services	15%	Cyclical
14	Station Inspections	Stations	100%	Cyclical
15	Station Leak Survey	Stations	100%	Cyclical
16	Odourization Equipment Inspection	Stations	100%	Cyclical
17	Distribution Mains and Services Leak Survey	Pipelines & Services	25%	Cyclical
18	Transmission and High Pressure Mains Leak Survey	Pipelines	100%	Cyclical
19	Public Building Leak Survey	Services & Accessible Customer Owned Piping	100%	Cyclical
20	Business District Leak Survey	Pipelines & Services	100%	Cyclical
21	Meters-Maintaining Compliance with Measurement Canada Requirements	Revenue Customer Metering	6%	Cyclical
22	Station Valve Inspection and Maintenance	Stations	100%	Cyclical
23	Transmission Valve Inspection and Maintenance	Stations	100%	Cyclical
24	Distribution Buried Valve Maintenance	Stations	100%	Cyclical
25	Downtown Winnipeg- Emergency Sectionalization Valve Maintenance	Stations	100%	Cyclical

c) Please see table below for quantitative data gathered through each of the programs by Centra's employees and/or contractors.

No.	Inspection and Maintenance Program	Type of Quantitative Data Gathered Through Program
1	Cathodic Protection System Monitoring	Pipe to soil potentials
2	Close Interval Potential Survey	Pipe to soil potentials
3	Coating Shielding Corrosion	General assessment of the potential of corrosion under coating
4	External Corrosion Direct Assessment	General assessment of the potential of corrosion at holidays
5	Monitoring of Steel Risers on Plastic Services	Pipe to soil potentials
6	Depth of Cover Surveys	Pipeline depth of cover
7	Geotechnical Monitoring of Pipelines in Slopes	Assessment of slope stability hazards and scour potential
8	Hydro Geotechnical Monitoring of Pipelines in Water courses	Pipeline depth of cover, assessment of scour and slope stability hazards and general coating condition
9	In-line Inspection	Metal loss anomalies, deformation anomalies and fittings
10	Aerial Pipeline Inspection	Condition of pipe, coating, supports, hangers and guards
11	Leak Inspection	Not "unique" program - See 15, 17, 18, 19 & 20.
12	Strained Service Failure Reporting	Examination of characteristics at services that failed due to strain
13	Customer Meter Set Maintenance Survey	Whether valves are seized
14	Station Inspections	Pressures, leaks, deficiencies
15	Station Leak Survey	Above and below grade leaks
16	Odourization Equipment Inspection	Pressures, odorant level in bulk tanks, state of pump.
17	Distribution Mains and Services Leak Survey	Above and below grade leaks and other concerning conditions that are visible along the pipeline alignment
18	Transmission and High Pressure Mains Leak Survey	Above and below grade leaks and other concerning conditions that are visible along the pipeline alignment
19	Public Building Leak Survey	Above and below grade leaks and other concerning conditions that are visible along the pipeline alignment
20	Business District Leak Survey	Above and below grade leaks and other concerning conditions that are visible along the pipeline alignment
21	Meters-Maintaining Compliance with Measurement Canada Requirements	Metering accuracy as it relates to Measurement Canada regulatory requirements
22	Station Valve Inspection and Maintenance	Ensure valves are accessible and operational
23	Transmission Valve Inspection and Maintenance	Ensure valves are accessible and operational
24	Distribution Buried Valve Maintenance	Ensure valves are accessible and operational
25	Downtown Winnipeg- Emergency Sectionalization Valve Maintenance	Ensure valves are accessible and operational

REFERENCE:

Tab 4, p. 15 of 22, lines 7-22

PREAMBLE TO IR (IF ANY):

The referenced text describes Centra's multi-point assessment framework for pressure regulating stations that has been in place for over 10 years and is used to identify stations for upgrading or rebuilding.

QUESTION:

a) Please provide an internal reference document (e.g. manual, presentation, standard) that describes the activities and data inputs comprising the referenced multi-point assessment process. If a reference document is not available, please explain why, and provide a representative example of an actual assessment completed in the last calendar year.
b) Please describe the process by which Centra identifies a particular sample of stations subject to inspection using the referenced assessment framework. If the analysis is cyclical, please indicate the frequency of stations undergoing assessment. If a different location identification methodology is in place, please describe it.
c) Given that the station multi-point assessment framework has been in place for more than a decade, has Centra reviewed its effectiveness, scope, and nature of the underlying activities, measurements and the resultant insights over this timeframe? What (if any) material modifications have taken place?

RESPONSE:

a) Stations are assessed by Gas Apparatus Maintenance & Control field staff on an annual basis where the general condition of the station is documented. The assessment is comprised of 8 different sections with various inputs per section where the condition rating ranges from "Not an issue" to "Major Concern". Please see the attachment to this response for an example of a completed assessment.

b) Stations with the highest scores on the assessment forms are reviewed and scheduled for upgrades accordingly. All stations are inspected and assessed annually to ensure records are up to date, and upgrades are prioritized accordingly. At times, other factors will trigger an upgrade such as: obsolescence of equipment, upgrades to attach new customers, new technology and operational reliability. The assessment is directed at identifying impacts of age to the station, not these other considerations.

c) The effectiveness of the program is demonstrated in the reliability performance of 99.99% for Centra's natural gas distribution system.

MANITOBA HYDRO - GAS FACILITY ASSESSMENT

FACILITY Num.: GS-029
LOCATION: LASALLE TBS
ASSESSED BY: GREG STEWART
DATE: OCT 18-2018

Note: Mark 'x' in appropriate column, one 'x' only per criteria

CONDITION RATING

HEALTH AND SAFETY	3 Major concern	2 Moderate concern	1 Deficiency noted	0 Not an issue	COMMENTS
Access and Egress		X			
Equipment suitable to workers needs? (ergonomics)		X			
Spacing of isolation valves to regulator				X	
Distance b/w gas facilities and electrical (at least 25ft)				X	
Other Concerns:					

COMPLIANCE	3 Problem prone	2 Poor condition	1 Present	0 None	COMMENTS
Obsolete parts/equipment *(298 regs replaced by 1098, 63FV relief valves replaced by 63EG)*		X			
Other Concerns:					

SECURITY OF STATION	3 High risk	2 Moderate risk	1 Slight if no risk	0 Not an issue	COMMENTS
Sufficient Bollards & proper placement				X	
Other Concerns:					

RELIABILITY OF SUPPLY	3 Nonexistent	2 Present	1 Moderate	0 Elaborate	COMMENTS
Backup System *(worker/monitor or relief valve, lead + lag, multiple runs, multiple relief valves)*			X		
Other Concerns:					

	=3 x	
6	=2 x →	3
1	=1 x →	1
0	=0 x →	3

7 =subtotal this sheet

MANITOBA HYDRO - GAS FACILITY ASSESSMENT

FACILITY Num.: GS-029
LOCATION: LASALLE TBS
ASSESSED BY: GREG STEWART
DATE: OCT 18-2018

Note: Mark 'x' in appropriate column, one 'x' only per criteria

CONDITION RATING

INTEGRITY OF SYSTEM	3 Poor condition	2 Acceptable condition	1 Good Condition	0 Excellent condition	COMMENTS
Corrosion	X				
Heaving of station piping due to temperature		X			
Stress/strain visible on components	X				
Isolation valves, block and by pass, regulation isolation				X	
Other Concerns:					

PUBLIC ACCEPTANCE	Major concern	Moderate concern	Minor concern	Not an issue	COMMENTS
Noise				X	
Aesthetics		X			
Proximity to structures *(buildings, roads, rail, watercourse)*		X			
Encroachment *(residential)*				X	
Other Concerns:					

SITE	Re-work the site	Will require work	No work required	Not an issue	COMMENTS
Drainage				X	
Condition of Station Buildings	X				
Vehicular Access - compacted site		X			
Settlement or heaving of structures		X			
Other Concerns:					

ENVIRONMENT	Major concern	Moderate concern	Minor concern	Not an issue	COMMENTS
Safe environmental practices are being followed at station *(containment of odourant, no garbage around site, no spills etc.*				X	
Other Concerns:					

9	=3 x	3
10	=2 x	5
	=1 x	
0	=0 x	5

19 =subtotal this sheet

26 =GRAND TOTAL BOTH SHEETS

43% = Percentage based on grand total of 60. Percentages larger than 100% can occur if there are criteria of "other concerns".

REFERENCE:

Tab 4, p. 15 of 22, lines 7-22

PREAMBLE TO IR (IF ANY):

The referenced text describes Centra's multi-point assessment framework for pressure regulating stations that has been in place for over 10 years and is used to identify stations for upgrading or rebuilding.

QUESTION:

d) Please describe whether and how this and other existing inspection and maintenance frameworks and programs are expected to be affected by the ongoing implementation of the Corporate Value Framework and other related enterprise-wide asset management enhancement activities.

RESPONSE:

The multi-point assessment framework and other existing inspection and maintenance programs will remain at this time. Inputs from these programs can be used as inputs into the Corporate Value Framework to assist in prioritizing projects. The Corporate Value Framework does not provide a process for evaluating system condition.

The implementation of enterprise-wide asset management enhancement activities may incorporate inspection and assessment methodologies. As those activities are still under development, it is premature to comment on the possible impacts to existing inspection and maintenance programs.

REFERENCE:

Tab 4, pp. 16-17, Appendix 4.3, Section 5 (pp. 40-58), Attachment 2.

PREAMBLE TO IR (IF ANY):

The first reference states that the Pipeline Risk Assessment methodology and the 2017 report filed in this application are relatively new and have yet to be used to identify specific projects. The second reference refers to the "Projects" section of the filed Five-Year Natural Gas Asset Management Capital Investment Plan, which showcases the Risk Analysis likelihood and consequence associated with each project included in the plan.

QUESTION:

a) Given the Applicant's acknowledgment that the Pipeline Risk Assessment Methodology filed in this application is yet to be used to identify specific projects, please describe Centra's intended purpose for filing this document within this application (other than ensuring completeness).
b) Considering the Centra's acknowledgment that Pipeline Risk Assessment Methodology is yet to be used to identify specific projects referenced in (a), please explain the rationale for inclusion and the source of the content conveying the "Risk Analysis" information included in each project's description and justification in the Five-Year Natural Gas Asset Management Capital Investment Plan (Appendix 4.3).
c) As stated at the outset of Attachment 2, the current methodology is the second iteration – developed on the basis of the original 2014 methodology. Please describe whether and how the original methodology was used in the asset management and investment planning process between 2014 and the publication of the second methodology.
d) Please provide the original 2014 Pipeline Risk methodology document.

RESPONSE:

a) The Pipeline Risk Assessment Methodology was filed as part of the PUB Completeness Review at the request of the PUB.

b) The Risk Analysis included in the Five-Year Natural Gas Asset Management Capital Investment Plan is different than the Pipeline Risk Assessment Methodology. The methodologies are different because the criteria used for evaluating capital projects versus relative risks of pipeline hazards are not the same. Appendix A of the Five-Year Natural Gas Asset Management Capital Investment Plan explains the criteria used in the methodology.

c) The current Risk Analysis used in the in the Five-Year Natural Gas Asset Management Capital Investment Plan was used from 2015-2017 as an interim model, while the C55 Corporate Value Framework was being developed. The 2014 Pipeline Risk Assessment has not been used for capital investment planning.

d) Please see attachment to this response.

Manitoba Hydro

Customer Service & Distribution
Distribution Engineering & Construction Division Rural
Distribution Standards Department

REPORT ON:

Pipeline Risk Assessment
File No: 20XX-04005

PROVINCE OF MANITOBA
L.J. GIGIAN
Member
24093
REGISTERED PROFESSIONAL ENGINEER
Nov. 6, 2014

PREPARED BY:	Lindsay Gigian
DATE PREPARED:	October 30, 2014
REVIEWED BY:	D. Petursson, D. Prydun, F. Velandia, K. Morgenstern, D. Shmyr, F. Ni

RECOMMENDED FOR IMPLEMENTATION

DEPARTMENT:	Distribution Standards
DATE:	November 6, 2014

DISTRIBUTION:

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Executive Summary

Risk assessment is a consistent and rational method of evaluating the hazards and consequences to the natural gas pipeline segments relative to one another. It is a valuable tool for making effective choices among risk-reduction measures, supporting specific operating and maintenance practices, assigning priorities among inspection, monitoring, and maintenance activities, and supporting decisions associated with modifications to pipelines.

The risk assessment program is divided into two parts; risk analysis and risk evaluation. During the risk analysis process, the 9700km of transmission and distribution pipelines are separated into segments sharing similar attributes (pipe material, internal pressure, cathodic protection, etc). Historical incident data and industry recognized risk determiners are used to assign each pipe segment a frequency analysis score and consequence analysis score which are then combined to determine the total risk score (figure 1: Pipeline Risk Assessment Structure).

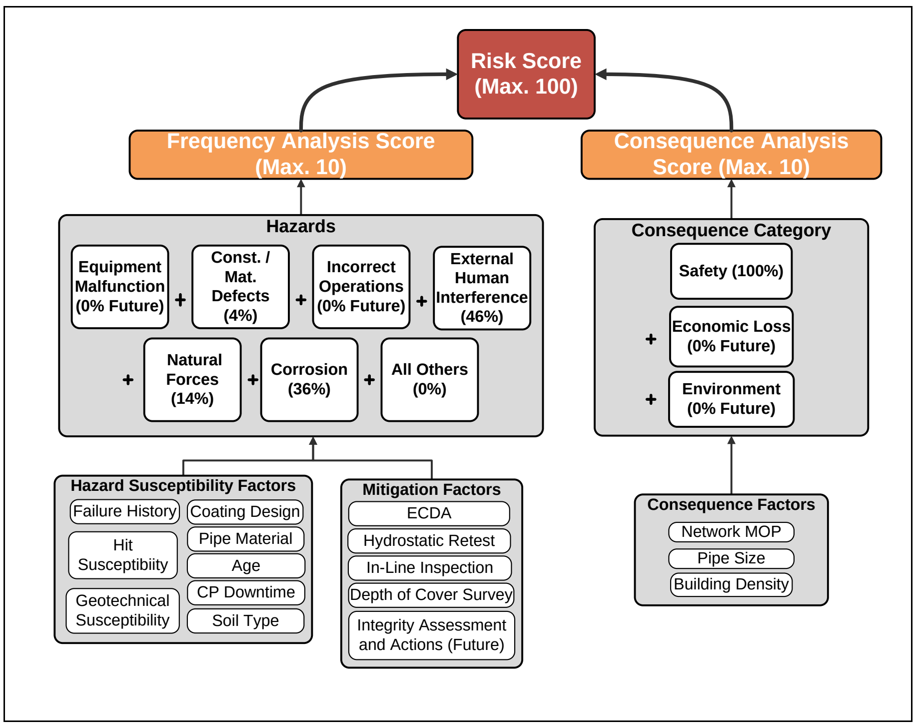

Figure 1: Pipeline Risk Assessment Structure

Frequency analysis is a measure of the likelihood of a pipeline failure occurring due to known hazards. The hazards considered in the pipeline system risk analysis are:

- External Human Interference
- Corrosion
- Natural Forces
- Construction / Material Defects

- Equipment Malfunction (future)
- Incorrect Operations (future)

Consequence analysis is an estimate of the severity of an incident. The 2014 model considers only safety however economic loss and environmental impacts are future considerations.

During the risk evaluation process, the highest ranked segments are further investigated to determine risk significance and assess risk reduction options. As a result of the 2014 risk assessment, the sites with significant risk and recommended action are:

- Transmission Pipe Red River Crossing near Selkirk: has a significant risk driven by External Human Interference and Natural Forces hazards. The location does not meet minimum depth of cover requirements and has geotechnical concerns with bank instability. This site was previously identified for remediation (MER 2013-04839) with an anticipated in-service-date of 2015.
- La Salle Transmission Pipe at PTH 100: has a significant risk driven by External Human Interference and Corrosion hazards. However, three insufficient covers at this site have recently been remediated which reduces the overall risk score. As a critical supply feed and some of the oldest pipe in the network, this pipeline would benefit from an In-Line Inspection (ILI) or an External Corrosion Direct Assessment (ECDA) Survey. ILI and ECDA mitigation activities are a method of investigating the corrosion hazard and offer a risk score reduction that lasts a number of years. An initial ECDA survey was completed in 2005.
- Transmission Pipe Seine River Crossing near Grande Pointe: has a significant risk driven by Natural Forces hazard. This site would benefit from a new depth of cover survey as the current survey is from 1997 and geotechnical potential for scour and lateral erosion is high. This site has been scheduled for a new depth of cover survey in 2015.
- Distribution Pipe Segments on Lipton Street, Ross Avenue, King Street & Notre Dame Avenue, Ingersoll Street, and Harbison Avenue; have a significant risk driven by Corrosion hazard. These segments would benefit from a condition assessment of their cathodic protection systems.
- High Pressure Pipe on Spruce, Telfer and Clifton; has a significant risk driven by Corrosion hazard. This segment would benefit from a condition assessment of their cathodic protection systems.

The risk assessment program is designed to be evolutionary and subsequent models will be capable of incorporating new information as it becomes available. Data collection improvements will reduce the number of missing or unknown fields and improve risk analysis results. The goal is to improve the overall integrity of the pipeline network while reducing the frequency and consequence of incidents through a cyclic risk management process.

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1. Introduction

Risk management is a consistent and rational method of reducing overall risk to the pipeline network by identifying and focusing resources on pipe segments with the highest relative risk.

Figure 2 from Annex B of CSA Z662-11 displays the risk assessment process as part of the overall risk management function. Risk assessment is composed of the risk analysis and risk evaluation processes. Risk analysis includes identifying the hazards, analyzing the frequency of hazardous events or incidents and their consequences, and estimating the overall risk. Risk evaluation is used to determine if the risk is significant and recommend options to reduce risk. While part of the risk management process, choosing risk reduction measures and implementing them is beyond the scope of the risk assessment process and are managed separately.

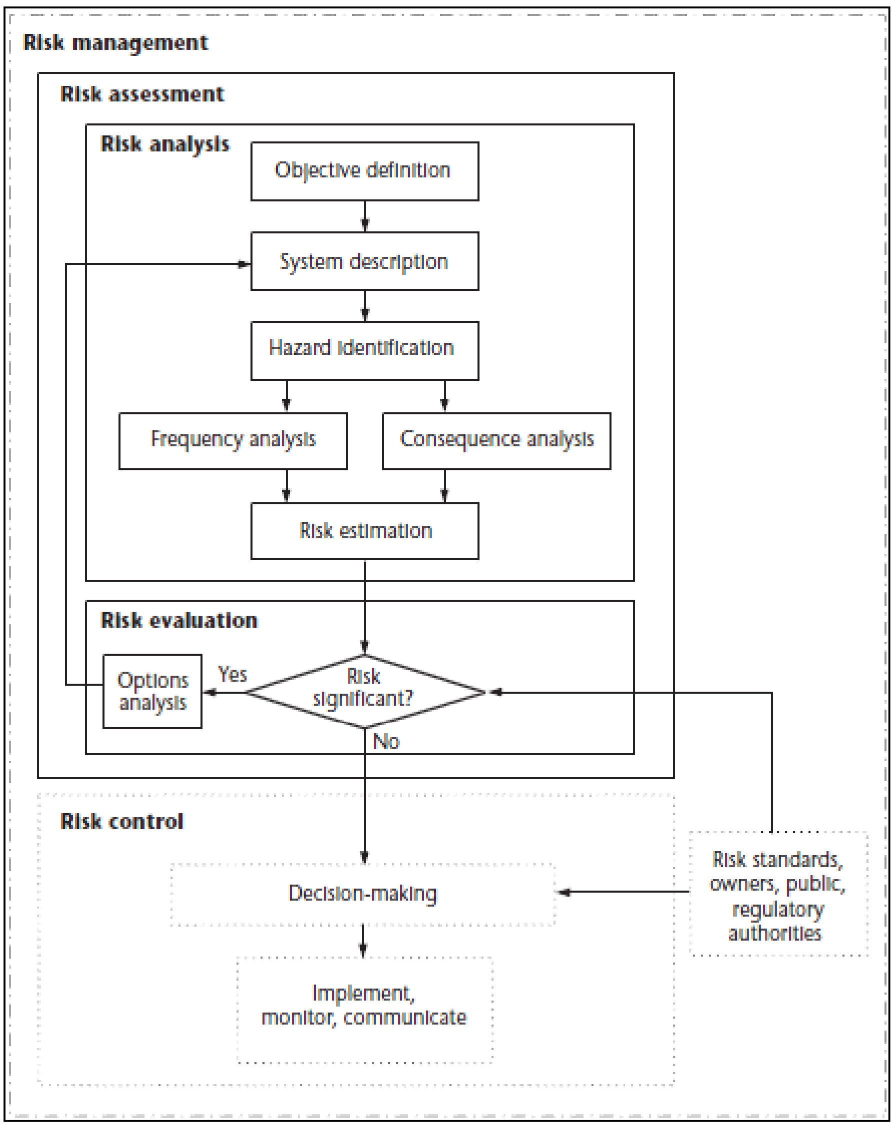

Figure 2: Risk Management Process

Risk assessment is a valuable tool for:

- Making effective choices among risk-reduction 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.

2. Objectives and Scope

The objective of the risk assessment is to assign relative risk scores to the transmission and distribution pipelines to assist in the decision making processes for design, construction, operation, inspection, monitoring, testing, maintenance, repair, modification, rehabilitation, and abandonment. The goal is to improve the overall integrity of the pipeline network while reducing the frequency and consequence of incidents. The Pipeline Risk Assessment does not include pipe or assets associated with stations or services.

3. Network Description

The network consists of approximately 9700km of pipeline in total of which 1800km is transmission pressure (>1720kPa) and 7900km is distribution pressure. The distribution pressure pipe is comprised of approximately 3600km of steel and 4300km of plastic.

4. Risk Analysis Methodology

To conduct the risk analysis, the Pipeline Integrity Engineer created a custom model using the software Smallworld GeoSpatial Analysis (GSA). GSA links together spatial and non-spatial data from multiple sources (ex. Smallworld eGIS, Banner, Microsoft Access and Excel, and AutoCAD) where it is then manipulated to suit our specific needs and concerns. Manitoba Hydro has complete control over the model inputs and parameters which is well suited to an evolutionary risk assessment approach.

The pipeline network is separated into 37,526 segments sharing similar attributes (pipe material, internal pressure, cathodic protection, etc.). Each of these segments is assigned a risk score by multiplying its frequency analysis score by its consequence analysis score. Since all of the segments are scored using the same criteria, the result is a relative risk ranking of the complete network. Figure 3: Pipeline Risk Assessment Structure is a simplified visual. The detailed version is included as Appendix A: MB Hydro Pipeline Risk Assessment Structure.

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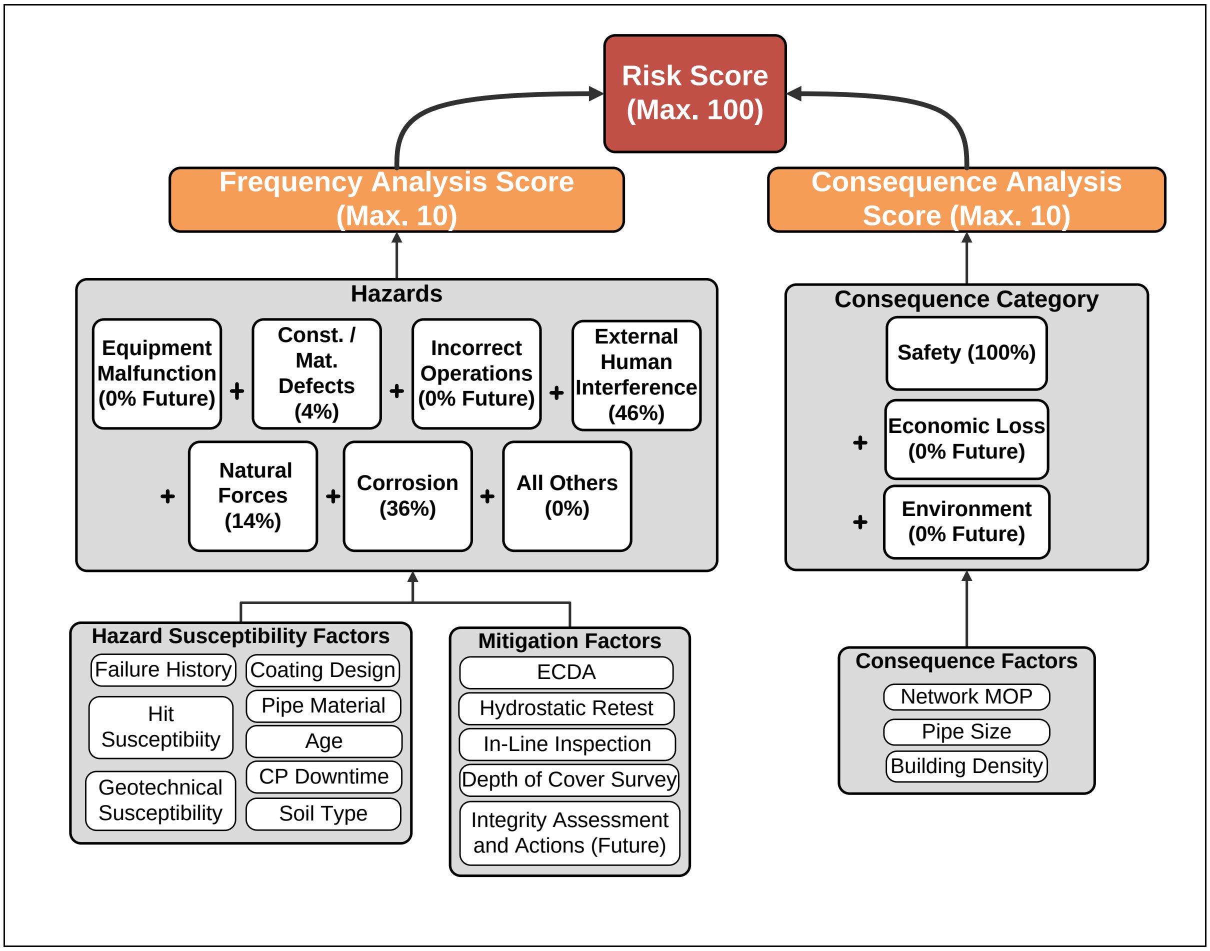

Figure 3: Pipeline Risk Assessment Structure

5. Limitations and Assumptions

The greatest limitation to the pipeline risk assessment is the number of unknowns which include:

- Unknown pipe attributes (blank fields) such as energized date, wall thickness, grade and/or coating. Unknown pipe attributes are either scored using tacit knowledge from senior staff or are assigned the maximum score possible.
- Unknown leak causes. An important factor in calculating the frequency of incidents is a review of the failure history. Since leaks with missing or unknown causes cannot be attributed to a specific hazard, that information is not used in the risk assessment. Changes to leak tracking forms to improve data quality are being implemented.

6. Frequency Analysis

Frequency analysis is a measure of the likelihood of a pipeline failure occurring due to known hazards. The pipeline network is divided into small segments with similar properties (ex. Age, coating, wall thickness, etc.). An algorithm is applied to each segment to calculate its individual Frequency Analysis Score. Within the Frequency Analysis Score algorithm, historical incident data, industry recognized risk determiners and mitigation activities are used to calculate Hazard Scores (0-10)(ex. Corrosion) for each individual pipeline segments as outlined in sections 9.0 Hazard Identification and Score, 10.0 Hazard Susceptibility Factors and 11.0 Mitigation Factors. Those individual Hazard Scores were then multiplied by the hazard weighting to obtain the Frequency Analysis Score (0-10).

Hazard Score Weightings

- External Human Interference Score: 46%
- Corrosion Score: 36%
- Natural Forces Score: 14%
- Construction / Material Defects Score: 4%
- Equipment Malfunction Score: 0%
- Incorrect Operations Score: 0%

The hazards titled equipment malfunction and incorrect operations are considered minimal and assigned a weighting of 0%. In subsequent years, with improved incident reporting, it may be beneficial to reconsider the impact of these hazards on the pipeline network.

7. Hazard Identification and Score

Within the frequency algorithm, historical incident data as well as industry recognized risk determiners were used to calculate hazard scores for each individual pipeline segments. Those individual hazard scores were then multiplied by the hazard weighting to obtain the Frequency score. The CGA Incident Cause Guideline (Appendix B) is used to classify hazards.

7.1. External Human Interference

A significant hazard to the pipeline network is external human interference. Incidents in this category are usually attributed to unintentional third party, company employee or company contractor damages. They may also be caused by intentional vandalism damages.

The External Human Interference score (0-10) is the sum of the Hazard Susceptibility Factors multiplied by their percentage weighting:

Hazard Susceptibility Factor	Percentage Weighting
Failure History (Outside Force)	45%
Insufficient Cover	15%
Line Locate Requests	15%
Pipe Material	15%
Soil Type	10%

7.2. Corrosion

Corrosion results in metal loss and a reduction in wall thickness of pipe. There are several factors considered that would make a pipe more susceptible to failure due to corrosion. The Corrosion score (0-10) is the sum of the Hazard Susceptibility Factors multiplied by their percentage weighting:

Hazard Susceptibility Factor	Percentage Weighting
Cathodic Protection Downtime	40%
Failure History (Corrosion)	30%
Age	20%
Pipe Coating	6%
Joint Coating	2%
Soil Type	2%

Non-metallic pipe is not susceptible to corrosion and should have a Corrosion score of 0.

7.3. Natural Forces

Failures associated with the hazard Natural Forces are either weather or geotechnical related. Causes include riverbank instability, soil erosion and frost heave. The Natural Forces score (0-10) is the sum of the Hazard Susceptibility Factors multiplied by their percentage weighting:

Hazard Susceptibility Factor	Percentage Weighting
Failure History (Natural Force)	45%
Geotechnical Susceptibility	20%
Watercourse Crossing Risk Rating	20%
Pipe Material	10%
Soil Type	5%

7.4. Construction / Material Defects

The pipeline is susceptible to failure due to poor construction practices and defective materials. Examples include leaks cause by improper welds, fusion, and mechanical fittings (improper installation), not following procedures during construction, cross bores, loose cap or cracked tee cap due to over tightening. The Construction / Material Defects Score (0-10) is the sum of the Hazard Susceptibility Factors multiplied by their percentage weighting.

Hazard Susceptibility Factor	Percentage Weighting
Failure History (Const. / Mat. Defect)	95%
Age (Long Seam Weld Defect Susceptibility)	5%

7.5. Equipment Malfunction

The susceptibility of a failure attributed to equipment malfunctioning are calculated in the Equipment Malfunction Hazard Score. Examples include:

- Malfunctioning regulator, control valve, or relief valve failure causing over-pressure.
- Mechanical fitting failure (compression fittings, seals/gaskets) where another primary cause does not exist.
- Leaking valves not repairable by regular maintenance.

Improvements in reporting methods are being undertaken to track failures resulting from equipment malfunction for future reporting consideration.

7.6. Incorrect Operations

The susceptibility of a failure attributed to the incorrect operation of the pipeline network post-commission is calculated in the Incorrect Operations Hazard Score. Examples include not following procedures, not having competency/training.

Improvements in reporting methods are being undertaken to track failures resulting from incorrect operations for future reporting consideration.

7.7. All Other Hazards

The All Others Hazard category is in place to track failures that do not fit into any of the other hazard categories. This hazard is a future consideration at this time.

8. Hazard Susceptibility Factors

8.1. Failure History

The External Human Interference, Corrosion, Natural Forces and Construction / Material Defect Hazard Scores consider that the number of historical failures is a good predictor of the likelihood of future failure incidents. Improvements in reporting methods are being undertaken to track failures more consistently.

The failure history factor (0-1) is determined by the number of below grade leak reports with the cause listed as “outside force” for External Human Interference Hazard, “corrosion” for Corrosion Hazard, and “Const Mat Defect” for Construction / Material Defect Hazard using the following table.

Min Leak History	*Max Leak History*	*Failure History (Outside Force) Factor*	*Failure History (Corrosion) Factor*	*Failure History (Natural Forces Factor)*	*Failure History (Const. Mat. Defects)*
4	100	1.00	1.00	1.00	1.00
3	4	0.75	0.75	0.75	0.75
2	3	0.50	0.50	0.50	0.50
1	2	0.25	0.25	0.25	0.25
0	1	0.00	0.00	0.00	0.00

Improvements in reporting methods are being undertaken to track failures more consistently and to include all hazard types.

8.2. Insufficient Cover

The External Human Interference Hazard Score considers that a location with insufficient cover has an increased susceptibility to being unintentionally damaged at that location.

The Insufficient Cover factor (0-1) is determined by the presence of a known insufficient cover on the gas main. Only insufficient covers not marked as completed are included for analysis.

Insufficient Cover on Gas Main	*Insufficient Cover Factor*
1 or more	1
0	0

8.3. Line Locate Requests

The External Human Interference Hazard Score considers that a location with a higher number of line locate requests has an increased susceptibility to being unintentionally damaged. It could also be suggested that in an area with a large number of line locate requests, there would be a number of excavations where line locate requests were never made.

In the 5 years after a new distribution main is energized it has an elevated risk of third party damage because it is often located in a new development where landowners are planting trees, shrubs, fences, etc.

The Line Locate Request factor (0-1) is a combination of the age of the main and the number of line locate requests within 30 metres of a gas main received by Manitoba Hydro.

Energized < 5 years ago	***Minimum Requests (>=)***	***Maximum Requests (<)***	***Line Locate Request Factor***
TRUE	10	10000	1
TRUE	5	10	0.5
TRUE	2	5	0.25
TRUE	0	2	0
FALSE	10	10000	0.25
FALSE	5	10	0.13
FALSE	2	5	0.06
FALSE	0	2	0

8.4. Pipe Material

The External Human Interference Hazard Score considers that the pipe material affects the extent of damage incurred. For example, plastic pipe is more likely to leak than steel pipe when damaged with the same force, etc.

Pipe Material	***eGIS Pipe Type***	***Pipe Material Factor***
Other / Unknown*	Other	0.50
Plastic	PE	0.50
High Density Plastic	PE-100	0.50
High Density Plastic	PE-HD	0.50
Steel	Stl	0.25
Aluminum	Alum	0.25

*Pipe segments with a pipe material field of other or unknown are assigned the highest pipe material factor that exists in the network, 0.5. Higher values are reserved for materials that do not exist in the MB Hydro network like cast iron (0.75), poly vinyl chloride (0.8) wrought iron (1.0).

8.5. Soil Type

The External Human Interference Hazard Score, the Corrosion Hazard Score and the Natural Forces Hazard Score consider the soil type to be a susceptibility factor.

An external human interference failure is considered more likely in denser soils like rock and clay and less likely in looser sands.

For corrosion to take place, the pipe must be in an electrolyte, typically moist soil. Soils will hold moisture differently, for example sand dries out much quicker than clay, effectively reducing the amount of active corrosion time.

Natural forces such as erosion are more likely in water or eroded soil types. Pipe segments are more susceptible to frost heaving in soils with higher moisture holding capabilities like clay.

The following factors are applied to the pipe segments based on interpreting the regional surficial geology maps:

Soil Types	***Soil Factor***
Unknown	1.00
Eroded Slopes	1.00
Water	1.00
Marsh	1.00
Unclassified	1.00
Clayey	0.9
Loamy	0.30
Coarse Loamy	0.50
Sands	0
Coarse Sands	0.1
Organic	0.3
Rock	1

8.6. Cathodic Protection Downtime

The Corrosion Hazard Score considers the cathodic protection downtime, where cathodic protection values were less than target levels, to be a susceptibility factor. Corrosion is a time dependent hazard meaning that the longer corrosion is active, the more likely it will result in a defect or incident.

The following factors are applied to the pipe segments based on the cathodic protection history of the cathodic section it is in.

Min. Cathodic Protection Downtime (years)(>=)	***Max. Cathodic Protection Downtime (years)(<)***	***Cathodic Protecton Downtime Factor***
10	100	1
6	10	0.75
3	6	0.5
1	3	0.25
0	1	0

8.7. Age

The Corrosion Hazard Score and the Construction and Material Defects Score consider the age of the pipeline to be a susceptibility factor.

Corrosion is a time dependent hazard meaning the longer the pipeline is undergoing active corrosion, the more likely it is to have a failure due to corrosion.

The following factors are applied to the metal pipe segments based on their age:

Min. Energized Date	*Max. Energized Date*	*Age Factor*
1/1/1800	12/31/1959	1
1/1/1960	12/31/1969	0.8
1/1/1970	12/31/1979	0.6
1/1/1980	12/31/1989	0.4
1/1/1990	12/31/1999	0.2
1/1/2000	12/31/2009	0.1
1/1/2010	12/31/2019	0

Construction and material defects are considered to be dependent on advancements in manufacturing and construction practices over time. Metal pipe segments energized prior to 1971 are considered susceptible to long seam weld defects. All plastic and metal segments energized in 1971 or later are not considered susceptible to long seam weld defects. (Baker, 2004)

8.8. Pipe Coating

The Corrosion Hazard Score considers that the type of coating on the pipeline will affect its susceptibility to corrosion. The following factors are applied to the pipe segments based on their pipe coating type:

Pipe Coating	*Coating Type*	*Pipe Coating Factor*
Unknown*	Unknown	0.75
Asphalt Enamel	Coated	0.75
Tape	Coated	0.75
Coal Tar Wrap	Coal Tar	0.75
Coal Tar	Coal Tar	0.75
DPAR	Epoxy	0.25
Dual Layer Abrasion Resistant FBE	Epoxy	0.25
Epoxy	Epoxy	0.25
FBE	Epoxy	0.25
Wax Coatings	Coated	0.75
Yellow Jacket	Poly	0.5

*Pipe segments with a pipe coating field of missing or null are assigned the highest pipe coating factor that exists in the network, 0.75. Higher values are reserved for bare pipe (1.0) of which MB Hydro has none.

8.9. Joint Coating

The Corrosion Hazard Score considers that the type of coating on the joint connections will affect its susceptibility to corrosion. The following factors are applied to the pipe segments based on their joint coating type:

Joint Coating	***Coating Type***	***Joint Coating Factor***
Bare	Bare	1.0
Unknown	Unknown	1.0
Tape	Coated	0.75
Wax Tape (Denso or Petrolatum)	Coated	0.75
Shrink Sleeves	Poly	0.5
Dual Powder Abrasion Resistant	Epoxy	0.25
Field Applied FBE	Epoxy	0.25
Liquid Epoxy Coating	Epoxy	0.25

8.10. Geotechnical Susceptibility

The Natural Forces Hazard Score considers the pipe segments geotechnical susceptibility. Transmission pipelines are rated during the geotechnical monitoring program. Distribution pipelines were not originally assessed under the geotechnical monitoring program however some locations have been added due to geotechnical concerns raised. The following factors are applied to the pipe segments based on their geotechnical monitoring program rating.

Highest Geotechnically Unstable Area Rating	***Geotechnically Unstable Area Factor***
HIGH	1
MODERATE	0.6
LOW	0.3
VERY LOW	0.1
<null>	0.1

8.11. Watercourse Crossing

The Natural Forces Hazard considers whether or not the pipe segment crosses a watercourse and the watercourse risk score as determined by the watercourse crossing program. The following factors are applied to the pipe segments:

Minimum Risk Score	*Maximum Risk Score*	*Watercourse Factor*
0	20	0.2
20	40	0.4
40	60	0.6
60	80	0.8
80	100	1.0

9. Mitigation Factors

Hazards can be mitigated in a number of ways including performing:

- External Human Interference
  - Depth of Cover (DOC) Survey completed in combination with External Corrosion Direct Assessment.

- Corrosion
  - External Corrosion Direct Assessment (ECDA)
  - In-Line Inspection (ILI)
  - Hydrostatic Retest

- Hazard Specific
  - Integrity Assessment including implementing recommendations

The mitigation factor is applied in the form of a credit to the final Hazard Score. The credit is reduced based on the time since the mitigation was completed as follows:

Minimum Time since Mitigation	*Maximum Time since Mitigation*	*ECDA Mitigation Factor*	*DOC Mitigation Factor*	*ILI Mitigation Factor*
0	1	0.125	0.125	0.125
1	2	0.250	0.250	0.250
2	3	0.375	0.375	0.375
3	4	0.500	0.500	0.500
4	5	0.625	0.625	0.625
5	6	0.750	0.750	0.750
6	7	0.875	0.875	0.875
7	100	1.000	1.000	1.000

10. Consequence Analysis

Consequence analysis is an estimate of the severity of an incident. Industry recognized risk determiners are used to calculate a Consequence Analysis Score by summing the individual Consequence Category Scores multiplied by their respective weightings.

Consequence Category Score and Weightings

- Safety Score: 100%
- Economic Loss Score: 0% (future)
- Environment Score: 0% (future)

11. Consequence Category Score Factors

Within the Consequence Analysis Score algorithm, pipe segment attributes and building density data were used to calculate Consequence Category Scores for each individual pipeline segments.

11.1. Safety

The Safety Consequence Category Score considers the Impact Radius and the Building Density in applying consequence factors:

Safety Factor	Percentage Weighting
Impact Radius	60%
Building Density	40%

The Impact Radius is a function of the pipe's network MOP (maximum operating pressure) and diameter (ASME B31.8S-2012):

$$\text{Impact Radius (metres)} = 0.00315 \bullet (\text{Pipe Diameter (mm)}) (\sqrt{\text{MOP (kPa)}})$$

The following factors are applied to the pipe segments based on their Impact Radius:

Minimum Impact Radius	***Maximum Impact Radius***	***Impact Radius Factor***
80	1000	1
60	80	0.8
40	60	0.6
20	40	0.4
0	20	0.2

The building density is estimated using the electrical service points around the pipeline. The service points 100m on either side of the line and along the length of the segment are counted. The results are then adjusted to estimate the building density (points/hectare). The following factors are applied to the pipe segments based on their estimated building density:

Minimum Building Density	***Maximum Building Density***	***Building Density Factor***
25	50	0.7
20	25	0.6
15	20	0.5
10	15	0.4
5	10	0.3
0	5	0.2

It is recognized that the population density is not a direct relation to the electrical demand points as there would be multiple residents in one home and largely populated buildings may be serviced by one point (ex. Offices). For this reason, the downtown area with distribution facility code D3008 is given an elevated building density factor of 0.7.

11.2. Economic Loss

The Economic Consequence Category Score is a future consideration.

11.3. Environment

The Environment Score is a future consideration.

12. Risk Assessment Model Results

12.1. Risk Estimation

The Frequency Analysis score (max. 10) and Consequence Analysis score (max. 10) are multiplied to obtain the total Risk score for each pipe segment. The complete pipeline network consists of over 33,000 segments, therefore, only the top 100 risk ranked segments are listed in Table 1. Focusing resources on the top ranking segments is the most effective means of improving the safety and reliability of the whole network.

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

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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

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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

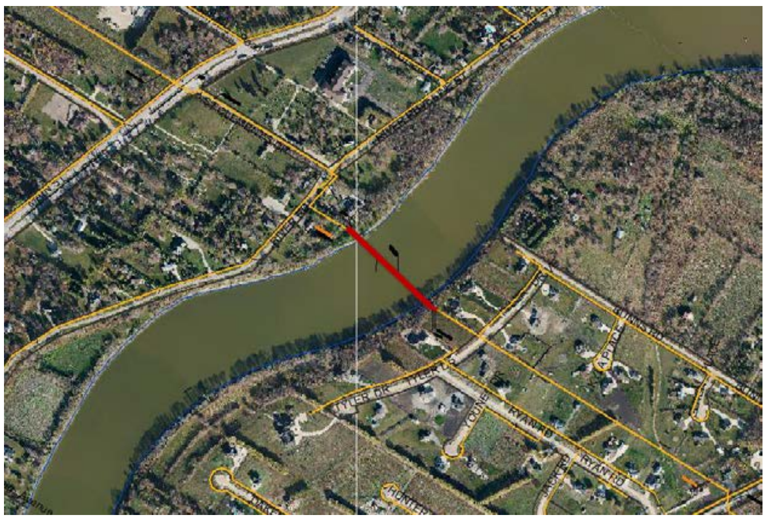
The following is an evaluation of the highest ranking pipe segments by risk score.

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.

13.2. La Salle Transmission Pipe at PTH 100

Rank: 2 & 3	**ID:** 37763138 & 104529414	**Facility Code:** T3001.003 & T3001.001C

Pipe Attributes: Steel 323.9mm transmission pipe (4830 kPa Network MOP). Constructed in 1955.

Pipe Location: LaSalle Transmission Pipeline PTH 100 crossing and segment north of crossing.

Scores:

Ext. Human Interf.(10)	Corrosion (10)	Natural Forces (10)	Const. / Mat. Defect (10)	Frequency Score (10)	Consequence Score (10)	Risk Score (100)
2.8	2.8	1.3	0.5	2.5	5.6	14

Primary Risk Drivers:

The primary frequency drivers are External Human Interference and Corrosion. The External Human Interference score is elevated due to insufficient covers at this location. The remediation has recently been completed (MER 2013-01003) however the records have not yet been updated.

The Corrosion Score is elevated due to the age and coating (coal tar wrap) of the pipeline.

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

Risk Significance:

The risk is no longer significant as the insufficient cover at this location has recently been remediated.

This pipe is a critical supply feed and some of the oldest pipe in the network. An External Corrosion Direct Assessment (ECDA) survey was completed in 2005 however nearly 10 years has passed. This pipeline would benefit from either an ECDA or In-Line-Inspection (ILI) at this time.

Options analysis:

Now that the insufficient cover remediation is complete, the External Human Interference score will be reduced from 2.8 to 1.3. The resulting risk score will be reduced 28 % from 14.0 to 10.1. A risk score of 10.1 would be ranked 340th overall.

If ECDA or ILI was conducted, a mitigation score would be applied and the resulting risk score would be reduced an additional 50% from 10.1 to 5.1 in the first year.

13.3. Distribution Pipe Lipton Street

Rank: 4	**ID:** 35356274	**Facility Code:** D3007

Pipe Attributes: Steel 60.3mm distribution pipe (420 kPa Network MOP). Energized date unknown.

Pipe Location: Lipton Street between St. Mathews and Ellice in Winnipeg.

Scores:

Ext. Human Interf.(10)	Corrosion (10	Natural Forces (10)	Const. / Mat. Defect (10)	Frequency Score (10)	Consequence Score (10)	Risk Score (100)
1.7	6.6	0.7	2.9	3.3	4.0	13.4

Primary Risk Drivers:

The primary frequency driver is Corrosion. The Corrosion Score is elevated due to the age and cathodic protection history of the pipe segment.

The primary consequence driver is that the pipe segment is in a high density area.

Risk Significance:

The risk is significant at this location. This segment is part of cathodic section NW01-0038 which has recorded almost 7 years in downtime. However, there has only been one recorded corrosion leak dated 8/7/1990 at a tape joint. This segment would benefit from a condition assessment of the cathodic protection system.

Options analysis:

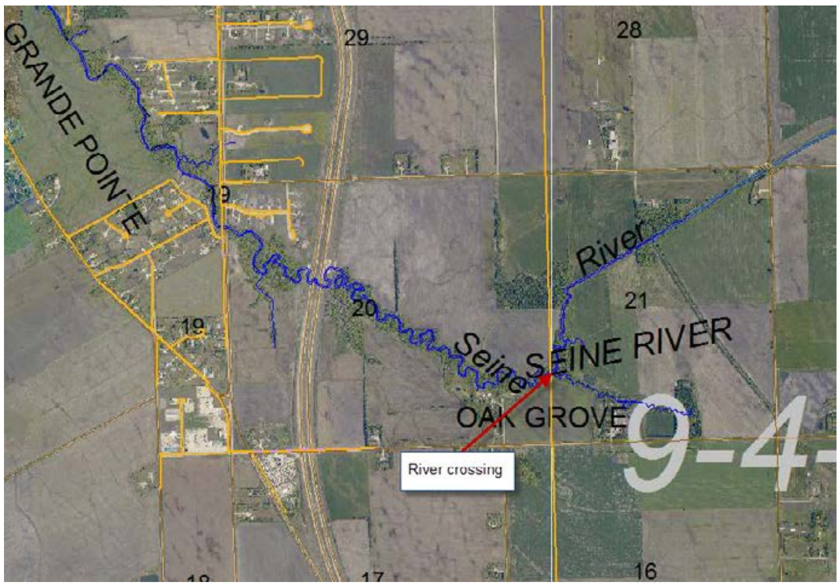
If a condition assessment of the cathodic protection system was conducted, a mitigation score based on the results would be applied, reducing the total risk score.

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:

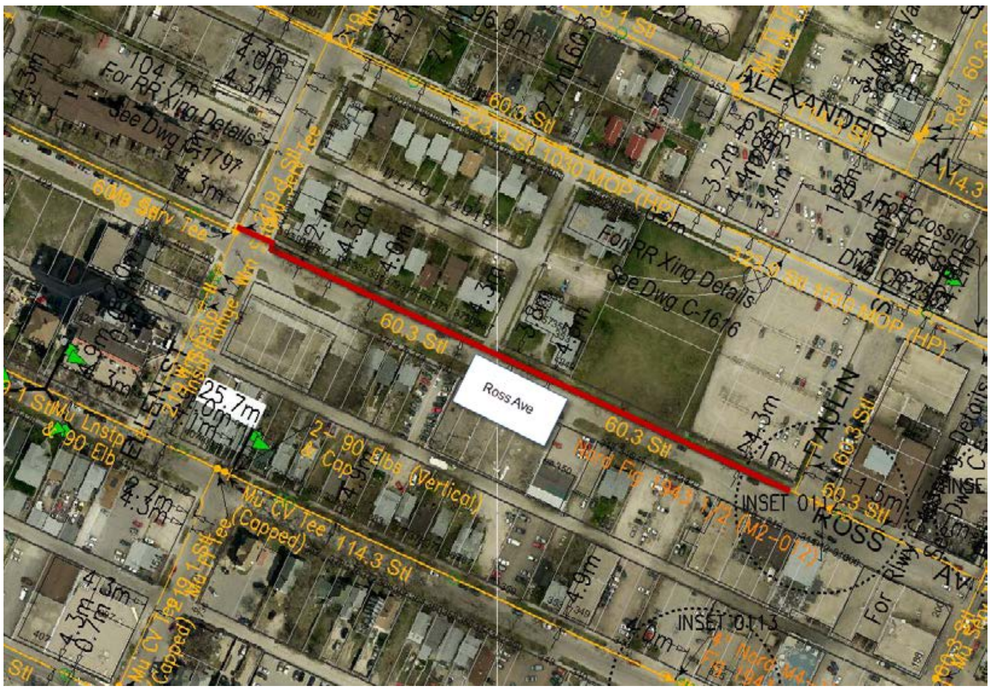
If a new depth of cover survey is performed to confirm the cover over the pipe segment and the potential influence of any bank instability, a mitigation score would be applied and the resulting risk score would be reduced 27% from 13.0 to 9.5 for the first year. A risk score of 9.5 would be ranked 492nd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

13.5. Distribution Pipe Ross Avenue

Rank: 6	**ID:** 34297408	**Facility Code:** D3008

Pipe Attributes: Steel 60.3mm distribution pipe (420 kPa Network MOP). Energized date unknown.

Pipe Location: Ross Avenue 300 block in Winnipeg.



Scores:						
Ext. Human Interf.(10)	Corrosion (10	Natural Forces (10)	Const. / Mat. Defect (10)	Frequency Score (10)	Consequence Score (10)	Risk Score (100)
1.7	6.6	0.7	0.5	3.2	4.0	13.0

Primary Risk Drivers:

The primary frequency driver is Corrosion. The Corrosion Score is elevated due to the age and cathodic protection history of the pipe segment.

The primary consequence driver is that the pipe segment is in a high density area.

Risk Significance:

The risk is significant at this location. This segment is part of cathodic section NW02-0013 which has recorded 6.3 years in downtime. However, there has only been one recorded corrosion leak dated 7/21/1990. This segment would benefit from a condition assessment of the cathodic protection system.

Options analysis:

If a condition assessment of the cathodic protection system was conducted, a mitigation score based on the results would be applied, reducing the total risk score.

13.6. Distribution Pipe King Street & Notre Dame

Rank: 7	**ID:** 6882203	**Facility Code:** D3008

Pipe Attributes: Steel 114.3mm distribution pipe (420 kPa Network MOP). Energized date unknown.

Pipe Location: King Street & Notre Dame Avenue in Winnipeg.

Scores:

Ext. Human Interf.(10)	Corrosion (10)	Natural Forces (10)	Const. / Mat. Defect (10)	Frequency Score (10)	Consequence Score (10)	Risk Score (100)
1.7	5.8	0.7	5.3	3.2	4.0	12.7

Primary Risk Drivers:

The primary frequency driver is Corrosion. The Construction / Material Defect Score is also elevated however it has little impact on the overall Frequency Score due to its low weighting (4%) relative to the other hazards. The Corrosion Score is elevated due to the age and cathodic protection history of the pipe segment. The Construction / Material Defect Score is elevated due to failure history.

The primary consequence driver is that the pipe segment is in a high density area.

Risk Significance:

The risk is significant at this location. This segment is part of cathodic section NW02-0014 which has recorded almost 7 years in downtime. However, there have been no recorded corrosion leaks. This segment would benefit from a condition assessment of the cathodic protection system.

The segment does have two previous failures attributed to construction / material defects (dated 6/9/2006 and 2/1/1985). Two construction / material leaks are not unusual considering the age of the pipeline and do not suggest a pattern of failure.

Options analysis:

If a condition assessment of the cathodic protection system was conducted, a mitigation score based on the results would be applied, reducing the total risk score.

13.7. Distribution Pipe Ingersoll Street

Rank: 8	**ID:** 35353653	**Facility Code:** D3007

Pipe Attributes: Steel 60.3mm distribution pipe (420 kPa Network MOP). Energized date unknown.

Pipe Location: Ingersoll Street between Ellice and Wellington in Winnipeg.

Scores:

Ext. Human Interf.(10)	Corrosion (10)	Natural Forces (10)	Const. / Mat. Defect (10)	Frequency Score (10)	Consequence Score (10)	Risk Score (100)
1.7	5.8	0.7	5.3	3.2	4.0	12.7

Primary Risk Drivers:

The primary frequency driver is Corrosion. The Corrosion Score is elevated due to the age and cathodic protection history of the pipe segment.

The primary consequence driver is that the pipe segment is in a high density area.

Risk Significance:

The risk is significant at this location. This segment is part of cathodic section NW01-0005 which has recorded 6.3 years in downtime. However, there are no reported corrosion leaks. This segment would benefit from a condition assessment of the cathodic protection system.

Options analysis:

If a condition assessment of the cathodic protection system was conducted, a mitigation score based on the results would be applied, reducing the total risk score.

13.8. Distribution Pipe Harbison Ave

Rank: 9	**ID:** 27316244	**Facility Code:** D3205

Pipe Attributes: Steel 60.3mm distribution pipe (420 kPa Network MOP). Energized date unknown.

Pipe Location: Harbison between Brazier and Henderson in Winnipeg.

Scores:

Ext. Human Interf.(10)	Corrosion (10)	Natural Forces (10)	Const. / Mat. Defect (10)	Frequency Score (10)	Consequence Score (10)	Risk Score (100)
2.8	4.8	0.7	10	3.5	3.6	12.6

Primary Risk Drivers:

The primary frequency driver is Corrosion. The Construction / Material Defect Score is also elevated however it has little impact on the overall Frequency Score due to its low weighting (4%) relative to the other hazards. The Corrosion Score is elevated due to the age and cathodic protection history of the pipe segment. The Construction / Material Defect Score is elevated due to failure history.

The primary consequence driver is that the pipe segment is in a high density area.

Risk Significance:

The risk is significant at this location. This segment is part of cathodic section NE01-0006 which has recorded 4.3 years in downtime. However, there have been no recorded corrosion leaks. This segment would benefit from a condition assessment of the cathodic protection system.

A review was conducted of the 8 below grade leaks on this pipe segment. Six of the leaks were directly attributed to dresser couplings and the other two leaks were classified as unknown cause. The conclusion is that these leaks occurred on high pressure services off the adjacent high pressure main that have since been abandoned. The services were relocated to the distribution main and the leak information which was attached to the service tee moved as well. All 8 of the leaks occurred between the years of 1985-1987. High pressure services have since been abandoned and the use of dresser couplings discontinued. No new leaks have been recorded in the past 27 years. This pipe segment will continue to be monitored by integrity activities including the Leak Survey Program and Below Grade Leak Analysis.

Options analysis:

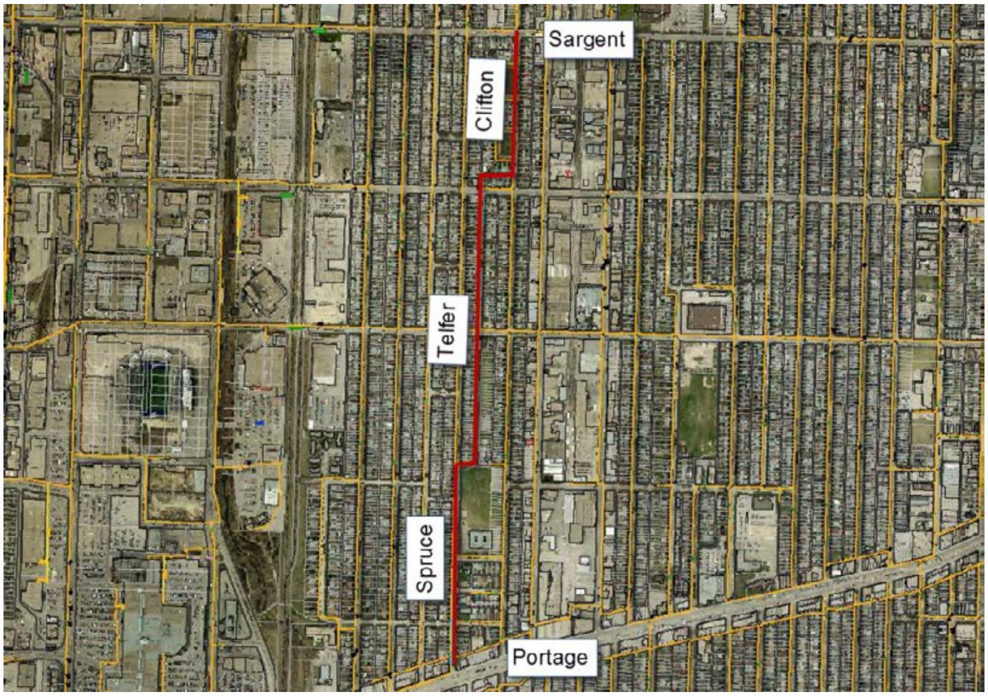
If a condition assessment of the cathodic protection system was conducted, a mitigation score based on the results would be applied, reduction the total risk score.

13.9. High Pressure Pipe Spruce, Telfer and Clifton

Rank: 10	**ID:** 36026367	**Facility Code:** H3015

Pipe Attributes: Steel 355.6mm high pressure pipe (1720 kPa Network MOP). Energized date unknown.

Pipe Location: Spruce, Telfer and Clifton between Portage and Sargent in Winnipeg.



Scores:

Ext. Human Interf.(10)	Corrosion (10)	Natural Forces (10)	Const. / Mat. Defect (10)	Frequency Score (10)	Consequence Score (10)	Risk Score (100)
1.7	3.8	0.7	0.5	2.3	5.6	12.6

Primary Risk Drivers:

The primary frequency driver is Corrosion. The Corrosion Score is elevated due to the age and cathodic protection history of the pipe segment.

The consequence drivers are that the pipe segment is in a high density area and that it has a larger impact area.

Risk Significance:

The risk is significant at this location. This segment is part of cathodic section WPG-9017 which has recorded 1.4 years in downtime. There have been no reported corrosion leaks; however this is a high pressure main through a dense residential neighborhood. This segment would benefit from a condition assessment of the cathodic protection system.

Options analysis:

If a condition assessment of the cathodic protection system was conducted, a mitigation score based on the results would be applied, reducting the total risk score.

14. Conclusions and Recommendations

The purpose of the Pipeline Risk Assessment Program is to identify the pipe segments with the highest relative risk. The goal is to improve the overall integrity of the pipeline network by focusing on reducing those highest ranked segment's risk scores.

The 2014 Pipeline Risk Assessment Model identified 10 sites for further risk evaluation and investigation into the primary risk drivers and the risk significance. If the risk was considered significant, an options analysis was conducted to determine what effect mitigative action would have on risk score reduction. The sites with significant risk and recommended action are:

- <u>Transmission Pipe Red River Crossing near Selkirk:</u> has a significant risk driven by External Human Interference and Natural Forces hazards. The location does not meet minimum depth of cover requirements and has geotechnical concerns with bank instability. This site was previously identified for remediation (MER 2013-04839) with an anticipated in-service-date of 2015.

- <u>La Salle Transmission Pipe at PTH 100:</u> has a significant risk driven by External Human Interference and Corrosion hazards. However, 3 insufficient covers at this site have recently been remediated which reduces the overall risk score. As a critical supply feed and some of the oldest pipe in the network, this pipeline would benefit from an In-Line Inspection or an External Corrosion Direct Assessment (ECDA) Survey. An initial ECDA survey was completed in 2005.

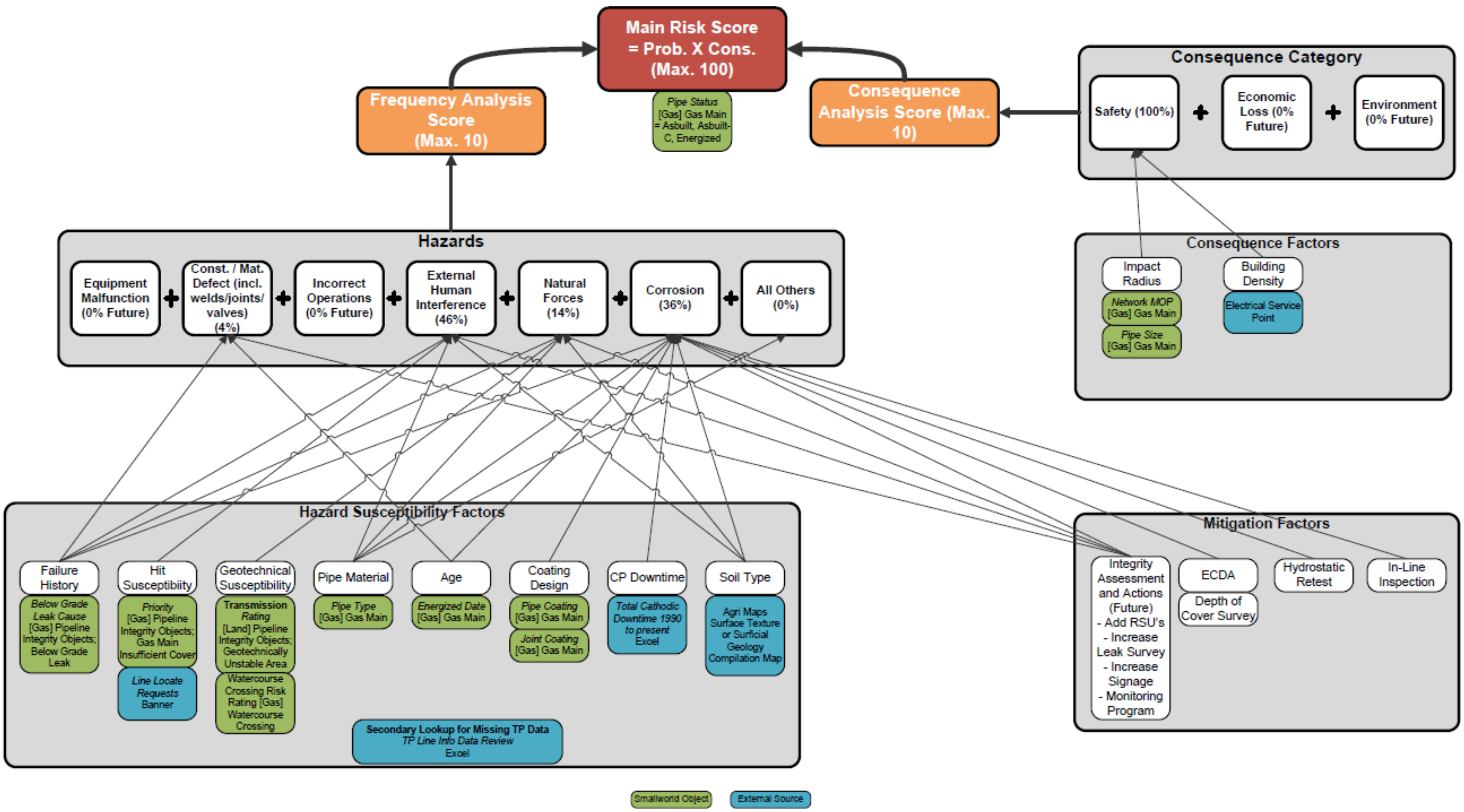
- <u>Transmission Pipe Seine River Crossing near Grande Pointe:</u> has a significant risk driven by Natural Forces hazard. This site would benefit from a new depth of cover survey as the current survey is from 1997 and geotechnical potential for scour and lateral erosion is high. This site has been scheduled for a new depth of cover survey in 2015.

- <u>Distribution Pipe Segments on Lipton Street, Ross Avenue, King Street & Notre Dame Avenue, Ingersoll Street, and Harbison Avenue;</u> have a significant risk driven by Corrosion hazard. These segments would benefit from a condition assessment of their cathodic protection systems.

- <u>High Pressure Pipe on Spruce, Telfer and Clifton;</u> has a significant risk driven by Corrosion hazard. This segment would benefit from a condition assessment of their cathodic protection systems.

Manitoba Hydro

Appendix A: MB hydro Pipeline Risk Assessment Structure



Appendix B: CGA Incident Cause Guidance

Cause	Sub-Cause	Guidance Notes
Corrosion / Degradation	Metal Loss	e.g. corrosion leaks
	Metal Cracking	
	Plastic Degradation	any time-dependent plastic pipe failure - e.g. split pipe, cracking, "1st generation" PE pipe with splitting tendency during squeeze-off
Equipment Malfunction	Control System Malfunction	regulator, control valve, or relief valve failure causing over-pressure
	Mechanical Fitting Malfunction	mechanical fitting failure (would include compression fittings, seals/gaskets), but does not include instances where another primary cause exists (e.g. geotechnical, 3rd party, etc.)
	Valve Malfunction	leaking valve, not repairable by regular maintenance
External Interference	1st or 2nd Party	1st Party - Company Employee 2nd Party - Company Contractor
	3rd Party	3rd Party - Contractor, Homeowner, Landowner, Other Utility, etc. Includes acts of terrorism, vandalism, etc.
Incorrect Operation	Improper Operation	post-commission: not following procedures, not having competency/training
	Insufficient Procedures	post-commission: insufficient procedure provided, inadequate documentation and/or records
Material, Manufacturing or Construction Defect	Defective Pipe Body	leaks caused by manufacturing or delivery of the pipe (e.g. laminations, seam weld defects)
	Defective Joining Method	leaks caused by improper welds, fusion, and mechanical fittings (improper installation)

	Other Improper Construction	leaks caused by pre-commission construction issues (e.g. not following procedures, not having competency/training, cross bore, loose tee cap, cracked tee cap due to over tightening)
Natural Forces	Geotechnical	includes soil erosion, ground movement, earth ground, frost heave
	Weather Related	includes lightning, flooding
	Wild fire	
	Wildlife / Animal	
Unable to Classify	Unable to Classify	

Reference Publications

ASME International (American Society of Mechanical Engineers)-B31.8S-2012 Managing System Integrity of Gas Pipelines

Baker, Michael. Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation. Integrity Management Program Delivery Order DTRS56-02-D-70036, 2004.

CAN/CSA (Canadian Standards Association)-Z662-11 Oil and Gas Pipeline Systems

Peabody, A.W. Peabody's Control of Pipeline Corrosion. 2nd ed. U.S.A: NACE Press, 2001.

The names and qualifications of personnel who participated in analysis

1. Lindsay Gigian, PEng. Pipeline Integrity
2. Kevin Morgenstern, EIT. Pipeline Integrity
3. Dan Shmyr, Administrator. Pipeline Integrity
4. Dan Prydun, PEng. Gas Standards and Pipeline Integrity.
5. Dave Petursson, PEng. Distribution Standards
6. Fernando Velandia, PEng. Corrosion Prevention

REFERENCE:

Tab 4, p.21 of 22, lines1-3

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide more information on the "materials tracking and traceability system for pipeline materials being installed as part of new construction" that Centra plans to evaluate as a part of its transition from asset maintenance to asset management. At a minimum, please describe the functional capabilities and intended uses of such a system in the context of pipeline system asset management, investment planning, and work execution.
b) Please describe the tools and processes currently in place at Centra to forecast the need for and track materials used in new construction, before, during, and after the completion of construction projects.
c) Please provide a calculation for Centra's Materials and Supplies Inventory Turns and Average Days in Inventory for the most recent five years. Please list all assumptions and material exclusions, if any.

RESPONSE:

a) The materials tracking and traceability system being implemented for transmission and high pressure pipeline systems is a material data record management system that will capture material information including specific location, manufacturer, and material test records or other appropriate material documentation. This exceeds current CSA Z662 requirements but reflects industry trends including the Canadian Gas Association Materials Traceability Task Force Guidance for Operators and Vendors (March 2018). This work is in response to materials being purchased and installed that are subsequently found to not meet the required material performance. These issues have been identified by the National Energy Board and major pipeline owners. This system and the additional detail it provides will permit a directed response to any issues which are identified after the material has been installed in the natural gas system. This system may provide input into investment planning if installed materials are subsequently determined to not be satisfactory for long term operation. This system will not directly affect project execution.

b) Quantities of materials stocked at Central Stores are generally ordered to maintain minimum levels and to reflect historic monthly usage. Multi-year outline agreements are tendered and put in place to reduce delivery times. Larger project materials, such as steel pipe or larger diameter polyethylene pipe, will be specifically ordered for the project and delivered directly to the project site.

Before Project Start:

Materials that are commonly used are stocked at our Central Stores. Materials that are not widely used or specialized are secured on a project specific basis.

RUCES (Regional Unit Cost Estimating System) and SAP (Systems, Applications & Products) are used to create an STO (Stock transfer order) to order the necessary materials through our central stores on an individual project basis.

Specialized materials that are not stocked at Manitoba Hydro Stores are secured and ordered through Purchasing following Purchasing's policies and guidelines.

During:

All project materials are ordered prior to project and picked up by the construction contractor performing the work. The Gas Inspector on site verifies all materials with the contractor representative to confirm all the necessary materials have been delivered for the project. The Gas Inspector also verifies the installation of the material on the as-built drawings.

After Project Completion:

Once a project is complete, for our base business contractors they will typically keep the extra materials in their inventory for future projects. For contractors on tendered projects, the materials will be returned and restocked at Notre Dame Stores, Central Stores, or Sutherland Stores.

For base business material issued by Centra, the contractor is responsible to provide an inventory report when requested. Centra sends an inspector to the Contractor's yards once per year to confirm their inventory.

Construction Supervisors also review Contractor bulk material requests before an STO is created. This pipe is tracked for 2" & 4" pipe to charge back to MERs when bulk pipe is used. Again, this is confirmed on site by the inspectors as well as yearly on inventory checks in the Contractor's yards.

c) Information on Centra's materials and supplies are:

Year		Turns		Average Stock Value		Total Usage Value
2018		3.17		$ 1,796,447		$ 5,686,104
2017		2.83		$ 1,823,982		$ 5,223,896
2016		3.32		$ 1,959,708		$ 6,501,823
2015		2.71		$ 2,178,098		$ 5,895,231
2014		2.36		$ 2,546,980		$ 6,010,943

Centra does not have a method to account for days in inventory.

Materials do not include materials directly ordered for projects including the majority of steel pipe, large diameter polyethylene pipe, major valves, most hot tap fittings and select other fittings. Selected materials are purchased by installation contractors for stations projects.

REFERENCE:

Tab 4, p. 22 of 22, lines 1-2.

PREAMBLE TO IR (IF ANY):

The reference speaks of Centra's plans to evaluate potential natural gas industry software that may assist the company in the transition to a Reliability-Centered Maintenance (RCM) approach

QUESTION:

a) Please confirm that the Copperleaf C-55 system that is being implemented at Manitoba Hydro / Centra, does not possess the modules that would enable Centra to adopt some contemplated RCM features or practices.
b) If confirmed, please describe the types of functions and analytical outcomes that the desired natural gas industry software would possess. If early business cases and/or cost estimates are available, please provide them.

RESPONSE:

a) Confirmed. The Copperleaf C-55 system that is being implemented at Manitoba Hydro/Centra does not possess the modules that would enable Centra to adopt some contemplated RCM features or practices.

b) Centra has reviewed natural gas industry software options and the functions and analytical outcomes that are of interest include mechanistic-probabilistic risk models that could be used to assess overall system risk and relative risk rankings within and across asset families to forecast future asset replacement requirements. Business cases and cost estimates are not available at this time.

REFERENCE:

Appendix 4.1, p. 4 of 17

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please elaborate on the nomenclature used in the "Project Status" column in the CEF18 Capital Expenditure and DSM Forecast Tables. Specifically, please confirm whether the "New Project" identifier suggests that the project is yet to commence execution at the time of filing, and/or is yet to receive internal approval to proceed.
b) When it comes to project status tracking more generally, please provide several representative examples of any standard internal project and program status reporting documents that are in use at Centra gas today for projects in excess of $1 million.

RATIONALE FOR QUESTION:

RESPONSE:

a) The 'Project Status' column in CEF18 categorizes all approved projects within the CEF as either 'Executing' or 'New'. Executing projects are those which have commenced construction whereas new projects are those in the planning or contracting stages.

b) Centra utilizes the Finance Centre for standard internal project and program status reporting. The Finance Centre was developed by Manitoba Hydro, and adopted by Centra, to offer a central location for standardized reporting functions. It provides access to timely and relevant financial information, which can be customized to the required level of detail, based upon the user's requirements. These on-line reports allow the users to select their own reporting criteria such as year-to-date, life-to-date, approved, etc., as well as sorting and filtering capabilities to allow focus on projects greater than $1 million. The Finance Centre reports are available to all staff and management.

Please see discussion included in CAC/CENTRA I-35d for additional project and program reporting controls and analysis performed.

REFERENCE:

Appendix 4.1, pp. 1 and 5 of 17 (CEF 18 and CEF 16)

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please describe the differences in terms of scope and function of the line item “Target Variance” used in CEF 18 (p. 1) and the line item “Portfolio Adjustment” used in CEF 16 (p.15).

b) Are the two categories intended to capture the impact of similar considerations?

   i. If yes, please describe the rationale for the significant differences in magnitude between the annual Target Variance Values in CEF 18 and the annual Portfolio Adjustment values in CEF 16.

   ii. If not, please describe the steps Centra took to allocate or otherwise account for the Portfolio Adjustment values when preparing CEF 18 and reconciling it with CEF 16.

RESPONSE:

a) The ‘Target Variance’ used in CEF18 and ‘Portfolio Adjustment’ used in CEF16 are both representative of the difference between annual capital spend targets and detailed project and program forecasts.

b) As discussed in PUB/Centra I-66(a-b) Business Operations Capital (“BOC”) targets are reviewed annually at the Vice-President level to assess if the allocation of funds is appropriate to balance operational priorities and optimize overall corporate value considering changes in business, financial and economic assumptions as well as operational risk factors. Based upon this review, the CEF18 10 year forecast was increased from CEF16 to reflect these requirements. In addition, Centra justified and approved 6 new projects, as shown on Page 4 of Appendix 4.1, and further refined its annual program requirements. As a result, the target variance amount declined substantially from CEF16.

REFERENCE:

Appendix 4.1, p. 3 of 17

PREAMBLE TO IR (IF ANY):

QUESTION:

Please confirm whether the DSM expenditure forecasted in CEF18 constitute capital or operating expenditures for the purposes of Centra's regulatory accounting.

RATIONALE FOR QUESTION:

RESPONSE:

DSM expenditures as forecasted in CEF18 are initially recorded in Other Expenses and then completely offset by recording equivalent amounts to the regulatory deferral account and the Net Movement in Regulatory Deferrals account. This basis of accounting recognizes DSM expenditures similar to capital expenditures in that they are initially deferred/capitalized and subsequently amortized to net income over a ten year period through the Net Movement account.

REFERENCE:

Appendix 4.1, p. 2 of 17, graphic "2018/19 Natural Gas Business Operations Capital by Investment Category."

PREAMBLE TO IR (IF ANY):

QUESTION:

a) For CEF18 projects and programs categorized as Mandated Compliance (including those below the $1M materiality threshold showcased in the exhibit), please provide a table showcasing the 10 most common compliance issues that the projects / programs seek to address, indicating the proportion of each type of project / issue within the CEF18 Mandated Compliance budget. Please indicate the specific legislative / regulatory /internal corporate instruments driving each type of planned investments.
   i. If Capital Investment Justifications / Capital Project Justifications for these projects are available, please file them as well.

b) Please confirm whether the definitions of System Renewal and System Efficiency Capital in the CEF18 (as showcased in the referenced graphic) are consistent with the verbal definitions of the same categories provided on p. 7 of 17 of Appendix 4.1 in reference to CEF16.

c) If the definitions of Renewal and Efficiency are the same in CEF18 as in CEF16, please articulate with the help of specific 2018-2020 project examples the criteria, evidence and other aspects of planning and decision-making process underlying the selection and planning of System Renewal relative to System Efficiency investments.

RESPONSE:

a) The most common compliance issues that Centra's Mandated Compliance investments seek to address are as follows:

   CSA Z662 is the PUB adopted standard for the design, construction, operations and maintenance of Centra's natural gas distribution system. CSA Z662 defines minimum requirements for the natural gas system. Specific examples include:

- Insufficient cover (pipeline integrity) - if a pipeline is found to not have the minimum amount of cover defined by CSA Z662, the pipe is identified to have a higher risk of damage. Several options are available to address non-compliance with the standard.
- Conduct leak surveys and investigate evidences of leaks. Leaks are then repaired for safety reasons.

Electricity & Gas Inspection Act - Compliance is required to permit the sale of natural gas on the basis of measurement.

PUB Order 159/11 and associated franchise agreements - include the requirement for “the removal or relocation of any part of the Gas Distribution System” when required by the Municipality.

Corrective Action Request – Centra’s Natural Gas Quality Assessment Process (“QAP”) was established by the PUB to assess and validate the Corporation’s competency and performance in the design, construction, operation, and maintenance of the natural gas transmission and distribution system. Corrective Action Requests are issued in response to a non-conformance identified through the QAP process.

The table below provides a list of Mandated Compliance projects and programs, the associated compliance issue being addressed, as well as the proportion of the total Mandated Compliance investment for the 2019/20 Test Year.

Program or Project	Legislative/Regulatory/Internal Corporate Instrument	Proportion of the CEF18 Mandated Compliance Budget
System Betterment: Integrity Program	Compliance for selected integrity items is required to meet the requirements of CSA Z662-15 Oil and Gas Pipeline Systems adopted by PUB Board.	40%
Gas Meter Compliance Program	Compliance is required to meet the Electricity and Gas Inspection Act.	33%
System Betterment: Plant Relocates Program	Compliance is required to meet PUB Board Order 159/11 and franchise agreements with individual cities, towns, rural municipalities or local government districts.	11%
Gas Leak Upgrades & Other Program	Compliance for selected customer service operations activities is required to meet the requirements of CSA Z662-15 Oil and Gas Pipeline Systems adopted by PUB Board.	8%
Medium Pressure Monitoring System Replacement Project	Work is in response to an identified non-compliance identified by Centra's Natural Gas Quality Assurance Program; Corrective Action Request Number DPW-NC-041.	8%

i. PUB/CENTRA 1-73 includes the Capital Investment Justifications (CIJ's) for the programs and project shown in the table above.

b) Confirmed, the definitions of System Renewal and System Efficiency are consistent between CEF18 and the definitions of the same categories provided on p. 7 of 17 of Appendix 4.1 in reference to CEF16.

c) As outlined in Appendix 4.2 of the Application, investment categories are commonly used within the industry to provide stakeholders with a better understanding of the primary driver for an investment. Centra does not set targets by investment categories. Projects are identified and developed to respond to an opportunity to reduce the risk of an outage, to minimize the size and duration of an outage or to improve the safe operation of the pipeline system. The project costs and benefits are reviewed as part of the management approval process before the project proceeds to implementation.

System Renewal projects replace, refurbish or remove an existing asset whereas System Efficiency projects either add a new asset or perform work on existing assets to improve the operation of the system with the goal of reducing costs, minimizing outage frequency/duration and/or prevent equipment damage.

The Brandon Primary Station Re-Construction project is an example of a System Renewal project. The Brandon Primary Station, originally constructed in 1957, is a critical asset in the gas distribution network and is the sole natural gas feed for the City of Brandon, Koch Industries, Husky Ethanol and surrounding area. Upgrades to the station were required to maintain reliability, increase capacity, reduce maintenance costs, reduce greenhouse gas emissions, and optimize land use. The last major regulation upgrade to the station occurred in 1987.

The St. Andrews Distribution System Upgrade project is an example of a System Efficiency project that was recommended for the natural gas distribution network in the RM of St. Andrews (northeast Winnipeg) as the capacity in this region was depleted and areas were operating below the minimum design pressure.

REFERENCE:

Appendix 4.1, Appendix 4.2, Appendix, 4.3

PREAMBLE TO IR (IF ANY):

While Appendix 4.2 provides the definitions of investment categories that Manitoba Hydro and Centra have adopted a common set of Level 1 and Level 2 Investment Category Definitions, Appendix 4.3 entails the utility's 2018-2023 asset management / capital investment plan, which employs different investment categorization nomenclature from that introduced in Appendix 4.2 and used in financial forecast tables in Appendix 4.1.

QUESTION:

a) Please provide an explanation as to why Centra's Capital Investment Plan introduced in Appendix 4.3 utilizes an investment categorization different from the nomenclature introduced as the newly applicable standard in the Appendix 4.2.
b) Please restate the Cost Summary table on pp. 10 and 11 of 64 in Appendix 4.3 using the standard investment nomenclature described in Appendix 4.3

RESPONSE:

a) Appendix 4.3 does not use a different investment categorization as noted in Appendix 4.2. Appendix 4.3 does not explicitly show the investment categories. All projects noted in Appendix 4.3 have associated Level 1 and Level 2 investment categories. All of the program items within programs will have associated Level 1 and Level 2 investment categories.

b) The following table provides the investment categories for all Programs and Projects in the Cost Summary in Appendix 4.3:

PROGRAMS	Level 1	Level 2
New Business	Capacity & Growth & Sustainment	Customer Connections & System Renewal
System Betterment- Relocations	Sustainment	Mandated Compliance & System Renewal
System Betterment- Integrity	Sustainment	Mandated Compliance & System Efficiency &System Renewal
System Betterment- Capacity & Other	Sustainment	Mandated Compliance &Decommissioning &System Efficiency & System Renewal
System Betterment- Measurement & Regulator Stations	Sustainment	System Efficiency & System Renewal
Meter Compliance Program	Capacity & Growth & Sustainment	Customer Connections &Mandated Compliance
Customer Service Operations- Capital	Sustainment	Mandated Compliance & System Efficiency &System Renewal
Gas Apparatus Maintenance & Control	Sustainment	Mandated Compliance & System Efficiency &System Renewal
Corrosion Control	Sustainment	System Efficiency
PROJECTS		
Winnipeg Waverley West MP - Phase 2	Capacity & Growth	System Load Capacity
Steinbach TP Upgrade	Capacity & Growth	System Load
St. Andrew's Distribution Upgrade	Sustainment	System Efficiency
In-Line Inspection Program	Sustainment	System Efficiency
Cathodic Rectifier Remote Monitoring Devices	Sustainment	System Efficiency
GS-123 Brandon Primary Gate Station Upgrades	Sustainment	System Renewal
Portage la Prairie TP Main – Secure Gas Supply	Sustainment	System Efficiency
Distribution System Monitoring	Sustainment	System Efficiency
St. Pierre TP Upgrade	Capacity & Growth	System Load Capacity
Red River TP Pipeline Replacement	Sustainment	System Efficiency
Addressing Encroachment on Pipelines	Sustainment	Mandated Compliance

REFERENCE:

Appendix 4.3 general, and Cost Summary table (pp. 10-11 of 64)

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please describe whether and how the preparation of the 2018-2023 Natural Gas Asset Management and Capital Investment Plan considered the trade-offs between maintenance and capital work associated with projects and programs comprising the forecast.
   i. Provide specific examples with quantified trade-offs for different types of projects and programs.

b) Please identify all capital projects and programs among those showcased in the table on pp. 10-11 that Centra expects to result in incremental annual maintenance / O&A expenditures over the plan period. Please quantify the anticipated increases.

RESPONSE:

a) There is no prioritization of capital verses operations and maintenance spending at this time. Please see the response to the PUB/Centra I-66.

b) The installation of natural gas fired line heaters will result in an increase in natural gas consumption costs. The cost of the natural gas consumption for the new line heaters was approximately $42,000 including taxes for 2018. The future increase will be an average of $5,000 per year with each new line heater installed. Eight line heaters have been installed to date and it is planned that three line heaters will installed per year for at least the next three years.

   The Medium Pressure Monitoring system requires radio spectrum licenses for the radio communications used and an associated software license. Allowing labour and material to respond to an assumed 3% field equipment failure, the total annual additional cost is estimated at $60,000. These costs will be absorbed within the existing targets.

REFERENCE:

Appendix 4.3 Cost Summary table (pp. 10-11 of 64)

PREAMBLE TO IR (IF ANY):

The Cost Summary table includes a Planning Item line item under the Projects section, the absolute value of which amounts to 0%, 15.9%, 45.3%, 76.8% and 100% of the Projects category subtotal for the plan years one through five, respectively. An asterisk provided below the table explains the presence of this category as a function of future project scopes and dollars that are yet to be determined but forecasted as a general planning item in expectation of the future projects magnitude, referencing Section 5.13 of the document for further discussion.

QUESTION:

a) Please describe the planning process and supporting considerations to establish the annual numerical values for the Planning Item category for years two through five of the plan (i.e. 2019-20 through 2022-23).

RESPONSE:

The annual numerical values for the Planning Items category for years two through five of the plan are estimates based on past years' experience. If Centra did not allocate funds to a planning item, it would create an incorrect indication that there would be a reduced capital requirement in the future years. While specific approved projects are not identified or listed, the Natural Gas Planning and Pipeline Integrity groups have potential projects or issues which require further scoping and development prior to being submitted for formal approval. Year-over-year as projects are scoped and approved, these numbers will be adjusted as appropriate. Often large customers, unforeseen system events, or 3rd parties such as Manitoba Infrastructure can trigger projects that cannot be quantified or scoped more than a year or two out.

REFERENCE:

Appendix 4.3 Cost Summary table (pp. 10-11 of 64)

PREAMBLE TO IR (IF ANY):

The Cost Summary table includes a Planning Item line item under the Projects section, the absolute value of which amounts to 0%, 15.9%, 45.3%, 76.8% and 100% of the Projects category subtotal for the plan years one through five, respectively. An asterisk provided below the table explains the presence of this category as a function of future project scopes and dollars that are yet to be determined but forecasted as a general planning item in expectation of the future projects magnitude, referencing Section 5.13 of the document for further discussion.

QUESTION:

b) Given that Centra appears to only be able to forecast about half of its specific project spending requirements three years into the future, and 0% of its project spending requirements five years into the future, how much confidence does Centra have in its 10-year overall capital project forecasts associated with CEF18?
c) Are there plans to enhance the multi-year planning process to provide more clarity and certainty for the plan out-years, or is the current level of project visibility seen as appropriate? If so, please provide the details of the scope of activities and timelines to enhance this capability.

RESPONSE:

b) As discussed in Section 3 of the Appendix 4.3, the projects within the Natural Gas Asset Management Plan are well developed for a two year period whereas the future project investments have been incorporated into a Planning Item to reflect the continued requirement for funding. Investments are planned and executed to mitigate risks to the operability and sustainability of the system and the assessment of these requirements is an ongoing process in which forecasts and plans are updated to reflect information as it becomes available. The total investment requirements over the 10 year period, as shown in CEF18 in Appendix 4.1 of the Application, reflects the investment needed to ensure the operability and sustainability of the natural gas system. As such, based upon the information available at this time, Centra has confidence in the overall investment requirements of $403.9 million over the 10 year period from 2018/19 to 2028/29 as reflected in CEF18.

c) Improvements to the multi-year planning process are expected to be one of the future benefits of the implementation of a natural gas asset management plan. Current plans are for the natural gas asset management plan to be in place for 2020/2021.

REFERENCE:

Appendix 4.3 Cost Summary table (pp. 10-11 of 64), and Section 5.13 (p. 58 of 64).

PREAMBLE TO IR (IF ANY):

In addition to restating the Planning item amounts from the table on pp. 10-11, Section 5.13 on p. 58 also includes a reference to and cost forecasts for the Advanced Metering Infrastructure (AMI) program that is reportedly in the planning stages. The cost forecasts associated with the AMI program are $16.6 million, $21.4 million, and $20.9 million for years three through five of the current planning period (2021/21-2022/23). These amounts do not appear to be included into the Cost Summary Table on pp.10-11 and no dedicated explanation for this project is provided anywhere in the document.

QUESTION:

a) Please confirm that the AMI project cost forecasts are not included in the summary cost table on pp.10-11. If confirmed, please explain the rationale for withholding this material investment category from the overall cost summary.
b) Please advise whether the above-referenced AMI program costs are captured in any cost forecasts within CEF18. If so, please indicate the years and line items containing these cost forecasts.
c) Please confirm that if the AMI program proceeds in the timeframe indicated on p. 58, while the other capital project and program costs remain in line with the current forecasts, Centra's annual capital investment requirements would increase between 43%-55% per year in years 2020-21 through 2022-23 (taking the Net Total Costs forecasts as the base amounts and adding the forecasted AMI amounts).
d) Please provide any business cases or other planning documents outlining the cost and benefit considerations of the contemplated AMI program.

RESPONSE:

a) to d)

Confirmed. During the work to complete the 2018 Natural Gas 5-year Asset Management Plan, it was determined that the required business planning for a project of AMI's magnitude was not sufficiently developed to go forward and therefore, AMI project cost forecasts were not included in CEF18 or in the summary table in Appendix 4.3. During the preparation of this IR response, it was discovered that an Annual Budget for AMI was inadvertently included as a Planning Item on page 58 of Appendix 4.3 which should have been removed. A business case has not yet been finalized, nor has a potential project scope or timeline been determined. To date, neither the Manitoba Hydro nor Centra Gas Executive Committees have approved or been asked to review an AMI project. Please see CAC/CENTRA I-16 for further discussion of Manitoba Hydro's planning related to AMI.

REFERENCE:

Appendix 4.3, pp. 10-11 Cost Summary Table and footnotes.

PREAMBLE TO IR (IF ANY):

Asterisked item "**" on p. 11 states that the function of the Target Adjustment applied below the Total Cost Line is to "reduce the 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 … can affect project delivery and total spending."

QUESTION:

a) Please confirm that the value of Target Adjustments amounts to the reduction of a capital plan constructed "bottom up" down to the target level set by the company's Senior Executive / Board of Directors.
b) Please comment on the fact that the value of Target Adjustment line item in each of the five plan years invariable amounts to 10% of the total forecasted plan costs. Please explain the rationale for selecting 10% as a target value for all plan years.

RESPONSE:

a) and b)

The Target Adjustment in the Natural Gas Asset Management Capital Investment Plan is representative of the difference between annual capital spend targets as compared to detailed project / program forecasts and the recognition of a planning item. The planning item is representative of future investment requirements that are in the early stages of identification as well as considering historical experience and ongoing trends. For further information, see CAC/CENTRA I-37a-e.

A target adjustment of 10% considers historical cash flow trends and is reflective of the 6 year average variance to target as shown in PUB/CENTRA I-62.

REFERENCE:

Appendix 4.3, Section 4.1, pp. 12-13 of 64

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide the historical expenditures for the past five available plan years (2012/13 through 2016/17) New Business program or its functional equivalent, breaking out the expenditures:

i. before and net of customer contributions

ii. separately for residential and commercial service installations.

RATIONALE FOR QUESTION:

RESPONSE:

i. The following table provides the historical actual expenditures (i.e. not plant in service) for the New Business program, gross and net of customer contributions for the period 2012/13 through to 2016/17.

	Actual Expenditures ($ Thousands)				
New Business	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Gross Expenditures	19 403	14 673	16 156	16 708	16 839
Customer Contributions	(2 782)	(2 032)	(3 089)	(1 788)	(2 685)
Total	**16 621**	**12 641**	**13 067**	**14 920**	**14 153**

ii. The following table provides the historical actual expenditures (i.e. not plant in service) for residential and commercial service installations for the period 2012/13 through to 2016/17.

	Actual Expenditures ($ Thousands)				
New Business	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Residential Services	7 005	6 999	8 451	7 836	7 128
Commercial Services	9 617	5 641	4 616	7 084	7 025
Total	**16 621**	**12 641**	**13 067**	**14 920**	**14 153**

REFERENCE:

Appendix 4.3, Section 4.1, pp. 12-13 of 64

PREAMBLE TO IR (IF ANY):

QUESTION:

b) When establishing the five-year forecast of the New Business program's annual investment requirements for the current plan, did Centra take the number of connection requests or the total expenditures as the base variable to be forecasted?

RESPONSE:

The total expenditure is the base variable that is forecasted. The forecast is performed based on the annual actual costs for the previous years, a review of the actual number of connections made in the previous years and any identified issues that may increase or decrease customer demand for natural gas service. Customer connections are typically less than 30 days for service only connections and less than 120 days for many new mains. With these short timelines, information on actual future connection requests is not available to assist in forecasting.

REFERENCE:

Appendix 4.3, Section 4.2, pp. 14-17 of 64

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please confirm whether the forecasted Plant Relocation costs (Section 4.2A) are gross or net of the anticipated customer contributions.

b) Please provide historical actuals for the Plant Relocation sub-program for the past five plan periods (2012/13 through 2016/17), both inclusive and net of customer contributions.

RATIONALE FOR QUESTION:

RESPONSE:

a) The forecast plant relocation program costs in Section 4.2A are presented as net of the anticipated customer contributions in Section 4.2A of Appendix 4.3.

b) The following table provides the historical actuals for the plant relocation program, gross and net of customer contributions for 2012/13 through 2016/17.

ACTUALS ($ Thousands)	2012/13	2013/14	2014/15	2015/16	2016/17
Plant Relocation Program					
Gross Expenditures	655	978	1 249	1 030	1 946
Customer Contributions	-	-	-	(140)	(835)
TOTAL	**655**	**978**	**1 249**	**890**	**1 111**

REFERENCE:

Appendix 4.3, Section 4.2, Section 4.2B1, p. 18 of 64

PREAMBLE TO IR (IF ANY):

The Corroding Service Assessment and Replacement Program justification notes that the original steel service lines identified for replacement due to corrosion / leaks would be replaced with plastic services.

QUESTION:

a) Please provide the economic rationale for replacing the corroded steel services with plastic equivalents. Please include any internal engineering, asset management, or capital planning decision documents or business cases associated with this decision.
b) If the decision to replace the steel services with plastic equivalents was reflected in a new Centra technical standard, please provide the standard in question.

RESPONSE:

a) The economic rationale for replacing a steel service line with a plastic equivalent is based on a comparison of the estimated repair cost of a leak versus the installation cost of a plastic service line. The estimated repair cost of a leak including labour and equipment for excavation and welding for repair is approximately $8,000 whereas, the estimated cost of installing a new plastic replacement service is $4,500.

b) The decision to replace steel services with plastic equivalents has not been reflected in a Centra technical standard.

REFERENCE:

Appendix 4.3, Section 4.2B.5, p. 22 of 64

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please identify all the programs and sub-programs described in Appendix 4.3 that underwent cost-benefit analysis functionally comparable to that described in paragraph 2 on p. 22 in the context of Farm Tap Removals.
b) For all programs where a comparable cost benefit analysis took place, please provide a representative example of such analysis performed in the past three years.

RESPONSE:

a) The farm tap removals were the only program item where options other than direct replacement were identified and evaluated.

b) Please see the attachment to this response for the Farm Tap Abandonment analysis.

D1910

MANITOBA HYDRO

INTEROFFICE MEMORANDUM

FROM	Phil Robertson, P. Eng. Gas Design Engineer-Rural Gas Engineering & Construction	TO	Tim Starodub, P. Eng. Department Manager Gas Engineering & Construction

DATE 2017 04 26

FILE

SUBJECT **FARM TAP ABANDONMENT PROGRAM**

Tim,
Gas Apparatus Maintenance & Control (GAM&C) has performed a review of the farm taps that they operate and maintain and have identified approximately 60 farm taps that require replacement. The key driver for the replacement of these 60 farm taps is the pressure regulators on the farm tap are no longer manufactured and required replacement parts are becoming more difficult to obtain. The body of the regulators is welded to the farm tap piping. Rebuilding the regulator in place can be done within a few hours by GAM&C if parts are available. Removal and replacement of a regulator requires more resources (GAM&C, Customer Service Operations welder, and non-destructive testing contractor) and time and could result in sustained outage to the supplied customer(s).

As background, the majority of gas customers are supplied from a medium pressure distribution system. Farm taps are used when the nearest medium pressure system is too distant to permit an economically feasible connection while a transmission pressure pipeline may be near the customer (s). A farm tap acts as a mini pressure regulation station to create a local medium pressure distribution system that may serve only a single customer. The pressure reduction at a farm tap is often 2800 kPa (400 psi) or more from the transmission pressure to medium pressure and an intensive inspection and maintenance program is applied.

As an alternate to a straight replacement in kind of the existing farm taps, Gas Planning provided a review of the identified farm taps to determine other options to provide natural gas to the connected customers. Since the time of original installation, the medium pressure distribution system has grown and may provide an opportunity for an economic direct connection for the customers provided by a farm tap. Similarly, in areas where there may be a number of farm taps in close proximity, it may be possible to use a single farm tap to supply multiple customers and reduce the number of farm taps in place.

The attached planning analysis identified 12 locations where it would be possible to abandon one or more of the farm taps. With the information from the planning analysis, a location specific 20 year life cycle cost was prepared considering:

- The construction costs to extend the existing medium pressure distribution system to serve the customers currently supplied by the farm taps or to provide a central farm tap and expanded distribution system to permit multiple farm taps to be abandoned.

- The estimated cost to replace the existing farm taps
- The 20 year net present value of the farm tap maintenance. This information was obtained working with GAM&C.
- The net system betterment contribution required for each project.

Neepawa		**2016-01016**				
Farm Tap	Upgrade needed	FT abandonment	New FT	2" PE (Km)	4" PE (Km)	Tie-in
FT-121		Yes				1
FT-122	Yes		Yes	2.6		1
FT-123	Yes	Yes				1
FT-124	Yes	Yes				1
Installation Costs	cost to upsize 1.4 km to 4"	FT replacement cost	20 Yr NPV of FT maint.	SB contribution w/out maint. Costs	Contribution w/ maint. Costs	
$198,659.00		$114,000.00	$44,000.00	$84,659.00	**$40,659.00**	Recommended

Beausejour SB		**2016-01017**				
Farm Tap	Upgrade needed	FT abandonment	New FT	2" PE (Km)	4" PE (Km)	Tie-in
FT-028	Yes	Yes			1	2
Installation Costs		FT replacement cost	20 Yr NPV of FT maint.	SB contribution w/out maint. Costs	Contribution w/ maint. Costs	
$92,226.00		$38,000.00	$22,000.00	$54,226.00	**$32,226.00**	Recommended

Lorrete HP SB		**2016-01018**				
Farm Tap	Upgrade needed	FT abandonment	New FT	2" PE (Km)	4" PE (Km)	Tie-in
FT-043		Yes		1	2.3	4
FT-048		Yes				1
FT-055		Yes				1
FT-050		Yes				1
Installation Costs		FT replacement cost	20 Yr NPV of FT maint.	SB contribution w/out maint. Costs	Contribution w/ maint. Costs	
$253,417.00		$0.00	$88,000.00	$253,417.00	**$165,417.00**	Not Recommended

Gimli Oak Island SB		**2016-01019**				
Farm Tap	Upgrade needed	FT abandonment	New FT	2" PE (Km)	4" PE (Km)	Tie-in
FT-051	Yes	Yes				1
Installation Costs		FT replacement cost	20 Yr NPV of FT maint.	SB contribution w/out maint. Costs	Contribution w/ maint. Costs	
$35,291.67		$38,000.00	$22,000.00	-$2,708.33	**-$24,708.33**	Recommended

South Petersfield		**2016-01020**				
Farm Tap	Upgrade needed	FT abandonment	New FT	2" PE (Km)	4" PE (Km)	Tie-in
FT-060	Yes	Yes		2		1
Installation Costs	cost to upsize 1.4 km to 4"	FT replacement cost	20 Yr NPV of FT maint.	SB contribution w/out maint. Costs	Contribution w/ maint. Costs	
$94,663.00		$38,000.00	$22,000.00	$56,663.00	**$34,663.00**	Recommended

Ft-047 to FT-163 Carberry TP		**2016-01021**				
Farm Tap	Upgrade needed	FT abandonment	New FT	2" PE (Km)	4" PE (Km)	Tie-in
FT-050	Yes	Yes		1.7		1
FT-154	Yes		Yes			1
FT-163		Yes				1
FT-147		Yes				1
Installation Costs	cost to upsize 1.4 km to 4"	FT replacement cost	20 Yr NPV of FT maint.	SB contribution w/out maint. Costs	Contribution w/ maint. Costs	
$166,717.00		$76,000.00	$44,000.00	$90,717.00	**$46,717.00**	Recommended

Ft-202 to FT-213 St Pierre		**2016-01022**				
Farm Tap	Upgrade needed	FT abandonment	New FT	2" PE (Km)	4" PE (Km)	Tie-in
FT-213	Yes		Yes	1		1
FT-202	Yes	Yes				1
Installation Costs		FT replacement cost	20 Yr NPV of FT maint.	SB contribution w/out maint. Costs	Contribution w/ maint. Costs	
$107,489.00		$76,000.00	$22,000.00	$31,489.00	**$9,489.00**	Recommended

FT-210 Grunthal		**2016-01023**				
Farm Tap	Upgrade needed	FT abandonment	New FT	2" PE (Km)	4" PE (Km)	Tie-in
FT-210	Yes	Yes		0.05		1
Installation Costs		FT replacement cost	20 Yr NPV of FT maint.	SB contribution w/out maint. Costs	Contribution w/ maint. Costs	
$36,984.37		$38,000.00	$22,000.00	-$1,015.63	**-$23,015.63**	Recommended

FT-212 Niverville		**2016-01024**				
Farm Tap	Upgrade needed	FT abandonment	New FT	2" PE (Km)	4" PE (Km)	Tie-in
FT-212	Yes	Yes		0.2		1
Installation Costs		FT replacement cost	20 Yr NPV of FT maint.	SB contribution w/out maint. Costs	Contribution w/ maint. Costs	
$35,875.00		$38,000.00	$22,000.00	-$2,125.00	**-$24,125.00**	Recommended

FT303 304 335 305 South Loop TP		**2016-01025**				
Farm Tap	Upgrade needed	FT abandonment	New FT	2" PE (Km)	4" PE (Km)	Tie-in
FT-303		Yes				1
FT-304	Yes		Yes	1.75		1
FT-335		Yes				1
FT-305	Yes	Yes				1
Installation Costs	cost to upsize 1.4 km to 4"	FT replacement cost	20 Yr NPV of FT maint.	SB contribution w/out maint. Costs	Contribution w/ maint. Costs	
$162,188.36		$76,000.00	$44,000.00	$86,188.36	**$42,188.36**	Recommended

FT313 344 314 315 South Loop TP		**2016-01026**				
Farm Tap	Upgrade needed	FT abandonment	New FT	2" PE (Km)	4" PE (Km)	Tie-in
FT-313	Yes	Yes				1
FT-344		Yes		3.9		1
FT-314	Yes		Yes			1
FT-315	Yes	Yes				1
Installation Costs	cost to upsize 1.4 km to 4"	FT replacement cost	20 Yr NPV of FT maint.	SB contribution w/out maint. Costs	Contribution w/ maint. Costs	
$271,556.00		$114,000.00	$44,000.00	$157,556.00	**$113,556.00**	Not Recommended

FT341 377 390 378 Portage TP		**2016-01027**					
Farm Tap	Upgrade needed	FT abandonment	New FT	2" PE (Km)	4" PE (Km)	Tie-in	
FT-341		Yes				1	
FT-377	Yes	Yes		3.9		1	
FT-390	Yes	Yes				1	
FT-378	Yes	Yes				1	
Installation Costs	cost to upsize 1.4 km to 4"	FT replacement cost	20 Yr NPV of FT maint.	SB contribution w/out maint. Costs	Contribution w/ maint. Costs		
$137,627.50	$182,544.06	$114,000.00	$88,000.00	$23,627.50	**-$64,372.50**	Recommended	

The cost summary of the recommended projects is:

TOTAL program cost	TOTAL FT replacement cost	TOTAL 20 Yr NPV of FT maint.	TOTAL SB contribution w/out maint. Costs	TOTAL contribution w/ maint. Costs
$1,067,720.90	$646,000.00	$352,000.00	$421,720.90	$69,720.90

There are individual projects that provide a net positive cash flow and the group of recommended projects provides an approximately neutral total cost.

Two of the twelve projects, 2016-01018 and 2016-01026 have System Betterment contributions in excess of $100,000 and would result in significantly increasing the total net contribution. 2016-01018 was recommended by Gas Planning as it ties two systems together which provides system pressure benefits, but it does not include any farm taps that require replacement. For these reasons, these two projects are not recommended to be included in this program.

Please advise if any questions.

Thanks

Phil Robertson, P. Eng.

REFERENCE:

Appendix 4.3, Section 4.2D, pp. 26-33 of 64

PREAMBLE TO IR (IF ANY):

Given Centra's statement that the Corporate Value Framework / C-55 functionalities were yet to be deployed for the development of the current plan, CAC's intent in requesting the below information is to understand the decision-making work underlying investment prioritization today

QUESTION:

a) Please provide business cases associated with each of the six elements / sub-programs comprising the System Betterment: Measurement and Regulator Stations Program.
b) Unless clearly stated in a business case(s) requested in sub (a), please describe the process and decision-making criteria applied in determining the priority locations for:
    i. Automated Isolation Valves proposed for installation in Section 4.2D.1;
    ii. Station Automaton Equipment for Regulator Stations proposed for installation in Section 4.2D.3;
    iii. Line Heater Installations proposed in Section 4.2D4, along with a copy of the referenced Risk Ranking System and Matrix;
    iv. Upgrades to Pressure Regulating Stations proposed in Section 4.2D5;
    v. Replacements of Indirect Line Heaters discussed in Section 4.2D6.
c) Of the six sub-programs described in Section 4.2D, please identify the programs driven by management's desire to improve the performance efficiency of otherwise functional assets that do not require replacement / refurbishment within the timeframe of the current Plan.

RESPONSE:

a) Please see the attachment to the response to PUB/Centra I-73 pages 345 to 349 (System Betterment- Measurement & Regulator Station CIJ).

b)

i. Automated Isolation Valves proposed for installation in Section 4.2D.1: Installation of automated isolation valves is prioritized to pipelines connected to primaries with existing remote pressure control capability already integrated into the SCADA system, like the La Salle and Ile de Chenes TP pipelines. Oak Bluff GS-030 station will be provided with automated isolation during the station upgrade in 2022. The application of automated valves is relatively new to Centra and opportunities continue to be evaluated.

ii. Station Automation Equipment for Regulator Stations proposed for installation in Section 4.2D.3: The Southloop primary stations (GS-146 Dominion City and GS-136 Oakville) require a minimum of 1-hour travel time for emergency response and seasonal adjustments. Providing remote pressure control and monitoring to these primary stations will allow immediate pressure control from the Gas SCADA Control Center, and reduce labor hours for seasonal adjustments to a distribution network that supplies various communities in southern Manitoba. GS-146 Dominion City primary was prioritized due to the additional benefit of segregating the existing outlet pipelines, which provides additional flexibility in isolation during a pipeline event.

iii. Line Heater Installations proposed in Section 4.2D.4, along with a copy of the referenced Risk Ranking System and Matrix: Manitoba Hydro selected the pressure reducing station requiring line heater installation from a Heat Requirement Matrix prepared by Manitoba Hydro International (please see response to CAC/Centra I-78d), but exercising professional judgment with the application of additional criteria such as site-specific considerations, including:

- History of operating issues including regulator failures
- Indications of stress and strain on pressure reducing station piping
- The number of customers
- Service of critical customers
- The availability of an alternate or back feed supply
- Expected variability/consistency in the gas supply quality

iv. Upgrades to Pressure Regulating Stations proposed in Section 4.2D5: The list of stations to be upgraded every year is obtained from the highest condition score (ranked from 0 to 100%) indicated in an annual Station Condition Assessment prepared by Gas Apparatus Maintenance & Control personnel. The document provides different condition marks ranked 0 to 3, the higher the score, the greater the concern on several conditions of the station including:
   - Site condition
   - Integrity of system
   - Reliability of supply
   - Compliance
   - Public acceptance
   - Environment
   - Health and safety
   - Security of Station

v. Replacements of Indirect Line Heaters discussed in Section 4.2D6: The prioritization criteria applied to replace the existing line heaters were based on the age of each line heater and the comparison of their thermal efficiencies. Fort Whyte GS-020 had been identified by the Gas Apparatus Maintenance & Control group as the oldest, 58 years old, and most thermal inefficient unit of the three heaters to replace. The other units were prioritized based on the number of reported failures in the last 15 years.

c) Centra does not have any programs driven by the desire to improve the performance efficiency of assets but when assets are being replaced at end of life to improve reliability and continuity of service Centra does strive to install assets that are more efficient.

REFERENCE:

Appendix 4.3, Section 4.5A p. 38 of 64

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide a business case(s) for the SCADA upgrade/expansion work proposed within the program.
b) Please define the targeted SCADA penetration levels on the Centra system upon the conclusion of this project (i.e. what % of gate stations and regulating stations will be SCADA-enabled once the project is completed).
c) For functionally similar SCADA upgrade / expansion work performed in the past five plan years, please provide the actual costs, along with the assessment of benefits being achieved (e.g. reduction of labour hours, lower number of trouble call truck rolls, etc.).

RATIONALE FOR QUESTION:

RESPONSE:

a) Please see attachment to this response for the GAM&C Program CIJ.

b) This capital investment aims to have all stations monitored once complete.

c) As one example, GS-207 Benito had SCADA monitoring installed with actual costs of $18,340. All capital projects of this type will have similar planned and actual costs. The purpose of installation of monitoring is to provide visibility of the health of the gas distribution system, allowing for timely response to supply issues before affecting the downstream customer.

C55-CIJ-PROG

CAPITAL INVESTMENT JUSTIFICATION FOR

Gas Station Upgrades

Investment Type (Program)

BUDGET RANGE (ANNUAL):	$500 to $800
CONTRIBUTIONS RANGE (ANNUAL):	$0 to $0
NET BUDGET RANGE (ANNUAL):	$500 to $800
	(values listed above are in thousands of dollars)
CORPORATE VALUE FRAMEWORK SCORE: (CVF scores reflect the Recommended alternative)	**Value:** 94,505 **Value/$K:** 10.10

DATE PREPARED: 2018/12/14

EC/MHEB APPROVAL MINUTE & DATE:

APPROVER	APPROVER TITLE	COMMENT	ORGANIZATIONAL UNIT	APPROVAL DATE
Waddell, Jared	DIRECTOR CUST SERVICE OPERATIONS - WPG		Director - CSO Wpg	2018/12/18
Brako, Tanis	GAS APPARATUS MTCE & CONTROL DEPT MGR		Gas Apparatus Maintenance & Control	2018/12/18
LAWRIE, SARAH	CHARTERED PROFESSIONAL ACCOUNTANT	On behalf Of Isaacson, Marie (misaacson).	Financial Advisory Services	2018/12/18
Isaac, Rob	DISTRIBUTION CAPITAL & RISK MGMT ADVISOR		Planning, Protection & Asset Strategy	2018/12/17

CAPITAL INVESTMENT MASTER DATA			
RESPONSIBLE OPERATING/CORPORATE GROUP:	Marketing & Customer Service	**REQUESTING OPERATING/CORPORATE GROUP:**	Marketing & Customer Service
RESPONSIBLE DIVISION:	Customer Service Operations - Winnipeg	**REQUESTING DIVISION:**	Customer Service Operations -
RESPONSIBLE DEPARTMENT:	Gas Apparatus Maintenance & Control		
I.M. NODE NUMBER:	2.2.40.25.08.1	**W.B.S. NUMBERs:**	B:00350
C55 INVESTMENT CODE:	13471		
SAP PROJECT TYPE:	24 - BOC-VP & Management	**PROGRAM TYPE**:	Common Scope
CORPORATE INVESTMENT CATEGORIES:	(Level 1) C3 / Sustainment (Level 2) CM / System Renewal		

CONTACTS			
PREPARED BY:	Brako, Tanis GAS APPARATUS MTCE & CONTROL DEPT MGR 53070	**REQUESTOR:**	
PROJECT MANAGER:	Brako, Tanis GAS APPARATUS MTCE & CONTROL DEPT MGR 53070		

MANITOBA HYDRO
CAPITAL INVESTMENT JUSTIFICATION
Gas Station Upgrades

RECOMMENDATION
Approve an annual budget range of \$0.5M to \$0.8M for the Gas Station Upgrades program which includes smaller investments typically less than \$0.1M. This program is required to replace obsolete station equipment and/or upgrade station equipment to help ensure a safe and reliable pipeline system is maintained.

SCOPE

Scope of work includes additions, upgrades and replacements of the following station assets to address operational requirements or condition issues:

- Regulators,
- Pilots,
- Gauges, and
- Valves.

The program also includes:

- Installation of odourization equipment used to odourize natural gas to make leaks detectable by smell for safety purposes,
- Replacement of obsolete Programmable Logic Controllers (PLCs) and Remote Telemetry Units (RTUs),
- Field radios, and networking and communication equipment associated with the Gas Supervisory control and data acquisition (SCADA) system.

BACKGROUND

Pressure regulation stations provide an interface between a high pressure supply source and a lower pressure delivery system. Metering and pressure regulating stations combine this pressure interface with a custody transfer point between TransCanada PipeLines or TransGas and Centra. Metering and pressure regulation stations also typically include the capability of adding odourant to the natural gas supplied. Pressure regulation and over pressure relief equipment are used to protect the downstream system from pressures that may exceed the maximum operating pressure of the system components. Metering and pressure regulation stations contain the majority of mechanical or electrical/instrumentation equipment in the natural gas system, and require regular upgrading and replacement.

As the station operator, Gas Apparatus Maintenance & Control works with the Gas Station Design section of Gas Engineering & Construction to identify and initiate required work in this program.

An increased focus of this program began in 2015/16 to address gas quality issues from the natural gas supplier, as well as for replacements of outdated and unsupported communication infrastructure.

JUSTIFICATION – BUSINESS CASE ANALYSIS (SUMMARY):

JUSTIFICATION

Replacing obsolete station equipment and/or upgrade station equipment improves the safety and reliability of Gas stations and facilities critical to serving the distribution system.

Natural gas outages can result in significant costs to both customers and the corporation. Investments in the Station Upgrades Program are planned in order to ensure a safe and reliable pipeline system is maintained and to significantly reduce the occurrence of outages.

The benefits to both customers and the corporation in addressing station issues in a timely manner include:

- Increased Reliability - Extended outages could affect hundreds, and possibly a much larger number, of customers,
- Increased Safety – Regulation requires natural gas be odourized as a safety measure for the public since natural gas is combustible, colourless, odourless, and difficult to detect,
- Less harmful emissions - as natural gas is an ozone depleting gas,
- Maintaining compliance with CSA standards and PUB directives,
- Decreased risk of a harmful event (fire/ explosion), reducing potential for liability.

PROGRAM ALTERNATIVES

Alternative Name	Annual Budget	Value	Value/ $K
Maximum	$800		
Minimum	$500		

PROGRAM RISK ANALYSIS

Each program item investment identified within this program will have different risks with proceeding. Each program item approval document will outline the risks of proceeding for that specific item.

IMPACT ON O&A COSTS

Minimal impact on operating and administration costs. Station upgrades generally involve the replacement or remediation of an existing asset and not the installation of new assets or systems.

RELATED INVESTMENTS

None.

OTHER ALTERNATIVES CONSIDERED

For the work performed in this program, projects are performed to respond to identified deficiencies. No alternatives were considered.

REFERENCE DOCUMENTS

None.

REFERENCE:

Appendix 4.3, Section 5.1, pp. 40-58 of 64

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please explain Centra's rationale for including the "Risk Analysis" summary content boxes in the "Projects" subsections of the Plan, but forgoing them in the "Programs" subsections.

RESPONSE:

Prior to the implementation of the Corporate Value Framework, Centra started the application of the risk assessment methodology to assist in communicating the relative risks of projects to senior personnel reviewing approval and planning documents. There was considered to be value to include this information as part of the project descriptions provided in the Plan. Historically, programs have been dealt with differently than projects.

REFERENCE:

Appendix 4.3, Section 5.1, pp. 40-41 of 64

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide the timeline over which Centra anticipates for the Waverly West load requirements to reach the capacity levels that the current system would be unable to sustain safely and reliably. Please state the associated probability of the load reaching the assumed level by the stated year. Specify whether these probabilities are calculated on the basis of past information or estimated.
b) Please describe the information / data in Centra's possession that give the utility sufficient confidence that the area's loading requirements will increase in the manner and timing referenced in the justification and timeline presented in the Plan.
c) Aside from constructing a new supply / primary station, did Centra evaluate any other alternatives for meeting the anticipated area load growth? If so, please described them and articulate the rationales for rejecting them in favour of the proposed solution.

RESPONSE:

a) It is estimated that the Waverly West load will reach the current system design capacity limits within two years. Centra does not define probability values for load growth.

b) Centra provides natural gas infrastructure to support housing developments and provides the installation of natural gas services for new customers in this area. Information on new customer attachments shows steady growth in this area as follows:

Year	New Natural Gas Customer
2013	600
2014	462
2015	393
2016	408
2017	502
2018	492
2019	106 (year to date)

c) Please see the response to PUB/CENTRA I-81c.

REFERENCE:

Appendix 4.3, Section 5.2, p. 42 of 64

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please clarify whether the “Almost Certain” risk likelihood referenced in the justification refers to the likelihood of the anticipated load growth (mitigatable by supply expansion), the likelihood of an area outage (mitigatable by the secondary supply), or both?
b) Please separate the costs of the contemplated supply capacity upgrade and the secondary supply system comprising the project.
c) Please provide the information regarding Steinbach natural gas system’s current capacity specifications, the rate of growth of capacity requirements over the last five years, and the projections of load growth over the Plan period. Please specify the numerical probability values associated with this information, including the manner in which they were derived.

RESPONSE:

a) Please see the response to PUB/CENTRA I-71a.

b) The incremental cost from a capacity upgrade only at the existing station to a second pipeline and station was estimated to be $2,500,000.

c) The existing pipeline is at 86% of capacity at peak loading conditions based on 2015 design winter loads.

   Steinbach is the fastest growing city in Manitoba with natural gas demand increasing at 2.3% per year compounding over the last 10 years.

   Sensitivity analysis was completed using annual gas load growth rates between 2% linear and 2.3% compounding.

   Centra does not define probability values for load growth.

REFERENCE:

Appendix 4.3, Section 5.2, p. 42 of 64

PREAMBLE TO IR (IF ANY):

QUESTION:

d) Given Centra's recent investments in Compressed Natural Gas (CNG) filling and transportation capabilities, did the utility evaluate whether and to what extent the available CNG emergency supply capabilities would be a more economical means of mitigating the impact of future outages, given the calculated likelihood of Steinbach's primary system failure? If so, please describe why a secondary system remains a preferred solution.

RESPONSE:

Centra does not have sufficient CNG capacity to replace the natural gas supply to Steinbach with a trucked gas supply. The secondary supply remains a preferred solution as it could avoid an outage from occurring.

REFERENCE:

Appendix 4.3, Section 5.3 p.43 of 64

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide information regarding the St. Andrew's system's current capacity, the current loading levels, recent load growth trends and the area's load forecast over the Plan period. Please specify the numerical probability values associated with this information, including the manner in which they were derived.
b) Please clarify whether the "Unlikely" likelihood depicted in the Risk Analysis graphic refers to the capacity growth requirements being unmet within the proposed timeline, a system outage, or any other risk.
c) Please detail the rationale for the proposed abandonment of GS-027 and the 2" PE along the Earl Grey Rd. as shown on the project map. Is the abandonment driven by asset condition, the assets no longer being required, or any other reason?

RESPONSE:

a) The system in this area is at capacity and areas are operating below the minimum design system pressure of 30 psig (210 kPa) used to initiate a system upgrade. Recent load growth trends have seen a 22% increase in gas load from 2004 to 2017. The loading was derived from actual meter and customer loads. Centra does not define probability values for load growth.

b) Please see the response to PUB/CENTRA I-71a.

c) The Farm Tap GS-027 and 2" PE along Earl Grey Road were no longer needed once the interconnection from GS-043 Liss Station was made to the pipeline on Lockport Rd.

REFERENCE:

Appendix 4.3, Section 5.4 pp. 44-45 of 64, Completeness Filing Attachment 6, pp. 9, 11

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please confirm whether the In-Line Inspection expenditures proposed in the current Plan represent capital or operating costs.
b) Please clarify whether the scope of planned expenditures entails acquisition of In-Line Inspection equipment and modifications to the outlined pipelines only, or whether the scope underlying the proposed expenditures also includes the actual inspection activities for the identified system segments.
c) Beyond the eight system segments specifically identified for modification in the current plan, how many other segments does Centra believe warrant modification in the future years to enable the use of In-Line Inspection equipment?
d) Aside from the capital costs of equipment purchase and/or pipeline modifications, what are the operating costs associated with In-Line Inspections and data record generation for a given unit of work (e.g. 1 km of pipeline, 1 segment, etc.)?
e) Please summarize the results of the In-Line Inspection at La Salle referenced on pp. 9 and 11 of the Attachment 6 of the Completeness Filing. Please identify the follow-up activities (if any) the need for which has been determined on the basis of the In-Line Inspection performed.
f) Please discuss whether Centra has performed any other In-Line Inspections in the period between 2011/12 and 2016/17, the cost of which may be below the $250,000 materiality threshold of the Attachment 6. If so please provide the total number of such inspections per year.

RESPONSE:

a) The In-Line Inspection expenditures in Appendix 4.3 represent capital costs.

b) The scope of the planned expenditures entails modifications of the outlined pipelines and acquisition of contractor services for the provision of supplying in-line inspection services.

c) Centra believes that several segments warrant modification in future years to enable the use of in-line inspection equipment. Typically, this will include transmission pressure rated pipelines with diameters 168.3 mm and larger. Specific details will be determined based on the review of previous in-line inspection work done.

d) All costs associated with in-line inspection, including data records generation are capital costs.

e) The in-line inspection identified 957 imperfections with 7 meeting the definition of defect in CSA Z662 Oil and Gas Pipeline Standard and requiring remediation prior to returning the pipeline to service. Five of the defects were determined to be manufacturing defects in the pipe and two were external corrosion defects. The maximum corroded depth was 41% of wall thickness at one location and 18% at the second. The remediation included cutting out the pipe defect as a pipe cylinder and installing a new section of pipe. Additional excavations were performed at seven additional locations to inspect the imperfections identified by the in-line inspection.

f) Centra performed no other In-line Inspections in the period between 2011/12 and 2016/17.

REFERENCE:

Appendix 4.3, Section 5.7, p. 50 of 64

PREAMBLE TO IR (IF ANY):

QUESTION:

Please discuss whether Centra considered the economic benefits of deferring the project scoping and execution until such time as the corrosion assessment would take place? If so, please provide the rationale for proceeding with the project ahead of corrosion inspections.

RESPONSE:

There was no consideration of delaying the project until a corrosion assessment was complete. A corrosion failure is only one of the threats to the pipeline and continuity of supply to the natural gas customers in Portage la Prairie. The Assiniboine River immediately adjacent to the south edge of Portage la Prairie is actively shifting and five river crossings have been replaced in the past related to shoreline erosion and slope movements. Geotechnical monitoring of the in-service river crossing has been in place for several years and slope movements have been seen. Third party damages also remain as a potential threat.

REFERENCE:

Appendix 4.3, Section 5.11, pp. 55-56 of 64, Attachment 3, PUB Completeness Filing.

PREAMBLE TO IR (IF ANY):

QUESTION:

Given the existence of standard and widely communicated setback distances (as illustrated in in the promotional document graphic on p. 56), why has Centra decided that acquiring additional land parcels is an appropriate and cost-effective way of mitigating the risk of easement encroachments? Please provide any economic analysis performed in making this decision, and discuss why each of the other options for limiting the risk of encroachment discussed in section 6.2.4 of Appendix 3 of the PUB Completeness Filing were rejected.

RESPONSE:

Centra has elected to try and obtain additional easements on its larger diameter pipeline systems to meet the setback distances defined in the American Petroleum Institute Guidelines ("API") for Property Development. As an example, the Ile des Chenes transmission pressure pipeline system is a NPS 16 pipeline that was installed in 1964. This pipeline is one of two NPS 16 supplies in the Centra system and is a key supply to Winnipeg and communities extending to Beausejour in the east and Riverton and Arborg in the north. The original easement is 15 meters wide with the pipe located at an offset of 6 meters from the east property line. The API recommended separation from a building to a pipeline is 15 meters. As Centra has no legal ability to restrict construction of a building immediately at the edge of an easement, a decision was made to try to purchase additional easements to obtain the 15 meter setback.

The risk control options shown in section 6.2.4 of Attachment 3 of the PUB Completeness Review Submission are shown as options that could reduce or control the risk due to external interference. They will not mitigate the consequences of a failure and are generally not considered sufficient for high value assets such as the Ile des Chenes pipeline.

Please see table below for an overview of the other risk control options:

6.2.4 Risk Control Option	Comment
Target public awareness programs to high risk areas such as new developments and densely populated areas	Notification to all land owners currently provided. A positive step but not considered sufficient.
Perform depth of cover surveys and remediate insufficient covers.	Currently done. Not considered sufficient.
Increased signage.	Signage in place. Not considered sufficient.
Select pipe material with better resistance or add barrier materials.	Pipe material selection is a new construction option. Placing barrier material will be expensive and not provide a benefit to reduce consequence of a line rupture
Reduce the percentage specified minimum yield strength (SMYS) (transmission)	For the Ile des Chenes line, an operating pressure reduction from 550 psi to approximately 400 psi would be necessary to reduce pipe hoop stress to the 30% SMYS level which is the pipe failure as a leak not a pipe failure as a rupture threshold. At a supply pressure of 400 psi, the pipeline would not be able to maintain the current winter supply volumes to Winnipeg. Communities further away on the pipeline system would have reduced volumes of gas available.
Relocate pipelines or widen easements	Replacing the Ile des Chenes line with a new primary station on its current alignment is estimated at $11 million. A new alignment would likely be longer and more expensive. Widening easements is the approach being used.
Restrict access (fencing)	While the land use is transitioning, portions remain as farm land and the installation of fencing is considered unacceptable.

Please note that no specific detailed economic analysis was performed.

REFERENCE:

Appendix 4.3, Section 5.12, p. 57 of 64

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide the modelling analysis outputs outlining the loading and temperature conditions under which a loss of one of the supply points would result in distribution capacity limitations.

b) Please describe the options other than the recommended option for mitigating the impact of a hypothetical loss of one of the three gas supply paths along with their costs, and provide the reasoning behind them being rejected in favour of the preferred alternative.

c) Please explain why the 2019-20 and 2020-21 projected cost flows for this project are marked with an asterisk unlike any other specific annual cost projections within the Plan document.

    i. Does this annotation indicate that the project estimates are more preliminary in nature than other forecasted project costs in this Plan?

RESPONSE:

a) The loss of the LaSalle transmission pressure pipeline at an ambient temperature of -15 C with system loading at 33 degree days [redacted] 1d would result in distribution capacity issues.

b) The system analysis indicated that sufficient transmission pressure capacity was available with any two of the three main transmission systems in operation and that the constraint was supply from the high pressure system to the medium pressure distribution system. The options evaluated involved increasing the ability to distribute gas within the high pressure system and included:

i. Option 1: Install 3.4 km of NPS 12, 150 psig rated interconnect from RS-027 on Inkster Ave to connect to the high pressure main on Pacific Ave. Estimated cost: $3.5 million.
ii. Option 2: Install 5.3 km of NPS12, 150 psig rated interconnect from RS-046 further west on King Edward St. to connect to the high pressure main on Pacific Ave. Station modifications at RS-046 would be required. Estimated cost: $5.5 million.
iii. Option 3: Install 5.5 km of NPS 12, 250 psig rated interconnect from the NPS 12, 250 psig main on Inkster to RS-023. Modifications to RS-023 and RS-027 would be required. Estimated cost: $5.4 million.
iv. Option 4: Install 2.2 km section of NPS 8, 700 psig rated interconnect from Oakbluff TP main to RS-021. Modify RS-021 to accept a transmission pressure inlet supply. Estimated cost: $1.5 million. Note: This option does not successfully address the high pressure capacity limitation and is not recommended.

Option 1 was selected over Options 2 and 3 based on a lower cost while Option 4 was rejected as not meeting the required system performance.

c) The project does not have an approved CIJ at this time. Additional detailed work is being performed to validate the cost estimate and the option selected. The location of the proposed work is fully within a developed urban area and involves the possible crossing of a rail yard and a major City of Winnipeg water distribution facility. More detailed design work is being performed in consultation with the rail company and the City of Winnipeg to establish acceptable pipe routing. This further work will permit greater cost certainty to be determined prior to requesting capital approval.

REFERENCE:

Appendix 4.3, p. 60 of 64, Risk Rating Criteria

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please discuss whether the magnitude of Manitoba Hydro's Financial and System Reliability risk rating criteria (e.g. the "Low" financial risk threshold being between $0-$50 million on a Net Income basis) are appropriate for use on a natural gas system of Centra's size, technical characteristics and financial value?
b) Does Centra intend to develop risk rating criteria more closely aligned with the financial considerations affecting its business and the technical nature of its operations? If so, what is the timeline for such a system to be developed?

RESPONSE:

a) The magnitude of Manitoba Hydro's Financial and System Reliability risk rating criteria is consistent with that applied by the corporation in reporting risks having an impact corporately (see also pg. 49 of Appendix 1, Corporate Risk Management Report). For discrete investment, planning Centra along with all other Manitoba Hydro operating groups are now evaluating specific investments applying the Corporate Value Framework.

b) No, Centra is now using the C55 Corporate Value Framework.

REFERENCE:

Appendix 4.3, p. 60 of 64, Risk Rating Criteria

PREAMBLE TO IR (IF ANY):

QUESTION:

Please describe the specific circumstances of the risk criteria provided in Appendix A being applied to the provided Plan. Describe the process, participants, and provide the internal approval documents signifying the completion of the risk assessment process related to the projects in the Plan contained in Appendix 4.3.

RESPONSE:

The risk criteria were applied to all projects shown in the plan. Centra started the application of the risk assessment methodology to assist in communicating the relative risks of projects to senior personnel reviewing approval and planning documents. The risk assessment was provided by the planner or engineer who had prepared the project CIJ/CPJ and was reviewed by the department manager. When Centra started the preparation of multi-year plans, the use of the risk analysis was considered to have value in describing the proposed work.

REFERENCE:

Appendix 4.3

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please describe the mix between internal construction staff and external contractors intended for performing the capital work comprising the 2018-2023 Plan.
   i. Discuss how the anticipated mix aligns with the actual experience over the past five years and with Manitoba Hydro's electrical construction practices.

b) Please provide key costing assumptions underlying the plan, including:
   i. Internal and External Labour Costs;
   ii. Engineering, Warehouse, Administrative and other applicable overheads;
   iii. Materials and Supplies costs;
   iv. Inflation Assumptions (assumed rate over the period and source price indices);
   v. Vehicle and Construction Equipment charges and rental rates;
   vi. Staff / contractor overtime costs;
   vii. Contingency uplifts included in budgets;
   viii. Outage coordination costs;
   ix. Site remediation costs;
   x. Land acquisition and leasing cost rates.

RESPONSE:

a) Most of the programs and projects in the 2018-2023 Natural Gas Asset Management Investment Plan will be completed by external contractors. Centra's field involvement on these projects will comprise of Centra's Pipeline Inspectors on-site to confirm the work is completed in accordance with the construction drawing(s), Standards and Procedures and other applicable requirements. Centra's Maintenance Personnel will assist in tapping/stopping and flaring activities where required.

Exceptions to the above in the 2018-2023 Natural Gas Asset Management Investment Plan are:

- 4.2B.2 System Betterment Integrity: Commercial Service Replacements will be completed by internal personnel.
- 4.2D.1 System Betterment Measurement & Regulator Stations: Emergency Response Automated Isolation Valves will be completed by internal personnel.
- 4.3 Natural Gas Meter Compliance Program is completed primarily by internal personnel and supplemented with staff from Manitoba Hydro's subsidiary (Manitoba Hydro Utility Services) as needed.
- 4.4 Customer Service Operations Other Capital will be completed by internal personnel.
- 4.5A GAM&C: SCADA Upgrade – Improve Monitoring will be completed by internal personnel.
- 4.6 Corrosion Control will be completed by both contractor and internal personnel. Contractor staff will perform the installation of the rectifiers and ground beds. Internal staff will perform installation of anodes.
- 5.5 Cathodic Rectifier Remote Monitoring Devices will be completed by a contractor as a turnkey project.
- 5.8 Distribution System Monitoring will be completed by both internal and contractor personnel. Internal staff will perform the site installations and project management services. Contractor personnel will be response for radio antenna rigging, radio installation, performance certification, software setup and training.

i. This mix of internal staff and external contractors is the same historically for natural gas programs and projects that have occurred over the past 5 years.

   Underground installations on the electrical distribution side of Manitoba Hydro are primarily completed by internal construction staff. Internal construction crews are supported by external contractor services when required. Support services primarily include hydrovac, directional drilling, cable ploughing, wetsaw, backhoes, dump truck and skid steer services. External contractors are used to complete multi-party installations in subdivisions and electrical ductline construction.

b) Key costing assumptions underlying the plan are as follows:

i. Projects are estimated individually taking into consideration the percent of internal and external labour as applicable. Internal costs are based on Centra's internal labour rates. External labour costs are based on existing contract unit rates or forecast unit rates based on historical information. For programs, the percent of internal and external labour is assumed to remain the same as historical.

ii. An overhead rate of 4% is applied to planned internal labour

iii. Materials and Supplies are planned as required for the specific project. Program materials are planned based on historical use for the specific program.

iv. Project plans are escalated using the most recently published escalation rates from Corporate Policy P911 titled *Projected Escalation, Interest, Exchange and Hurdle Rates.* Program Plans are typically escalated by 2%.

v. Internal vehicle and construction equipment costs are embedded in Centra's internal labour rates. For external contractors, vehicle and equipment costs are typically included in the unit or lump sum rates and not estimated separately.

vi. Where applicable on projects, internal field staff overtime costs are generally estimated to be 20% of total project hours. For new customer projects within programs, estimates are capped at 15% of contracted costs for the overall business unit overheads regardless of overtime costs. Contractor overtime costs are typically included in the unit or lump sum rates and not estimated separately.

vii. Contingency in projects and projects within programs budget estimates is typically 15%. Contingency for new customer project estimates is 5%.

viii. Outage coordination costs are not estimated separately. They are typically not a large component of the overall project.

ix. Where applicable, site remediation estimates are based on actual permit costs, existing contractor unit rates or similar historical project costs for the estimated area to be impacted.

x. Where applicable, land acquisition and easement costs vary depending on the size required and the specific appraised land value. Estimates are included for each project based on information provided by Manitoba Hydro's Property Department or by using similar historical project costs.

REFERENCE:

Appendix 4.3

PREAMBLE TO IR (IF ANY):

QUESTION:

c) Please also specify the units of major assets (by Centra's depreciation accounting class) to be replaced and costs per unit.

RESPONSE:

c) Units of major assets to be replaced and cost per unit in accordance with Centra's depreciation classes are not specifically identified as part of forecasting asset retirements. The asset retirements forecast for 2018/19 and 2019/20 as reflected in Schedules 6.1.7 and 6.1.8 is estimated based on a review of historical actual retirements for the respective depreciation classes. When known, projected retirements are adjusted to reflect known differences between forecast and historical expenditures.

REFERENCE:

Appendix 4.4, Economic Evaluation Table, p.12 of 137, Overall Asset Health Tables, p. 19 of 137.

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please confirm that all the references to “Manitoba Hydro” within the ACA document can be interpreted to mean “Centra Gas Manitoba.” If there are any special reasons for using “Manitoba Hydro” rather than “Centra Gas” within this document, please disclose them.

b) Please confirm that all replacement values showcased in the Economic Evaluation table on p. 12 and the related Economic Evaluation tables throughout the report were calculated on the basis of Centra’s actual equipment replacement costs in the year 2015.

c) If confirmed, please provide a table showcasing all the units replaced across the Critical Asset Sub-Groups in the year 2015, along with their total construction costs. If not confirmed, please provide any documents in support of the values chosen.

d) Using the replacement value figures and the “Soccer Field” Asset Health diagrams on p. 19, please provide a table quantifying the replacement value of Centra’s assets in Fair/Poor and Critical condition, both at the time of the assessment, and using the 20-year forecast.

e) Please discuss the reasoning behind grouping the Poor and Fair assets into a single category. Please separate the poor and fair category assessment for all Critical Asset Sub-Groups and restate the “soccer field” diagrams.

f) For all critical asset sub-classes please break each “soccer field” diagram into two – one showing the health assessment of assets for which condition data other than age is available, and the second for assets for which no condition data is available. Please specify the percentage of total asset counts for each group.

RESPONSE:

a) All references to "Manitoba Hydro" within the ACA document can be interpreted to mean "Centra Gas Manitoba" and "Minell Pipelines Ltd". Minell Pipelines Ltd assets consist of a 66 km of NPS 6 pipeline and one primary station that are regulated by the National Energy Board.

b) All replacement values showcased in the ACA report were calculated on the basis of Centra's estimates and replacement costs in years prior to 2015.

c) Please see the attachment to this response for pipeline replacement costs.

d) Please see the following tables quantifying the replacement value of Centra's assets in Fair/Poor and Critical condition:

Replacement value of Centra's assets in Fair/Poor condition				
Critical Assets Groups	**Time of the assessment**		**20 year forecast** 1.8%/yr escalation	
	% of total	**$Million**	**% of total**	**$Million**
Stations	3	4.2	3	6.0
Valves	3	3.5	3	5.0
TP Pipelines	4	20.3	27	195.9
HP/MP Pipelines	3	27.2	17	220.4
Services	66	51.9	69	77.6
Total	**-**	**107.1**	**-**	**504.9**

Replacement value of Centra's assets in Critical condition				
Critical Assets Groups	**Time of the assessment**		**20 year forecast** 1.8%/yr escalation	
	% of total	**$Million**	**% of total**	**$Million**
Stations	1	1.4	1	2.0
Valves	4	4.6	1	1.6
TP Pipelines	0	0.0	4	29.1
HP/MP Pipelines	1	9.1	5	64.8
Services	4	3.1	7	7.9
Total	**-**	**18.2**	**-**	**105.4**

e) The rationale for a single ‘fair/poor’ category is to represent assets that are estimated to have a condition ranging from fair to poor. Centra does not have the necessary asset condition information to create a higher resolution ‘fair/poor’ category split.

f) Typically, when asset condition information other than age is available, it is available for an entire critical asset group. Therefore, the ‘soccer field’ diagrams would not change. The exception is the ‘Services’ critical asset group. Centra does not have the necessary information to separate the ‘Service soccer field’ diagram based on services with asset condition information other than age.

The assets for which Centra has health information (other than age) as of April 2019 are:

Critical asset groups				Has heath information (other than age)
Stations and control points	Stations	Primary gate stations		Yes
		Gate stations		Yes
		Regulation stations		Yes
		Farm taps	Regulators	Yes
			Valves	Yes
			Piping	No
	Control Points	Steel valves		Yes
		Piping		No
Pipelines	Transmission Pressure			Yes
	High and Medium Pressure[1]			Yes
Services				Partial[2]

1. Information on PE pipe is limited to leak history.

2. Approximately 33,000 out of 280,000 (12%) service metersets. Collection of health information is in progress as part of Service Riser Audit pipeline integrity activity.

Conceptual Level Cost Estimate Template - Natural Gas

Costs as of: October 2015

Item		Unit Cost	PE Mains/HP Main		Steel Mains Distribution & Transmission		HD PE	
			Quantity	Cost	Quantity	Cost	Quantity	Cost
Pipe (PE) Distribution	2" PE (Urban)	$ 55 /m	2125091.7	$ 116,880,044	2266341.48	$ 124,648,781	295.0	$ 16,225
	4" PE (Urban)	$ 65 /m	475799.17	$ 30,926,946	600230.05	$ 39,014,953	91384.35	$ 5,939,983
	6" PE (Urban)	$ 120 /m	9494.39	$ 1,139,326	38811.55	$ 4,657,386		$ -
	8" PE (Urban)	$ 160 /m	6191.28	$ 990,605	201190.79	$ 32,190,527		$ -
Pipe (PE) RURAL	2" PE (Plough)	$ 30 /m	2920059.87	$ 87,601,796		$ -		$ -
	4" PE (Plough)	$ 50 /m	624867.34	$ 31,243,367		$ -		$ -
	6" PE (Plough)	$ 70 /m	21962.79	$ 1,537,395		$ -		$ -
	8" PE (Stick w trench)	$ 140 /m	6191.28	$ 866,779		$ -		$ -
Pipe (Steel) Transmission	2" Steel	$ 130 /m	20186.0	$ 2,624,179	119750.47	$ 15,567,562		$ -
	3" Steel	$ 155 /m		$ -	328662.57	$ 50,942,698		$ -
	4" Steel	$ 175 /m	18408.91	$ 3,221,558	655784.99	$ 114,762,373		$ -
	6" Steel	$ 250 /m	10654.27	$ 2,663,566	450673.31	$ 112,668,328		$ -
	8" Steel	$ 350 /m	45091.61	$ 15,782,063	117258.28	$ 41,040,398		$ -
	10" Steel	$ 425 /m	5325.33	$ 2,263,264	45637.17	$ 19,395,799		$ -
	12" Steel	$ 500 /m	29630.65	$ 14,815,324	121784.26	$ 60,892,128		$ -
	14" Steel	$ 575 /m	44570.19	$ 25,627,859		$ -		$ -
	16" Steel	$ 650 /m	20260.79	$ 13,169,511	40669.82	$ 26,435,384		$ -
Service Pipe	1/2 " - 1 "	$ 30 / m	6,489,355	$ 194,680,650		$ -		$ -
	1 1/4 " - 2 "	$ 55 / m	578,952	$ 31,842,360		$ -		$ -
	3 " - 4 "	$ 65 / m	40,948	$ 2,661,620		$ -		$ -
	6 "	$ 120 / m	1,743	$ 209,160		$ -		$ -
	8 "	$ 160 / m	2,504	$ 400,640		$ -		$ -
Pig Launchers - Recievers	6" Launcher - Reciever	$ 44,000 /unit		$ -		$ -		$ -
	8" Launcher - Reciever	$ 64,000 /unit		$ -		$ -		$ -
	12" Launcher - Reciever	$ 118,000 /unit		$ -		$ -		$ -
	16" Launcher - Reciever	$ 170,000 /unit		$ -		$ -		$ -
Stations	New MP Regulation Station	$ 275,000 /station		$ -		$ -		$ -
	New Gate Station	$ 500,000 /station		$ -		$ -		$ -
	New Primary Station *	$ 1,000,000 /station		$ -		$ -		$ -
Miscellaneous	Land (reg station)	$ 50,000 /lot		$ -		$ -		$ -
	Design, Inspection & X-Ray	Included in pipe costs						
				$ -		$ -		$ -
Sub-Total				**$ 581,148,014**		**$ 642,216,315**		**$ 5,956,208**
Contingency @ 15%				$ 87,172,202		$ 96,332,447		$ 893,431
Total				**$ 668,320,216**		**$ 738,548,763**		**$ 6,849,639**

Notes:
1) When quoting costs state: "Allow 25% for accuracy"
2) Valves required every 25 kms for Class 2, every 13 kms for Class 3, every 8 kms for Class 4 locations.
3) General assumptions regarding piping costs:
- based on 10 km or longer
- < 10km would require a premium $/m and are much more variable depending on the project
- Dollar values are based on historical data

* Consult with Stations Design for Primary Station Costing

REFERENCE:

Appendix 4.4, pp. 3, 17, 21 of 137

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please describe the process for forecasting asset condition in 20 years using the "current replacement rates," as indicated on p. 17. Specifically showcase the methodology of how Centra translates the current replacement rates (represented throughout the ACA as Years, such as in the Life Expectancy table on p. 21), are translated into kms and other applicable units.
b) Since, as stated on p. 3 of the ACA, the current replacement rates are not consistent with life expectancy of a number of asset classes, has Centra attempted to run a sensitivity analysis of the forecasted condition using replacement rates different from the current levels. If so, please provide the results of this analysis. If not – please articulate why the sensitivity analysis was not considered or completed.

RESPONSE:

a) The process for forecasting the asset condition in 20 years involved the Pipeline Risk Methodology 2014 which is the predecessor of the Pipeline Risk Methodology report in Attachment 2 to the PUB Completeness Review. The frequency analysis score of the 2014 methodology was used to estimate asset condition. This frequency analysis score used an 'age factor'. To make the 20 year forecast for pipelines, the 'age factor' was adjusted by 20 years to estimate a frequency analysis score.

   For stations and control points the current rate of asset replacement indicated that full replacement would be achieved within the estimated life expectancy of stations, as no 'backlog' of work exists.

   For services the current rate of asset replacement indicated that full replacement would not be achieved within the estimated life expectancy of services. The portion of services in this 'gap' was applied to the typical asset condition score characteristics on page 124 of Appendix 4.4. For example, this included adding the additional portion of regulators that would be older than 25 years in 20 years.

b) Centra has not attempted to run a sensitivity analysis of the forecasted condition using replacement rates. This sensitivity analysis was not completed because Centra did not intend to increase replacement rates based solely on the comparison of estimated life expectancies and replacement rates. Rather, Centra identified that key asset condition information gaps exist particularly for pipelines and services. Page 25 of Appendix 4.4 states that,

   "deficiencies as a result of a critical information gas include:

   - *Insufficient condition monitoring precludes an accurate determination of the end of useful life and does not allow for the accurate investment planning of capital resources to replace pipelines."*

REFERENCE:

Appendix 4.4, p. 18 of 137, "Typical Asset Condition Score Characteristics" Table, p. 18 Critical Natural Gas Asset Risk Map.

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please clearly list all types of information used to calculate asset health scores for each critical asset class and sub-class showcased in the report.

b) Please describe the formulations of individual assets' health indices, if different from the table on p. 18. Where multi-parameter health indices are in place, please describe the relative weighting of each parameter, along with the rationale for the weighting.

c) Please explain the implications on the current 2018-2023 Investment Plan (Appendix 4.3) and the regular-course asset management activities over the plan period of the Risk Assessment presented in Figure 3 on p. 23. Specifically, please comment:

    i. Whether and how the risk assessment has influenced the allocation of Plan capital dollars across the programs.

    ii. Whether the scope and nature of planned maintenance, inspection and data collection / analysis activities over the next five years is driven by the insights of the risk analysis.

d) Using a numerical example, please explain how Centra arrived at the conclusion on p. 23 that transmission pipelines and stations are "the highest overall risks to Manitoba Hydro." Specifically, please explain why High-Impact / Rare Likelihood risk scores for Stations and Pipelines produce higher overall risk scores than Low-Impact / Almost Certain Likelihood scores for HP/MP pipelines and Services.

RESPONSE:

a) and b)

Please refer to response to CAC/CENTRA I-74a.

c)

i. The risk assessment presented in Figure 3 on page 23 of Appendix 4.4 contributed to the justification of performing additional condition monitoring. The condition monitoring that had implications on the current 2018-2023 Investment Plan (Appendix 4.3) included Gas In-Line Inspection.

ii. The scope and nature of new planned maintenance, inspection and data collection / analysis activities over the next five years is primarily driven by the insights of lack of condition based information and recommendations on page 94 and page 128 of Appendix 4.4.

d) The conclusion that Stations and Pipelines are regarded as a higher risk than high pressure/medium pressure (HP/MP) pipelines and Services is based on the very high consequence magnitude that a loss of natural gas supply to a city or community would have. The loss of supply from transmission pressure pipelines and station affects many more customers than the loss of a HP/MP pipeline or service and can take much longer to resolve. Although more frequent, failures associated with degradation on HP/MP pipelines and services typically involve small numbers of customers and can generally be resolved in a short period of time. This has not been modeled numerically.

REFERENCE:

Appendix 4.4, Section 4, pp. 24-28,

PREAMBLE TO IR (IF ANY):

Section 4 of the ACA Report entitled "Recommendations" outlines in some detail a number of current gaps related to maintenance and data availability for Centra's assets, primarily related to Pipelines and Services classes. The report does not identify any gaps for the Stations asset class.

QUESTION:

a) Please estimate the impact on recurring annual O&A expenditures of Centra adopting all recommendations provided for Pipelines and Services. Please separate the impact of High and Medium Priority recommendations for each asset type.
b) Please describe the steps that the ACA report's authors took to adjust the report's findings for the impact of the information gaps described within the report. List all assumptions and extrapolation techniques used to derive the asset health indices comprising the report's findings.
c) Specifically, please explain the nature of the estimation process that took place to generate the condition assessment for the pipeline assets, as indicated on p. 90.

RESPONSE:

a) The recommendations provided for Pipelines and Services in the ACAA report with an impact to O&A include several activities for both pipelines and services. These activities are funded within the current O&A target using a combination of internal resources and external services. The activities will address both the high and medium priority recommendations.
    i. For pipelines, the work includes coating shielding investigation and external corrosion direct assessment ("ECDA"). The annual costs for 2019/20 and 2020/21 are estimated as $420,000 and will reduce to $110,000 per year in 2021/22 and

beyond as the planned coating shielding investigation is completed in 2020/21 while the ECDA continues.

ii. For services, a service riser audit is scheduled to be complete in 2022/23 at a cost of approximately $460,000 per year.

b) Please see the response to CAC/CENTRA I-74 a-b.

c) The estimation process to calculate the investment gap to address transmission pipeline condition involved multiplying the percentage of pipeline expected for change from 'good' asset health to 'fair/poor' and 'critical' asset health by the total estimated replacement cost transmission pressure pipelines. This score was then divided by 20 years, to calculate the cost per year.

REFERENCE:

Appendix 4.4, pp. 45, 65 of 137

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide an original copy of a recently completed Gas Facility Assessment form for a Centra station. Please also describe the process of how the information gathered through these forms is processed and analyzed. Confirm whether the information collected on forms is digitized or not.

b) Please provide the source data for each of the 10 years over which the average rate of 29 Metal Loss Corrosion-related leaks per year was calculated as per the p. 65 reference.

RESPONSE:

a) Please see Attachment 1 to this response. The process involves:
   a. Paper versions of the referenced form are filled out at stations annually by select, senior field staff.
   b. The information from the paper versions is then transcribed into the referenced form which is saved on a Manitoba Hydro intranet site for further analysis. The inspection results are digital.
   c. The stations are sorted by condition score and the stations with the highest score are prioritized for project selection.
   d. Prior to finalizing the project selection in the Capital Expenditure Forecast, engineering reviews the project selections with field staff. This review provides an opportunity to reprioritize projects.
   e. Finally, projects selections are submitted as Capital Investment Justifications for approval to Manitoba Hydro management.

b) Please see Attachment 2 to this response.

MANITOBA HYDRO - GAS FACILITY ASSESSMENT

FACILITY Num.: GS-003
LOCATION: TRANSCONA
ASSESSED BY: GREG STEWART
DATE: SEPT 26-2018

Note: Mark 'x' in appropriate column, one 'x' only per criteria

	CONDITION RATING 3	2	1	0	
HEALTH AND SAFETY	Major concern	Moderate concern	Deficiency noted	Not an issue	COMMENTS
Access and Egress		X			
Equipment suitable to workers needs? (ergonomics)			X		
Spacing of isolation valves to regulator				X	
Distance b/w gas facilities and electrical (at least 25ft)				X	
Other Concerns:					
COMPLIANCE	Problem prone	Poor condition	Present	None	COMMENTS
Obsolete parts/equipment					
(298 regs replaced by 1098,				X	
63FV relief valves replaced by 63EG)					
Other Concerns:					
SECURITY OF STATION	High risk	Moderate risk	Slight if no risk	Not an issue	COMMENTS
Sufficient Bollards & proper placement	X				
Other Concerns:					
RELIABILITY OF SUPPLY	Nonexistent	Present	Moderate	Elaborate	COMMENTS
Backup System					
(worker/monitor or relief valve, lead + lag, multiple runs,		X			
multiple relief valves)					
Other Concerns:					

3	=3 x	1
4	=2 x	2
1	=1 x	1
0	=0 x	3

8 =subtotal this sheet

MANITOBA HYDRO - GAS FACILITY ASSESSMENT

FACILITY Num.: GS-003
LOCATION: TRANSCONA
ASSESSED BY: GREG STEWART
DATE: SEPT 26-2018

Note: Mark 'x' in appropriate column, one 'x' only per criteria

CONDITION RATING

INTEGRITY OF SYSTEM	3 Poor condition	2 Acceptable condition	1 Good Condition	0 Excellent condition	COMMENTS
Corrosion	X				
Heaving of station piping due to temperature		X			
Stress/strain visible on components			X		
Isolation valves, block and by pass, regulation isolation			X		
Other Concerns:					

PUBLIC ACCEPTANCE	Major concern	Moderate concern	Minor concern	Not an issue	COMMENTS
Noise		X			
Aesthetics		X			
Proximity to structures *(buildings, roads, rail, watercourse)*				X	
Encroachment *(residential)*		X			
Other Concerns:					

SITE	Re-work the site	Will require work	No work required	Not an issue	COMMENTS
Drainage	X				
Condition of Station Buildings			X		
Vehicular Access - compacted site		X			
Settlement or heaving of structures		X			
Other Concerns:					

ENVIRONMENT	Major concern	Moderate concern	Minor concern	Not an issue	COMMENTS
Safe environmental practices are being followed at station *(containment of odourant, no garbage around site, no spills etc.*				X	
Other Concerns:					

6	=3 x	2
12	=2 x	6
3	=1 x	3
0	=0 x	2

21 =subtotal this sheet

29 =GRAND TOTAL BOTH SHEETS

48% = Percentage based on grand total of 60. Percentages larger than 100% can occur if there are criteria of "other concerns".

Service Order Number	Below Grade Leak Date	Below Grade Leak Location	Below Grade Leak Cause	Pressure Class	Reported Diameter	Site Location	Location.X	Location.Y
2431692	2005-04-06 0:00	Service	Corrosion Facility	MP			62380212	552317616
2442851	2005-04-14 0:00	Service	Corrosion Facility	MP			62830937	553060915
2455821	2005-05-12 0:00	Service	Corrosion Facility	MP			62895387	552575465
2466644	2005-05-29 0:00	Service	Corrosion Facility	MP			63225889	551407017
2474796	2005-05-31 0:00	Main	Corrosion Facility	MP			64178499	553098832
2474792	2005-06-01 0:00	ServT.	Corrosion Facility	MP			64515123	552964477
2480174	2005-06-09 0:00	Service	Corrosion Facility	MP		701 REGENT AVE W	64206888	552902562
2478541	2005-06-13 0:00	Main	Corrosion Facility	MP			63349563	551863535
2479551	2005-06-14 0:00	Service	Corrosion Facility	MP			63021032	553418212
2478405	2005-06-21 0:00	Service	Corrosion Facility	MP			63226029	551968838
2486717	2005-06-21 0:00		Corrosion Facility	MP			63470701	552717916
2481140	2005-06-21 0:00	Service	Corrosion Facility	MP			64251749	552931264
2492577	2005-06-29 0:00		Corrosion Facility	MP		PLESSIS & SANFORD FLEMING (S	64181872	553002489
2492895	2005-07-04 0:00	Main	Corrosion Facility	MP			62123768	552442460
2494254	2005-07-06 0:00	Service	Corrosion Facility	MP			63758357	552408540
2495366	2005-07-12 0:00	Service	Corrosion Facility	MP			63852198	552353205
2493000	2005-07-13 0:00	ServT.	Corrosion Facility	MP			63879869	552486423
2498546	2005-07-13 0:00	Service	Corrosion Facility				62186103	552648773
2499577	2005-07-14 0:00	Service	Corrosion Facility	MP			62858414	552926878
2498468	2005-07-14 0:00	Service	Corrosion Facility				63936378	552299755
2501652	2005-07-15 0:00	Main	Corrosion Facility	MP			62906668	552902365
2488615	2005-07-21 0:00	Main	Corrosion Facility	MP		FRONTENAC BAY & AUTUMNWOO	63768454	552563705
2501626	2005-07-25 0:00		Corrosion Facility	MP		ELLICE & FERRY- S.E. CORNER	62801893	552845936
2505472	2005-07-25 0:00	Main	Corrosion Facility			BROWNELL BAY--BTWN 61 & 59	62131555	552442334
2507704	2005-07-26 0:00	Service	Corrosion Facility	MP			62131575	552442788
2506432	2005-07-26 0:00	Service	Corrosion Facility	MP			62451299	552662281
2507695	2005-07-27 0:00	ServT.	Corrosion Facility	MP			62271780	552516824
2501633	2005-07-27 0:00	Main	Corrosion Facility	MP			62892583	552930399
2510190	2005-07-29 0:00	ServT.	Corrosion Facility	MP			62338252	552722030
2510192	2005-08-02 0:00	ServT.	Corrosion Facility	MP			62279175	552560306
2507693	2005-08-03 0:00	Main	Corrosion Facility	MP			62275329	552516674
2510195	2005-08-03 0:00		Corrosion Facility	MP			62265652	552829996
2512314	2005-08-05 0:00	Main	Corrosion Facility	MP			62073549	552859576
2512662	2005-08-05 0:00	Service	Corrosion Facility	MP			62108745	552834525
2514108	2005-08-05 0:00	Service	Corrosion Facility	MP			62141744	552831732
2512315	2005-08-05 0:00	ServT.	Corrosion Facility	MP			62065230	552864763
2520513	2005-08-05 0:00	ServT.	Corrosion Facility	MP			62108334	552786774
2518188	2005-08-08 0:00	Service	Corrosion Facility	MP			62238479	552670836
2518201	2005-08-09 0:00	Service	Corrosion Facility	MP		DAVID & PORTAGE AVE NORTH C	62143368	552694665
2518175	2005-08-09 0:00	ServT.	Corrosion Facility	MP			62085463	552757989
2518177	2005-08-09 0:00	Service	Corrosion Facility	MP			62079149	552782633
2520493	2005-08-15 0:00	Service	Corrosion Facility	MP			62122429	552418827
2520501	2005-08-15 0:00	Service	Corrosion Facility	MP			62076903	552417287
2520564	2005-08-15 0:00	Main	Corrosion Facility	MP			62105035	552422162
2520560	2005-08-15 0:00	ServT.	Corrosion Facility	MP			62117084	552450993
2520556	2005-08-15 0:00	ServT.	Corrosion Facility	MP			62126065	552450596
2520545	2005-08-15 0:00	ServT.	Corrosion Facility	MP			62130173	552450414
2520565	2005-08-15 0:00	Service	Corrosion Facility	MP			62104397	552418115
2520496	2005-08-16 0:00	Service	Corrosion Facility	MP			62078713	552465920
2520585	2005-08-16 0:00	Service	Corrosion Facility	MP			62245776	552447617
2525227	2005-08-24 0:00	Main	Corrosion/Degradation	TP	6	MINNELL GATE STATION	32370170	556827101
2522618	2005-08-29 0:00	Service	Corrosion Facility	MP			62281093	552344277
2535365	2005-08-30 0:00	Service	Corrosion Facility	MP			63060925	555346294
2536466	2005-09-13 0:00	Service	Corrosion Facility	MP			63269993	552960862
2539656	2005-09-19 0:00	Main	Corrosion Facility	MP			63738348	552598809
2555831	2005-10-12 0:00	Service	Corrosion Facility	MP			62761397	552929405
2565446	2005-10-25 0:00	Service	Corrosion Facility	MP			62953213	553147606
2563019	2005-10-25 0:00	Service	Corrosion Facility	MP			63362424	551803654
2827784	2006-02-23 0:00	Service	Corrosion Facility	MP			62987474	553328115
2949581	2006-03-14 0:00	Service	Corrosion Facility	MP			63830364	553504422
3063117	2006-04-26 0:00	Service	Corrosion Facility	MP			62222636	552336621
3057670	2006-04-28 0:00	Service	Corrosion Facility	MP			63755845	552066274
3066144	2006-05-03 0:00	Main	Corrosion Facility	MP			63411002	552042640
3069209	2006-05-04 0:00	Service	Corrosion Facility	MP			63574384	552051421
3069206	2006-05-04 0:00	Service	Corrosion Facility	MP			63580429	552054845
3143266	2006-05-25 0:00	Service	Corrosion Facility	MP			62160306	552867874
3205152	2006-07-12 0:00	Main	Corrosion Facility	MP		NW CORNER OF CULLEN DR & RA	62110327	552340411
3226053	2006-07-20 0:00	Main	Corrosion Facility	MP		NW CORNER OF CULLEN DR & RA	62110382	552339611
3308420	2006-07-25 0:00	Service	Corrosion Facility	MP			62230885	552535355
3325995	2006-08-03 0:00	Service	Corrosion Facility	MP			63277756	551411312
3349506	2006-08-12 0:00	Main	Corrosion Facility	MP			62211738	552526582
3342942	2006-08-23 0:00	Service	Corrosion Facility	MP			62893304	552951771
3394837	2006-09-12 0:00	ServT.	Corrosion Facility	MP			63297099	552801670
3399201	2006-09-13 0:00	Service	Corrosion Facility	MP			63368424	552959827
3518671	2006-12-08 0:00	Service	Corrosion Facility	MP			63822511	553366484
3556994	2007-01-28 0:00	Main	Corrosion Facility	MP			63530533	552449290
3690400	2007-04-27 0:00		Corrosion Facility	MP			63881834	553337882
3823389	2007-06-12 0:00		Corrosion Facility	MP			63818391	553547795
3823396	2007-06-15 0:00		Corrosion Facility	MP			63833852	553483917
3846750	2007-07-17 0:00		Corrosion Facility	MP			63501521	553083851
3978596	2007-10-03 0:00		Corrosion Facility	MP			63299220	552817615
4015722	2007-10-30 0:00		Corrosion Facility	MP			65143736	555717067
4027350	2007-11-06 0:00		Corrosion Facility	MP			62969006	553456808
4052129	2007-12-04 0:00		Corrosion Facility	MP			64120136	561333224
4238572	2008-05-15 0:00	Service	Corrosion Facility	MP			43194557	552222977
4267578	2008-05-28 0:00		Corrosion Facility	MP			64178929	553070839

Service Order Number	Below Grade Leak Date	Below Grade Leak Location	Below Grade Leak Cause	Pressure Class	Reported Diameter	Site Location	Location.X	Location.Y
4306058	2008-06-10 0:00		Corrosion Facility	MP			64002382	552778603
4306052	2008-06-11 0:00		Corrosion Facility	MP			63759086	552743849
4339854	2008-07-02 0:00	Service	Corrosion Facility	MP			62223319	552458795
4373590	2008-07-18 0:00		Corrosion Facility	MP			63766078	552587659
4419963	2008-08-15 0:00		Corrosion Facility	MP			62365070	552732112
4422891	2008-08-18 0:00		Corrosion Facility	MP			62100203	552826188
4431080	2008-08-20 0:00		Corrosion Facility	MP			62257086	552565301
4452911	2008-09-02 0:00		Corrosion Facility				63376960	552803217
4463543	2008-09-04 0:00		Corrosion Facility	MP			63836122	553467678
4850005	2009-05-06 0:00		Corrosion Facility	MP			63121295	552861126
4807086	2009-05-29 0:00	Main	Corrosion Facility	MP			62930394	552362833
4825098	2009-06-09 0:00		Corrosion Facility	MP			63268666	551429531
4836297	2009-06-16 0:00		Corrosion Facility	MP			63327420	552600056
4860944	2009-06-29 0:00	Service	Corrosion Facility	MP			63039014	552821448
5043771	2009-07-06 0:00	Main	Corrosion Facility	MP		5887 MAIN ST, PTH 9, S OF LOWE	64725420	555221699
4887567	2009-07-14 0:00	Service	Corrosion Facility	MP			63234836	551395445
5063123	2009-07-14 0:00	Service	Corrosion Facility	MP			63235731	551394288
4885969	2009-07-14 0:00	Service	Corrosion Facility	MP			63249382	551441063
4938665	2009-08-17 0:00	Main	Corrosion Facility	MP			62927080	552991770
5033094	2009-10-26 0:00	Main	Corrosion Facility	MP			62911698	553069336
5058634	2009-11-18 0:00		Corrosion Facility	MP			63268078	551409978
4887574	2009-11-20 0:00	Service	Corrosion Facility	MP			63323872	551673653
5128551	2009-12-19 0:00	Main	Corrosion Facility	MP			62068303	552447219
7688337	2009-12-31 0:00		Corrosion Facility	MP			62200741	552599513
5196134	2010-02-04 0:00		Corrosion Facility	MP			63282074	551402659
5344838	2010-05-26 0:00	Service	Corrosion Facility	MP			63268278	551430309
5352584	2010-05-31 0:00	Service	Corrosion Facility	MP			63221115	551958593
5357214	2010-06-01 0:00	Service	Corrosion Facility	MP			62220035	552517390
5370403	2010-06-08 0:00		Corrosion Facility	MP			63902113	553491564
5375136	2010-06-11 0:00	ServT.	Corrosion Facility	MP			63867015	553041027
5388904	2010-06-21 0:00	Main	Corrosion Facility	MP			63712621	553221350
5412426	2010-06-30 0:00	Main	Corrosion Facility	MP			63871220	553485965
5422260	2010-07-02 0:00	ServT.	Corrosion Facility	MP			63230378	551427911
5413295	2010-07-05 0:00	ServT.	Corrosion Facility	MP			63841310	553505443
5413289	2010-07-05 0:00	ServT.	Corrosion Facility	MP			63835096	553509489
5413299	2010-07-05 0:00	ServT.	Corrosion Facility	MP		268 MCIVOR AVE	63847050	553501708
5423844	2010-07-07 0:00		Corrosion Facility	MP			63839855	553506391
5482832	2010-07-29 0:00		Corrosion Facility	MP			64420198	559579425
5455344	2010-07-29 0:00	Service	Corrosion Facility	MP			63182457	553376239
5468999	2010-08-09 0:00	Service	Corrosion Facility	MP			62900580	553481794
5472122	2010-08-10 0:00	Service	Corrosion Facility	MP			62919831	553477717
5471704	2010-08-11 0:00	Main	Corrosion Facility	MP			62935261	553371718
5472110	2010-08-11 0:00	Main	Corrosion Facility	MP			62809144	553334328
5473592	2010-08-12 0:00	Main	Corrosion Facility	MP			62947725	553424772
5480017	2010-08-17 0:00	Service	Corrosion Facility	MP			62883731	553445933
5482657	2010-08-18 0:00	ServT.	Corrosion Facility	MP			63890177	553499340
5480045	2010-08-19 0:00	Service	Corrosion Facility	MP			62888772	553446252
5898217	2010-11-10 0:00	Service	Corrosion Facility	MP			62556843	552366197
5958853	2010-11-16 0:00	Service	Corrosion Facility	MP			62555930	552366230
5969052	2010-11-16 0:00	Service	Corrosion Facility	MP		61 RUE LE MAIRE	63235386	551394734
6090193	2010-11-22 0:00		Corrosion Facility	MP			62098671	552788966
6023844	2010-11-25 0:00		Corrosion Facility	MP			62074275	552355391
5968812	2010-11-30 0:00	Service	Corrosion Facility	MP		1114 DES TRAPISTES	63263647	551385242
5968932	2010-12-03 0:00	Service	Corrosion Facility	MP		1112 RUE TRAPPISTES	63265372	551386225
6556165	2011-01-24 0:00	Service	Corrosion Facility	MP			62947432	552615920
7075131	2011-04-26 0:00	Service	Corrosion Facility	MP			66747476	554982898
6991101	2011-04-26 0:00	Service	Corrosion Facility	MP			66747476	554982898
7025751	2011-05-28 0:00		Corrosion Facility	MP		1577 DUBLIN AVE	62928397	553045892
7452165	2011-06-24 0:00	Main	Corrosion Facility	MP		KING & 5TH ST SE	55140528	553545835
7443262	2011-06-27 0:00	ServT.	Corrosion Facility	MP			64549274	552950254
7443300	2011-06-28 0:00		Corrosion Facility	MP		SW CORNER OF PANDORA AVE &	64507584	552872657
7585289	2011-07-03 0:00	Service	Corrosion Facility	MP			62110895	552393689
7367800	2011-07-08 0:00	Main	Corrosion Facility	MP			62129381	552391838
7706749	2011-08-08 0:00	ServT.	Corrosion Facility	MP			62232091	552570552
7595608	2011-08-10 0:00		Corrosion Facility			SW CORNER KINGEDWARD @ SA	62873071	552882544
7688375	2011-08-24 0:00		Corrosion Facility	MP			62262713	552507542
7688318	2011-08-25 0:00		Corrosion Facility				62191202	552538805
7688332	2011-08-26 0:00		Corrosion Facility	MP			62153972	552549880
7688328	2011-08-26 0:00		Corrosion Facility	MP			62142259	552567521
7686644	2011-08-29 0:00		Corrosion Facility	MP			62238958	552563780
7983418	2011-11-07 0:00		Corrosion Facility	MP			61731160	552502055
8818878	2012-05-02 0:00		Corrosion Facility	MP		1832 KING EDWARD	62870142	553174533
8804721	2012-05-03 0:00		Corrosion Facility	MP		1000 HENRY AVE	63168152	553061623
8903826	2012-05-22 0:00		Corrosion Facility	MP		172 EGERTON RD	63657429	552551245
8965964	2012-05-30 0:00		Corrosion Facility	MP		256 RIVER RD	63397343	552051804
8985610	2012-06-01 0:00		Corrosion Facility	MP			63507501	552058570
8965970	2012-06-22 0:00	Service	Corrosion Facility	MP		20 WISCONSIN ST	63591245	552060971
9140085	2012-06-25 0:00	Main	Corrosion Facility	MP		NW CORNER OF CORYDON AVE +	62926305	552506893
8985727	2012-07-04 0:00		Corrosion Facility	MP			63417493	552095496
8962157	2012-07-10 0:00	Service	Corrosion Facility	MP		36 ST. MICHAEL ROAD	63537472	552166583
9140476	2012-07-17 0:00	Service	Corrosion Facility	MP			62927576	552535780
9253760	2012-07-18 0:00	Service	Corrosion Facility	MP		1718 CHANCELLOR DRIVE	63248605	551847674
9494233	2012-09-03 0:00		Corrosion Facility	MP		2 RAMBLEWOOD ROAD	64062996	551801514
9585759	2012-09-09 0:00	Service	Corrosion Facility	MP		48 CARTWRIGHT RD	63117819	553559020
9747573	2012-10-23 0:00	Main	Corrosion Facility	MP			62985900	553384587
9893375	2012-11-28 0:00	Service	Corrosion Facility	MP		DALE BLVD @ EVENWOOD CRES	62078180	552363142

Service Order Number	Below Grade Leak Date	Below Grade Leak Location	Below Grade Leak Cause	Pressure Class	Reported Diameter	Site Location	Location.X	Location.Y
10065075	2013-02-22 0:00		Corrosion Facility	MP		1109 HENDERSON HWY	63685039	553349342
10189719	2013-05-08 0:00	Service	Corrosion Facility	MP			63042174	552935380
10195357	2013-05-09 0:00	Service	Corrosion Facility	MP			62173941	552576648
10212324	2013-05-16 0:00	ServT.	Corrosion Facility	MP		70 BUNN'S GROVE	63897136	553535513
10308894	2013-06-04 0:00	ServT.	Corrosion Facility	MP		616 MCIVOR AVE	63937676	553442699
10292907	2013-06-17 0:00	Service	Corrosion Facility	MP		836 PRITCHARD FARM RD	64151985	553638969
10292910	2013-06-17 0:00	ServT.	Corrosion Facility	MP		388 FOXDALE AVE	63911780	553485266
10292916	2013-06-17 0:00		Corrosion Facility	MP		271 BONNER AVE	63865208	553548193
10308891	2013-06-19 0:00	Service	Corrosion Facility	MP		1881 ROTHESAY ST	63860139	553496783
10296712	2013-06-20 0:00	Service	Corrosion Facility	MP		6 CONTINENTAL AVE	63915685	553423149
10296780	2013-06-21 0:00	Main	Corrosion Facility			MCIVOR AVE & ROTHESAY ST-NW	63858495	553494256
10327105	2013-07-02 0:00	ServT.	Corrosion Facility	MP			63898500	553187902
10349926	2013-07-09 0:00	Main	Corrosion Facility	MP		764 KIMBERLY	63787160	553144154
10352622	2013-07-17 0:00	Service	Corrosion Facility			544 Selkirk Ave	63303787	553095873
10376656	2013-08-15 0:00	Service	Corrosion Facility	MP			63080806	553338342
10413406	2013-08-15 0:00	Main	Corrosion Facility	MP			62104102	552417845
10425339	2013-08-21 0:00	Service	Corrosion Facility	MP			62873394	553426556
10438762	2013-08-26 0:00	Service	Corrosion Facility	MP			63029214	553420176
10399162	2013-09-05 0:00	Service	Corrosion Facility	MP			63324460	553544415
10415275	2013-09-10 0:00	Main	Corrosion Facility	MP			63182457	553376239
10498065	2013-09-19 0:00		Corrosion Facility	MP		409 Selkirk Ave	63344396	553076856
10501466	2013-09-20 0:00	Service	Corrosion Facility	MP			62151640	552794857
10514735	2013-09-25 0:00		Corrosion Facility	MP			63215481	551595557
10448467	2013-10-16 0:00	Service	Corrosion Facility	MP			63021032	553418212
10448611	2013-10-23 0:00	Main	Corrosion Facility	MP			62876300	553445761
10782413	2014-03-07 0:00		Corrosion Facility	MP			63494718	552971448
10782403	2014-03-07 0:00	Service	Corrosion Facility				63101228	553211569
10817115	2014-04-01 0:00	Service	Corrosion Facility	MP			63320762	553039433
10828635	2014-04-29 0:00	Main	Corrosion Facility	MP		NOTRE DAME AVE & KING EDWAF	62872209	553092970
10883964	2014-05-08 0:00	Main	Corrosion Facility	MP			64333303	552873878
10883184	2014-05-12 0:00	Main	Corrosion Facility	MP			63646092	552111927
10884249	2014-05-12 0:00	Service	Corrosion Facility	MP			62073513	552309073
10891076	2014-05-14 0:00	Main	Corrosion Facility	MP			63268159	551604412
10893602	2014-05-14 0:00	Service	Corrosion Facility	MP			63268159	551604412
10875541	2014-05-15 0:00	Service	Corrosion Facility	MP			64347975	553029418
10907738	2014-05-22 0:00		Corrosion Facility				64194163	552967301
10930244	2014-05-30 0:00	ServT.	Corrosion Facility	MP			63782887	552527906
10991866	2014-06-25 0:00	Main	Corrosion Facility	MP			64006712	552778720
11039848	2014-07-17 0:00	Service	Corrosion Facility	MP			63325943	552833631
11034298	2014-07-17 0:00	ServT.	Corrosion Facility	MP			62334664	552825649
11177412	2014-07-17 0:00	Service	Corrosion Facility	MP			63325943	552833631
11029457	2014-07-21 0:00	Service	Corrosion Facility	MP			63398274	553001562
11072369	2014-07-31 0:00	ServT.	Corrosion Facility	MP			62080775	552318705
11072358	2014-07-31 0:00	Service	Corrosion Facility	MP			62077718	552324941
11188740	2014-08-05 0:00	Service	Corrosion Facility	MP			62107607	552382279
11072759	2014-08-06 0:00	Service	Corrosion Facility	MP			62071941	552409950
11072331	2014-08-07 0:00	Service	Corrosion Facility	MP			62079266	552321766
11089812	2014-08-23 0:00	Service	Corrosion Facility	MP			62098592	552787078
11047677	2014-08-25 0:00	ServT.	Corrosion Facility	MP			62155701	552862430
11045796	2014-08-27 0:00	Service	Corrosion Facility	MP			62098529	552785584
11045689	2014-09-03 0:00	Service	Corrosion Facility	MP			62098730	552790367
11047875	2014-09-11 0:00	ServT.	Corrosion Facility				62100203	552826188
11050802	2014-09-11 0:00	ServT.	Corrosion Facility	MP			62104630	552418329
11045779	2014-09-12 0:00	ServT.	Corrosion Facility	MP			62100438	552831817
11045752	2014-09-12 0:00	Main	Corrosion Facility	MP			62100121	552824211
11045659	2014-09-23 0:00	Service	Corrosion Facility	MP			62060634	552800848
11075163	2014-09-25 0:00	Main	Corrosion Facility	MP			62546247	552339541
11045732	2014-09-29 0:00	Service	Corrosion Facility	MP			62157394	552630299
11050878	2014-10-06 0:00	Service	Corrosion Facility	MP			62087071	552363787
11072952	2014-10-07 0:00	Service	Corrosion Facility	MP			62090720	552401681
11072986	2014-10-13 0:00		Corrosion Facility	MP			62530600	552436822
11072975	2014-10-14 0:00	Service	Corrosion Facility	MP			62107928	552389584
11079886	2014-10-15 0:00	Main	Corrosion Facility	MP		NW CORNER OF CULLEN DR AND	62110315	552340145
11190053	2014-10-20 0:00	Service	Corrosion Facility	MP			62818457	552811752
11190891	2014-10-21 0:00	Main	Corrosion Facility	MP			62109955	552314752
11072825	2014-11-03 0:00	Service	Corrosion Facility	MP			62127805	552378519
11351640	2015-01-08 0:00	Service	Corrosion/Degradation	MP	3/4		63569490	553145255
11458206	2015-03-20 0:00	Service	Corrosion/Degradation	MP	11/4		63839080	561104935
11571196	2015-05-19 0:00	Service	Corrosion/Degradation	MP	3/4		63248605	551847674
11596220	2015-05-30 0:00	Service	Corrosion/Degradation	MP	3/4		62863862	552529781
11617042	2015-06-07 0:00	Service	Corrosion/Degradation	MP	3/4		62858788	552531609
11805018	2015-06-08 0:00	Service	Corrosion/Degradation	MP	3/4"		63679481	552072542
11805055	2015-06-08 0:00	Service	Corrosion/Degradation	MP	3/4"		63682518	552072792
11617611	2015-06-08 0:00	Service	Corrosion/Degradation	MP	3/4	3085 Main St	63772918	553660785
11568677	2015-06-26 0:00	Service	Corrosion/Degradation	MP	3/4"	875 PORTAGE AVE	63154276	552759066
11706269	2015-07-08 0:00	Main	Corrosion/Degradation	MP	2"	EAST LAKE DR & GULL LAKE ROA	63249088	551926514
11745827	2015-08-03 0:00	Service	Corrosion/Degradation	MP	3/4"		63653504	552077416
11786075	2015-08-23 0:00	Service	Corrosion/Degradation	MP	3/4"		63123698	553494322
11790926	2015-08-25 0:00	Service	Corrosion/Degradation	MP	3/4"		66762428	548803813
11796577	2015-08-27 0:00	Service	Corrosion/Degradation	MP	3/4	141 WESTGROVE WAY	62068285	552446808
11581565	2015-09-29 0:00	Service	Corrosion/Degradation	MP	3/4		63800582	552406055
11670122	2015-10-08 0:00	Service	Corrosion/Degradation	MP	3/4		63506489	552239039
11670098	2015-10-09 0:00	Service	Corrosion/Degradation	MP	3/4		63431990	552019276
11706454	2015-10-14 0:00	Service	Corrosion/Degradation	MP	3/4		63349594	551742199
12050176	2016-01-20 0:00	Service	Corrosion/Degradation	MP	3/4"		65072404	555567920
12030930	2016-01-26 0:00	Service	Corrosion/Degradation	MP	3/4"		63843801	553275228

Service Order Number	Below Grade Leak Date	Below Grade Leak Location	Below Grade Leak Cause	Pressure Class	Reported Diameter	Site Location	Location.X	Location.Y
11670095	2016-02-05 0:00	Service	Corrosion/Degradation	MP	4"		63439065	552000116
12179614	2016-03-23 0:00	Service	Corrosion/Degradation	MP	2"	2110 NOTRE DAME AVE.	62830393	553088572
12190121	2016-03-29 0:00	Service	Corrosion/Degradation	MP	3/4	2016 Henderson Hwy	63835953	553572048
12280743	2016-04-20 0:00	Service	Corrosion/Degradation	MP	3/4		62128394	552392916
12642406	2016-06-28 0:00	Service	Corrosion/Degradation	MP	3/4	135 CULEN DR	62107375	552372623
	2016-07-06 0:00	Main	Corrosion/Degradation	TP	4"	GS-119	44452124	554520843
12779061	2016-07-21 0:00	Service	Corrosion/Degradation	MP	3/4	193 MAPLEGLEN DR	63148746	553406401
12797824	2016-07-25 0:00	Service	Corrosion/Degradation	MP	3/4	23 MANSARD CLOSE	63166255	553437389
12795903	2016-07-25 0:00	Service	Corrosion/Degradation	MP	3/4		63426466	553470348
12820743	2016-07-31 0:00	Service	Corrosion/Degradation	MP	3/4"		63522496	553324597
12861132	2016-08-18 0:00	Service	Corrosion/Degradation	MP	3/4"	96 4TH AVE	64207982	561066749
12860991	2016-08-18 0:00	Service	Corrosion/Degradation	MP	3/4"	20 6TH AVE	64183367	561150246
13016778	2016-12-31 0:00	Service	Corrosion/Degradation	MP	3/4	106 HOME ST	66745764	548947761
	2017-02-10 0:00	Main	Corrosion/Degradation	MP	2"	GS-009	62652524	555053647
13092078	2017-02-15 0:00	Service	Corrosion/Degradation	MP	3/4"	183 ENFIELD CRES	63518988	552672663
13157286	2017-03-29 0:00	Service	Corrosion/Degradation	MP	3/4"	67 Monck Ave/68 Claremont Ave	63469618	552625453
13177101	2017-04-13 0:00	Service	Corrosion/Degradation	MP	2"	1175 SHERWIN RD.	62840520	553053056
13248983	2017-05-30 0:00	Service	Corrosion/Degradation	MP	3/4"	286 BELVIDERE ST.	62694541	552686322
13276334	2017-06-16 0:00	Service	Corrosion/Degradation	MP	3/4"	332 Dowling Ave E	64394634	553014556
13328674	2017-07-20 0:00	Main	Corrosion/Degradation	MP	2"	18 Canberra Rd	63819645	552479567
13327323	2017-07-25 0:00	Main	Corrosion/Degradation	MP	2"	12 Cancerra Rd	63816944	552480044
13342997	2017-08-04 0:00	Service	Corrosion/Degradation	MP	2"	125 GARRY ST.	63373212	552800269
13350135	2017-08-11 0:00	Main	Corrosion/Degradation	MP	4"	PLINGUET ST AND MCTAVISH ST	63628164	552847026
13390365	2017-08-15 0:00	Service	Corrosion/Degradation	MP	3/4"	247 CARROLL RD.	62257259	552569434
13432906	2017-08-15 0:00	Service	Corrosion/Degradation	MP	1/2"	615 DALE BLVD.	62104846	552433626
13357477	2017-08-17 0:00	Service	Corrosion/Degradation	MP	3/4"	6640 RANNOCK AVE	62114365	552339080
13390357	2017-08-17 0:00	Main	Corrosion/Degradation	MP	2"	71 COLERIDGE PARK DR.	62138539	552547095
13444502	2017-08-17 0:00	Service	Corrosion/Degradation	MP	3/4"	875 DALE BLVD.	62077067	552334833
13432942	2017-08-22 0:00	Service	Corrosion/Degradation	MP	3/4	221 HAMMOND RD.	62096526	552410261
	2017-10-04 0:00	Main	Corrosion/Degradation	MP	8"	1741 Grant Ave	62965950	552425997
13425581	2017-10-11 0:00	Main	Corrosion/Degradation	MP	2"	36 DEERHORN LANE	62240425	552854594
13490101	2017-12-14 0:00	Service	Corrosion/Degradation	MP	3/4"		63202278	551574773
13492123	2017-12-18 0:00	Service	Corrosion/Degradation	MP	26.7		43264036	552011365
13598060	2018-03-28 0:00	Service	Corrosion/Degradation	MP	2"	2200 GRANT AVE	62732062	552422807
13654621	2018-05-02 0:00	Service	Corrosion/Degradation	MP	1 1/4"	805 CORYDON AVE	63252957	552581531
13710448	2018-06-08 0:00	Service	Corrosion/Degradation	MP	3/4"	15 GREENDELL AVE	63559833	552058166
13765698	2018-07-17 0:00	Main	Corrosion/Degradation	MP	4"	RD 25W & PTH 3-3 MI EAST OF MC	57108926	544938237
13809691	2018-08-15 0:00	Service	Corrosion/Degradation	MP	3/4"	78 BROTMAN BAY	63684863	551924756
13815951	2018-08-18 0:00	Service	Corrosion/Degradation	MP	3/4"	2 HALLFIELD BAY	63746177	551872932
13814230	2018-08-20 0:00	Service	Corrosion/Degradation	MP	3/4"	51 LAKESHORE RD.	63214641	551846276
13815949	2018-08-20 0:00	Service	Corrosion/Degradation	MP	3/4"	95 RADCLIFFE RD.	63402061	551730973
13830730	2018-08-21 0:00	Service	Corrosion/Degradation	MP	3/4"	7 CORNELL DR.	63374593	551779990
13830733	2018-08-22 0:00	Service	Corrosion/Degradation	MP	3/4"	87 CORNELL DR.	63391528	551755704
13820148	2018-08-22 0:00	Service	Corrosion/Degradation	MP	3/4	14 LAKE ALBRIN BAY	63157505	551931497
13857094	2018-09-14 0:00	Service	Corrosion/Degradation	MP	3/4"	270 RED OAK DR.	63980902	553209160
13857257	2018-09-17 0:00	Service	Corrosion/Degradation	MP	3/4"	266 RED OAK DR.	63979484	553209844
13912608	2018-10-18 0:00	Service	Corrosion/Degradation	MP	3/4"	46 RED OAK DR	63940457	553252561
13942904	2018-12-07 0:00	Service	Corrosion/Degradation	MP	3/4"		63023430	552396772
13954742	2018-12-22 0:00	Service	Corrosion/Degradation	MP	3/4	965 KILKENNY DR.	63394446	551678590

REFERENCE:

Attachment 6, PUB Completeness Review

PREAMBLE TO IR (IF ANY):

This exhibit contains financial and scope details of Centra's past projects at the cost of over $250,000.

QUESTION:

a) Please confirm whether the past year capital costs and future year projections in the tables on pages 2 and 7 are presented before or net of requisite third-party contributions for connection / expansion and relocation work, as applicable.

RESPONSE:

The past year capital costs and future year projections in the tables are presented before requisite third-party contributions.

REFERENCE:

Attachment 6, PUB Completeness Review

PREAMBLE TO IR (IF ANY):

This exhibit contains financial and scope details of Centra's past projects at the cost of over $250,000.

QUESTION:

b) Does Centra have in place any form of a corporate pipeline abandonment policy, guidelines or technical standards? If so, please provide the associated documents.

RESPONSE:

Yes, please see Attachments 1 and 2 to this response for Centra's Natural Gas Standard 512.10 and 740.03.

500 Design

Scope

This standard applies to the abandonment requirements for all pipelines and services in the Manitoba Hydro natural gas distribution system.

References

740.03 – Abandonment
5.000.16 – Medium Pressure Service Line Abandonment

Distribution Systems

The deactivation and abandonment of distribution piping and services shall be subject to the following requirements:

a) The piping in question shall be purged of the natural gas product throughout the entire length
b) The piping
   i. shall be removed or
   ii. disconnected from the distribution system and the open ends capped, plugged or otherwise effectively sealed to prevent the flow of natural gas.
c) Capping, plugging and sealing of service lines shall be completed outside the buildings served by such piping.
d) The service pipe attachment appurtenance to the distribution main shall be abandoned in such a manner as to permanently seal any natural gas leakage from the attached appurtenance.

Distribution Services

Additional requirements for distribution services shall be according to Natural Gas Standard 740.03

Pipeline Systems operated at 30% SMYS & Greater

The decision to deactivate and abandon a pipeline operated at 30% SMYS & greater shall be subject to the following requirements:

a) A documented abandonment plan that includes;
   i. Rationale for abandonment
   ii. Landowner consultation
   iii. Effect on terrain and water
   iv. Roadways and rail crossings
   v. Current and potential land use
   vi. Assessment for safety hazards and environmental damage that could be created by ground subsidence, erosion and the creation of water conduits.

b) The abandoned pipeline segment shall be;
   i. purged of natural gas
   ii. cut and separated from any in-service piping
   iii. capped, plugged or otherwise effectively sealed
   iv. cut off at pipeline depth; and
   v. left unpressurized

c) Surface Equipment, valves and appurtenances, shall be removed to the depth of the abandoned pipeline.

d) Above ground abandoned pipelines and related equipment shall be removed

e) Records of the abandonment shall be created, maintained and include;
   i. All the work associated with the abandonment as identified by this standard
   ii. Abandoned pipeline length
   iii. Abandoned pipeline diameter
   iv. Abandoned material type
   v. Geographic reference
   vi. Abandoned pipeline depth if available

National Energy Board Regulated Pipeline Systems

Pipeline systems regulated by the National Energy Board require additional requirements for compliance when abandoning a pipeline. Please refer to the National Energy Board **Regulating Pipeline Abandonment** publication for additional information.

Scope

This standard specifies requirements for abandoning a gas service on a plastic main or on a steel main where the service tee is either a Mueller No-Blo tee or a Mueller or Continental Autoperf Tee. The standard does not apply to farm taps, high pressure services, services over 114.3mm in diameter, tubing services, or services with homemade tapping tees.

References

620.03 Steel Fitting Coating and Wrapping
630.03 Tracer Wire Installation
611.01 Purging
Manitoba Regulation 217/2006 Workplace Safety and Health Regulation
Procedure 5.000.16 ~~Medium Pressure~~ Natural Gas Service Abandonment
Procedure 5.400.09 Excavating Practices for Natural Gas Lines
Manitoba Hydro: Polyethylene Fusion Guide
SWP – Service and Main Alterations
SWP – Steel Tapping and Stopping

General

- Obtain clearances from all utilities prior to the commencement of any excavation work.
- Use barricades to protect excavations as required.
- All pipe shall be disconnected using appropriate no blow techniques.
- The service line on the customer's property shall be abandoned in place unless otherwise directed for specific situations.

Service Line at Distribution Pressure Main

The method of abandonment will be dependent on the type of tee and the pipe material as shown:

Steel Service, Mueller No-Blo Tee (Figure 1):

- The gas shall be shut off at the tee on the main using Mueller No-Blo equipment.
- The service line shall be depressurized through the service riser.
- The service line shall be cut a minimum distance of 150 mm (6") from the service tee and a minimum 150 mm section of the service pipe shall be removed. The service line shall be purged.
- The service tee outlet shall be seal welded by an acceptable method.
- A leak test shall be performed on the service tee.

- The completion cap shall be re-installed.
- The service tee shall be wrapped with an approved fitting wrap.
- The disconnected service line shall be seal welded. Alternatively, an expander plug can be set a minimum of 100 mm into the pipe and the end of the pipe sealed with poly tape.
- The service line shall be left without cathodic protection pipe wrap is not required on the abandoned service line.

Figure 1
Steel Service with Mueller No-Blo Tee

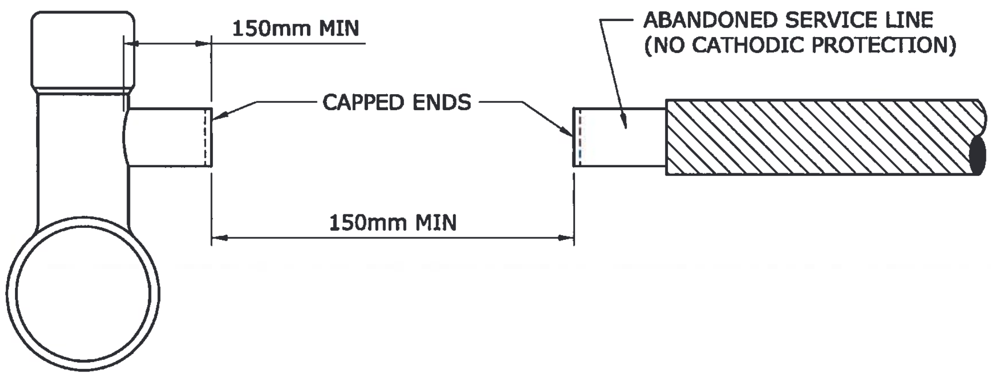


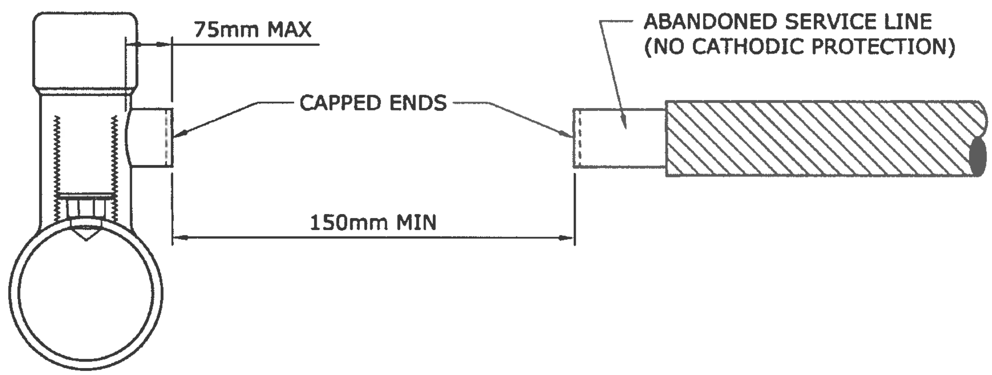
Table 1

RECOMMENDED WELD DISTANCE	
Size of Fitting (NPS)	Minimum Distance Between Stopper Face and Weld or Cut
¾	150 mm
1	150 mm
1 ¼	150 mm
1 ½	180 mm
2	200 mm
2 ½	230 mm
3	260 mm
4	310 mm

Steel Service, Self Tapping Tee (Figure 2):

- The gas shall be shut off at the tee on the main.
- The cutter shall be screwed down completely.
- The service line shall be depressurized through the service riser.
- The service line shall be cut a maximum distance of 75 mm from the service tee and a minimum 150 mm section of the service pipe shall be removed. The service line shall be purged.
- The service tee outlet shall be sea welded by an acceptable method.
- The service tee shall be leak tested.
- The service tee shall be wrapped with an approved pipe wrap.
- The disconnected service line shall be seal welded using an acceptable method. Alternatively, an expander plug can be set a minimum of 100 mm into the pipe and the end of the pipe sealed with poly tape.
- The service line shall be left without cathodic protection. Pipe wrap is not required on the abandoned service line.

Figure 2
Steel Service with Self Tapping Tee



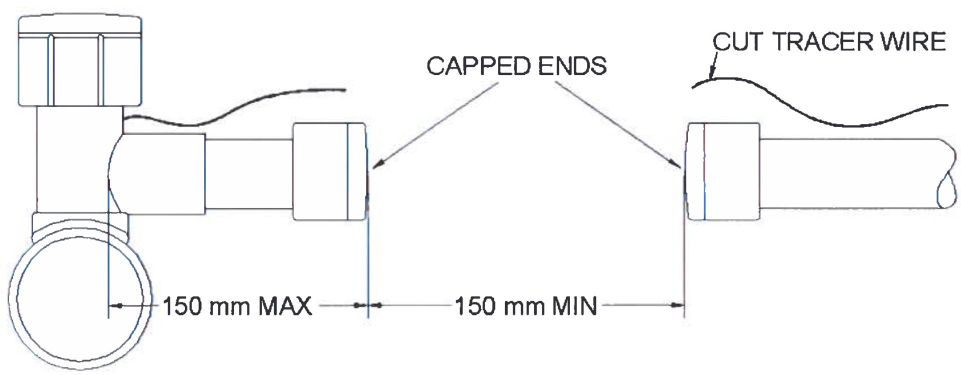
Polyethylene Service

- The gas shall be shut off at the tee on the main by turning the cutter down.
- The service line shall be depressurized through the service riser.
- The service line shall be cut a maximum distance of 75 mm from the service tee and the service tee outlet shall be capped using the appropriate size of socket fusion end cap. Use of a mechanical end cap (Perm-a-sert or other) is an acceptable alternative. Electrofusion end caps shall be used when the service piping

polyethylene materials are different from the socket fusion end caps. (See Dissimilar Plastics, page 2 of Polyethylene Fusion Guide).

- The disconnected service line shall be purged.
- The tee shall be re-pressurized, the capped service end shall be soap-tested, and then the gas shall be stopped once more.
- The disconnected service line shall be capped a minimum of 150 mm away from the stub at the tee using the appropriate size of socket fusion end cap. Use of an mechanical end cap (Perm-a-sert or other) is an acceptable alternative. Electrofusion end caps shall be used when the service piping polyethylene materials are different from the socket fusion end caps. (See Dissimilar Plastics, page 2 of Polyethylene Fusion Guide).
- The tracer wire for the service shall be cut at the tracer wire at the main. The cut end of the wire shall be sealed with a mastic pad in accordance with Standard 630.04 Tracer Wire Connection.
- Continuity of the tracer wire along the main shall be checked once the hole is filled.

Figure 3
Polyethylene Service



	Socket Fusion End Cap	Mechanical Coupling
1/2 CTS	CIIC 01-06-03	CIIC 03-35-72
3/4 NPS	CIIC 01-06-04	CIIC 03-35-73
1 NPS	CIIC 01-06-05	CIIC 03-35-74
1 1/4 NPS	CIIC 01-06-06	CIIC 03-35-75

5/8 Tubing Service

- The gas shall be shut off at the tee on the main by turning the cutter down.
- The top half of the fitting shall be circumferentially welded to the main.
- The service line shall be depressurized at the service riser.
- The hinge and clasp of the mechanical service tee shall be cut from the fitting to leave the saddle on the main.
- The remaining fitting to main interfaces shall be welded.
- The service line shall be removed from the tee.
- The disconnected service line shall be purged.
- The service tee outlet shall be cut at the start of the threads.
- The service tee outlet shall be seal welded by an acceptable method.
- A leak test shall be performed on the abandoned service tee.
- The completion cap shall be re-installed.
- The service tee shall be wrapped with an approved pipe wrap.
- The disconnected service line end shall be sealed.
- The service line shall be left without cathodic protection. Pipe wrap is not required on the abandoned service line.

Service Line at High Pressure Main

To be developed in conjunction with High Pressure Service abandonment procedure.

Riser

Steel Service

Following the stopping / abandonment at the main:

- The service line shall be cut a minimum of 150 mm below grade.
- The service line shall be plugged by setting an expander plug a minimum 100 below the end of the pipe. The end of the pipe shall be wrapped with polyethylene tape. Pipe wrap is not required.
- Restoration of the grade and surface shall be performed at the original site of the riser.

Polyethylene Service

Following the stopping / abandonment at the main:

- The gas pipe, riser, and tracer wire shall be cut 150 mm below ground surface.
- The gas pipe (within the riser) shall be plugged using cement or silicone caulking. Insert paper or plastic film approximately 100 mm into the riser to create a stop for the cement or caulking. The top end of the riser shall be sealed with polyethylene tape. , Alternative plugging methods as approved by the Gas Standards Engineer will be acceptable.
- Where present, the top wall bracket shall be disconnected and removed.
- Restoration of the grade and surface shall be performed at the original site of the riser.

Meter Set

Outside Meter

- The meter set, regulator, and associated piping shall be disconnected and removed. The meter is to be returned to the Meter Shop unless other alternative arrangements are made. All other materials are to become scrap and are to be recycled.
- Where the meter set is connected to a wall entry pipe, the wall entry pipe shall be capped, plugged, or otherwise effectively sealed as approved by the Gas Standards Engineer.
- For below grade entry, the wall pipe shall be plugged or capped appropriately and wrapped with an approved pipe wrap to provide a permanent seal.

Inside Meter

- The regulator and piping shall be disconnected and removed from the outside of the building.
- The meter and meter piping shall be disconnected and removed. The meter is to be returned to the Meter Shop unless other alternative arrangements are made. All other materials are to become scrap and are to be recycled.
- The customer piping shall be capped.
- If the wall entry pipe is loose or leaking, it shall be removed and the hole patched with cement or other appropriate materials to provide a permanent weather proof seal.
- If the wall entry pipe is to remain, it shall be capped on both ends.

MUELLER® NO-BLO® FORGED STEEL SERVICE TEE FEATURES

Mueller Co. 3.1

REV. 12-06

Mueller NO-BLO Service Tees are used to make main to service connections. These tees are available in a wide range of sizes and inlet and outlet combinations.

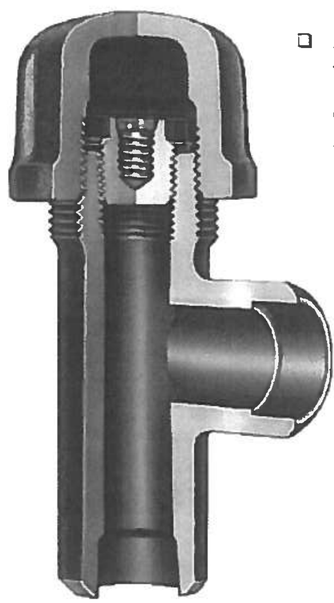
The tees are available with either weld or external (M.I.P.) thread inlets.

The threaded inlet tees can be used with Mueller Service Saddles to make main to service connections that do not require welding.

Outlets include weld, thread (M.I.P. or F.I.P.) and compression connections.

Mueller NO-BLO Service Tee Features

- COMPLETION CAP – is available in Cast Iron or steel for most tees and provides a secondary seal.
- COMPLETION PLUG – makes primary seal.
- INLETS – are available in either weld or external (M.I.P.) thread styles.



- MAXIMUM WORKING PRESSURE – 250 psig for tees with Cast Iron caps and 1440 psig for tees with steel caps. Tees with compression connection outlets have lower pressure ratings.
- OUTLETS – are available in weld, external (M.I.P.) thread, internal (F.I.P.) thread, and several popular compression connections.
- BODY – is machined from solid steel forging for strength.

MUELLER® AUTOPERF® TEE FEATURES

6.1

REV. 12-06

Mueller AUTOPERF Tees provide a fast economical way to make a main to service connection.

These products have a self contained, one piece, hardened perforator that is used to cut a hole in the main to initiate service. This eliminates the need for drilling machines and control valves.

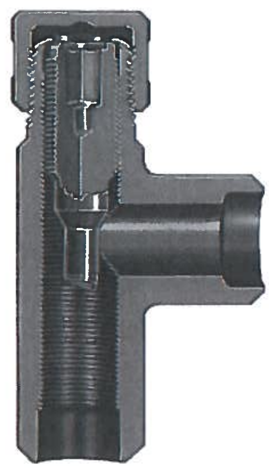
The perforator retains the pipe coupon and also functions as a shut-off.

Installation is fast and simple using proven Mueller® NO-BLO® Methods and tools.

Mueller AUTOPERF Tees are available with several popular inlet/outlet combinations.

Mueller AUTOPERF Tee Features

- ❑ COMPLETION CAP – is made of steel and provides a secondary seal.
- ❑ TOP – of tee body can be crimped to prevent unintentional removal of the perforator.
- ❑ HARDENED – hex socket prevents distortion.
- ❑ TIP DESIGN – formed with helices to reduce torque for easier operation. Inside of tip is machined to retain pipe coupon.



- ❑ PERFORATOR – is heat treated for maximum strength. The threads are lubricated with a dry film lubricant to assure smooth operation. The perforator is also designed to function as a shut-off.
- ❑ PRECISION – machined threads provide perforator support throughout the length of the body.

REFERENCE:

Attachment 6, PUB Completeness Review

PREAMBLE TO IR (IF ANY):

This exhibit contains financial and scope details of Centra's past projects at the cost of over $250,000.

QUESTION:

c) Please confirm the accounting consequences of abandoned pipe infrastructure.

RESPONSE:

Abandoned pipe infrastructure is accounted for as an asset retirement. When a plant asset is retired from service and not replaced with another asset (i.e. terminal retirement), the costs associated with the retirement of the asset from service are included in the calculation of the net gain or loss amount to be recognized in depreciation expense of the period. The retirement gain or loss is then deferred in a regulatory deferral account and completely offset through the Net Movement in Regulatory Deferral Accounts such that there is a net zero impact on net income. As part of this Application, Centra is proposing that the deferral account for asset retirement gains or losses be amortized through the Net Movement Account over a period of 34 years.

REFERENCE:

Attachment 6, PUB Completeness Review

PREAMBLE TO IR (IF ANY):

This exhibit contains financial and scope details of Centra's past projects at the cost of over $250,000.

QUESTION:

d) Please provide the 2013 consultant's report related to the issue of high liquid levels in the gas stream referenced in all three projects noted on p. 14 of Attachment 6.

RESPONSE:

Please see the attachment to this response for the PRS Ice Formation Study (September 18, 2013).

CENTRA GAS MANITOBA INC.
2019/20 GENERAL RATE APPLICATION

A copy of CAC/CENTRA I-78d Attachment can be found at the link below:

https://www.hydro.mb.ca/regulatory_affairs/pdf/natural_gas/general_rate_application_2019/information_requests/cac-centra_i-78d-attachment.pdf

REFERENCE:

Attachment 6, PUB Completeness Review, Details of Capital Plant Additions

PREAMBLE TO IR (IF ANY):

In the context of discussing Centra's ability to recover the costs of relocation work, p.5 of Attachment 6 states:

"Costs for work performed for municipalities and local governments are recovered based on the depreciated cost of the asset in compliance with PUB approved franchise agreements. A significant portion of the natural gas system is close to becoming fully depreciated, yielding minimal cost recovery for this work."

QUESTION:

Please confirm whether Centra is eligible to recover the labour and other associated costs incurred in the course of relocation work, along with the depreciated cost of the actual equipment being relocated.

i. If confirmed, please indicate whether Centra consistently recovers the costs of relocation other than the costs of depreciated assets.

RESPONSE:

Centra is eligible to recover costs in accordance with the franchise agreements as amended in PUB Order 159/11. Centra is not eligible to recover the labour and associated costs incurred in the relocation work. The cost that can be recovered is:

> *"the Municipality shall pay to the Company an amount equal to the cost of labour and material required in the original construction of that part of the Gas Distribution System that the Municipality requests to be relocated, less depreciation and the value of any materials salvaged;"* (PUB Order 159/11, pg. 37)

REFERENCE:

Attachment 6, PUB Completeness Review, p. 9 of 27, Figure 11, p 10 of 27.

PREAMBLE TO IR (IF ANY):

Figure 11 the "Plant & Intangible Additions – System Betterment – Measurement & Regulation Stations Program," showcases Centra's past and forecasted capital additions for upgrades made to measurement and regulated stations. The additions exhibit a positive year-over-year trend, with a particularly large step increase taking place between 2015/16 and 2016/17, when the additions almost double. The additions in the subsequent years (i.e. 2017/18, along with Forecast and Test Years) continue increasing from the step increase in 2016/17.

QUESTION:

Please describe the circumstances that took place between 2015/16 and 2016/17 years that led to the material and sustained increase in this expenditure category, including into the future.

i. Please list and provide all new evidence, business cases, and/or other pertinent information that Centra relied on to justify the increased investments in this facet of its operations.

RESPONSE:

Centra Gas began installing in line heaters in Pressure Reducing Stations (PRS) in 2015/16 and these expenditures increased significantly in 2016/17. In line heaters will continue to be installed into the future. In addition, there has been a general increase in work related to upgrading/replacing gate stations including adding future provision for in line heaters.

i. Please see the attachment to the response to PUB/Centra I-73 (page 345) for the System Betterment - Measurement & Regulator Stations Capital Investment Justification ("CIJ") and the attachment to the response to CAC/Centra I-78 d) for the MHI PRS Ice Formation Study Recommendation for the justification for the increase in these investments.

REFERENCE:

Attachment 6, PUB Completeness Review, p 10 of 27.

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please discuss the technical considerations other than consistency with Manitoba Hydro's practices that make the operational activity such as meter testing eligible for capitalization.
b) Please confirm whether Centra would earn a regulated return on capitalized costs of meter testing if permitted the advocated accounting treatment.

RATIONALE FOR QUESTION:

Centra is proposing to capitalize the Meter Testing costs commencing in the Test Year.

RESPONSE:

a) International Accounting Standards ("IAS") 16, Property, Plant & Equipment ("PP&E"), allows certain inspections of PP&E assets to be capitalized and depreciated over the time period until the next scheduled inspection. Specifically, paragraph 14 of IAS 16 states:

   > ***A condition of continuing to operate*** *an item of property, plant and equipment (for example, an aircraft) may be* ***performing regular major inspections*** *for faults regardless of whether parts of the item are replaced.* <u>*When each major inspection is performed, its cost is recognised in the carrying amount of the item of property, plant and equipment*</u> *as a replacement if the recognition criteria are satisfied. Any remaining carrying amount of the cost of the previous inspection (as distinct from physical parts) is derecognised.*

   The testing of meters (both Gas and Electric) is regulated and required by Measurement Canada, which requires testing samples of meters at predetermined intervals to meet predetermined thresholds. Failure to test meters results in the meters no longer being eligible for use, thus taken out of service. As such, testing the meters satisfies the "condition of continuing to operate" criteria for the capitalization of major inspection costs.

The notion of which inspections qualify as a "major inspection" is not identified in IAS 16 and thus is a matter of professional judgement. For Manitoba Hydro and Centra, the Electric and Gas meter testing processes are material to the Manitoba Hydro and Centra financial statements, and are required activities by Measurement Canada, thus are considered major inspection programs.

b) Under rate base rate of return methodology, Centra earns a return on all property, plant and equipment. This methodology is being used to calculate a maximum allowed return as a benchmark for rate setting under a cost of service approach.

REFERENCE:

Attachment 6, PUB Completeness Review pp. 20, 22 of 27.

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide the business case(s) prepared and approved for the construction of the La Salle Compressed Natural Gas (CNG) Facility and two CNG Tube Trailers enabling Centra to ensure continued supply across Manitoba in the event of both planned and unplanned outages.

b) Please discuss the impact of these new capabilities on Centra's current pipeline risk framework, and particularly the articulation of risk consequence severity of outages.

   i. Does the CNG capability reduce the severity consequence of potential outages? If so, by how much and under what circumstances?

   ii. Has Centra updated its risk framework definitions and thresholds to reflect this new capability?

RESPONSE:

a) Please see the attachment to this response for the CIJ for CNG Filling Station.

b)

   i. The CNG capability has reduced the consequence severity of potential outages in some circumstances. Specifically, this is applicable where the loss of supply is approximately equal to or less than the load of 1200 residential customers at -10^{o}C. This CNG capability would be used to prioritize service in the event of an outage, similar to what was done in response to the Otterburne incident wherein service was prioritized to personal care homes and other public institutions.

   ii. Centra has included consideration of its CNG capability in PUB Completeness Review Attachment 2 - Pipeline Risk Methodology report. The Pipeline Risk Methodology includes a 'System Reliability Factor' to reflect the CNG capability.

NC55-CIJ-PROJ-AD

CAPITAL INVESTMENT JUSTIFICATION ADDENDUM FOR

Compressed Natural Gas Filling Station- Natural Gas System
Category: Project

Addendum Number: 1

	(thousands of dollars)		
	PREVIOUSLY APPROVED	REVISED	INCREASE (DECREASE)
BUDGET:	$3,500	$4,882	$1,382
CONTRIBUTIONS:	($0)	($0)	($0)
NET BUDGET:	$3,500	$4,984	$1,484

NPV BENEFIT/(COSTS)		

DATE PREPARED: 2017 05 19

REQUIRES EC OR MHEB APPROVAL; Choose an item.

EC/MHEB APPROVAL MINUTE:

DATE APPROVED:

APPROVER LAST NAME, FIRST NAME	APPROVER TITLE	ORGANIZATIONAL UNIT COST CENTRE	SIGNATURE	APPROVAL DATE YYYY/MM/DD
Isaacson, Marie	Accountant, MFS-CS&D	50625		
Brako, Tanis	GAM&C Dept Manager	53070		
Starodub, Tim	Gas E&C Dept Manager	52955		
Steele, Chuck	DE&C Director	52600		
Prydun, Mark	CSO Wpg & North Director	54200		
Vinish, Siobhan	VP Marketing & Customer Service	54200		

ADDENDUM NUMBER	DATE YYYY/MM/DD	REVISION (SUMMARY OF CHANGE)
1	2017-08-31	Revised cost

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:	**1.2.3.23.1.1**	**W.B.S. NUMBERs:**	P:25365
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** **LEVEL 2**	C3 / Sustainment 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:	Brako, Tanis GAM&C Dept Manager	**REQUESTOR:**	Brako, Tanis GAM&C Dept Manager
PROJECT MANAGER:	Brako, Tanis GAM&C Dept Manager		

MANITOBA HYDRO
CAPITAL INVESTMENT JUSTIFICATION ADDENDUM
MP Monitoring System Replacement – Natural Gas System

RECOMMENDATION

It is recommended that the budget for the Compressed Natural Gas Filling Station project be increased from $3.5 million to $4.9 million. The budget increase reflects actual tendered costs, increased costs due to winter construction, and projects delays. It is also recommended that the cash flow be revised to include the project completion in FY 2017/18. It is recommended that the final ISD move to September 2017. The original ISD was February 2017.

SCOPE

The scope of the project is defined as:

- Preparation of a Functional Report by Change Energy West Inc. (now called Pura Energy Ltd),
- Specification and procurement of a decanting station,
- Design of CNG Filling Station by Change Energy West Inc.,
- Installation of all equipment required to produce CNG at the existing propane tank site near La Salle, MB including compressors, CNG dryer, electrical control room, site security, etc,
- Modifications to existing Manitoba Hydro natural gas piping in order to supply the CNG filling station,
- Buildings, site electrical, fencing, drainage and site grading to allow for CNG trailer storage and ease of filling,
- Provision for future expansion and potential for natural gas vehicles (NGV),
- Maintenance and Operation Procedures,
- Training documents for MH personnel,

Other items as deemed necessary by the functional design report.

BACKGROUND

As part of the CS&D Business Plan – 2014/2015 to provide exceptional customer safety and value, initiative 2.7 is identified to assess natural gas supply options for emergency situations. This initiative involves the examination of alternatives and logistics to address emergency natural gas outage situations. Based on the CS&D Risk Map rating system, this initiative has an associated risk rating of 8A, where maximum risk using this tool is 9A.

Pura Energy Ltd., a consulting group with expertise in CNG, was engaged as a consultant to review the technical and economic scoping for compression, transport and decanting of CNG for delivery during emergency response situations. The report can be found as an appendix to this CPJ and is titled “Manitoba Hydro CNG Scoping Study Final Report”.

The CNG scoping report outlines recommendations for trailers, decanting and compression solutions. It provides recommendations on compression rates and trailer sizes to suit the proposed emergency situation support. The report and cost estimate was based on the GS-030 Oak Bluff Primary Gate Station location for preliminary scoping purposes. An Executive Memo, dated June 4, 2015 was completed to justify the purchase of two 170 mcf CNG trailers with an associated cost of $448,000 USD.

BACKGROUND
Pura Energy Ltd. was engaged as the design consultant as outlined in the Manitoba Hydro CNG Scoping Study. The budget identified in this CPJ must be increased due to actual tendered costs, increased costs due to winter construction, and project delays.

JUSTIFICATION – BUSINESS CASE ANALYSIS (SUMMARY)

JUSTIFICATION

As part of the CS&D Business Plan – 2014/2015 to provide exceptional customer safety and value, initiative 2.7 is identified to assess natural gas supply options for emergency situations. Due to recent natural gas outages, the implementation of this initiative is recommended to ensure customer safety and value.

Recent examples of unplanned outages include:

- Loss of supply to primary station (Otterburne outage 2014)
- Failure of unknown or unexpected origin (Stonewall outage 2003)
- Pipeline damage requiring significant time to repair (Bunclody near miss 2011)
- Significant damage to a pressure regulation station (Elie near miss 2011)

The capability of CNG for emergency natural gas outage situations would also contribute to pipeline reliability at Manitoba Hydro as a risk reduction methodology. Equipped with alternatives for maintaining natural gas supply, the consequences of customer impact, corporate image impact and financial impact can be reduced, thus reducing the risk of small volume unplanned natural gas outages.

CNG can be used to support construction and maintenance activities while the potential for commercial use of the CNG compression system is an opportunity that will be explored.

Previously approved and related to this project was the procurement of CNG tube trailers. These trailers are anticipated to be in place by winter 2017/18.

Without a contingency plan for a natural gas outage, the corporation is taking on risk due to the impacts that an outage creates. It is recommended that this portion of the initiative be approved for implementation based on the justification outlined.

ANALYSIS OF ALTERNATIVES:

ECONOMIC ANALYSIS		
Discount Rate	For current corporate rates see P911 **4.4%**	Real Discount Rate%

RECOMMENDED OPTION	**NPV Benefits/(Costs)** (thousands of dollars)
CNG Filling Station Construction	

PROJECT RISK ANALYSIS

There are limited additional risks as the project is 90% complete. The following risk has been identified associated with the completion of the CNG Filling Station:

1. Project delays due to external approvals. External approvals are required to commission the CNG Filling Station by the Office of the Fire Commissioner. If delays in communication occur the schedule could be pushed back and may affect project costs.

ESTIMATED COST FLOW

The annual projected cost flows (in thousands of dollars) listed below show the impact on annual budget requirements between the previously approved CIJ/Addendum to the proposed Addendum.

	PREVIOUSLY APPROVED			PROPOSED			INCREASE (DECREASE)		
Fiscal Year	**Budget**	**Contributions**	**Net Budget**	**Budget**	**Contributions**	**Net Budget**	**Budget**	**Contributions**	**Net Budget**
Prev. Actuals	$ 3,507.00	$ -	$ 3,507.00	$ 3,507.00	$ -	$ 3,507.00	$ -	$ -	$ -
2017/2018	$ -	$ -	$ -	$ 1,280.00	$ -	$ 1,280.00	$ 1,280.00	$ -	$ 1,280.00
2018/2019	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2019/2020	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2020/2021	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2021/2022	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2022/2023+	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	**$ 3,507.00**	**$ -**	**$ 3,507.00**	**$ 4,787.00**	**$ -**	**$ 4,787.00**	**$ 1,280.00**	**$ -**	**$ 1,280.00**

IMPACT ON O&A COSTS

Monthly as well as yearly maintenance and operational costs will be required once the new CNG Filling Station is commissioned. Maintenance will be provided by third party services and operation of the station will be done by GAM&C staff.

PROPOSED SCHEDULE

The previously approved project schedule was delayed by large equipment procurement, tendering delays

PROPOSED SCHEDULE
and scope changes. The revised project schedule is as follows: 1. Commissioning: May 23-26, 2017 2. Site Completion: July 30, 2017 The revised project ISD is August 2017.

RELATED INVESTMENTS
None

REFERENCE DOCUMENTS
No changes from approved CPJ.

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TITLE PAGE AND MASTER DATA FORM INSTRUCTIONS:

Title Page
Project Name: Project name should reflect the key details of the project to differentiate it from another similar project. Project name should also be reflected in the page headers that follow.
Project Category: *Do not change*
Addendum Number: Enter the Addendum number (e.g. 1, 2, 3)
Budget: Budgeted investment costs prior to customer contributions.
Contributions: Customer contributions associated with investment.
Net Budget: Total investment budget net of customer contributions.
NPV Benefit/(Cost): The NPV based on the calculation prepared in the NPV spreadsheet. Contact Economic Analysis for assistance.
Date Prepared: Document completion date.
Requires EC or MHEB Approval: If required, select EC or MHEB. Refer to approval threshold rules.
EC/MHEB Approval Minute & Approval Date: To be updated by Financial Planning when applicable.
Approval Table: List the individuals required to approve the investment, including name, title, and cost centre. Minimum approval requirements include MFS Representative and positions listed in the approval threshold rules reflective of the proposed budget (gross of contributions). Additional approvers can be listed on an as needed basis. Add rows to table as needed. **MFS Representative should be the first to review the document(s) in electronic form. Once approved by MFS, document(s) will be printed and routed to remaining approvers.**
Addendum Table: Enter information related to previously approved Addendums.

Master Data & Contact Table
Responsible Operating/Corporate Group, Responsible Division, Responsible Department: The Operating/Corporate Group, Division, and Department that owns the budget for the investment(s) looking for approval. Responsible for the management of the complex and its associated investments. Responsible for the variances explanation, and develops the project outlook.
Requesting Operating/Corporate Group, Requesting Division: Operating/Corporate Group and Division that initiated the investment request.
I.M. Node Number: Placement of the WBS in the SAP IM hierarchy. Contact MFS Rep.
C55 Project Code: *Do not change*
SAP Project Type: Select appropriate value from dropdown.
W.B.S. Numbers: WBS Level 1 (Project From SAP). P number associated with the project. Contact MFS Rep.
C55 Project Sub-Category: Select appropriate value from dropdown.
Corporate Investment Categories: Categories explaining the reasons for the investment. Select appropriate Level 1 and Level 2 value from dropdown. For additional information see Corporate Investment Categories site
NERC Compliance: Yes or No indicates whether this investment requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards. For additional information see the NERC site.
Prepared By: Name, position, and department of employee that completed the document.
Requestor: Name, position, and department of employee who identified or requested the investment be created.
Project Manager: Name, position, and department of employee who is responsible for execution of the investment. Should be a member of the Responsible Division.

Note: This instructions page and the preceding blank page can be deleted prior to printing.

REFERENCE:

Attachment 6, PUB Completeness Review pp. 22-23,

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please articulate how the acquisition of additional easements, as proposed in the Winnipeg Natural Gas Supply Transmission Easement Widening project, is necessary "to reduce consequences associated with a pipeline failure and to reduce the risk associated with the need to de-rate a pipeline and the associated reduction in capacity."
b) Have alternatives other than obtainment of easements been considered to accomplish the desired ends, such as those described in the section 6.2.4, Attachment 3 of the PUB Completeness filing, which discusses risk control options for external interference hazards? If so, please describe these and substantiate the reasons for their rejection. If no other alternatives were considered, please explain why.

RESPONSE:

a) The consequences associated with a transmission pressure pipeline operating at pressures resulting in pipe hoop stresses above 30% of specified minimum yield stress ("SMYS") include the potential for pipeline rupture and subsequent ignition of the blowing gas. The impact and damages associated with a pipeline rupture and blowing/burning gas is determined by pipeline diameter, pipeline operating pressure and the separation between the pipeline and nearest structure or person. The pipeline diameter and pipeline operating pressure are set for an existing pipeline but it would be possible to increase the separation from the pipeline to future, adjacent, structures by obtaining wider easements. In the event of a pipeline rupture, greater separation between the pipeline and adjacent structures reduces the risk of property damage.

b) Please see the response to CAC/CENTRA I-68

REFERENCE:

Attachment 2, PUB Completeness Review, pp. 2-3 of 36

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide a copy of the custom risk assessment model with all formulas intact.
b) Does Centra intend to continue using the custom model into the future as the corporate-wide asset management enhancement initiatives described in Tab 4 (including the Corporate Value Framework and C-55 software) continue being implemented?
c) Please discuss the manner in which Centra's own historical incidence data and "industry recognized risk determiners" have been used to calculate the likelihood of incidents occurring for each pipeline segment and hazard category.
    i. Please specify the number of years for which Centra possesses historical incident data.
    ii. Please also list the source of the industry recognized risk determiners noted on p. 3.
    iii. Please discuss how Centra's own data compare with industry standards, including the potential reasons for any material differences between the two sets of inputs.

RESPONSE:

a) The document "Pipeline Risk Methodology Version 1.0" filed as Attachment 2 to the PUB Completenes Review describes in full detail the formulas and tables that have been used to build the custom risk model within the software program Smallworld GeoSpatial Analysis ("GSA"). GSA links to the Centra eGIS system and all associated databases. The GSA program and license, and full access to eGIS and the databases are required to view the intact formulas.

b) The custom risk model was developed to assess the risk from an unintentional release of gas. Unlike the Corporate Value Framework and C55 software, it does not compare projects.

c) Each pipeline segment is assigned a score (0-1) for each of the hazard susceptibility factors described in Section 6.8 Hazard Susceptibility Factors. Those Hazard Susceptibility Factors have been based on historical incidence data and industry recognized risk determiners. An example of historical incidence data can be seen in 6.8.7 Failure History (Corrosion Volume). Pipe segments that are in cathodic sections with a greater number of historical leaks are assigned a higher factor than pipe segments in cathodic sections with less historical leaks. An example, industry recognized risk determiners can be seen in 6.8.5 Pipe Material. Plastic pipe is assigned a higher factor than steel pipe because industry recognizes that plastic pipe is more likely to leak than steel pipe when damaged with the same force.

   i. Centra possesses very limited historical incident data from as far back as the 1960's.

   ii. Page 3 is the executive summary. More detail is provided within the main body of the document in section 6.8 Hazard Susceptibility Factors and 6.10 Consequence Identification and Score. In general though, "industry recognized risk determiners" is a term that was used for factors the pipeline integrity engineer chose based on knowledge they had gained either from working on industry task forces, discussions with other Subject Matter Experts, or from the Reference Publications on Page 36.

   iii. The general methodology and approach which results in an incident per 1000 km-years frequency score based on a consensus Canadian Gas Association ("CGA") approach however CGA companies do not publicly share their results. Centra is not familiar with an industry standard source that is available for comparison purposes.

REFERENCE:

Attachment 2, PUB Completeness Review

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please confirm whether the reference to "expanding the assets" in the context of discussion of future methodological developments of the risk model refers to plans of developing tools capable of modelling the risk of insufficient system capacity due to expansion activities not being completed in time, or not being available for other reasons.
b) Please confirm that at present, Centra's risk modelling capabilities do not include an ability to model the quantitative impact of insufficient system capacity being available at the time when it is required.
c) Please describe the process of collecting the input on hazard susceptibility factors and weightings from subject matter experts referenced on p.8. Please describe the organizational positions / professional backgrounds of the SMEs that took part in this work (if different from those listed on p. 36 of the document).
d) Please describe the number / percentage of blank pipe attribute and leak cause input cells (per category as applicable) where authors resorted to manual intervention as noted on p. 13.
e) Please discuss the source and justification of the Line Locate Request Factor scores provided on p. 19
f) Please describe the extent of data availability on all Metal Pipe Corrosion Volume, Corrosion Concentration and Corrosion Trend, as listed in the table on p.15.
g) Please explain the purpose of the Average Hazard Score in the model, relative to the individual hazard scores of each pipeline segment.
h) Please provide Centra's incident history data since 2011/12 through the most recent actual year, using the CGA Incident Cause Guidance framework referenced in Appendix A (p. 35).
i) Please articulate the merits of conducting both the Risk Evaluation and the Risk Analysis processes for the same assets.

j) Was Risk Analysis performed on any of the assets included in the scope of projects or programs proposed in the 2018-2023 Asset Management Investment Plan? (Appendix 4.3).

RESPONSE:

a) The current risk methodology was built to assess failures (defined as unintentional releases of gas) on pipeline assets. The reference to "expanding the assets" refers to developing risk methodologies for assets other than pipelines, such as service risers.

b) The current pipeline risk methodology was developed to assess the risk from an unintentional release of gas. It is not designed for or capable of quantifying the impact of broader types of risk, such as insufficient system capacity being available at the time when it is required.

c) Page 8 refers to changes that were made from the previous version. The process of collecting some of the input for changes since the last version was documented in a meeting record dated September 7, 2016. It is likely that other input was received in a less formal communication and not documented.

d) Please see the following table for the percentage of blank pipe attribute and leak cause input cells (per category as applicable):

Pipe Attributes with Blank Data	Percentage Blank (Distribution)	Percentage Blank (Transmission)
Energized Date / Age	47%	2%
Steel Grade (used in Transmission analysis only)	n/a	1%
Steel Wall Thickness (used in Transmission analysis only)	n/a	1%
Pipe Coating	97%	6%
Joint Coating (used in Transmission analysis only)	n/a	56%

e) When Centra began using the software program Smallworld GeoSpatial Analysis ("GSA"), the manufacturer provided an example of a risk model structure that could be used. The Line Locate Request Factor was structured after what they called "One Call Tickets", table below. The justification for this structure is:

1. A pipe segment with a higher number of past line locate requests is considered to have an increased exposure to future activities, and unintentional damage.
2. A pipe segment in a newer area is considered to have an increased exposure to landscaping activities such as planting trees, etc.

Less Than 5 Years	*Min Tickets*	*Max Tickets*	*One Call Tickets Factor*	*Comments*
Y	10	1000	1.00	Past 5 years
Y	5	10	0.50	Past 5 years
Y	2	5	0.25	Past 5 years
Y	0	2	0.00	Past 5 years
N	10	1000	0.25	Greater than 5 years
N	5	10	0.13	Greater than 5 years
N	2	5	0.06	Greater than 5 years
N	0	2	0.00	Greater than 5 years

f) The three Corrosion susceptibility factors are based on historical incidence data and are described in section 6.8.8, 6.8.9 and 6.8.10 of the report.

g) The Hazard Score of each pipeline segment is a dimensionless number. The purpose of the Average Hazard Score and the Average Frequency score was to attempt to assign a quantitative value to the Frequency Score.

h) Please see attachment to this response.

i) Risk Analysis is a structured process used to identify both the extent and likelihood of consequences associated with hazards. After performing the pipeline risk analysis, the result is a relative risk ranking of every pipeline segment from highest to lowest estimated risk values. The only merit at this point is in knowing that pipeline A is at more risk than pipeline B.

   Risk Evaluation is the process of judging the significance of those estimated risk values. Until the risk evaluation is completed, there is no concept of how many pipe segments have significant risk that requires further action.

j) The Pipeline Risk Methodology was applied to all pipe in Centra's natural gas system in 2017 as indicated in the PUB Completeness Review Attachment 3.

Date of Incident	Cause	Sub-Cause
2018-Jan-08	External Interference	EI - 3rd Party
2018-Jan-10	External Interference	EI - 3rd Party
2018-Jan-22	External Interference	EI - 3rd Party
2018-Jan-31	External Interference	EI - 1st or 2nd Party
2018-Feb-06	External Interference	EI - 3rd Party
2018-Feb-08	Natural Forces	NF - Geotechnical
2018-Feb-09	External Interference	EI - 3rd Party
2018-Feb-10	Natural Forces	NF - Geotechnical
2018-Feb-26	External Interference	EI - 3rd Party
2018-Feb-28	Natural Forces	NF - Geotechnical
2018-Mar-08	External Interference	EI - 3rd Party
2018-Mar-23	External Interference	EI - 3rd Party
2018-Mar-24	Natural Forces	NF - Geotechnical
2018-Mar-27	External Interference	EI - 3rd Party
2018-Mar-28	Natural Forces	NF - Geotechnical
2018-Mar-28	Corrosion / Degradation	CD - Seal Degradation
2018-Apr-09	Natural Forces	NF - Geotechnical
2018-Apr-12	External Interference	EI - 3rd Party
2018-Apr-13	Natural Forces	NF - Geotechnical
2018-Apr-16	Material, Manufacturing, or Construction Defect	MMC - Other Improper Construction
2018-Apr-17	External Interference	EI - 3rd Party
2018-Apr-19	External Interference	EI - 3rd Party
2018-Apr-23	External Interference	EI - 3rd Party
2018-Apr-26	External Interference	EI - 1st or 2nd Party
2018-Apr-27	External Interference	EI - 3rd Party
2018-May-02	Corrosion / Degradation	CD - Metal Loss
2018-May-04	External Interference	EI - 3rd Party
2018-May-05	External Interference	EI - 3rd Party
2018-May-07	Natural Forces	NF - Geotechnical
2018-May-09	External Interference	EI - 3rd Party
2018-May-10	External Interference	EI - 3rd Party
2018-May-10	External Interference	EI - 3rd Party
2018-May-12	Natural Forces	NF - Geotechnical
2018-May-19	External Interference	EI - 3rd Party
2018-May-21	External Interference	EI - 3rd Party
2018-May-22	Material, Manufacturing, or Construction Defect	MMC - Defective Pipe Body
2018-May-23	External Interference	EI - 3rd Party
2018-May-24	External Interference	EI - 3rd Party
2018-May-25	External Interference	EI - 3rd Party
2018-May-26	External Interference	EI - 3rd Party
2018-May-30	External Interference	EI - 3rd Party
2018-Jun-08	Corrosion / Degradation	CD - Metal Loss
2018-Jun-09	External Interference	EI - 3rd Party
2018-Jun-22	External Interference	EI - 3rd Party
2018-Jun-27	External Interference	EI - 3rd Party
2018-Jun-28	External Interference	EI - 3rd Party
2018-Jul-04	External Interference	EI - 3rd Party
2018-Jul-04	External Interference	EI - 3rd Party
2018-Jul-07	External Interference	EI - 3rd Party
2018-Jul-16	External Interference	EI - 3rd Party
2018-Jul-17	Corrosion / Degradation	CD - Seal Degradation
2018-Jul-17	Corrosion / Degradation	CD - Seal Degradation
2018-Jul-18	External Interference	EI - 3rd Party
2018-Jul-24	External Interference	EI - 3rd Party
2018-Aug-02	External Interference	EI - 3rd Party

2018-Aug-02	External Interference	EI - 3rd Party
2018-Aug-08	External Interference	EI - 3rd Party
2018-Aug-13	External Interference	EI - 3rd Party
2018-Aug-14	External Interference	EI - 3rd Party
2018-Aug-14	External Interference	EI - 3rd Party
2018-Aug-14	Material, Manufacturing, or Construction Defect	MMC - Other Improper Construction
2018-Aug-15	Corrosion / Degradation	CD - Seal Degradation
2018-Aug-15	Natural Forces	NF - Geotechnical
2018-Aug-16	Material, Manufacturing, or Construction Defect	MMC - Defective Joining Method
2018-Aug-17	Natural Forces	NF - Geotechnical
2018-Aug-17	External Interference	EI - 3rd Party
2018-Aug-20	Material, Manufacturing, or Construction Defect	MMC - Other Improper Construction
2018-Aug-20	Natural Forces	NF - Geotechnical
2018-Aug-20	Corrosion / Degradation	CD - Metal Loss
2018-Aug-20	Corrosion / Degradation	CD - Metal Loss
2018-Aug-21	Corrosion / Degradation	CD - Metal Loss
2018-Aug-22	External Interference	EI - 3rd Party
2018-Aug-22	External Interference	EI - 3rd Party
2018-Aug-22	Corrosion / Degradation	CD - Metal Loss
2018-Aug-22	Natural Forces	NF - Geotechnical
2018-Aug-22	Corrosion / Degradation	CD - Metal Loss
2018-Aug-23	External Interference	EI - 3rd Party
2018-Aug-24	External Interference	EI - 3rd Party
2018-Aug-24	Corrosion / Degradation	CD - Metal Loss
2018-Aug-28	External Interference	EI - 3rd Party
2018-Aug-28	External Interference	EI - 3rd Party
2018-Aug-30	Natural Forces	NF - Geotechnical
2018-Aug-31	External Interference	EI - 3rd Party
2018-Aug-31	External Interference	EI - 3rd Party
2018-Sep-04	External Interference	EI - 3rd Party
2018-Sep-04	External Interference	EI - 3rd Party
2018-Sep-06	Unable to Classify	Unable to Classify
2018-Sep-10	External Interference	EI - 3rd Party
2018-Sep-12	Material, Manufacturing, or Construction Defect	MMC - Other Improper Construction
2018-Sep-14	Corrosion / Degradation	CD - Metal Loss
2018-Sep-17	External Interference	EI - 3rd Party
2018-Sep-17	Corrosion / Degradation	CD - Metal Loss
2018-Sep-17	Material, Manufacturing, or Construction Defect	MMC - Other Improper Construction
2018-Sep-17	Corrosion / Degradation	CD - Seal Degradation
2018-Sep-18	External Interference	EI - 3rd Party
2018-Sep-21	External Interference	EI - 3rd Party
2018-Sep-27	External Interference	EI - 1st or 2nd Party
2018-Sep-28	External Interference	EI - 3rd Party
2018-Oct-05	External Interference	EI - 3rd Party
2018-Oct-06	External Interference	EI - 3rd Party
2018-Oct-07	Material, Manufacturing, or Construction Defect	MMC - Other Improper Construction
2018-Oct-11	External Interference	EI - 3rd Party
2018-Oct-15	External Interference	EI - 3rd Party
2018-Oct-17	Unable to Classify	Unable to Classify
2018-Oct-18	Corrosion / Degradation	CD - Metal Loss
2018-Oct-23	External Interference	EI - 3rd Party
2018-Oct-23	Unable to Classify	Unable to Classify
2018-Oct-23	Material, Manufacturing, or Construction Defect	MMC - Other Improper Construction
2018-Oct-25	Natural Forces	NF - Geotechnical
2018-Oct-29	External Interference	EI - 3rd Party
2018-Oct-30	Natural Forces	NF - Geotechnical

2018-Nov-01	External Interference	EI - 3rd Party
2018-Nov-02	External Interference	EI - 3rd Party
2018-Nov-04	Natural Forces	NF - Geotechnical
2018-Nov-07	External Interference	EI - 3rd Party
2018-Nov-08	External Interference	EI - 3rd Party
2018-Nov-10	Natural Forces	NF - Geotechnical
2018-Nov-20	External Interference	EI - 3rd Party
2018-Nov-24	Natural Forces	NF - Geotechnical
2018-Nov-26	Unable to Classify	Unable to Classify
2018-Nov-26	Material, Manufacturing, or Construction Defect	MMC - Other Improper Construction
2018-Dec-03	External Interference	EI - 3rd Party
2018-Dec-04	Natural Forces	NF - Geotechnical
2018-Dec-06	External Interference	EI - 3rd Party
2018-Dec-06	Corrosion / Degradation	CD - Seal Degradation
2018-Dec-07	External Interference	EI - 3rd Party
2018-Dec-07	Unable to Classify	Unable to Classify
2018-Dec-10	External Interference	EI - 1st or 2nd Party
2018-Dec-10	Natural Forces	NF - Geotechnical
2018-Dec-10	Natural Forces	NF - Geotechnical
2018-Dec-12	External Interference	EI - 3rd Party
2018-Dec-12	Material, Manufacturing, or Construction Defect	MMC - Other Improper Construction
2018-Dec-12	Unable to Classify	Unable to Classify
2018-Dec-13	External Interference	EI - 1st or 2nd Party
2018-Dec-15	Natural Forces	NF - Geotechnical
2018-Dec-17	External Interference	EI - 3rd Party
2018-Dec-18	Natural Forces	NF - Geotechnical
2018-Dec-22	Corrosion / Degradation	CD - Metal Loss

Date of Incident	Cause	Sub-Cause
2017-Jan-16	Natural Forces	NF - Geotechnical
2017-Jan-30	External Interference	EI - 1st or 2nd Party
2017-Feb-02	External Interference	EI - 3rd Party
2017-Feb-06	External Interference	EI - 3rd Party
2017-Feb-13	External Interference	EI - 3rd Party
2017-Feb-13	Natural Forces	NF - Geotechnical
2017-Feb-15	Corrosion / Degradation	CD - Metal Loss
2017-Feb-18	External Interference	EI - 3rd Party
2017-Mar-03	External Interference	EI - 1st or 2nd Party
2017-Mar-07	External Interference	EI - 1st or 2nd Party
2017-Mar-19	Material, Manufacturing, or Construction Defect	MMC - Other Improper Construction
2017-Mar-21	Natural Forces	NF - Geotechnical
2017-Mar-28	Natural Forces	NF - Geotechnical
2017-Mar-29	Corrosion / Degradation	CD - Metal Loss
2017-Mar-30	External Interference	EI - 3rd Party
2017-Mar-30	External Interference	EI - 1st or 2nd Party
2017-Apr-03	Corrosion / Degradation	CD - Seal Degradation
2017-Apr-05	External Interference	EI - 3rd Party
2017-Apr-13	Corrosion / Degradation	CD - Metal Loss
2017-Apr-13	Corrosion / Degradation	CD - Seal Degradation
2017-Apr-17	External Interference	EI - 3rd Party
2017-Apr-18	Material, Manufacturing, or Construction Defect	MMC - Other Improper Construction
2017-Apr-19	External Interference	EI - 3rd Party
2017-Apr-25	External Interference	EI - 3rd Party
2017-Apr-28	External Interference	EI - 3rd Party
2017-May-01	External Interference	EI - 3rd Party
2017-May-04	External Interference	EI - 3rd Party
2017-May-08	External Interference	EI - 3rd Party
2017-May-09	External Interference	EI - 3rd Party
2017-May-10	External Interference	EI - 3rd Party
2017-May-11	External Interference	EI - 3rd Party
2017-May-12	Natural Forces	NF - Geotechnical
2017-May-13	External Interference	EI - 3rd Party
2017-May-13	External Interference	EI - 3rd Party
2017-May-17	External Interference	EI - 3rd Party
2017-May-17	External Interference	EI - 3rd Party
2017-May-17	External Interference	EI - 3rd Party
2017-May-21	External Interference	EI - 3rd Party
2017-May-24	External Interference	EI - 3rd Party
2017-May-30	External Interference	EI - 3rd Party
2017-May-30	Corrosion / Degradation	CD - Metal Loss
2017-Jun-05	External Interference	EI - 3rd Party
2017-Jun-06	Material, Manufacturing, or Construction Defect	MMC - Defective Joining Method
2017-Jun-09	Natural Forces	NF - Geotechnical
2017-Jun-09	External Interference	EI - 3rd Party
2017-Jun-14	External Interference	EI - 3rd Party
2017-Jun-16	Corrosion / Degradation	CD - Metal Loss
2017-Jun-26	External Interference	EI - 3rd Party
2017-Jun-27	Corrosion / Degradation	CD - Seal Degradation
2017-Jun-28	External Interference	EI - 3rd Party
2017-Jun-30	Material, Manufacturing, or Construction Defect	MMC - Defective Joining Method
2017-Jul-04	External Interference	EI - 3rd Party
2017-Jul-05	External Interference	EI - 3rd Party
2017-Jul-06	External Interference	EI - 3rd Party
2017-Jul-06	External Interference	EI - 3rd Party

2017-Jul-06	External Interference	EI - 1st or 2nd Party
2017-Jul-10	External Interference	EI - 3rd Party
2017-Jul-10	External Interference	EI - 3rd Party
2017-Jul-10	External Interference	EI - 3rd Party
2017-Jul-12	Material, Manufacturing, or Construction Defect	MMC - Defective Joining Method
2017-Jul-13	Natural Forces	NF - Geotechnical
2017-Jul-14	External Interference	EI - 3rd Party
2017-Jul-14	External Interference	EI - 3rd Party
2017-Jul-17	External Interference	EI - 3rd Party
2017-Jul-17	Material, Manufacturing, or Construction Defect	MMC - Defective Joining Method
2017-Jul-20	External Interference	EI - 3rd Party
2017-Jul-20	Corrosion / Degradation	CD - Metal Loss
2017-Jul-20	Natural Forces	NF - Geotechnical
2017-Jul-21	Natural Forces	NF - Weather Related
2017-Jul-25	Corrosion / Degradation	CD - Metal Loss
2017-Jul-26	Material, Manufacturing, or Construction Defect	MMC - Defective Joining Method
2017-Jul-26	External Interference	EI - 3rd Party
2017-Jul-26	External Interference	EI - 3rd Party
2017-Jul-26	External Interference	EI - 3rd Party
2017-Jul-27	External Interference	EI - 3rd Party
2017-Jul-28	External Interference	EI - 3rd Party
2017-Aug-01	External Interference	EI - 3rd Party
2017-Aug-04	Corrosion / Degradation	CD - Metal Loss
2017-Aug-09	External Interference	EI - 3rd Party
2017-Aug-10	External Interference	EI - 3rd Party
2017-Aug-11	Corrosion / Degradation	CD - Seal Degradation
2017-Aug-11	External Interference	EI - 3rd Party
2017-Aug-15	Corrosion / Degradation	CD - Metal Loss
2017-Aug-15	Corrosion / Degradation	CD - Seal Degradation
2017-Aug-17	Corrosion / Degradation	CD - Metal Loss
2017-Aug-17	Corrosion / Degradation	CD - Metal Loss
2017-Aug-17	Corrosion / Degradation	CD - Metal Loss
2017-Aug-18	Natural Forces	NF - Geotechnical
2017-Aug-18	External Interference	EI - 3rd Party
2017-Aug-18	External Interference	EI - 3rd Party
2017-Aug-19	Natural Forces	NF - Geotechnical
2017-Aug-21	External Interference	EI - 3rd Party
2017-Aug-22	Corrosion / Degradation	CD - Metal Loss
2017-Aug-23	External Interference	EI - 3rd Party
2017-Aug-24	External Interference	EI - 3rd Party
2017-Aug-24	External Interference	EI - 3rd Party
2017-Aug-28	External Interference	EI - 3rd Party
2017-Aug-31	Material, Manufacturing, or Construction Defect	MMC - Defective Pipe Body
2017-Sep-06	External Interference	EI - 3rd Party
2017-Sep-06	External Interference	EI - 3rd Party
2017-Sep-07	External Interference	EI - 3rd Party
2017-Sep-07	External Interference	EI - 3rd Party
2017-Sep-12	External Interference	EI - 3rd Party
2017-Sep-13	External Interference	EI - 3rd Party
2017-Sep-14	Corrosion / Degradation	CD - Seal Degradation
2017-Sep-14	Corrosion / Degradation	CD - Seal Degradation
2017-Sep-19	Material, Manufacturing, or Construction Defect	MMC - Other Improper Construction
2017-Sep-19	External Interference	EI - 1st or 2nd Party
2017-Sep-23	External Interference	EI - 3rd Party
2017-Sep-25	External Interference	EI - 3rd Party
2017-Sep-25	External Interference	EI - 3rd Party

2017-Sep-29	Material, Manufacturing, or Construction Defect	MMC - Other Improper Construction
2017-Oct-02	External Interference	EI - 3rd Party
2017-Oct-05	External Interference	EI - 3rd Party
2017-Oct-07	External Interference	EI - 3rd Party
2017-Oct-11	Corrosion / Degradation	CD - Metal Loss
2017-Oct-12	Material, Manufacturing, or Construction Defect	MMC - Defective Joining Method
2017-Oct-17	External Interference	EI - 3rd Party
2017-Oct-23	External Interference	EI - 3rd Party
2017-Oct-23	External Interference	EI - 3rd Party
2017-Oct-28	Corrosion / Degradation	CD - Seal Degradation
2017-Oct-30	External Interference	EI - 3rd Party
2017-Nov-01	External Interference	EI - 3rd Party
2017-Nov-02	External Interference	EI - 3rd Party
2017-Nov-06	External Interference	EI - 3rd Party
2017-Nov-15	External Interference	EI - 3rd Party
2017-Nov-20	External Interference	EI - 3rd Party
2017-Nov-24	External Interference	EI - 1st or 2nd Party
2017-Nov-25	External Interference	EI - 3rd Party
2017-Nov-28	External Interference	EI - 3rd Party
2017-Dec-07	External Interference	EI - 3rd Party
2017-Dec-14	Corrosion / Degradation	CD - Metal Loss
2017-Dec-18	Corrosion / Degradation	CD - Metal Loss

Date of Incident	Cause	Sub-Cause
2016-Jan-07	External Interference	EI - 3rd Party
2016-Jan-20	Corrosion / Degradation	CD - Metal Loss
2016-Jan-26	Corrosion / Degradation	CD - Metal Loss
2016-Jan-26	External Interference	EI - 3rd Party
2016-Jan-29	External Interference	EI - 1st or 2nd Party
2016-Feb-02	Natural Forces	NF - Geotechnical
2016-Feb-05	Corrosion / Degradation	CD - Metal Loss
2016-Feb-29	External Interference	EI - 1st or 2nd Party
2016-Mar-03	External Interference	EI - 1st or 2nd Party
2016-Mar-12	Natural Forces	NF - Geotechnical
2016-Mar-17	External Interference	EI - 1st or 2nd Party
2016-Mar-21	Material, Manuf, or Construction Defect	MMC - Defective Joining Method
2016-Mar-23	Corrosion / Degradation	CD - Metal Loss
2016-Mar-28	External Interference	EI - 3rd Party
2016-Mar-29	Corrosion / Degradation	CD - Metal Loss
2016-Apr-04	Material, Manuf, or Construction Defect	MMC - Other Improper Construction
2016-Apr-06	External Interference	EI - 3rd Party
2016-Apr-13	External Interference	EI - 3rd Party
2016-Apr-14	External Interference	EI - 3rd Party
2016-Apr-15	Material, Manuf, or Construction Defect	MMC - Other Improper Construction
2016-Apr-20	External Interference	EI - 3rd Party
2016-Apr-20	Corrosion / Degradation	CD - Metal Loss
2016-Apr-22	External Interference	EI - 3rd Party
2016-Apr-25	Material, Manuf, or Construction Defect	MMC - Other Improper Construction
2016-Apr-26	Natural Forces	NF - Geotechnical
2016-Apr-28	Material, Manuf, or Construction Defect	MMC - Other Improper Construction
2016-Apr-29	External Interference	EI - 3rd Party
2016-May-04	Natural Forces	NF - Geotechnical
2016-May-04	External Interference	EI - 3rd Party
2016-May-09	External Interference	EI - 3rd Party
2016-May-11	External Interference	EI - 3rd Party
2016-May-18	External Interference	EI - 3rd Party
2016-May-19	External Interference	EI - 3rd Party
2016-May-21	External Interference	EI - 3rd Party
2016-May-25	External Interference	EI - 3rd Party
2016-May-31	External Interference	EI - 1st or 2nd Party
2016-Jun-02	Material, Manuf, or Construction Defect	MMC - Other Improper Construction
2016-Jun-06	Corrosion / Degradation	CD - Metal Loss
2016-Jun-13	External Interference	EI - 3rd Party
2016-Jun-14	External Interference	EI - 3rd Party
2016-Jun-15	Material, Manuf, or Construction Defect	MMC - Other Improper Construction
2016-Jun-16	External Interference	EI - 3rd Party
2016-Jun-20	External Interference	EI - 3rd Party
2016-Jun-24	External Interference	EI - 3rd Party
2016-Jun-28	Corrosion / Degradation	CD - Metal Loss
2016-Jun-29	External Interference	EI - 3rd Party
2016-Jun-29	External Interference	EI - 3rd Party
2016-Jun-30	External Interference	EI - 3rd Party
2016-Jul-07	Material, Manuf, or Construction Defect	MMC - Other Improper Construction
2016-Jul-11	Corrosion / Degradation	CD - Metal Loss
2016-Jul-12	External Interference	EI - 3rd Party
2016-Jul-19	External Interference	EI - 3rd Party
2016-Jul-21	Corrosion / Degradation	CD - Metal Loss
2016-Jul-22	External Interference	EI - 3rd Party
2016-Jul-25	Corrosion / Degradation	CD - Metal Loss

2016-Jul-25	Corrosion / Degradation	CD - Metal Loss
2016-Jul-27	External Interference	EI - 3rd Party
2016-Jul-31	Corrosion / Degradation	CD - Metal Loss
2016-Aug-02	External Interference	EI - 3rd Party
2016-Aug-04	External Interference	EI - 1st or 2nd Party
2016-Aug-04	External Interference	EI - 1st or 2nd Party
2016-Aug-04	External Interference	EI - 3rd Party
2016-Aug-04	External Interference	EI - 3rd Party
2016-Aug-05	External Interference	EI - 3rd Party
2016-Aug-06	Material, Manuf, or Construction Defect	MMC - Defective Joining Method
2016-Aug-06	Material, Manuf, or Construction Defect	MMC - Defective Joining Method
2016-Aug-08	Natural Forces	NF - Geotechnical
2016-Aug-10	External Interference	EI - 3rd Party
2016-Aug-16	External Interference	EI - 3rd Party
2016-Aug-16	Material, Manuf, or Construction Defect	MMC - Other Improper Construction
2016-Aug-18	External Interference	EI - 3rd Party
2016-Aug-18	Corrosion / Degradation	CD - Metal Loss
2016-Aug-18	Corrosion / Degradation	CD - Metal Loss
2016-Aug-20	Natural Forces	NF - Geotechnical
2016-Aug-22	External Interference	EI - 3rd Party
2016-Aug-23	External Interference	EI - 3rd Party
2016-Aug-25	External Interference	EI - 3rd Party
2016-Aug-26	External Interference	EI - 3rd Party
2016-Aug-26	External Interference	EI - 3rd Party
2016-Sep-02	External Interference	EI - 3rd Party
2016-Sep-06	External Interference	EI - 3rd Party
2016-Sep-14	External Interference	EI - 3rd Party
2016-Sep-23	External Interference	EI - 3rd Party
2016-Sep-23	External Interference	EI - 3rd Party
2016-Sep-29	External Interference	EI - 3rd Party
2016-Sep-30	Material, Manuf, or Construction Defect	MMC - Other Improper Construction
2016-Oct-03	External Interference	EI - 3rd Party
2016-Oct-03	External Interference	EI - 3rd Party
2016-Oct-03	External Interference	EI - 3rd Party
2016-Oct-05	External Interference	EI - 3rd Party
2016-Oct-08	External Interference	EI - 3rd Party
2016-Oct-15	External Interference	EI - 3rd Party
2016-Oct-17	External Interference	EI - 3rd Party
2016-Oct-20	External Interference	EI - 3rd Party
2016-Oct-20	External Interference	EI - 3rd Party
2016-Oct-20	Material, Manuf, or Construction Defect	MMC - Defective Pipe Body
2016-Oct-24	External Interference	EI - 3rd Party
2016-Oct-26	Material, Manuf, or Construction Defect	MMC - Other Improper Construction
2016-Oct-28	External Interference	EI - 3rd Party
2016-Oct-31	External Interference	EI - 3rd Party
2016-Nov-15	Material, Manuf, or Construction Defect	MMC - Other Improper Construction
2016-Nov-18	External Interference	EI - 3rd Party
2016-Nov-28	External Interference	EI - 3rd Party
2016-Dec-01	External Interference	EI - 1st or 2nd Party
2016-Dec-12	External Interference	EI - 3rd Party
2016-Dec-30	External Interference	EI - 3rd Party
2016-Dec-31	Corrosion / Degradation	CD - Metal Loss

Date of Incident	Cause	Sub-Cause
2015-Jan-08	Natural Forces	NF- Geotechnical
2015-Jan-19	External Interference	EI - 1st or 2nd Party
2015-Jan-20	External Interference	EI - 1st or 2nd Party
2015-Jan-28	External Interference	EI - 3rd Party
2015-Feb-25	External Interference	EI - 3rd Party
2015-Feb-28	Material Manuf or Construction Defect	MMC - Defective Joining Method
2015-Mar-02	External Interference	EI - 3rd Party
2015-Mar-05	Unable to Classify	Unable to Classify
2015-Mar-05	External Interference	EI - 3rd Party
2015-Mar-12	External Interference	EI - 3rd Party
2015-Mar-12	External Interference	EI - 3rd Party
2015-Mar-20	Natural Forces	NF- Geotechnical
2015-Mar-24	External Interference	EI - 3rd Party
2015-Apr-09	External Interference	EI - 3rd Party
2015-Apr-13	Material Manuf or Construction Defect	MMC - Defective Joining Method
2015-Apr-16	External Interference	EI - 3rd Party
2015-Apr-17	External Interference	EI - 3rd Party
2015-Apr-18	Natural Forces	NF- Geotechnical
2015-Apr-29	External Interference	EI - 3rd Party
2015-Apr-30	Material Manuf or Construction Defect	MMC - Other Improper Construction
2015-May-06	Material Manuf or Construction Defect	MMC - Other Improper Construction
2015-May-11	External Interference	EI - 3rd Party
2015-May-11	External Interference	EI - 3rd Party
2015-May-13	External Interference	EI - 3rd Party
2015-May-13	External Interference	EI - 3rd Party
2015-May-19	Corrosion / Degredation	CD - Metal Loss
2015-May-21	Material Manuf or Construction Defect	MMC - Other Improper Construction
2015-May-22	External Interference	EI - 3rd Party
2015-May-22	Corrosion / Degredation	CD - Metal Loss
2015-May-25	External Interference	EI - 3rd Party
2015-May-29	External Interference	EI - 3rd Party
2015-May-30	Corrosion / Degredation	CD - Metal Loss
2015-May-31	External Interference	EI - 3rd Party
2015-Jun-01	External Interference	EI - 3rd Party
2015-Jun-02	Natural Forces	NF- Geotechnical
2015-Jun-03	Material Manuf or Construction Defect	MMC - Other Improper Construction
2015-Jun-03	Natural Forces	NF- Geotechnical
2015-Jun-03	Material Manuf or Construction Defect	MMC - Other Improper Construction
2015-Jun-04	Natural Forces	NF- Geotechnical
2015-Jun-04	External Interference	EI - 3rd Party
2015-Jun-04	External Interference	EI - 3rd Party
2015-Jun-07	Unable to Classify	Unable to Classify
2015-Jun-08	Material Manuf or Construction Defect	MMC - Other Improper Construction
2015-Jun-08	Corrosion / Degredation	CD - Metal Loss
2015-Jun-08	Corrosion / Degredation	CD - Metal Loss
2015-Jun-09	Material Manuf or Construction Defect	MMC - Other Improper Construction
2015-Jun-09	Material Manuf or Construction Defect	MMC - Defective Joining Method
2015-Jun-10	External Interference	EI - 3rd Party
2015-Jun-10	Equipment Malfunction	EM - Mechanical Fitting Malfunction
2015-Jun-11	External Interference	EI - 3rd Party
2015-Jun-11	External Interference	EI - 3rd Party
2015-Jun-13	External Interference	EI - 3rd Party
2015-Jun-16	Material Manuf or Construction Defect	MMC - Other Improper Construction
2015-Jun-17	External Interference	EI - 3rd Party
2015-Jun-17	External Interference	EI - 3rd Party

2015-Jun-17	External Interference	EI - 3rd Party
2015-Jun-17	Natural Forces	NF- Geotechnical
2015-Jun-17	Natural Forces	NF- Geotechnical
2015-Jun-22	External Interference	EI - 3rd Party
2015-Jun-22	Material Manuf or Construction Defect	MMC - Defective Joining Method
2015-Jun-22	External Interference	EI - 3rd Party
2015-Jun-23	External Interference	EI - 3rd Party
2015-Jun-24	Material Manuf or Construction Defect	MMC - Defective Joining Method
2015-Jun-24	Natural Forces	NF- Geotechnical
2015-Jun-26	External Interference	EI - 1st or 2nd Party
2015-Jun-29	External Interference	EI - 3rd Party
2015-Jun-30	External Interference	EI - 3rd Party
2015-Jul-02	External Interference	EI - 3rd Party
2015-Jul-02	External Interference	EI - 3rd Party
2015-Jul-02	External Interference	EI - 3rd Party
2015-Jul-06	External Interference	EI - 3rd Party
2015-Jul-06	External Interference	EI - 3rd Party
2015-Jul-07	Equipment Malfunction	EM - Mechanical Fitting Malfunction
2015-Jul-07	Material Manuf or Construction Defect	MMC - Defective Joining Method
2015-Jul-08	Corrosion / Degredation	CD - Metal Cracking
2015-Jul-12	External Interference	EI - 3rd Party
2015-Jul-13	External Interference	EI - 3rd Party
2015-Jul-13	External Interference	EI - 3rd Party
2015-Jul-13	Material Manuf or Construction Defect	MMC - Other Improper Construction
2015-Jul-14	External Interference	EI - 3rd Party
2015-Jul-15	External Interference	EI - 3rd Party
2015-Jul-16	External Interference	EI - 3rd Party
2015-Jul-20	External Interference	EI - 3rd Party
2015-Jul-21	External Interference	EI - 3rd Party
2015-Jul-21	Material Manuf or Construction Defect	MMC - Other Improper Construction
2015-Jul-22	External Interference	EI - 3rd Party
2015-Jul-23	Equipment Malfunction	EM - Mechanical Fitting Malfunction
2015-Jul-23	Material Manuf or Construction Defect	MMC - Other Improper Construction
2015-Jul-27	Material Manuf or Construction Defect	MMC - Other Improper Construction
2015-Jul-28	External Interference	EI - 3rd Party
2015-Jul-28	Equipment Malfunction	EM - Mechanical Fitting Malfunction
2015-Jul-30	External Interference	EI - 3rd Party
2015-Jul-30	Material Manuf or Construction Defect	MMC - Other Improper Construction
2015-Jul-31	External Interference	EI - 3rd Party
2015-Aug-03	Corrosion / Degredation	CD - Metal Loss
2015-Aug-04	External Interference	EI - 3rd Party
2015-Aug-04	External Interference	EI - 3rd Party
2015-Aug-07	External Interference	EI - 3rd Party
2015-Aug-10	External Interference	EI - 3rd Party
2015-Aug-13	External Interference	EI - 3rd Party
2015-Aug-13	External Interference	EI - 3rd Party
2015-Aug-14	External Interference	EI - 3rd Party
2015-Aug-14	External Interference	EI - 3rd Party
2015-Aug-18	Material Manuf or Construction Defect	MMC - Other Improper Construction
2015-Aug-19	External Interference	EI - 1st or 2nd Party
2015-Aug-19	External Interference	EI - 3rd Party
2015-Aug-19	Material Manuf or Construction Defect	MMC - Other Improper Construction
2015-Aug-20	External Interference	EI - 3rd Party
2015-Aug-23	Corrosion / Degredation	CD - Metal Loss
2015-Aug-23	Material Manuf or Construction Defect	MMC - Defective Joining Method
2015-Aug-24	Corrosion / Degredation	CD - Metal Loss

2015-Aug-25	External Interference	EI - 3rd Party
2015-Aug-25	Corrosion / Degredation	CD - Metal Loss
2015-Aug-27	External Interference	EI - 3rd Party
2015-Aug-27	Corrosion / Degredation	CD - Metal Loss
2015-Aug-28	Natural Forces	NF- Geotechnical
2015-Sep-01	External Interference	EI - 3rd Party
2015-Sep-01	External Interference	EI - 3rd Party
2015-Sep-12	External Interference	EI - 3rd Party
2015-Sep-12	External Interference	EI - 3rd Party
2015-Sep-16	External Interference	EI - 3rd Party
2015-Sep-16	Material Manuf or Construction Defect	MMC - Other Improper Construction
2015-Sep-17	Natural Forces	NF- Geotechnical
2015-Sep-18	External Interference	EI - 3rd Party
2015-Sep-18	Natural Forces	NF- Geotechnical
2015-Sep-19	External Interference	EI - 3rd Party
2015-Sep-22	External Interference	EI - 3rd Party
2015-Sep-23	External Interference	EI - 3rd Party
2015-Sep-23	External Interference	EI - 1st or 2nd Party
2015-Sep-24	External Interference	EI - 3rd Party
2015-Sep-25	External Interference	EI - 3rd Party
2015-Sep-28	External Interference	EI - 3rd Party
2015-Sep-29	Corrosion / Degredation	CD - Metal Loss
2015-Sep-30	External Interference	EI - 3rd Party
2015-Oct-03	External Interference	EI - 3rd Party
2015-Oct-04	External Interference	EI - 3rd Party
2015-Oct-05	External Interference	EI - 3rd Party
2015-Oct-07	Equipment Malfunction	EM - Mechanical Fitting Malfunction
2015-Oct-08	Unable to Classify	Unable to Classify
2015-Oct-09	Corrosion / Degredation	CD - Metal Loss
2015-Oct-13	Material Manuf or Construction Defect	MMC - Other Improper Construction
2015-Oct-14	Corrosion / Degredation	CD - Metal Loss
2015-Oct-14	Material Manuf or Construction Defect	MMC - Defective Joining Method
2015-Oct-15	Material Manuf or Construction Defect	MMC - Other Improper Construction
2015-Oct-19	Material Manuf or Construction Defect	MMC - Other Improper Construction
2015-Oct-21	Unable to Classify	Unable to Classify
2015-Oct-21	External Interference	EI - 3rd Party
2015-Oct-21	External Interference	EI - 3rd Party
2015-Oct-22	External Interference	EI - 3rd Party
2015-Oct-28	External Interference	EI - 3rd Party
2015-Nov-02	External Interference	EI - 3rd Party
2015-Nov-03	External Interference	EI - 3rd Party
2015-Nov-08	External Interference	EI - 3rd Party
2015-Nov-20	External Interference	EI - 1st or 2nd Party
2015-Nov-27	External Interference	EI - 3rd Party
2015-Dec-02	External Interference	EI - 3rd Party
2015-Dec-11	External Interference	EI - 3rd Party

Date of Incident	Cause	Sub-Cause
2014-01-15	Material, Manufacturing or Construction Defect	MMC - Defective Pipe Body
2014-01-23	External Interference	EI - 3rd Party
2014-01-24	Corrosion / Degradation	CD - Metal Loss
2014-02-04	Material, Manufacturing or Construction Defect	MMC - Defective Pipe Body
2014-02-06	Material, Manufacturing or Construction Defect	MMC - Defective Pipe Body
2014-02-12	External Interference	EI - 3rd Party
2014-02-13	External Interference	EI - 3rd Party
2014-02-15	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2014-02-25	Material, Manufacturing or Construction Defect	MMC - Defective Pipe Body
2014-02-27	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2014-03-07	External Interference	EI - 1st or 2nd Party
2014-03-07	Corrosion / Degradation	CD - Metal Loss
2014-03-07	Corrosion / Degradation	CD - Metal Loss
2014-03-11	External Interference	EI - 3rd Party
2014-03-12	External Interference	EI - 3rd Party
2014-03-12	Material, Manufacturing or Construction Defect	MMC - Defective Pipe Body
2014-03-13	Material, Manufacturing or Construction Defect	MMC - Defective Pipe Body
2014-03-13	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2014-03-16	External Interference	EI - 3rd Party
2014-03-19	Material, Manufacturing or Construction Defect	MMC - Defective Joining Method
2014-03-24	Material, Manufacturing or Construction Defect	MMC - Defective Pipe Body
2014-03-26	Material, Manufacturing or Construction Defect	MMC - Defective Joining Method
2014-03-26	Natural Forces	NF - Geotechnical
2014-03-29	Corrosion / Degradation	CD - Metal Loss
2014-03-31	External Interference	EI - 1st or 2nd Party
2014-03-31	External Interference	EI - 1st or 2nd Party
2014-04-01	Corrosion / Degradation	CD - Metal Loss
2014-04-09	Material, Manufacturing or Construction Defect	MMC - Defective Pipe Body
2014-04-09	Material, Manufacturing or Construction Defect	MMC - Defective Joining Method
2014-04-21	External Interference	EI - 3rd Party
2014-04-22	External Interference	EI - 3rd Party
2014-04-28	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2014-05-07	Material, Manufacturing or Construction Defect	MMC - Defective Joining Method
2014-05-07	Material, Manufacturing or Construction Defect	MMC - Defective Pipe Body
2014-05-08	Corrosion / Degradation	CD - Metal Loss
2014-05-09	Material, Manufacturing or Construction Defect	MMC - Defective Joining Method
2014-05-11	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2014-05-12	Corrosion / Degradation	CD - Metal Loss
2014-05-12	Corrosion / Degradation	CD - Metal Loss
2014-05-14	Corrosion / Degradation	CD - Metal Loss
2014-05-14	Corrosion / Degradation	CD - Metal Loss
2014-05-15	Corrosion / Degradation	CD - Metal Loss
2014-05-15	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2014-05-20	Material, Manufacturing or Construction Defect	MMC - Defective Joining Method
2014-05-22	External Interference	EI - 3rd Party
2014-05-22	Corrosion / Degradation	CD - Metal Loss
2014-05-26	Material, Manufacturing or Construction Defect	MMC - Defective Joining Method
2014-05-30	Corrosion / Degradation	CD - Metal Loss
2014-05-31	External Interference	EI - 3rd Party
2014-05-31	External Interference	EI - 3rd Party
2014-06-03	External Interference	EI - 3rd Party
2014-06-09	External Interference	EI - 3rd Party
2014-06-09	External Interference	EI - 3rd Party
2014-06-12	External Interference	EI - 3rd Party
2014-06-17	External Interference	EI - 3rd Party

2014-06-25	Corrosion / Degradation	CD - Metal Loss
2014-06-26	External Interference	EI - 3rd Party
2014-06-26	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2014-07-02	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2014-07-02	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2014-07-03	External Interference	EI - 3rd Party
2014-07-03	External Interference	EI - 3rd Party
2014-07-03	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2014-07-04	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2014-07-04	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2014-07-07	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2014-07-08	External Interference	EI - 3rd Party
2014-07-08	External Interference	EI - 3rd Party
2014-07-08	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2014-07-09	External Interference	EI - 3rd Party
2014-07-09	External Interference	EI - 3rd Party
2014-07-11	External Interference	EI - 3rd Party
2014-07-11	External Interference	EI - 1st or 2nd Party
2014-07-11	External Interference	EI - 1st or 2nd Party
2014-07-15	External Interference	EI - 3rd Party
2014-07-17	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2014-07-17	Corrosion / Degradation	CD - Metal Loss
2014-07-17	Corrosion / Degradation	CD - Metal Loss
2014-07-17	Corrosion / Degradation	CD - Metal Loss
2014-07-21	Corrosion / Degradation	CD - Metal Loss
2014-07-22	Unable to Classify	Unable to Classify
2014-07-23	External Interference	EI - 3rd Party
2014-07-23	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2014-07-23	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2014-07-24	External Interference	EI - 3rd Party
2014-07-24	Material, Manufacturing or Construction Defect	MMC - Defective Joining Method
2014-07-26	External Interference	EI - 3rd Party
2014-07-28	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2014-07-29	External Interference	EI - 3rd Party
2014-07-31	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2014-07-31	Unable to Classify	Unable to Classify
2014-07-31	Corrosion / Degradation	CD - Metal Loss
2014-07-31	Corrosion / Degradation	CD - Metal Loss
2014-08-02	External Interference	EI - 3rd Party
2014-08-03	External Interference	EI - 3rd Party
2014-08-05	Corrosion / Degradation	CD - Metal Loss
2014-08-06	Corrosion / Degradation	CD - Metal Loss
2014-08-07	External Interference	EI - 3rd Party
2014-08-07	Corrosion / Degradation	CD - Metal Loss
2014-08-08	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2014-08-11	External Interference	EI - 3rd Party
2014-08-11	External Interference	EI - 3rd Party
2014-08-11	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2014-08-12	External Interference	EI - 3rd Party
2014-08-13	External Interference	EI - 3rd Party
2014-08-15	External Interference	EI - 1st or 2nd Party
2014-08-19	External Interference	EI - 3rd Party
2014-08-19	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2014-08-19	Corrosion / Degradation	CD - Metal Loss
2014-08-20	External Interference	EI - 3rd Party
2014-08-20	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction

2014-08-21	External Interference	EI - 3rd Party
2014-08-21	External Interference	EI - 3rd Party
2014-08-22	External Interference	EI - 3rd Party
2014-08-23	Corrosion / Degradation	CD - Metal Loss
2014-08-25	Corrosion / Degradation	CD - Metal Loss
2014-08-26	External Interference	EI - 3rd Party
2014-08-27	External Interference	EI - 3rd Party
2014-08-27	External Interference	EI - 3rd Party
2014-08-27	Corrosion / Degradation	CD - Metal Loss
2014-08-27	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2014-08-29	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2014-08-30	External Interference	EI - 3rd Party
2014-09-02	External Interference	EI - 3rd Party
2014-09-02	External Interference	EI - 3rd Party
2014-09-02	External Interference	EI - 3rd Party
2014-09-03	Corrosion / Degradation	CD - Metal Loss
2014-09-03	Material, Manufacturing or Construction Defect	MMC - Defective Joining Method
2014-09-03	Material, Manufacturing or Construction Defect	MMC - Defective Joining Method
2014-09-11	External Interference	EI - 3rd Party
2014-09-11	Corrosion / Degradation	CD - Metal Loss
2014-09-11	Corrosion / Degradation	CD - Metal Loss
2014-09-12	External Interference	EI - 3rd Party
2014-09-12	Corrosion / Degradation	CD - Metal Loss
2014-09-12	Corrosion / Degradation	CD - Metal Loss
2014-09-15	External Interference	EI - 3rd Party
2014-09-16	External Interference	EI - 3rd Party
2014-09-16	External Interference	EI - 3rd Party
2014-09-17	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2014-09-23	External Interference	EI - 3rd Party
2014-09-23	Corrosion / Degradation	CD - Metal Loss
2014-09-25	Corrosion / Degradation	CD - Metal Loss
2014-09-26	External Interference	EI - 3rd Party
2014-09-29	External Interference	EI - 3rd Party
2014-09-29	External Interference	EI - 3rd Party
2014-09-29	Corrosion / Degradation	CD - Metal Loss
2014-09-30	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2014-10-01	External Interference	EI - 3rd Party
2014-10-02	Material, Manufacturing or Construction Defect	MMC - Defective Joining Method
2014-10-03	External Interference	EI - 1st or 2nd Party
2014-10-06	External Interference	EI - 3rd Party
2014-10-06	Corrosion / Degradation	CD - Metal Loss
2014-10-07	Unable to Classify	Unable to Classify
2014-10-07	Corrosion / Degradation	CD - Metal Loss
2014-10-07	Unable to Classify	Unable to Classify
2014-10-08	Material, Manufacturing or Construction Defect	MMC - Defective Pipe Body
2014-10-11	External Interference	EI - 3rd Party
2014-10-13	Corrosion / Degradation	CD - Metal Loss
2014-10-14	Corrosion / Degradation	CD - Metal Loss
2014-10-15	External Interference	EI - 3rd Party
2014-10-15	Corrosion / Degradation	CD - Metal Loss
2014-10-16	External Interference	EI - 3rd Party
2014-10-17	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2014-10-18	External Interference	EI - 3rd Party
2014-10-20	Corrosion / Degradation	CD - Metal Loss
2014-10-22	Corrosion / Degradation	CD - Metal Loss
2014-10-23	External Interference	EI - 3rd Party

2014-10-27	External Interference	EI - 3rd Party
2014-10-30	External Interference	EI - 3rd Party
2014-11-03	Corrosion / Degradation	CD - Metal Loss
2014-11-03	Material, Manufacturing or Construction Defect	MMC - Defective Joining Method
2014-11-17	External Interference	EI - 3rd Party
2014-11-18	External Interference	EI - 1st or 2nd Party
2014-11-20	External Interference	EI - 3rd Party
2014-11-22	External Interference	EI - 1st or 2nd Party
2014-11-26	External Interference	EI - 3rd Party
2014-12-15	External Interference	EI - 3rd Party
2014-12-16	External Interference	EI - 1st or 2nd Party

Date of Incident	Cause	Sub-Cause
2013-01-02	External Interference	EI - 3rd Party
2013-01-08	External Interference	EI - 3rd Party
2013-01-17	External Interference	EI - 3rd Party
2013-01-25	External Interference	EI - 3rd Party
2013-02-03	External Interference	EI - 3rd Party
2013-02-05	Equipment Malfunction	EM - Mechanical Fitting Malfunction
2013-02-07	External Interference	EI - 1st or 2nd Party
2013-02-11	External Interference	EI - 3rd Party
2013-02-18	Corrosion / Degradation	CD - Metal Loss
2013-02-21	External Interference	EI - 1st or 2nd Party
2013-02-22	Corrosion / Degradation	CD - Metal Loss
2013-02-22	External Interference	EI - 3rd Party
2013-02-25	External Interference	EI - 3rd Party
2013-03-06	Material, Manufacturing or Construction Defect	MMC - Defective Joining Method
2013-03-13	External Interference	EI - 1st or 2nd Party
2013-03-15	External Interference	EI - 3rd Party
2013-03-18	External Interference	EI - 3rd Party
2013-03-25	External Interference	EI - 3rd Party
2013-03-28	External Interference	EI - 3rd Party
2013-04-02	External Interference	EI - 3rd Party
2013-04-02	External Interference	EI - 3rd Party
2013-04-05	Corrosion / Degradation	CD - Metal Loss
2013-04-08	Corrosion / Degradation	CD - Metal Loss
2013-04-24	Material, Manufacturing or Construction Defect	MMC - Defective Joining Method
2013-04-26	External Interference	EI - 1st or 2nd Party
2013-05-01	Corrosion / Degradation	CD - Metal Loss
2013-05-05	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2013-05-06	Corrosion / Degradation	CD - Metal Loss
2013-05-08	Corrosion / Degradation	CD - Metal Loss
2013-05-08	Corrosion / Degradation	CD - Metal Loss
2013-05-08	Unable to Classify	Unable to Classify
2013-05-08	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2013-05-08	External Interference	EI - 3rd Party
2013-05-09	Corrosion / Degradation	CD - Metal Loss
2013-05-09	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2013-05-09	External Interference	EI - 3rd Party
2013-05-10	Corrosion / Degradation	CD - Metal Loss
2013-05-10	External Interference	EI - 3rd Party
2013-05-10	External Interference	EI - 3rd Party
2013-05-15	External Interference	EI - 3rd Party
2013-05-16	Corrosion / Degradation	CD - Metal Loss
2013-05-17	External Interference	EI - 3rd Party
2013-05-18	External Interference	EI - 3rd Party
2013-05-23	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2013-05-23	External Interference	EI - 3rd Party
2013-05-27	External Interference	EI - 3rd Party
2013-05-29	Corrosion / Degradation	CD - Metal Loss
2013-06-04	Corrosion / Degradation	CD - Metal Loss
2013-06-04	External Interference	EI - 3rd Party
2013-06-05	External Interference	EI - 3rd Party
2013-06-06	Corrosion / Degradation	CD - Metal Loss
2013-06-06	External Interference	EI - 3rd Party
2013-06-07	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2013-06-10	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2013-06-10	External Interference	EI - 3rd Party

2013-06-11	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2013-06-11	Corrosion / Degradation	CD - Metal Cracking
2013-06-11	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2013-06-11	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2013-06-12	Material, Manufacturing or Construction Defect	MMC - Defective Joining Method
2013-06-13	Material, Manufacturing or Construction Defect	MMC - Defective Joining Method
2013-06-13	External Interference	EI - 1st or 2nd Party
2013-06-17	Corrosion / Degradation	CD - Metal Loss
2013-06-17	Corrosion / Degradation	CD - Metal Loss
2013-06-17	Corrosion / Degradation	CD - Metal Loss
2013-06-17	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2013-06-18	External Interference	EI - 3rd Party
2013-06-19	Corrosion / Degradation	CD - Metal Loss
2013-06-20	Corrosion / Degradation	CD - Metal Loss
2013-06-21	Corrosion / Degradation	CD - Metal Loss
2013-06-24	Corrosion / Degradation	CD - Metal Loss
2013-06-25	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2013-06-26	Corrosion / Degradation	CD - Metal Cracking
2013-06-26	External Interference	EI - 3rd Party
2013-06-28	External Interference	EI - 3rd Party
2013-07-02	Corrosion / Degradation	CD - Metal Loss
2013-07-03	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2013-07-03	Material, Manufacturing or Construction Defect	MMC - Defective Joining Method
2013-07-04	Corrosion / Degradation	CD - Metal Loss
2013-07-09	Corrosion / Degradation	CD - Metal Loss
2013-07-09	External Interference	EI - 3rd Party
2013-07-10	External Interference	EI - 3rd Party
2013-07-10	External Interference	EI - 3rd Party
2013-07-13	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2013-07-18	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2013-07-18	Corrosion / Degradation	CD - Metal Loss
2013-07-19	External Interference	EI - 3rd Party
2013-07-23	External Interference	EI - 3rd Party
2013-07-24	External Interference	EI - 3rd Party
2013-07-24	External Interference	EI - 3rd Party
2013-07-29	Corrosion / Degradation	CD - Metal Loss
2013-07-29	External Interference	EI - 3rd Party
2013-07-29	External Interference	EI - 3rd Party
2013-07-30	Corrosion / Degradation	CD - Metal Loss
2013-07-31	External Interference	EI - 3rd Party
2013-08-01	External Interference	EI - 3rd Party
2013-08-03	External Interference	EI - 3rd Party
2013-08-07	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2013-08-07	Corrosion / Degradation	CD - Metal Cracking
2013-08-07	External Interference	EI - 3rd Party
2013-08-07	External Interference	EI - 3rd Party
2013-08-10	External Interference	EI - 3rd Party
2013-08-14	Material, Manufacturing or Construction Defect	MMC - Defective Joining Method
2013-08-15	Material, Manufacturing or Construction Defect	MMC - Defective Joining Method
2013-08-15	Corrosion / Degradation	CD - Metal Loss
2013-08-15	Corrosion / Degradation	CD - Metal Loss
2013-08-15	External Interference	EI - 3rd Party
2013-08-20	External Interference	EI - 3rd Party
2013-08-21	Corrosion / Degradation	CD - Metal Loss
2013-08-21	External Interference	EI - 3rd Party
2013-08-26	Corrosion / Degradation	CD - Metal Loss

2013-08-26	External Interference	EI - 3rd Party
2013-08-27	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2013-08-27	External Interference	EI - 3rd Party
2013-08-30	External Interference	EI - 3rd Party
2013-08-31	Corrosion / Degradation	CD - Metal Cracking
2013-09-03	Corrosion / Degradation	CD - Metal Loss
2013-09-04	Material, Manufacturing or Construction Defect	MMC - Defective Joining Method
2013-09-04	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2013-09-05	Corrosion / Degradation	CD - Metal Loss
2013-09-05	External Interference	EI - 3rd Party
2013-09-08	External Interference	EI - 3rd Party
2013-09-10	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2013-09-10	Corrosion / Degradation	CD - Metal Loss
2013-09-10	External Interference	EI - 3rd Party
2013-09-12	Corrosion / Degradation	CD - Metal Cracking
2013-09-13	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2013-09-15	External Interference	EI - 3rd Party
2013-09-17	External Interference	EI - 3rd Party
2013-09-18	External Interference	EI - 3rd Party
2013-09-19	Corrosion / Degradation	CD - Metal Loss
2013-09-20	Corrosion / Degradation	CD - Metal Loss
2013-09-21	External Interference	EI - 3rd Party
2013-09-23	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2013-09-24	Corrosion / Degradation	CD - Metal Cracking
2013-09-25	Corrosion / Degradation	CD - Metal Loss
2013-09-25	External Interference	EI - 3rd Party
2013-09-25	External Interference	EI - 3rd Party
2013-09-26	External Interference	EI - 3rd Party
2013-10-01	External Interference	EI - 3rd Party
2013-10-05	External Interference	EI - 3rd Party
2013-10-09	External Interference	EI - 3rd Party
2013-10-09	External Interference	EI - 1st or 2nd Party
2013-10-16	Corrosion / Degradation	CD - Metal Loss
2013-10-16	External Interference	EI - 3rd Party
2013-10-16	External Interference	EI - 3rd Party
2013-10-17	Material, Manufacturing or Construction Defect	MMC - Defective Joining Method
2013-10-17	External Interference	EI - 3rd Party
2013-10-19	External Interference	EI - 3rd Party
2013-10-20	External Interference	EI - 3rd Party
2013-10-21	External Interference	EI - 3rd Party
2013-10-22	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2013-10-22	Corrosion / Degradation	CD - Metal Loss
2013-10-23	Material, Manufacturing or Construction Defect	MMC - Defective Joining Method
2013-10-23	Corrosion / Degradation	CD - Metal Loss
2013-10-23	External Interference	EI - 3rd Party
2013-10-23	External Interference	EI - 3rd Party
2013-10-24	Corrosion / Degradation	CD - Metal Loss
2013-10-28	External Interference	EI - 3rd Party
2013-11-16	External Interference	EI - 3rd Party
2013-11-20	External Interference	EI - 3rd Party
2013-11-20	External Interference	EI - 1st or 2nd Party
2013-11-22	External Interference	EI - 3rd Party
2013-11-25	External Interference	EI - 3rd Party
2013-11-29	External Interference	EI - 3rd Party
2013-12-05	External Interference	EI - 3rd Party
2013-12-06	External Interference	EI - 3rd Party

2013-12-09	Corrosion / Degradation	CD - Metal Cracking
2013-12-09	External Interference	EI - 3rd Party
2013-12-16	External Interference	EI - 3rd Party
2013-12-18	Equipment Malfunction	EM - Mechanical Fitting Malfunction

Date of Incident	Cause	Sub-Cause
2012-01-11	External Interference	EI - 3rd Party
2012-01-16	External Interference	EI - 3rd Party
2012-01-19	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-01-20	External Interference	EI - 3rd Party
2012-01-23	External Interference	EI - 3rd Party
2012-01-24	External Interference	EI - 1st or 2nd Party
2012-01-26	External Interference	EI - 3rd Party
2012-01-31	External Interference	EI - 1st or 2nd Party
2012-02-12	Corrosion / Degradation	CD - Metal Cracking
2012-02-14	External Interference	EI - 1st or 2nd Party
2012-02-21	Incorrect Operation	IO - Improper Operation
2012-02-28	External Interference	EI - 3rd Party
2012-02-28	External Interference	EI - 3rd Party
2012-03-02	External Interference	EI - 3rd Party
2012-03-21	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-03-21	External Interference	EI - 1st or 2nd Party
2012-03-22	External Interference	EI - 3rd Party
2012-04-05	External Interference	EI - 3rd Party
2012-04-09	External Interference	EI - 3rd Party
2012-04-13	Equipment Malfunction	EM - Mechanical Fitting Malfunction
2012-04-14	External Interference	EI - 3rd Party
2012-04-17	External Interference	EI - 3rd Party
2012-04-19	External Interference	EI - 3rd Party
2012-04-25	External Interference	EI - 3rd Party
2012-04-28	Equipment Malfunction	EM - Mechanical Fitting Malfunction
2012-04-28	External Interference	EI - 3rd Party
2012-04-30	External Interference	EI - 3rd Party
2012-05-02	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-05-02	Corrosion / Degradation	CD - Metal Loss
2012-05-03	Corrosion / Degradation	CD - Metal Loss
2012-05-03	Corrosion / Degradation	CD - Metal Loss
2012-05-04	External Interference	EI - 3rd Party
2012-05-09	External Interference	EI - 3rd Party
2012-05-14	External Interference	EI - 3rd Party
2012-05-15	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-05-15	Incorrect Operation	IO - Improper Operation
2012-05-15	External Interference	EI - 3rd Party
2012-05-16	Material, Manufacturing or Construction Defect	MMC - Defective Joining Method
2012-05-17	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-05-18	Material, Manufacturing or Construction Defect	MMC - Defective Pipe Body
2012-05-18	External Interference	EI - 3rd Party
2012-05-18	External Interference	EI - 3rd Party
2012-05-22	Corrosion / Degradation	CD - Metal Loss
2012-05-22	External Interference	EI - 3rd Party
2012-05-22	Incorrect Operation	IO - Improper Operation
2012-05-30	Corrosion / Degradation	CD - Metal Loss
2012-05-31	External Interference	EI - 3rd Party
2012-06-01	Corrosion / Degradation	CD - Metal Loss
2012-06-01	External Interference	EI - 3rd Party
2012-06-04	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-06-06	Incorrect Operation	IO - Improper Operation
2012-06-07	Unable to Classify	Unable to Classify
2012-06-07	Incorrect Operation	IO - Improper Operation
2012-06-09	External Interference	EI - 3rd Party
2012-06-12	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction

2012-06-13	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-06-14	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-06-14	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-06-15	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-06-18	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-06-18	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-06-18	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-06-21	External Interference	EI - 1st or 2nd Party
2012-06-22	Corrosion / Degradation	CD - Metal Loss
2012-06-22	External Interference	EI - 3rd Party
2012-06-25	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-06-25	Corrosion / Degradation	CD - Metal Loss
2012-06-26	External Interference	EI - 3rd Party
2012-07-02	External Interference	EI - 3rd Party
2012-07-04	Corrosion / Degradation	CD - Metal Loss
2012-07-04	External Interference	EI - 3rd Party
2012-07-06	Natural Forces	NF - Weather Related
2012-07-09	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-07-09	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-07-09	External Interference	EI - 3rd Party
2012-07-09	External Interference	EI - 1st or 2nd Party
2012-07-10	Material, Manufacturing or Construction Defect	MMC - Defective Joining Method
2012-07-10	Corrosion / Degradation	CD - Metal Loss
2012-07-10	Corrosion / Degradation	CD - Metal Loss
2012-07-11	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-07-11	External Interference	EI - 3rd Party
2012-07-11	External Interference	EI - 3rd Party
2012-07-16	Equipment Malfunction	EM - Mechanical Fitting Malfunction
2012-07-16	External Interference	EI - 3rd Party
2012-07-16	External Interference	EI - 3rd Party
2012-07-17	Corrosion / Degradation	CD - Metal Loss
2012-07-17	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-07-18	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-07-18	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-07-18	Corrosion / Degradation	CD - Metal Loss
2012-07-18	External Interference	EI - 1st or 2nd Party
2012-07-19	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-07-20	Equipment Malfunction	EM - Mechanical Fitting Malfunction
2012-07-20	External Interference	EI - 1st or 2nd Party
2012-07-20	External Interference	EI - 3rd Party
2012-07-24	Unable to Classify	Unable to Classify
2012-07-24	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-07-24	External Interference	EI - 3rd Party
2012-07-24	External Interference	EI - 3rd Party
2012-07-25	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-07-26	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-07-26	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-07-26	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-07-31	External Interference	EI - 3rd Party
2012-08-01	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-08-01	Unable to Classify	Unable to Classify
2012-08-02	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-08-03	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-08-08	External Interference	EI - 3rd Party
2012-08-09	External Interference	EI - 3rd Party
2012-08-13	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction

2012-08-13	External Interference	EI - 3rd Party
2012-08-13	External Interference	EI - 3rd Party
2012-08-14	External Interference	EI - 3rd Party
2012-08-15	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-08-17	External Interference	EI - 3rd Party
2012-08-20	External Interference	EI - 3rd Party
2012-08-20	External Interference	EI - 3rd Party
2012-08-22	External Interference	EI - 3rd Party
2012-08-22	External Interference	EI - 3rd Party
2012-08-30	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-09-01	External Interference	EI - 3rd Party
2012-09-03	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-09-08	External Interference	EI - 3rd Party
2012-09-09	Corrosion / Degradation	CD - Metal Loss
2012-09-11	External Interference	EI - 3rd Party
2012-09-13	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-09-19	External Interference	EI - 3rd Party
2012-09-22	External Interference	EI - 3rd Party
2012-09-25	External Interference	EI - 3rd Party
2012-09-26	External Interference	EI - 3rd Party
2012-09-29	External Interference	EI - 3rd Party
2012-10-01	External Interference	EI - 3rd Party
2012-10-11	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-10-15	External Interference	EI - 3rd Party
2012-10-16	External Interference	EI - 1st or 2nd Party
2012-10-16	External Interference	EI - 3rd Party
2012-10-16	External Interference	EI - 3rd Party
2012-10-17	External Interference	EI - 3rd Party
2012-10-19	External Interference	EI - 3rd Party
2012-10-23	Corrosion / Degradation	CD - Metal Loss
2012-10-23	External Interference	EI - 1st or 2nd Party
2012-10-25	External Interference	EI - 3rd Party
2012-10-29	External Interference	EI - 3rd Party
2012-10-30	External Interference	EI - 3rd Party
2012-10-30	External Interference	EI - 3rd Party
2012-11-13	External Interference	EI - 3rd Party
2012-11-20	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-11-21	External Interference	EI - 3rd Party
2012-11-22	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-11-26	External Interference	EI - 3rd Party
2012-11-28	Corrosion / Degradation	CD - Metal Loss
2012-12-05	External Interference	EI - 1st or 2nd Party
2012-12-11	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-12-17	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2012-12-17	External Interference	EI - 3rd Party
2012-12-20	External Interference	EI - 3rd Party
2012-12-26	Incorrect Operation	IO - Improper Operation

Date of Incident	Cause	Sub-Cause
2010-01-04	External Interference	EI - 3rd Party
2010-01-23	External Interference	EI - 3rd Party
2010-01-29	External Interference	EI - 3rd Party
2010-02-01	External Interference	EI - 3rd Party
2010-02-10	External Interference	EI - 3rd Party
2010-02-11	Incorrect Operation	IO - Improper Operation
2010-03-01	External Interference	EI - 3rd Party
2010-03-08	External Interference	EI - 3rd Party
2010-03-09	External Interference	EI - 3rd Party
2010-03-09	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2010-03-22	Incorrect Operation	IO - Improper Operation
2010-03-31	External Interference	EI - 3rd Party
2010-04-06	External Interference	EI - 3rd Party
2010-04-15	External Interference	EI - 3rd Party
2010-04-21	External Interference	EI - 3rd Party
2010-04-22	Incorrect Operation	IO - Improper Operation
2010-04-23	External Interference	EI - 3rd Party
2010-04-26	External Interference	EI - 3rd Party
2010-04-28	External Interference	EI - 3rd Party
2010-05-06	External Interference	EI - 3rd Party
2010-05-07	External Interference	EI - 3rd Party
2010-05-07	External Interference	EI - 3rd Party
2010-05-13	External Interference	EI - 3rd Party
2010-05-13	Incorrect Operation	IO - Improper Operation
2010-05-16	External Interference	EI - 3rd Party
2010-05-21	External Interference	EI - 3rd Party
2010-05-25	Incorrect Operation	IO - Improper Operation
2010-06-01	External Interference	EI - 3rd Party
2010-06-02	External Interference	EI - 3rd Party
2010-06-07	External Interference	EI - 3rd Party
2010-06-08	Incorrect Operation	IO - Improper Operation
2010-06-12	External Interference	EI - 3rd Party
2010-06-12	External Interference	EI - 3rd Party
2010-06-14	External Interference	EI - 3rd Party
2010-06-14	External Interference	EI - 3rd Party
2010-06-14	External Interference	EI - 3rd Party
2010-06-15	External Interference	EI - 3rd Party
2010-06-15	External Interference	EI - 3rd Party
2010-06-15	External Interference	EI - 3rd Party
2010-06-16	External Interference	EI - 3rd Party
2010-06-21	External Interference	EI - 3rd Party
2010-06-22	External Interference	EI - 3rd Party
2010-06-25	External Interference	EI - 3rd Party
2010-06-25	External Interference	EI - 1st or 2nd Party
2010-07-01	External Interference	EI - 3rd Party
2010-07-05	External Interference	EI - 3rd Party
2010-07-07	External Interference	EI - 3rd Party
2010-07-15	External Interference	EI - 3rd Party
2010-07-15	External Interference	EI - 3rd Party
2010-07-23	External Interference	EI - 3rd Party
2010-07-26	External Interference	EI - 3rd Party
2010-08-03	External Interference	EI - 3rd Party
2010-08-03	External Interference	EI - 3rd Party
2010-08-05	External Interference	EI - 3rd Party
2010-08-06	External Interference	EI - 3rd Party

2010-08-09	External Interference	EI - 3rd Party
2010-08-16	External Interference	EI - 3rd Party
2010-08-19	External Interference	EI - 3rd Party
2010-08-20	External Interference	EI - 3rd Party
2010-08-23	External Interference	EI - 3rd Party
2010-08-24	External Interference	EI - 3rd Party
2010-08-24	External Interference	EI - 3rd Party
2010-08-24	External Interference	EI - 3rd Party
2010-08-24	External Interference	EI - 3rd Party
2010-08-24	External Interference	EI - 3rd Party
2010-08-25	External Interference	EI - 3rd Party
2010-08-27	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2010-08-27	External Interference	EI - 3rd Party
2010-09-07	External Interference	EI - 3rd Party
2010-09-13	External Interference	EI - 3rd Party
2010-09-15	External Interference	EI - 3rd Party
2010-09-16	External Interference	EI - 3rd Party
2010-09-24	Incorrect Operation	IO - Improper Operation
2010-09-25	External Interference	EI - 3rd Party
2010-09-28	External Interference	EI - 3rd Party
2010-09-29	External Interference	EI - 3rd Party
2010-10-01	External Interference	EI - 3rd Party
2010-10-01	External Interference	EI - 3rd Party
2010-10-02	External Interference	EI - 3rd Party
2010-10-04	External Interference	EI - 3rd Party
2010-10-05	External Interference	EI - 3rd Party
2010-10-06	External Interference	EI - 3rd Party
2010-10-08	External Interference	EI - 3rd Party
2010-10-12	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2010-10-17	External Interference	EI - 3rd Party
2010-10-21	External Interference	EI - 3rd Party
2010-10-25	External Interference	EI - 3rd Party
2010-10-28	External Interference	EI - 3rd Party
2010-10-29	External Interference	EI - 3rd Party
2010-10-29	External Interference	EI - 3rd Party
2010-10-31	External Interference	EI - 3rd Party
2010-11-03	External Interference	EI - 3rd Party
2010-11-03	External Interference	EI - 3rd Party
2010-11-04	External Interference	EI - 3rd Party
2010-11-16	Incorrect Operation	IO - Improper Operation
2010-11-19	External Interference	EI - 1st or 2nd Party
2010-11-24	External Interference	EI - 1st or 2nd Party
2010-12-06	External Interference	EI - 3rd Party
2010-12-06	External Interference	EI - 3rd Party
2010-12-15	External Interference	EI - 3rd Party
2010-12-16	External Interference	EI - 3rd Party
2011-01-17	External Interference	EI - 1st or 2nd Party
2011-01-18	External Interference	EI - 1st or 2nd Party
2011-01-19	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2011-01-20	External Interference	EI - 3rd Party
2011-01-24	Corrosion / Degradation	CD - Metal Cracking
2011-01-24	Corrosion / Degradation	CD - Metal Loss
2011-01-25	External Interference	EI - 3rd Party
2011-01-25	External Interference	EI - 3rd Party
2011-02-04	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2011-02-04	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction

2011-02-04	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2011-02-09	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2011-02-09	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2011-02-11	Incorrect Operation	IO - Improper Operation
2011-02-13	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2011-02-17	Corrosion / Degradation	CD - Metal Cracking
2011-02-17	External Interference	EI - 3rd Party
2011-02-18	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2011-02-18	Corrosion / Degradation	CD - Metal Cracking
2011-02-19	External Interference	EI - 3rd Party
2011-02-21	External Interference	EI - 3rd Party
2011-02-28	Incorrect Operation	IO - Improper Operation
2011-03-05	External Interference	EI - 1st or 2nd Party
2011-03-07	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2011-03-07	External Interference	EI - 3rd Party
2011-03-09	External Interference	EI - 3rd Party
2011-03-09	External Interference	EI - 3rd Party
2011-03-16	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2011-03-17	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2011-03-17	Incorrect Operation	IO - Improper Operation
2011-03-21	External Interference	EI - 3rd Party
2011-03-29	Equipment Malfunction	EM - Valve Malfunction
2011-03-31	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2011-04-03	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2011-04-04	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2011-04-05	Corrosion / Degradation	CD - Metal Cracking
2011-04-11	External Interference	EI - 3rd Party
2011-04-12	External Interference	EI - 3rd Party
2011-04-13	External Interference	EI - 3rd Party
2011-04-25	External Interference	EI - 3rd Party
2011-04-26	Corrosion / Degradation	CD - Metal Cracking
2011-04-26	Corrosion / Degradation	CD - Metal Cracking
2011-04-26	External Interference	EI - 3rd Party
2011-04-28	External Interference	EI - 3rd Party
2011-05-02	External Interference	EI - 3rd Party
2011-05-03	External Interference	EI - 3rd Party
2011-05-11	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2011-05-11	External Interference	EI - 3rd Party
2011-05-12	Corrosion / Degradation	CD - Metal Cracking
2011-05-12	External Interference	EI - 3rd Party
2011-05-13	External Interference	EI - 3rd Party
2011-05-13	External Interference	EI - 3rd Party
2011-05-13	External Interference	EI - 1st or 2nd Party
2011-05-14	External Interference	EI - 3rd Party
2011-05-17	External Interference	EI - 3rd Party
2011-05-17	External Interference	EI - 3rd Party
2011-05-21	Material, Manufacturing or Construction Defect	MMC - Defective Joining Method
2011-05-24	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2011-05-24	External Interference	EI - 3rd Party
2011-05-25	Equipment Malfunction	EM - Valve Malfunction
2011-05-26	External Interference	EI - 3rd Party
2011-05-28	Corrosion / Degradation	CD - Metal Cracking
2011-06-07	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2011-06-07	External Interference	EI - 3rd Party
2011-06-08	Incorrect Operation	IO - Improper Operation
2011-06-09	Corrosion / Degradation	CD - Metal Cracking

2011-06-09	External Interference	EI - 3rd Party
2011-06-14	Material, Manufacturing or Construction Defect	MMC - Defective Joining Method
2011-06-14	External Interference	EI - 3rd Party
2011-06-15	External Interference	EI - 3rd Party
2011-06-15	External Interference	EI - 3rd Party
2011-06-15	External Interference	EI - 3rd Party
2011-06-20	External Interference	EI - 3rd Party
2011-06-21	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2011-06-23	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2011-06-23	External Interference	EI - 3rd Party
2011-06-24	Corrosion / Degradation	CD - Metal Loss
2011-06-24	External Interference	EI - 3rd Party
2011-06-26	Unable to Classify	Unable to Classify
2011-06-27	Corrosion / Degradation	CD - Metal Loss
2011-06-28	Corrosion / Degradation	CD - Metal Loss
2011-06-28	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2011-06-29	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2011-06-30	External Interference	EI - 3rd Party
2011-06-30	External Interference	EI - 3rd Party
2011-07-03	Corrosion / Degradation	CD - Metal Loss
2011-07-04	External Interference	EI - 3rd Party
2011-07-05	External Interference	EI - 3rd Party
2011-07-07	External Interference	EI - 1st or 2nd Party
2011-07-07	External Interference	EI - 1st or 2nd Party
2011-07-08	Corrosion / Degradation	CD - Metal Loss
2011-07-08	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2011-07-18	External Interference	EI - 3rd Party
2011-07-20	Material, Manufacturing or Construction Defect	MMC - Defective Joining Method
2011-07-21	External Interference	EI - 3rd Party
2011-07-22	External Interference	EI - 3rd Party
2011-07-22	External Interference	EI - 3rd Party
2011-07-25	Corrosion / Degradation	CD - Metal Loss
2011-07-25	External Interference	EI - 3rd Party
2011-07-26	External Interference	EI - 3rd Party
2011-07-27	Equipment Malfunction	EM - Valve Malfunction
2011-07-27	External Interference	EI - 3rd Party
2011-07-28	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2011-07-28	External Interference	EI - 3rd Party
2011-07-28	External Interference	EI - 3rd Party
2011-08-02	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2011-08-03	External Interference	EI - 3rd Party
2011-08-04	External Interference	EI - 3rd Party
2011-08-05	External Interference	EI - 3rd Party
2011-08-08	Corrosion / Degradation	CD - Metal Loss
2011-08-08	Incorrect Operation	IO - Improper Operation
2011-08-08	External Interference	EI - 3rd Party
2011-08-09	External Interference	EI - 3rd Party
2011-08-09	External Interference	EI - 3rd Party
2011-08-10	Corrosion / Degradation	CD - Metal Cracking
2011-08-11	External Interference	EI - 3rd Party
2011-08-12	Incorrect Operation	IO - Improper Operation
2011-08-13	External Interference	EI - 3rd Party
2011-08-16	External Interference	EI - 3rd Party
2011-08-16	External Interference	EI - 3rd Party
2011-08-16	Incorrect Operation	IO - Improper Operation
2011-08-17	External Interference	EI - 3rd Party

2011-08-22	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2011-08-22	Corrosion / Degradation	CD - Metal Loss
2011-08-22	External Interference	EI - 3rd Party
2011-08-22	External Interference	EI - 3rd Party
2011-08-24	Corrosion / Degradation	CD - Metal Loss
2011-08-24	External Interference	EI - 3rd Party
2011-08-24	External Interference	EI - 3rd Party
2011-08-25	Corrosion / Degradation	CD - Metal Cracking
2011-08-25	External Interference	EI - 3rd Party
2011-08-26	Corrosion / Degradation	CD - Metal Loss
2011-08-26	Corrosion / Degradation	CD - Metal Cracking
2011-08-29	Corrosion / Degradation	CD - Metal Loss
2011-08-29	External Interference	EI - 3rd Party
2011-08-30	External Interference	EI - 3rd Party
2011-08-31	External Interference	EI - 3rd Party
2011-09-09	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2011-09-09	External Interference	EI - 3rd Party
2011-09-09	External Interference	EI - 1st or 2nd Party
2011-09-09	External Interference	EI - 1st or 2nd Party
2011-09-13	Incorrect Operation	IO - Improper Operation
2011-09-19	Incorrect Operation	EI - 3rd Party
2011-09-23	Incorrect Operation	EI - 3rd Party
2011-09-23	External Interference	EI - 3rd Party
2011-09-27	Corrosion / Degradation	CD - Metal Cracking
2011-09-30	Incorrect Operation	EI - 3rd Party
2011-10-04	Incorrect Operation	IO - Improper Operation
2011-10-06	External Interference	EI - 3rd Party
2011-10-07	External Interference	EI - 3rd Party
2011-10-11	Incorrect Operation	IO - Improper Operation
2011-10-12	External Interference	EI - 3rd Party
2011-10-16	External Interference	EI - 3rd Party
2011-10-17	Incorrect Operation	IO - Improper Operation
2011-10-21	Corrosion / Degradation	CD - Metal Loss
2011-10-21	Corrosion / Degradation	CD - Metal Cracking
2011-10-24	Corrosion / Degradation	CD - Metal Cracking
2011-10-24	External Interference	EI - 3rd Party
2011-10-26	External Interference	EI - 3rd Party
2011-10-28	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2011-10-28	External Interference	EI - 3rd Party
2011-11-01	Corrosion / Degradation	CD - Metal Cracking
2011-11-03	External Interference	EI - 3rd Party
2011-11-03	External Interference	EI - 3rd Party
2011-11-03	External Interference	EI - 3rd Party
2011-11-05	External Interference	EI - 3rd Party
2011-11-07	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2011-11-07	Material, Manufacturing or Construction Defect	MMC - Other Improper Construction
2011-11-14	Equipment Malfunction	EM - Mechanical Fitting Malfunction
2011-11-17	External Interference	EI - 3rd Party
2011-11-21	External Interference	EI - 3rd Party
2011-11-22	External Interference	EI - 3rd Party
2011-11-23	External Interference	EI - 3rd Party
2011-12-02	Unable to Classify	Unable to Classify
2011-12-15	External Interference	EI - 3rd Party
2011-12-20	External Interference	EI - 3rd Party
2011-12-28	Material, Manufacturing or Construction Defect	EM - Valve Malfunction

REFERENCE:

Attachment 3, PUB Completeness Review

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please confirm that the type of units displayed on the Risk Matrix graphs and legends on p 3.
b) Please describe the manner in which the results of the 2017 Pipeline Risk Assessment have informed the engineering and system planning work at Centra for the Test Year and beyond.
c) Please also confirm whether Centra's / Manitoba Hydro's Executive Team and/or Board have reviewed the document. If so, please list any resolutions or other forms of formal feedback and recommendations to Management in relation to the report and/or its underlying methodology.

RESPONSE:

a) The units for frequency are 'incidents / 1000 kmyr'. The characteristics of the frequency score are described on page 12 Table 1. The units for consequence are 'units / incident'. The characteristics of the consequence score are described in page 13 Table 2.

b) Centra's Pipeline Risk Assessment Program results have not yet identified projects to replace and/or decommission an asset. It has been used to better understand the pipeline segments that the model identifies as higher risk and support/validate some of the risk control operating decisions. As explained in Tab 4 under Centra's Asset Management roadmap plan, work is planned in 2019/20 to evaluate options and where considered appropriate to develop plans for the relatively highest risk pipeline segments.

c) The report has been shared and communicated with the Directors and key Managers within the Engineering & Construction and Customer Service Operations Divisions responsible for gas assets. There have not been any formal recommendations in relation to the 2017 Pipeline Risk Assessment report. In terms of the underlying methodology, the Corporation's direction consists of centralizing asset management governance and implementing mature and consistent asset management practices across the Corporation. This includes developing risk assessment methodologies that will support the Reliability-Centered Maintenance approach.

REFERENCE:

Tab 4, Appendices

PREAMBLE TO IR (IF ANY):

QUESTION:

Please describe in detail the analytical and planning process that took place to develop the 2018-2023 Asset Management / Investment Plan contained in Appendix 4.3.

i. Please describe the nature and sequencing of each step performed by the engineering, asset management, operations, procurement, finance, and other Centra professionals between reviewing the raw input information and delivering the final product.
ii. Please specify the steps of approvals process that the plan underwent.
iii. Please discuss how the overall target figures for the plan were developed.

RESPONSE:

i. The 2018-2023 Natural Gas Asset Management Capital Investment Plan is a document that reports on the gas capital requirements and capital plans for each section, department or division. The document is an assembly of the information prepared by these individual groups rather than the process for developing this information. The document reports on information on programs and projects which are approved through the capital financial approval process.

ii. All individual programs and projects are approved individually following the approval process appropriate for the value of the expenditure. The plan itself is prepared by the Gas Engineering & Construction Department, reviewed and approved by the Manager of Gas Engineering and Construction, then reviewed and approved by the Director of Engineering and Construction.

iii. Please see the response to PUB/CENTRA I-66a.

REFERENCE:

Tab 1, Letter of Application, page 2 of 3, h, and Tab 9, page 3 of 23, [redacted]

PREAMBLE TO IR (IF ANY):

Centra is seeking approval of certain proposed storage and transportation costs to be effective April 1, 2020 as discussed in Tab 9 of the Application

QUESTION:

[redacted]

RESPONSE:

a) [redacted]

Response to b) & c):

[redacted]

REFERENCE:

Tab 8, page 4 and 5 of 52 "Centra Supply"

PREAMBLE TO IR (IF ANY):

"Centra purchased the majority of its Primary Gas at the AECO hub and at the Alberta border ("Empress") under a two-year gas supply contract with ConocoPhillips Canada Marketing and Trading ULC ("ConocoPhillips") from November 1, 2016 to October 31, 2018."

"Earlier in 2018, Centra concluded its Western Canadian gas supply RFP process for the period November 1, 2018 through October 31, 2020. ConocoPhillips was the successful proponent."

QUESTION:

a) Provide a copy of Centra's RFP for Primary gas supply for the 2016/2018 period.
b) Provide a copy of Centra's RFP for Primary gas supply for the 2018/2020 period
c) If there are differences between the 2016/2018 and 2018/2020 RFP, provide a detailed explanation as to any differences?
d) Why was a 2-year period selected and where there any other timeframes beyond the 2-year period considered by Centra?
e) Provide a copy of the 2016/2018 gas supply contact?
f) Provide a copy of the 2018/2020 gas supply contract?
g) Provide a detailed comparison between the 2016/2018 and 2018/2020 gas supply contracts with ConocoPhillips?
h) Provide all analysis and evaluations undertaken by Centra in the selection of ConocoPhillips?
i) Did Centra retain any independent consultants in the analysis and evaluation in the selection of ConocoPhillips?
j) How many other gas suppliers responded to the 2016/2018 RFP for Primary Gas?
k) How many other gas suppliers responded to the 2018/2020 RFP for Primary Gas?
l) Does Centra have any gas purchase arrangements with parties regarding US gas purchases and if so, provide copies of any contract arrangements? If not, which department is responsible for the US gas purchases?

RESPONSE:

Response to a) & b):

Please see the response to PUB I-109 a).

c) [redacted] 1a

Given the prevalence of NGTL restrictions affecting nominations to Empress since 2017, [redacted] In light 1a of these restrictions and the changed market conditions affecting Empress[1], [redacted].

d) Centra selected a two-year period [redacted] 1c

[1] Discussed in Tab 8, page 5 of 52, lines 19-26.
[redacted] 1a

e) and f)

The gas supply contract contains specific pricing details, and Conoco has advised Centra that it is not willing to disclose the contract to any party other than the PUB due to its commercial sensitivity. Conoco has expressed that, notwithstanding confidentiality agreements, [redacted]. 2b

In addition to Conoco's objection to the release of the specific pricing details of the contract, Centra notes the following concerns:

i. The review of the specific pricing details of the supply contract have previously been reviewed and approved in accordance with the well-established PUB process since 2010, with the contract being filed in strict confidence with the PUB only. The public review process has involved reviewing Centra's forecast and actual supply costs under the contract in aggregate, along with numerous information requests with respect to non-price related contract details. In addition, the responses to PUB/Centra I-109 e) and f) provide forecast Primary Gas costs at Empress for each proponent bid received by Centra in relation to the 2016-18 and 2018-2020 RFPs.

ii. [redacted]. Potential counterparties expect confidential treatment of the contract as set forth in the natural gas industry standard NAESB base contract. Disclosure of specific pricing details of the contract to parties other than the PUB could impair future RFP response rates and prejudice future negotiations which ultimately may harm Centra's customers. 1c

g) Please see the responses to PUB/CENTRA I-109d and g.

h) Please see the response to PUB/CENTRA I-109b, e and f.

i) No, the analysis and evaluation was conducted internally.

j) and k)

Please see the response to PUB/CENTRA I-109b.

l) [redacted] Centra does not share transaction-specific details, and Centra does not have consent from this counterparty to share transactional information which is proprietary, competitive, and commercially sensitive. 1a

The Gas Supply function within Centra is responsible for all gas purchases, U.S. or otherwise.

REFERENCE:

Tab 8, page 5 of 52

PREAMBLE TO IR (IF ANY):

"The result is an increase in the market value of existing NGTL transportation to Empress, …"

QUESTION:

a) What is the difference between NGTL's Firm Transportation-Delivery toll and the market value of AECO to Empress transportation?
b) Provide all analysis and a detailed explanation to support the "an increase in the market value of existing NGTL Transportation to Empress"?
c) How is the market value of NGTL transportation established?
d) Provide a detailed description of how tolls are established on the NGTL system?
e) When was the last time the NEB conducted a detailed toll design proceeding regarding the establishment of NGTL tolls?
f) When is the lag in the availability of NGTL capacity to connect north-western Alberta and north-eastern BC gas supplies expected to be resolved?
g) Provide a list of all NGTL facilities applications before the NEB related to the connection of the northern gas supplies?
h) Now that Centra is a shipper on NGTL, has or is Centra planning to intervene in NGTL facilities applications? If so, provide all of Centra's filing before the NEB regarding any of NGTL facility applications?

RESPONSE:

a) and b)
Please see PUB/CENTRA I-116a and PUB/CENTRA I-123b.

c) The market value of any transportation path is established by trading between buyers and sellers, each seeking to maximize their own respective value on each individual transaction.

d) On a yearly basis, NGTL determines its Total Revenue Requirement. The non-transportation and full-path revenue are subtracted from that amount to determine the Net Transportation Revenue Requirement. The receipt and delivery metering revenue is then subtracted to determine the Net Transmission Revenue Requirement. This amount is split equally between Receipt and Delivery and the separate metering costs are added back to form the Receipt Revenue Requirement and the Delivery Revenue Requirement. Discretionary revenue (i.e. interruptible and short-term firm-transportation) is subtracted from these amounts and separate firm receipt and firm delivery tolls are calculated. NGTL's tolls must be approved by the NEB.

e) NGTL has been regulated by the NEB since April 29, 2009. A toll design proceeding has not been conducted since then. The current rate design methodology was filed as a settlement on November 27, 2009 and approved by the NEB on August 12, 2010. Please also see the response to CAC/CENTRA I-102a and b.

f) There is a lag in the availability of NGTL capacity to connect supply in north-western Alberta and north-eastern B.C. to the East Gate of the NGTL System (which includes Empress) and other export and intra-Alberta delivery locations. NGTL has been expanding its system over the past number of years and estimates that another $8.6 billion will be spent between 2019 and 2022 on various projects. NGTL expansion plans beyond that date are unknown.

g) The following NGTL facilities applications related to the connection of the north-west Alberta and north-east B.C. supplies are currently before the NEB:

- West Path Delivery Project (approved April 2019)
- 2021 NGTL System Expansion Project
- McLeod River North Project
- Buffalo Creek B2 and Goodfish A2 Compressor Station Unit Addition
- North Central Corridor Loop (North Star Section 1)
- Edson Mainline Expansion Project
- North Corridor Expansion Project

h) Centra has intervened in the following NGTL facility applications for the purpose of monitoring the proceedings and obtaining all information related to the applications:

- 2017 NGTL System Expansion Project
- 2016 Meter Station and Laterals Abandonment Program
- Peace River Mainline Abandonment Project
- North Montney Mainline Variance
- 2021 NGTL System Expansion Project

Centra has also monitored other facility applications by simply checking the NEB's inbox on a daily basis.

REFERENCE:

Tab 8, page 6 of 52, Figure 8.3

PREAMBLE TO IR (IF ANY):

QUESTION:

a) In Centra's opinion why has the number of marketer supply customers declined from November 1, 2015 to November 1, 2017, provide a detailed explanation?
b) Has this declined continued effective November1, 2018?

RATIONALE FOR QUESTION:

To better understand Figure 8.3

RESPONSE:

a) Centra is not able to speculate as to the reason(s) that fewer customers have elected to have their Primary Gas supplied by marketers under the Western Transportation Service ("WTS") in recent years.

b) Yes, WTS customer numbers have continued to decline. The number of WTS customers is 6,700 as of November 1, 2018.

   Centra would also like to take the opportunity to correct its evidence regarding the number of WTS customers (Tab 8, page 6 of 52, Figure 8.3). The following chart provides corrected customer counts (denoted in red font) as of November 1 for each of 2015, 2016 and 2017, as well as the number of WTS customers as of November 1, 2018:

Customers and Primary Gas MDQ for WTS		
	Number of Customers	Maximum Daily Quantity (GJ/day)
November 1, 2015	14,800	13,164
November 1, 2016	11,600	11,225
November 1, 2017	8,900	10,355
November 1, 2018	6,700	8,787

REFERENCE:

Tab 8, page 8 of 52, Gas Management Agreement with SaskEnergy

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Provide a copy of the gas management agreement with SaskEnergy?

b) Is Centra required to hold transportation capacity on the TransGas and Many Islands pipelines and if so, provide copies of Centra's transportation agreements with these two pipeline companies?

c) How is the price of natural gas established for the natural gas that is purchased by Centra?

RATIONALE FOR QUESTION:

To ensure a complete understanding of the gas management agreement with SaskEnergy

RESPONSE:

a) Centra does not share transaction-specific details, and Centra does not have consent from this counterparty to share transactional information which is proprietary, competitive, and commercially sensitive.

b) Under Centra's gas management agreement with SaskEnergy, [redacted] 1a

c) Please see part a) above.

REFERENCE:

Tab 8, page 9 of 52 NGTL (Transportation) and TCPL Mainline (Transportation)

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Provide list and copies of all executed transportation contacts with TCPL Mainline?
b) Provide list and copies of all executed transportation contracts with NGTL?

RATIONALE FOR QUESTION:

To ensure CAC has all the relevant pipeline transportation agreements and contracts.

RESPONSE:

a) Please see Attachment 1 to this response for a list of Centra's TCPL Mainline contracts. The following are links to the TCPL Mainline's Firm Transportation ("FT") and Interruptible Transportation ("IT") pro-forma contracts that are representative of the contracts executed by Centra and TCPL:
   - FT: http://www.tccustomerexpress.com/docs/ml_regulatory_tariff/36_FT_Contract.pdf
   - IT: http://www.tccustomerexpress.com/docs/ml_regulatory_tariff/22_IT_Contract_NEB_2007_07_19.pdf

   Please see Attachment 2 to this response for a copy of Centra's Storage Transportation Service ("STS") contract with TCPL. Centra's FT and STS contract renewals are performed electronically, whereas Centra's IT contract remains in effect until terminated by either party.

b) Please see Attachment 3 to this response for a list of Centra's contracts with NGTL. Please see Attachment 4 to this response and the attachment to CAC/CENTRA I-98a for the executed agreements.

Centra Gas Manitoba Inc.
2019/20 General Rate Application

Contract Number	Service Requester	Contract Expiry Date	Service Type	Primary Receipt	Primary Delivery	Contract Demand (GJ/d)
37575	Centra Gas Manitoba Inc.	2021-Oct-31	FT	Empress	Centram MDA	90,000
47882	Centra Gas Manitoba Inc.	2021-Oct-31	FT	Empress	Centram MDA	15,000
52663	Centra Gas Manitoba Inc.	2021-Oct-31	FT	Empress	Centram MDA	20,000
54691	Centra Gas Manitoba Inc.	2021-Oct-31	FT	Empress	Centram MDA	15,000
57571	Centra Gas Manitoba Inc.	2021-Oct-31	FT	Empress	Centram MDA	20,000
[redacted]	Centra Gas Manitoba Inc.	[redacted]	FT	Empress	Centram MDA	[redacted] 1a
3036	Centra Gas Manitoba Inc.	2021-Oct-31	FT	Empress	Centram SSDA	1,200
47883	Centra Gas Manitoba Inc.	2021-Oct-31	FT	Empress	Centram SSDA	2,000
44646	Centra Gas Manitoba Inc.	2021-Oct-31	FT	Emerson 2	Centram MDA	20,625
44686	Centra Gas Manitoba Inc.	2021-Oct-31	FT	Emerson 2	Centram MDA	375
47199	Centra Gas Manitoba Inc.	2021-Oct-31	FT	Emerson 2	Centram MDA	48,750
56658	Centra Gas Manitoba Inc.	2021-Oct-31	FT	Empress	Centrat MDA	90
2771	Centra Gas Manitoba Inc.	2022-Mar-31	STS	MDA	Emerson	54,000
16699	Centra Gas Manitoba Inc.	Auto-renewing	IT	Various	Various	Up to FT quantity

Centra Gas Manitoba Inc.
2019/20 General Rate Application

Contract Number	Service Requester	Contract Expiry Date	Service Type	Primary Delivery	Contract Demand (GJ/d)
[redacted]	Centra Gas Manitoba Inc.	[redacted]	FT-D	Empress	[redacted] 1a
[redacted]	Centra Gas Manitoba Inc.	[redacted]	FT-D	Empress	[redacted] 1a

REFERENCE:

Tab 8, page 10 of 52, Centra Transmission Holdings Inc. (“CTHI”)

PREAMBLE TO IR (IF ANY):

“Centra holds corresponding firm annual capacity on CTHI to serve this customer (R.M. of Piney).”

QUESTION:

Provide a copy of the firm service capacity agreement with CTHI?

RESPONSE:

Please see the attachment to this response. This attachment contains commercially sensitive information and is being filed confidentially.

REFERENCE:

Tab 8, page 10 of 52

PREAMBLE TO IR (IF ANY):

"Centra's forecast transportation load factor from Western Canada for the 2018/2019 Gas Year is approximately [redacted] compared to a forecast sales load factor of approximately [redacted]." 1d

QUESTION:

Provide a list and detailed description of programs or methods Centra has or is planning to undertake to improve its transportation load factor from Western Canada?

RESPONSE:

Although the sales (i.e., annual consumption) load factor of Centra's market is [redacted], Centra's integrated portfolio of transportation and storage assets allows Centra to achieve a forecast annual transportation load factor from Western Canada of [redacted] in a normal weather year. 1d To the extent that Centra's TCPL Mainline transportation from Empress is not fully utilized in serving market demand or storage refill requirements, Centra executes Capacity Management transactions (as discussed in section 8.2.1 of Tab 8), [redacted]. 1c

REFERENCE:

Tab 8, page 12 of 52, lines 1 to 12

PREAMBLE TO IR (IF ANY):

"The storage refill is accomplished utilizing the following transportation contracts:"

QUESTION:

Provide a table listing the transportation contract load factors for each of the transportation contracts listed for the years 2015 through to 2018 and any forecasts beyond 2018 that Centra may have developed?

RESPONSE:

The requested information can be found in Centra's Capacity Management reporting as found in Tab 8, Appendices 8.6 through 8.8 and which provide transportation load factors by path for the Gas Years of 2014/15 through 2016/17. Centra's 2017/18 Capacity Management reporting was completed since Centra's General Rate Application filed on November 30, 2018 and is filed as Appendix 8.9 to the Application.

Other than forecasting its transportation load factor from Western Canada[1], Centra does not forecast transportation load factors on other paths as they are largely weather-dependent in relation to storage utilization.

[1] Centra 2019/20 GRA, Tab 8, page 10 of 52, line 19

REFERENCE:

Tab 8, page 14 of 52, lines 17 to 25

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Provide all background and information, including [redacted]

b) Provide all information supporting the statement [redacted]

c) Provide a detailed explanation as to why would [redacted] 1c

[redacted] Has Centra submitted or presented its concerns [redacted]

RATIONALE FOR QUESTION:

To better understand the rationale for the contracting of capacity on TCPL Mainline.

RESPONSE:

a) [redacted] 1c

[redacted]

b) and c)

[redacted] 1c

[redacted]

d) [redacted]

[redacted]

[redacted]

1c

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

REFERENCE:

Tab 8, page 14 and 15 of 52

PREAMBLE TO IR (IF ANY):

NGTL Contracted Capacity

QUESTION:

a) Provide a copy of the NGTL agreement for the [redacted] incremental capacity on NGTL? 1a
b) Is this capacity a Delivery Capacity contract at Empress?
c) Has a cost of this incremental capacity been determined by Centra, and if so, provide?
   i. Unit cost per GJ?
   ii. Annual Costs?
d) Provide a detailed explanation and all supporting documentation as to how was the [redacted] contract length determine for the incremental capacity? 1a

RESPONSE:

a) Please see the attachment to this response for a copy of the agreement. This attachment contains commercially sensitive information and is being filed confidentially

b) Yes, this is a Delivery contract (FT-D) to the Empress Border.

c) The values below have been calculated using the 2019 final delivery point rates and 2019 interim abandonment surcharge.
   i. The unit cost to Centra for the incremental NGTL capacity based on the current NGTL toll would be \$0.1808/GJ (including the \$0.0095/GJ abandonment surcharge and term-differentiated discount[1]). However, the in-service date for this incremental capacity is [redacted]. 1a

[1] For terms of 5 years or greater, FT-D contracts are tolled at 90% of the 1-2 year FT-D toll. For terms of 3-4 years FT-D contracts are tolled at 95% of the 1-2 year FT-D toll.

ii. The estimated annual cost to Centra for the incremental [redacted] of capacity is [redacted] (based on NGTL's current term-differentiated toll levels and including the abandonment surcharge of [redacted]). 1a

d) The minimum term for expansion capacity on NGTL is eight years. As part of the open season, NGTL advised that bids would be evaluated solely on the requested term length. Given the high demand for firm transportation to NGTL's East Gate, Centra [redacted] 1c

Also, Centra was aware that an earlier open season for capacity to NGTL's West Gate saw bids of more than 15 years to secure capacity. Accordingly, [redacted] 1c [redacted]. Ultimately, the average 1a term of awarded expansion capacity was 25.6 years and all available capacity was fully subscribed in the open season.

REFERENCE:

Tab 8, page 16 of 52, lines 27 to 29

PREAMBLE TO IR (IF ANY):

QUESTION:

Provide a copy of or detailed description of Centra's credit requirements?

RATIONALE FOR QUESTION:

To better understand Centra's Capacity Management Program ("CM")

RESPONSE:

Centra's current credit requirements are as follows:

- Counterparties must have agreed to a North American Energy Standards Board (NAESB) agreement with Centra prior to transacting;
- Counterparties must have an investment grade credit rating from one of Standard & Poor's, Moody's or DBRS; or unrated counterparties (or those rated below investment grade) must post collateral in a form acceptable to Centra;
- Counterparties are awarded unsecured credit on a sliding scale based on credit rating;
- Acceptable forms of collateral are Parental Guarantee from an investment grade rated parent company or Letter of Credit from an "A" rated financial institution;
- Should the credit requirement of a transaction exceed the remaining unsecured/secured credit limit for a counterparty, additional collateral must be posted.

REFERENCE:

Tab 8, page 16 of 52 -- 2017 settlement between and its shippers

PREAMBLE TO IR (IF ANY):

"A settlement between GLGT and its shippers related to a FERC rate case filed by GLGT was reached in 2017 …"

QUESTION:

a) Did Centra participate in the 2017 GLGT settlement between GLGT and its shippers?
   i. If not, why not?
b) Provide a copy of the settlement agreement between GLGT and its shippers?

RESPONSE:

a) Yes, Centra participated in the referenced settlement process.

b) The Stipulation and Agreement of Settlement between GLGT and the settling parties can be viewed on GLGT's website, the link to which is provided below:

   http://www.glgt.com/infopostings/tariff/pdf/GLGT%20Settlement%20Filing.pdf

REFERENCE:

Tab 8, page 19 of 52, lines 3 to 5 and lines 7 to 9

PREAMBLE TO IR (IF ANY):

"The majority of the natural gas supply used to serve Centra's franchise territory comes from the Western Canadian Sedimentary Basin and is transported by way of the NGTL system and the TCPL Mainline." and "The TCPL Mainline physically transports all-natural gas supplies that are consumed in Centra's service territory."

QUESTION:

a) What is the minority natural gas supply used to serve Centra's franchise territory?
b) Regarding the physical flows on TransCanada Mainline, is Centra referring to transportation between Empress and the Centra's franchise region and Emerson to Centra's franchise region?
c) Provide a yearly historical comparison from 2013 to 2018 as to the physical deliveries on the TransCanada Mainline system between Empress and Centra's franchise region and between Emerson and Centra's franchise region?

RESPONSE:

a) Please see Tab 8, page 7 of 52, lines 1-23 regarding Supplemental Gas.

b) Yes.

c) Although all gas is physically delivered to Centra's system from the TCPL Mainline, data is not available on whether or what volumes of gas may have physically originated at Emerson and been physically delivered to Centra's system. In practice, pipeline systems are operated in an integrated manner and shippers' nominations of contracted transportation paths may or may not physically flow according to the contract path. The pipeline is nonetheless responsible for ensuring that contractual delivery commitments are met, whether by physical flows that match shippers' contracted transportation paths or by displacement. Please also see the responses to CAC/CENTRA I-107 and CAC/CENTRA I-108.

REFERENCE:

Tab 8, Page 19 of 52, lines 11 to 15

PREAMBLE TO IR (IF ANY):

"Centra participates on industry committees that monitor and participates in reviewing tolls, tariff, services, facilities and procedures on NGTL and the TCPL Mainline. A number of settlements have been reached and regulatory proceedings have taken place before the National Energy Board ("NEB") since 2015/2016 COG proceedings before the PUB."

QUESTION:

a) Provide a list of all settlement proceedings before the NEB regarding TCPL and NGTL since the 2015/2016 COG proceedings?
b) Provide a list of all settlement proceedings before the NEB regarding TCPL Mainline and NGTL that Centra's participated since the 2015/2016 COG proceedings?
c) What are these industry committees called and provide any formal or informal rules governing these industry committees?
d) If there are formal and informal rules governing these industry committees, has the NEB approved or commented on the rules and if so, provide the NEB copies of the NEB approvals or comments on the rules governing these industry committees?
e) Are there any restrictions as to what parties can participate industry committees such as governments or government agencies?
f) Is the list of participants publicly available, if so, provide the lists of participants for the TCPL Mainline and NGTL? If not, are there any published reasons as to why the list of participants not publicly available?

RESPONSE:

a) and b)

TCPL Mainline

No settlements have been reached on the Mainline since the 2015/2016 COG proceeding before the PUB. However there have been a number of Mainline regulatory proceedings before the NEB as follows:

- RH-001-2016: Application to Amend the Canadian Mainline Transportation Tariff (STS);
- RH-002-2017: Application for Herbert Long-Term Fixed Price Service;
- RH-003-2017: Application for Dawn Long-Term Fixed Price Service;
- RH-001-2018: Application for 2018-2020 Mainline Tolls; and
- RH-002-2018: Application for North Bay Junction Long-Term Fixed Price Service.

Centra participated as an intervenor in the aforementioned proceedings before the NEB.

NGTL

The following settlements were filed and approved by the NEB:

- 2016 and 2017 Revenue Requirement Settlement; and
- 2018 and 2019 Revenue Requirement Settlement.

Centra participated in the aforementioned settlement processes as a member of the Tolls, Tariff, Facilities and Procedures Task Force (“TTFP”) industry committee for the NGTL System.

NGTL filed a Rate Design and Services Application with the NEB on March 14, 2019. The Board has since decided to set this Application, including the contested settlement that led to it, down for a public hearing. Centra was approved by the NEB as an intervenor in this proceeding on April 26, 2019. Centra and other interested parties are now awaiting procedural direction from the NEB on this matter.

c) TCPL Mainline

The TCPL Mainline's industry committee is called the Mainline Tolls Task Force ("TTF"). The TTF Charter and Procedures are publicly available on TransCanada's website, links to which are below:

Charter:
http://www.tccustomerexpress.com/docs/ml_industry_committee/TTF%20Charter.pdf

Procedures:
http://www.tccustomerexpress.com/docs/ml_industry_committee/TTF%20Procedures.pdf

NGTL

NGTL's industry committee is called the Tolls, Tariff, Facilities and Procedures Task Force ("TTFP"). The TTFP procedures are publicly available on TransCanada's website, a link to which is below:

http://www.tccustomerexpress.com/docs/ab_industry_committee_ttfp/TTFP%20Procedures%20-%20ADOPTED%20May%2012,%202009.pdf

d) The TTF and TTFP rules are formalized in their respective procedures, provided in the response to part c) above. Centra is not aware if the NEB approved or commented on the rules.

e) Please see section 2.0 *Membership and Participation* in the TTF Procedures and section 4.0 *Membership* in the TTFP Procedures for restrictions on participation.

f) The TTF and TTFP lists of participants are not publicly available. As per section 3.0 *Confidentiality* of the TTF Procedures and section 6.0 *Without Prejudice* of the TTFP procedures, task force-related material is considered to be confidential and shall not be shared outside of those forums. The TTF and TTFP membership lists are considered to be task force-related materials, thus are confidential.

REFERENCE:

Tab 8, page 20 of 52, TCPL Mainline Tolls

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Regarding the NEB RH-001-2018 proceeding:
   i. Provide a copy all submissions, evidence and filings by Centra, including any submissions by consultants retained by Centra?
   ii. Provide a copy of any interim or final decisions by the NEB.

b) Provide a list of all other toll settlements proceedings since the 2015/2016 COG proceedings for which Centra may not have agreed with the industry committees' recommendations and filed evidence before the NEB? If this has occurred, provide copies of all Centra's filings before the NEB, as well as the decisions of the NEB regarding Centra's filings.

RATIONALE FOR QUESTION:

To better understand Centra's positions regarding TCPL Mainline tolls since the 2015/2016 COG proceedings

RESPONSE:

a)
   i. The submissions of Centra and Drazen Consulting Group Inc. (Centra's consultant) related to the RH-001-2018 regulatory proceeding before the NEB can be found using the following link: https://apps.neb-one.gc.ca/REGDOCS/Item/View/3546815

   ii. The NEB's Letter Decision and related orders for the RH-001-2018 regulatory proceeding can be found using the following link: https://apps.neb-one.gc.ca/REGDOCS/Item/View/3723990

b) RH-001-2018 was the only regulatory proceeding related to Mainline toll settlements since the PUB's 2015/2016 COG proceeding. The regulatory proceedings related to Mainline services are described in the response to CAC/CENTRA I-102a and b.

REFERENCE:

Tab 8, page 21 of 52 Long-Term Fixed Price (LTFP") Services, NEB proceeding RH-003-2017

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Provide all documentation submitted by Centra in the RH-003-2017 proceeding, including written evidence, oral testimony, final arguments.
b) Given the NEB approved the TCPL Mainline application as filed:
   i. Does this mean in-path diversions to Emerson 2 will be disallowed?
   ii. Has Centra undertaken any studies or analysis on the effect of the NEB decision on Centra's ability to divert natural gas off the TCPL Mainline? Provide a full discussion on the possible risks to Manitoba natural gas customers if Centra's ability to divert natural gas off the TCPL Mainline system?

RATIONALE FOR QUESTION:

To better understand Centra's position in RH-003-2017 and the decision of the NEB

RESPONSE:

a) The Dawn LTFP Service (RH-003-2017) proceeding before the NEB was a written proceeding with oral final argument. Centra's written submissions related to this proceeding can be found using the following link:

   https://apps.neb-one.gc.ca/REGDOCS/Item/View/3224729

   The transcript of Centra's oral final argument can be found using the following link, paragraphs 845 – 1012 (PDF pages 7 - 30):

   https://apps.neb-one.gc.ca/REGDOCS/Item/View/3328147 b)

i. Dawn LTFP shippers cannot divert their contracts to any Mainline delivery points (i.e., neither in-path nor out-of-path diversions of Dawn LTFP capacity are permitted to Mainline delivery points including Emerson). The NEB approved this provision of TCPL's Dawn LTFP Service application in its RH-003-2017 decision.

ii. Centra's rights to divert its FT contracts and thus mitigate its unutilized demand charges ("UDC") are unaffected by the NEB's RH-003-2017 decision. It is Dawn LTFP shippers who cannot divert their contracts to Mainline delivery points. Please also see the response to PUB/CENTRA I-131a through c.

REFERENCE:

Tab 9, page 1 and 2 of 23

PREAMBLE TO IR (IF ANY):

[redacted]

QUESTION:

[redacted]

RESPONSE:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

REFERENCE:

Tab 9, page 3 of 23

PREAMBLE TO IR (IF ANY):

[redacted]

QUESTION:

[redacted]

RESPONSE:

a) to d)

[redacted]

e) to g)

[redacted]

h) [redacted]

REFERENCE:

Tab 9, page 5 of 23

PREAMBLE TO IR (IF ANY):

[redacted]

QUESTION:

[redacted]

RESPONSE:

[redacted]

[redacted]

REFERENCE:

Tab 9, page 5 of 23, lines 22 to 24

PREAMBLE TO IR (IF ANY):

[redacted]

QUESTION:

[redacted]

RESPONSE:

a) [redacted]

b) [redacted]

c) [redacted]

REFERENCE:

Tab 9, page 6 of 23[redacted]

PREAMBLE TO IR (IF ANY):

[redacted]

QUESTION:

a) [redacted]

b) [redacted]

c) [redacted]

d) [redacted]

e) [redacted]

f) [redacted]

g) [redacted]

RESPONSE:

a) and b)

[redacted]

c) [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]

REFERENCE:

Tab 9, page 7 of 23, Section 9.2.1 [redacted]

PREAMBLE TO IR (IF ANY):

[redacted]

QUESTION:

[redacted]

RESPONSE:

[redacted]

[redacted]

REFERENCE:

Tab 9, page 8 of 23, lines 21 to 24, Footnote 2, and Appendix 9.2(a)

PREAMBLE TO IR (IF ANY):

[redacted]

QUESTION:

[redacted]

RESPONSE:

a) [redacted]

b) [redacted]

c) [redacted]

d) [redacted]

[redacted]

REFERENCE:

Tab 9, page 10 of 23 [redacted]

PREAMBLE TO IR (IF ANY):

QUESTION:

[redacted]

RATIONALE FOR QUESTION:

[redacted]

RESPONSE:

a) [redacted]

b) [redacted]

[redacted]

c) [redacted]

[redacted]

REFERENCE:

Tab 9. page 15 and 16 of 23

PREAMBLE TO IR (IF ANY):

[redacted]

QUESTION:

a) [redacted]

b) [redacted]

c) [redacted]

RESPONSE:

a), b) and c)

[redacted]

REFERENCE:

Tab 9, page 18 of 23

PREAMBLE TO IR (IF ANY):

[redacted]

QUESTION:

a) [redacted]

b) [redacted]

c) [redacted]

d) [redacted]

RESPONSE:

a) [redacted]

b) [redacted]

c) [redacted]

d) [redacted]

[redacted]

REFERENCE:

Tab 9, page 18 of 23

PREAMBLE TO IR (IF ANY):

[redacted]

QUESTION:

[redacted]

RESPONSE:

a) and b)

[redacted]

REFERENCE:

Tab 9, page 18 and 19 of 23

PREAMBLE TO IR (IF ANY):

[redacted]

QUESTION:

a) [redacted]

b) [redacted]

RESPONSE:

a) [redacted]

b) [redacted]

REFERENCE:

Tab 9, page 19 of 23

PREAMBLE TO IR (IF ANY):

[redacted]

QUESTION:

[redacted]

RESPONSE:

a) [redacted]

[redacted]

b) to d)

[redacted]

[redacted]

e) [redacted] is

[redacted]

[redacted]

f) [redacted]

[redacted]

[redacted]

g) [redacted]

[redacted]

h) [redacted]

REFERENCE:

Tab 9

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Provide a history of Centra's utilization of contracted transportation capacity on the NGTL, TransCanada Mainline, ANR and GLGT for the periods 2013 through to 2018 including:
   i. Annual utilization
   ii. Annual costs

RATIONALE FOR QUESTION:

To better understand the utilization of existing transportation contracts on the various pipelines.

RESPONSE:

a) [redacted]

[redacted]

[redacted]

[redacted]

REFERENCE:

Appendix 9.4 [redacted]

PREAMBLE TO IR (IF ANY):

QUESTION:

a) [redacted]

b) [redacted]

RATIONALE FOR QUESTION:

[redacted]

RESPONSE:

a) [redacted]

b) [redacted]

REFERENCE:

Appendix 9.5 [redacted]

PREAMBLE TO IR (IF ANY)

QUESTION:

[redacted]

RATIONALE FOR QUESTION:

[redacted]

RESPONSE:

[redacted]

REFERENCE:

Supplement to Centra's 2019/20 General Rate Application – Tab 9 [redacted]

PREAMBLE TO IR (IF ANY):

QUESTION:

a) [redacted]
b) [redacted]
c) [redacted]

RATIONALE FOR QUESTION:

[redacted]

RESPONSE:

[redacted]

[redacted]

[redacted]