ENBRIDGE

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Enbridge Gas Inc.
500 Consumers Road
North York, Ontario M2J 1P8
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October 23, 2020

VIA EMAIL and RESS

Ms. Christine Long
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Long:

Re: Enbridge Gas Inc. (Enbridge Gas)
Ontario Energy Board (OEB) File: EB-2020-0136
NPS 20 Replacement Cherry to Bathurst – Interrogatory Responses

Further to the interrogatory responses filed by Enbridge Gas on October 21, 2020, enclosed please find the following outstanding responses.

- Exhibit I.ED.5
- Exhibit I.EP.2
- Exhibit I.EP.3
- Exhibit I.EP.8
- Exhibit I.EP.10
- Exhibit I.EP.12
- Exhibit I.EP.18
- Exhibit I.FRPO.5
- Exhibit I.PP.13
- Exhibit I.STAFF.3

Please contact the undersigned if you have any questions.

Yours truly,

(Original Digitally Signed)

Joel Denomy
Technical Manager, Regulatory Applications

ENBRIDGE GAS INC.
Answer to Interrogatory from
Environmental Defence (ED)

INTERROGATORY

Reference:

Exhibit B, Schedule 1, Pages 17-25

Question:

What is the threshold demand level at which an NPS 16 pipeline would be sufficient? Alternatively, if a single threshold demand level cannot be provided, please provide a number of scenarios wherein reduced demand would allow for an NPS 16 pipe. Please compare those demand levels with the current demand levels.

Response:

The Cherry to Bathurst section of the KOL forms a critical section of the HP pipeline grid that provides natural gas supply to downtown Toronto and surrounding area. Under normal operating conditions, an NPS 16 pipeline would be sufficient to supply the network with natural gas to supply current demand for temperatures down to the design degree day of -23°C or 41 degree days. However, as detailed at Exhibit B, Tab 1, Schedule 1 Pages 17 to 25, if pressures are not maintained then supply interruptions to customers could occur. In its filing, Enbridge Gas examined three scenarios: No Feed from MSL Line; No Feed From West Mall Feeder Station; and Isolation of DV Line. In all three scenarios, the downsizing of the C2B segment of the KOL was proved to be a non-viable option with current demand levels.

The analysis to determine the threshold demand level at which an NPS 16 pipeline would be sufficient is an iterative process that is time-intensive to complete. As such, Enbridge Gas only explored this analysis under one of the three scenarios noted above. The Isolation of the DV Line was chosen to complete this analysis because it was determined to be the most likely outage to occur, given that it has occurred on three separate occasions in recent years, whereas the other two scenarios (No Feed from the MSL Line and No Feed from West Mall Feeder Station) are potential, but hypothetical, situations. Refer to Exhibit I.ED.2.

If the DV Line was isolated on an 18 degree day (0°C), the current demand would have to be reduced by approximately 18% in order to ensure the continued supply of customers.[1] Enbridge Gas would like to underline that this assumed required reduction in natural gas consumption is only a high level approximation and not an exact figure. Much more detailed work would need to be done before Enbridge Gas could conclusively indicate what demand reductions are required to support an NPS 16 solution. Enbridge Gas has not completed any analysis to comprehensively identify which customers would necessarily be impacted by requiring their supply be reduced. As referenced in Exhibit I.ED.3, Enbridge Gas is unable to assume that future forecast reductions in natural gas demand will actually occur. Future natural gas demand growth will factor into implementing many of the emission reductions targets identified in Exhibit I.ED.3, and Enbridge Gas is unable to speculate at this time which customers would be identified as having their supplies reduced. Enbridge Gas's continued focus, as it is obligated to serve the firm demands of its customers, is to ensure it has the assets required to safely meet its customer's immediate and long-term demand requirements on an annual and Design Day and hourly basis and that remains its top priority.

The potential reduction in demand required to implement an NPS 16 solution would not have a corresponding meaningful reduction in project cost. Please refer to Exhibit I.FRPO.5 for cost estimate details. An NPS 16 solution would have the further disadvantage of impacting existing operational flexibility that is critical to maintain supply to the downtown core of Toronto during adverse operating conditions. A reduction in pipe size for this segment alone on the KOL line would also reduce Enbridge Gas's ability to implement a straightforward inline-inspection program on the KOL main should it choose to do so in the future. The existing pipeline has many unpiggable fittings on it currently, but Enbridge Gas's current design practices for Vital Mains require piggable fittings for any new installation. A pipeline constructed with different sizes negates this potential for single ILI runs, leading to increased future costs if an ILI program is developed for this pipeline in the future.

[1] The assumed 56,000m^3/h demand to be served would need to be reduced to 46050m^3/h. The required reduction in demand would be higher in colder conditions.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe (EP)

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, Page 1, paragraph 1

Preamble:

Energy Probe would like to understand how and why Enbridge management reached the decision to replace this particular section of KOL from Cherry Street to Bathurst Street.

Question**:**

a) On which date did Enbridge Gas management decide to replace this section of KOL?

b) Please provide the positions/titles of management staff who made the decision.

c) Please file the information that was presented to management staff in support of the decision including all presentations and reports.

Response:

a) to c) Enbridge Gas management formally endorsed this Project on September 20, 2019, with the VP, Engineering, signing off on the Project Charter. The Project Charter is set out at Attachment 1 to this response. However, this Project has been recognized by Enbridge Gas management as being a critical replacement project as early as 2016 (refer to Exhibit I.EP.3). The Project was also identified within the Asset Management Plan in 2018 (refer to Exhibit I.EP.3 and Exhibit I.EP.4). Enbridge Gas staff met with senior management multiple times between February-April 2019, where verbal approval was provided to commence the project management process. The Project progressed through the Screening stage, with a Decision Record to proceed to the Initiation stage being signed off by Enbridge Gas's VP, Engineering in parallel with the Project Charter on September 20, 2019. The Screening Decision Record is set out at Attachment 2 to this response. The Project received approval on October 31, 2019 from the Director, System

Improvement, to advance to the Design and Procurement stage. This Decision Record is set out at Attachment 3 to this response.

The Project Charter was signed off by the Manager, Capital Development & Delivery, the Director, System Improvement, and the VP, Engineering on September 20, 2019. The following table identifies the titles of all management that met about the Project from February-April, 2019.

MANAGERS/SPECIALISTS	DIRECTORS	VP & SVP
Manager Asset Classes	Director Asset Management	VP Engineering
Technical Manager Asset Management Major Pipelines	Director Major Projects & Planning	SVP Operations
Manager Integrity Assessment & Risk	Asset Class Director - Pipelines	
Asset Class Manager Pipelines	Toronto Regional Director	
Manager Capital Development & Delivery		
Specialist II Asset Management Major Projects		

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NPS 20 Replacement Cherry to Bathurst-Phase 1

Project # 20016967

Project Charter

Report

Document Owner: Melany Afara

DOCUMENT VERSION REGISTER

Version #	Version Date	Author / Department	• Change Area [Section and Title] ○ Change Description
1	April 9, 2019	M. Afara	○ Initial Document
2	June 10, 2019	M. Afara	○ Updated Business Need to include Inline Inspection, updated cost table
3	September5, 2019	M. Afara	○ Added information to Business Need

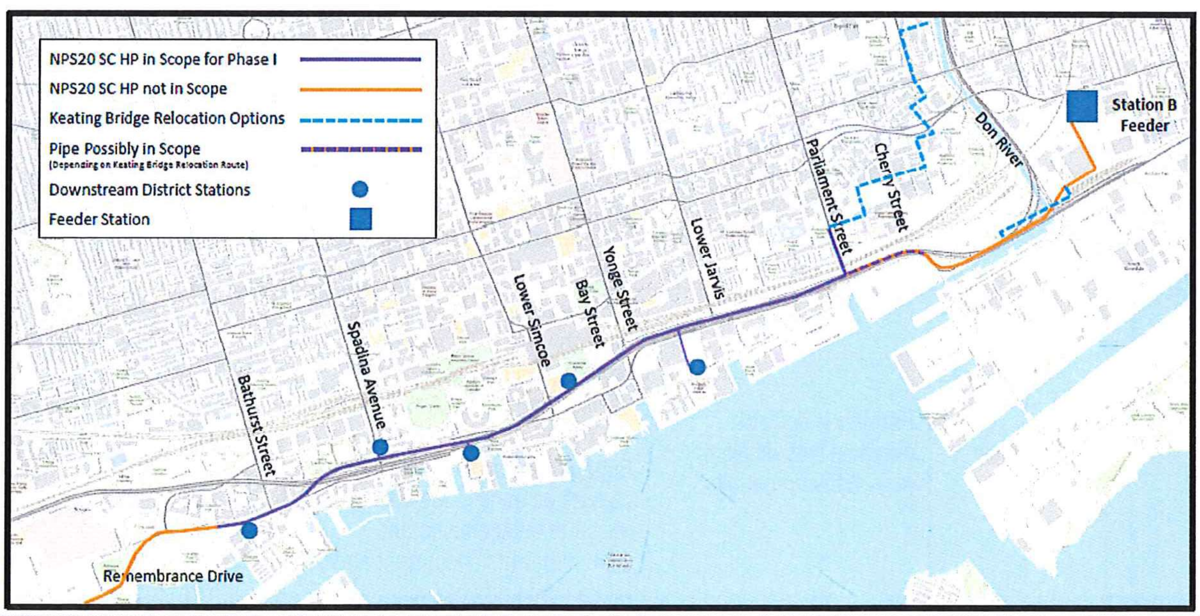
APPROVALS

Position	Name	Signature	Date
Manager Capital Development & Delivery, System Improvement	Byron Madrid	Byron Madrid	2019.09.16
Director System Improvement, Engineering	Neil MacNeil	Neil MacNeil	2019.09.19
VP Engineering, Utilities & Power Operations	Michelle George	Michelle George	2019.09.20

1 PROJECT OVERVIEW

Project Name:	NPS 20 Replacement – Phase 1 (Cherry to Remembrance)		
AFE Number	20016967	Sponsor	Tracey Teed Martin
Type of Project	Replacement	Project Manager	Melany Afara
Required In-Service Date	2021/2022	Customer(s)	N/A
Project Description	A size for size replacement of approximately 4.5 km of the existing NPS 20 HP steel natural gas main on Lake Shore Blvd. from Cherry Street to Remembrance Drive. Approximately 4.5 km of the existing NPS 20 HP will be abandoned. Construction Method: TBD A Leave to Construct (LTC) application may be required based on the requirement of new land and easements along the pipeline route.		
Business Need	The assessment of the vintage steel pipelines (installed in 1954) has indicated that the NPS 20 KOL line requires replacement due to pipeline condition. In 2016 and 2018, inline inspections (ILI) using a robotic crawler were performed on approximately 1.9 km of the 4.5 km of pipe selected for Phase 1. The 2016 ILI survey found 2 areas that required immediate rehabilitation activities via 2 Integrity digs. There are an additional 6 Integrity digs recommended over the next 10 years. The 2018 inspection identified 24 further dig locations that would require Integrity remediation over the next 10 years as per the guidance from CSA Z662. These digs are required to mitigate the corrosion and dent features that could exhibit more than 80% wall loss or have a high probability of failure, representing significant degradation of the pipe. Costs for such Integrity digs, based on the integrity digs in 2017 and 2018, range from $350,000 to $450,000 per integrity dig. This implies that over the next 10 years EGI could be expected to spend $10,500,000 to $13,500,000 to rehabilitate these 30 locations. The Integrity Digs would only rehabilitate the pipe at the localized dig sites, and would not improve the condition of the remaining pipe section. These Integrity digs would also require multiple construction zones which would result in impacts to the local traffic and businesses in a highly congested area of downtown Toronto. The multiple interruptions would have a negative impact to the reputation of delivering safe and reliable service, for Enbridge. Furthermore, the ILI survey also indicated another 10 features that may require mitigation activity within 15 years ($3.5M~$4.5M additional spend), which is an indication that the pipe is reaching the end of its safe and reliable service life and that a repair approach is not a sustainable or cost effective approach. Vintage steel mains installed in the 1970s and prior have been found to have varying degrees of corrosion associated with the declining cathodic protection and poor coating. Potential risks include corrosion, unknown compression coupling fittings, shallow blow-off valves, reduced depth of cover, lack of cathodic protection, latent third party damages, and mitered bends. This pipeline is located in a densely populated downtown area of the city where a pipeline failure could place public safety at risk. The potential consequences of a failure are amplified as a result of the densely populated downtown characteristics that include high consequence area, wall-to-wall concrete, downtown core with residential, commercial and critical customers, Lake Shore Blvd/Gardiner Expressway, utility congested road		

	allowance, proximity to railway/public transportation, etc. The pipeline supplies natural gas to a number of large volume customers (including hospitals) who would have their natural gas supply impacted in the instance of a pipeline failure. In addition, this pipeline is required to continue to handle the expected growth in the downtown area. In the 2018 Q4 Risk Summary, this pipeline has been identified to have 3.2km in the ALARP (As Low As Reasonably Practical) risk zone, based on historical EGI leak data and time-independent failures per damage prevention records, which triggers the company to explore mitigation options. The mitigation strategy for this large diameter steel main to reduce or prevent risk from approaching the intolerable risk region is replacement. In addition, a number of identified upcoming developments by the City of Toronto, and by third parties, will need to be considered when selecting the route alternatives. These third party projects will play an important part in the selection, location and timing of the routing options.
Project Priorities	1. Determine possible pipeline routes 2. Determine a design that is feasible and operable 3. Determine if an LTC is required 4. Complete EA and public Open Houses (if required) 5. Secure external permits and agreements for the project 6. Meet all regulatory and contractual obligations and external stakeholder requirements. Passing Stage Gates on schedule with all dependencies in place, to allow construction to begin in 2021.



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1.1 Scope Boundaries

Major Activities In Scope	Major Activities Out of Scope
Installation of approximately 4.5 km of NPS 20 HP natural gas main	N/A
Abandonment of approximately 4.5 km of NPS 20 HP natural gas main from Cherry to Remembrance Drive.	De-rating the line is out of scope. The line will be abandoned.
Review Station Requirements/Replacements and determine which stations supplied by this pipeline require replacement along pipeline replacement route	TBD

1.2 Funding

Funding has been secured for this project for 2019. $500K for planning has been approved in AFE: 20016967.

2 RISKS & ASSUMPTIONS

2.1 Key Risks

ID	Type	Item	Mitigation Plan	Probability	Consequence
1	Cost	All costs associated with this project are based on a Class 5 estimate using a conceptual route. Route selection activities may identify alternate preferred route locations or specific construction constraints/challenges that may impact the cost estimate.	Once route selection is completed, re-evaluation of the cost estimate is required.	Medium	Low
2	Schedule	Leave to Construct application may not be approved by Ontario Energy Board	This risk is not within internal control. Working with Regulatory to provide all required information. This project may also be considered as an eligible ICM project.	Medium	High
3	Schedule	Permitting delays – potential long delays for responses on permits	Work with internal stakeholders through the LTC (if required) processes and through pre-consultation to discuss routes that are permit-able. Engage external permitting authorities early in the design phase to obtain buy-in and coordinate with concurrent and/or future third party projects.	Medium	Medium
4	Schedule	Land agreements – potential long delays for	Work with land and discuss easements required in advance to	Low	Medium

		obtaining required land (TWS and permanent easements if required)	avoid project delays. Engage land owners early in the design process to reduce project delays.		
5	Technical	Contaminated Soil in the vicinity of the existing NPS 20 HP pipeline	Potential to affect cost and schedule. Have Environmental testing done early. Work with contractor to discuss cost-effective alternatives/installation methods to avoid unnecessary contaminated soil handling and hauling costs.	High	Low
6	Stakeholder	Risk of obtaining City of Toronto Approvals given the work in the area and the Gardiner Rebuilding	Work with the City of Toronto throughout the design and route selection process to proceed with a design that is permit-able and acceptable to the City.	High	High

2.2 Assumptions & Constraints

1	New external third party projects or developments may impact the route selection process and has since changed the preferred 2017 route. A new or modified preferred route is being considered and Golder Associates Ltd. is being utilized for the Route selection process
2	Route Selection is completed by Golder on time to allow for the EA process to begin
3	MOE approval required prior to submitting the LTC (25 days prior) – if LTC is deemed to be required
4	OEB approval for Leave to Construct will be granted within a reasonable timeframe. This is a requirement for this project to proceed on schedule.
5	There will be no major impediments during the permitting process. All permits and land agreements can be obtained within approximately 9 months or less.
6	All materials can be obtained in the time in between the approval of the LTC application and the start of construction, even though this duration may only be a span of a few months.
7	Class 5 cost estimate has been completed. Class 3 will be required prior to submitting an LTC.
8	Environmental soil testing may determine contaminated soil impacts are larger than what was originally considered in Class 5 cost estimate completed in 2017.

3 SCOPE, SCHEDULE & COST

3.1 Cost Estimate

Table 1 below shows the estimate currently in Power Plan. The estimate will be updated in the Project Charter and Project Management Plan as the project progresses and the Route selection process is complete.

Table 2 – Shifting of Dollars in Power Plan if the project moves up to 2021/2022.

ID	Category	Year 1 2019	Year 2 2020	Year 3 2021	Year 4 2022	Year 5 2023
1	Direct Capital	$500K	$3.5M	$102.225 M	$41.9 M	$2 M

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	Cost					
8	Retirement				$26.25M	
9	TOTAL Project cost	$176.375 M				

3.2 Schedule

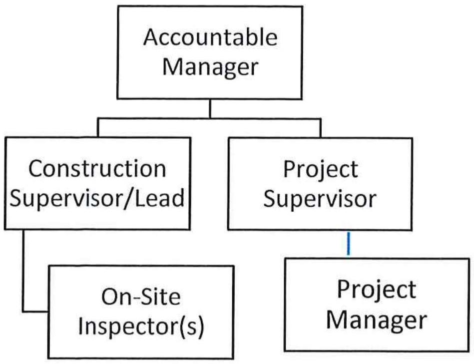
Further details on the project schedule can be found in the attached document.

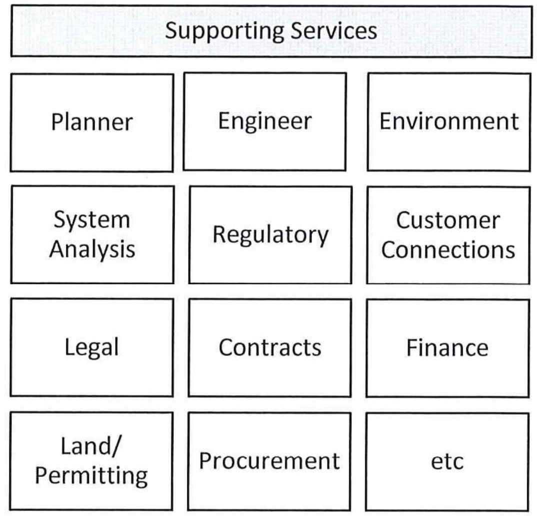
		2018				2019				2020				2021				2022				
	Phase	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	Key Milestones
1	Screening																					-Decision Stage Gate Record required to move into Planning Phase -Decision required to move project up to 2021
2	Planning																					-Route selection process complete August 2019 -EA will start September 2019 -Open House December 2019 -LTC filing (if required) anticipated May 2020 -Permit applications begin June 2020 -Geotech/SUE start Jan 2020
3	Design & Procurement																					-Anticipated OEB approval November 2020 -Permits received March 2021 -OTC package complete March/April 2021
4	Construction																					-Construction start April 2021
5	Start up																					-Construction finish June 2022
6	Closeout																					-LTC Interim Report Sept 2023 -Final monitoring Report Feb 2024

3.3 Team & Stakeholders

The project will be managed with oversight as outlined below.

Construction Team Organizational Chart and Support Services





Supporting Functions

Function	Name	Function	Name
Accountable Manager	Byron Madrid	Design/Approving Engineer	Julie Otieno
Construction Supervisor	TBD	System Analysis	Elli Cristea
On-site Inspector	TBD	Planning Specialist	Allison Chong/ Mark Cairns/ Jim Arnott
Project Supervisor	Aron Murdoch	Environment	Kelsey Mills
Project Manager/ LTC Lead	Melany Afara	Project Controls	Francis-Olivier Joncas
Land	TBD	Permitting	TBD

3.4 Roles and Responsibilities

Department		Capital Development	Engineering Construction	Regulatory	Land/ Permitting/ Environment	Finance	Legal	Procurement	Construction Contractor
Phase	1.0 Screening	A/R	R	R	R	R	R	-	-
	2.0 Planning	A/R	C	C	R	I	I	C	C
	3.0 Design & Procurement	A/R	R	C	R	I	R	R	C

	4.0 Construction	R	A/R	I	C	I	C	C	R
	5.0 Energize & Closeout	A/R	R	I	C	I	C	C	R

3.5 COMMUNICATION PLAN

Key Communications are outlined below. Additional communications will be included in the Project Management plan for this project.

Communication Type	Frequency / requirements	Responsible
Project Updates	Bi-weekly meetings to discuss project planning progression	M. Afara

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NPS 20 Replacement Cherry to Bathurst-Phase 1

Project # 20016967

Screening Stage 1 – Gate Decision Record

Form

Document ID:	20016967
Document Owner:	M. Afara

Version #:	2
Version Date:	2019-04-22
Effective Date:	2019-05-03

1 STAGE GATE 1 DELIVERABLES

	Screening Deliverables	Completed [as per Standard, or Deviated]	Person Responsible for Completing Deliverable	Planned Completion Date [yyyy-mm-dd]	Comments
	Capital Project Advancement Memo (Initial)	Standard	M. Afara	2019-07-10	
	Project Charter (Initial)	Standard	M. Afara	2019-04-22	Initial Project Charter complete
	Cost Estimate (Initiated)	Standard	F. Joncas	2017-07-13	Initial Class 5 Estimate was completed in 2017. Another estimate will be completed as the route selection is completed.
Project Reviews					
	System Operability Review – For LP projects SORT (Initial)	Deviated			Not Required
	Constructability Review (Initial)	Deviated	J. Arnott	2017-07-13	Initial constructability review was completed in 2017. As the route selection is in progress, another constructability review will be required once a permit-able route is identified.
	Other Reviews: Contingency, Cold Eyes, etc.	Standard	N/A	2017-07-13	Additional cold eyes reviews will be completed once a permit-able route is identified and route selection process (by Golder) has commenced.

Notes:

1. The Decision Record is used only when a deliverable is not completed as per a Standard or only part of the deliverable is completed
2. Project reviews are pre-authorized, documented and signed off. Deviation decision records are required if there are changes from the number of reviews originally plan
3. All reviews are required unless previously authorized well in advance of the stage gate challenge with the applicable "review or standard owner"

2 PROJECT DESCRIPTION

A size for size replacement of approximately 4.5 km of the existing NPS 20 HP steel natural gas main on Lake Shore Blvd. from Cherry Street to Remembrance Drive. Approximately 4.5 km of the existing NPS 20 HP will be abandoned. The Method of Construction is still to be determined. A leave to Construct (LTC) application may be required based on the requirement of new land and easements along the pipeline route.

The assessment of the vintage steel pipelines (installed in 1954) has indicated that the NPS 20 KOL line requires replacement due to pipeline condition. In 2016 and 2018, inline inspections (ILI) using a robotic crawler were performed on approximately 1.9Km of the 4.5 Km of pipe selected for Phase-1. The 2016 ILI survey found 2 areas that required immediate rehabilitation activities via 2 Integrity digs. There are an additional 6 Integrity digs recommended over the next 10 years. The 2018 inspection identified 24 further dig locations that would require Integrity remediation over the next 10 years as per the guidance from CSA Z662. These digs are required to mitigate the corrosion and dent features that could exhibit more than 80% wall loss or have a high probability of failure, representing significant degradation of the pipe.

Costs for such Integrity digs, based on the integrity digs in 2017 and 2018, can range from $350,000 to $450,000 per integrity dig. This implies that over the next 10 years EGI could be expected to spend $10,500,000 to $13,500,000 to rehabilitate these 30 locations. These Integrity digs would also require multiple construction zone impacts to the local traffic and businesses in a highly congested area of downtown Toronto. The multiple interruptions would have a negative impact to the reputation of safe and reliable service for Enbridge. Furthermore, the ILI survey also indicated another 10 features that may require mitigation activity within 15 years ($3.5M~$4.5M additional spend), which is an indication that the pipe is reaching the end of its safe and reliable service life and that a repair approach is not a sustainable approach.

This pipeline is located in a densely populated area where a pipeline failure could place public safety at risk. In addition, the pipeline supplies natural gas to a number of large volume customers (including hospitals) who would have their natural gas supply impacted in the instance of a pipeline failure. A number of identified upcoming developments by the City of Toronto, and by third parties, will need to be considered when selecting the route alternatives. These third party projects will play an important part in the selection, location and timing of the routing options.

3 PROJECT COSTS

Year	Current Estimate – Net Direct Capital Based on moving project to 2021 start of Construction
2019	$500,000

2020	$3,500,000
2021	$102,225,001
2022	$41,900,000
2023	$2,000,000
Subtotal	$150,125,000
Retirement	$26,250,000
TOTAL	$176,375,000

Please note the above table has been updated in Power Plan to align with the approval to move this project up to a 2021 construction start date.

The Subtotal in the above table does not include abandonment costs in the Target Budget based on Asset Plan and Current Estimate. It only includes Net Direct Capital costs. The total forecast cost for the project is approximately $176,375,000 including retirement capital.

4 OPEN ISSUES

Open Issues	Planned Resolution	Planned Resolution Date [yyyy-mm-dd]
Route Selection – Golder is in the process of completing an analytical Route Selection	This will be completed as part of the Planning Stage. This will be Part of Stage Gate 2	2019-08-01
Cost Estimate – Refine based on Route selection	This will be completed in the Planning Stage. As the route selection is more clearly defined the cost estimate will be refined to a Class 3. This is a Stage Gate 2 item.	2019-09-01

5 RECOVERY PLAN FOR INCOMPLETE OR DELAYED PLGC DELIVERABLES

Deliverable	Recovery Plan Required? Y / N [If Yes, fill In next column]	Due Date and Any Comments
Route Selection	Y	Will be completed in the Planning Phase (Stage Gate 2) 2019-08-01
Project Timeline	Y	Confirmation required based on moving into the Planning Phase 2019-05-05 and sign off of this stage gate memo.
Cost Estimate	Y	Will be completed in the Planning Phase (Stage Gate 2) in parallel with Route Selection. 2019-08-01

6 SIGN OFF

Approval of the Screening Stage Gate indicates an understanding and formal agreement that the project is ready to proceed to the Planning Stage, which includes endorsements from all functional groups. By signing this document, the approver agrees that the Project is approved to pass Gate 1 and to advance to the Planning Stage of the Project Lifecycle.

Position Title / Department	Name	Signature	Date [yyyy-mm-dd]
Manager Capital Development & Delivery, System Improvement	Byron Madrid	Byron Madrid	2019.09.16
Director System Improvement	Neil MacNeil	Neil MacNeil	2019 09 19
Director Asset Management	Hilary Thompson		
Director Toronto Region Ops	Tracey Teed Martin		
VP Engineering	Michelle George	MGG	2019 09 20
SVP Operations	Jim Sanders		

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SI-PC CONTROL DOCUMENT

Gate 2 Decision Record

SI-PC Project Lifecycle Gating Controls
Stage 2 – Initiation

Template

Document ID:	SI-PC-02-003
Document Owner:	System Improvement – Project Controls (SI-PC)

Version #:	1.0
Version Date:	2019-10-24
Effective Date:	2019-10-31

Approver Name:	Neil MacNeil
Approver Title:	Director, System Improvement
Approval Date:	<yyyy-mm-dd> 2019-10-31

DOCUMENT TEMPLATE VERSION REGISTER (delete this section)

Version #	Version Date [yyyy-mm-dd]	Author / Department	Reviewer / Department	Approved By / Department	Approval Date [yyyy-mm-dd]	• Change Area [Section and Title] ○ Change Description
1.0	2019-09-18	Melany Afara/ Capital Development	Aron Murdoch /Capital Development Byron Madrid/ Capital Development & Delivery	Neil MacNeil / System Improvement	Click or tap to enter a date.	First Release

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NPS 20 Replacement Cherry to Bathurst Project (20016967)

Gate 2 Decision Record

SI-PC Project Lifecycle Gating Controls Stage 2 - Initiation

Form

Document ID:	NPS 20 Replacement Cherry to Bathurst
Document Owner:	Capital Development
Project Manager:	M. Afara
Document Location:	

Version #:	1.0
Version Date:	2019-09-18

1. STAGE GATE 2 DELIVERABLES AND PROJECT REVIEWS

Initiation Deliverables	Completed [as per Standard, or Deviated]	Person Responsible for Completing Deliverable	Planned Completion Date [yyyy-mm-dd]	Comments
Project WBS	Standard	M. Afara	19-Sep-18	Please click the link in "Initiation Deliverables" to view the item in further detail.
Schedule – Class 4	Standard	M. Afara	19-Sep-18	Please click the link in "Initiation Deliverables" to view the item in further detail.
Cost Estimate – Class 4	Standard	M. Afara	19-Sep-18	Please click the link in "Initiation Deliverables" to view the item in further detail.
Risk Register	Standard	M. Afara	19-Sep-18	Please click the link in "Initiation Deliverables" to view the item in further detail.
Project Management Plan	Standard	M. Afara	19-Oct-10	Please click the link in "Initiation Deliverables" to view the item in further detail.
Initiation Project Reviews	**Completed [as per Standard, or Deviated]**	**Person Responsible for Completing Deliverable**	**Planned Completion Date** [yyyy-mm-dd]	**Comments**
Cold Eyes Review (SME, etc.)	Standard	M. Afara	19-Oct-31	This will be completed in the Design Phase
Planning Kickoff	Standard	M. Afara	19-Oct-8	Completed. Please click on the link to view the slides from the kick-off

2. OPEN ISSUES

Open Issues	Planned Resolution	Planned Resolution Date [yyyy-mm-dd]
Cold Eyes Review	This will be completed in the Design Phase.	19-Oct-31
		Click or tap to enter a date.

3. RECOVERY PLAN FOR INCOMPLETE OR DELAYED PLGC DELIVERABLES/REVIEWS

The Stage Gate Approver can approve the project moving to the next stage with incomplete or delayed deliverables if the table below is completed. The Stage Gate Approver can request that some or all of these deliverables be completed at a later date.

Deliverable/Reviews	Recovery Plan Required? Y / N [If Yes, fill In next column]	Due Date and Any Comments
Cold Eyes Review	Y	This will be completed in the Design phase once topography is received and the EA process has started. In order to have a draft design to review.

4. SIGN OFF

Approval of the Stage Gate 2 Initiation – Decision Record indicates an understanding and formal agreement that the project is ready to proceed to Stage 3 – Design & Procurement. By signing this document, the approver agrees to endorse the project proceeding to Stage 3 – Design & Procurement

Approver Title / Department	Name	Signature	Date [yyyy-mm-dd]
Director, System Improvement	NEIL MACNEIL	Neil MacNeil	Click or tap to enter a date.
			Click or tap to enter a date.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe (EP)

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, page 2

Preamble:

“Analysis conducted by Enbridge Gas in 2015 and 2016 via an asset health review (AHR) observed that vintage steel mains, defined as those mains installed in the 1970s and prior thereto, have demonstrated declining health compared to steel mains installed after the 1970s.”

Question**:**

Please file the Asset Health Review report conducted in 2015 and 2016 that Enbridge is referencing.

Response:

The Asset Health Review process involved an evaluation of Enbridge Gas’s gas carrying assets and their characteristics. The information gathered from this process was used to rank each of the assets in terms of risk. From this review several pipelines were identified as requiring further investigation due to their risk. One of those pipelines was the vintage steel NPS 20 KOL from Lisgar to Station B.

Attachment 1 to this response is a February 2016 presentation on “Asset Renewal Plan Recommendation / Next Steps”, with an associated “scoring matrix” which recommends that certain pipelines be investigated.

The work and findings from the Asset Health Review process were an important input to the EGD 2018-2027 Asset Management Plan, which was the Company’s first ten year asset management plan. The NPS 20 KOL Replacement Project is identified in that asset plan.

Attachment 2 to this response is an excerpt from the 2018-2027 Asset Management Plan describing EGD’s steel mains, including the NPS 20 KOL.

Attachment 3 to this response is an excerpt from the 2018-2027 Asset Management Plan describing the NPS 20 KOL Replacement Project.

Attachment 4 to this response is a 2019 presentation provided to Enbridge Gas management at various meetings over the course of 2019. This presentation provides information of Enbridge Gas's approach regarding Vintage Steel mains.

Asset Renewal Plan Recommendation / Next steps

To: Director of Asset Management, Director of AR&I

Asset Management (AR&I)
Feb 26th 2016

Objectives

1) Review the pipeline selection process for Asset Renewal

2) Review the recommendations

3) Agreement on next steps

Recommended for further investigations:
1) Lakeshore
2) Martin Grove
3) St. Laurent 270*

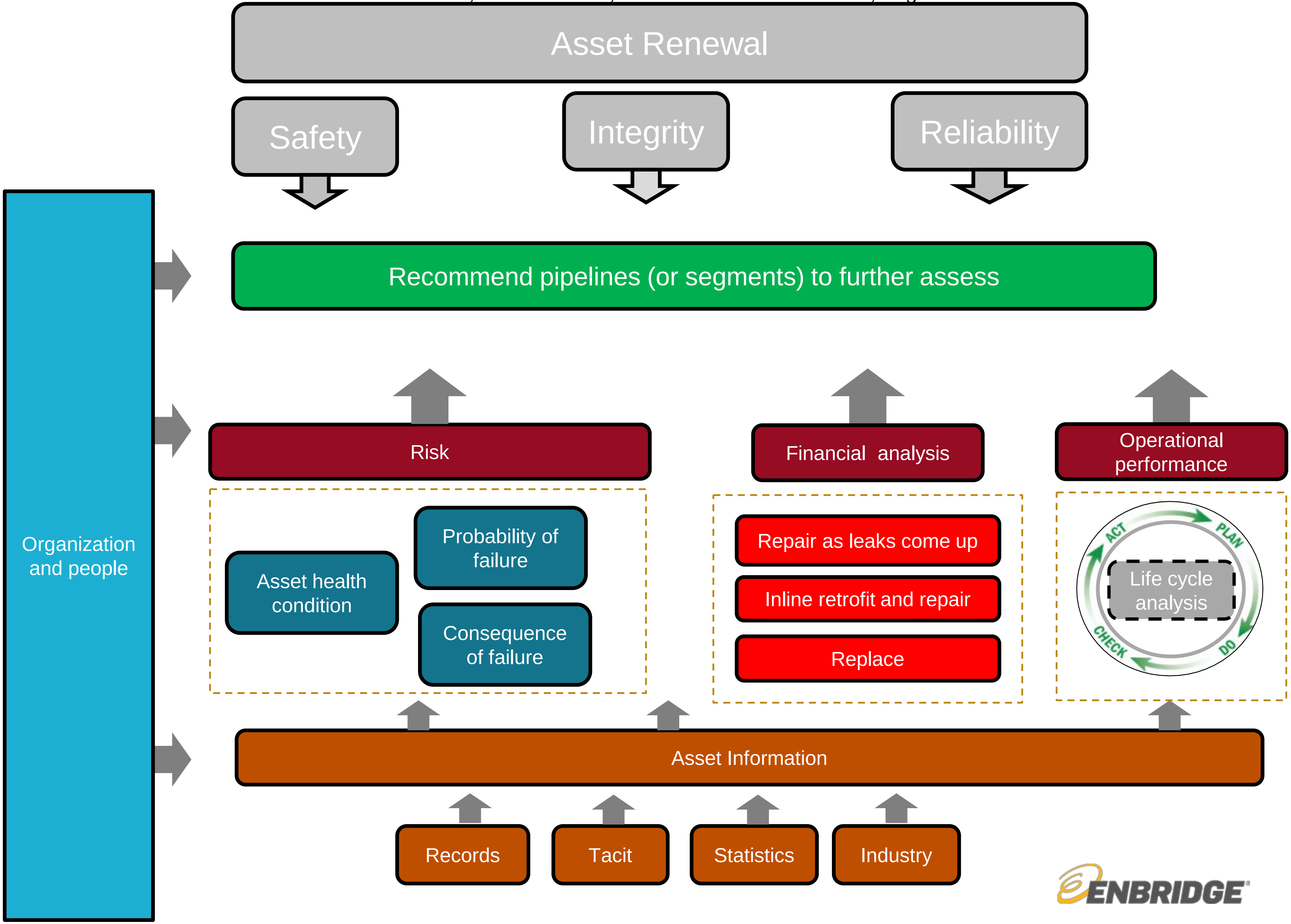
Best condition

Corrosion (60%)

Factor	Lake Shore	Don Valley	Colllingwood	Martin Grove	Ottawa Valley	St. Laurent 470	St. Laurent 270
20% – Latent damage causing corrosion: Depth of Cover, Activity level, damage rate (statistical), leak repair.	**8%**	**11%**	**13%**	**9%**	**13%**	**12%**	**10%**
40% – Cathodic Protection; Coating; Corrosion features prediction	**12%**	**13%**	**25%**	**24%**	**24%**	**26%**	**29%**
Vintage (30%)	**6%**	**12%**	**6%**	**6%**	**6%**	**6%**	**6%**
Design (10%)	**5%**	**9%**	**8%**	**4%**	**8%**	**4%**	**8%**
	31%	45%	53%	43%	52%	47%	53%
	1.05	1.25	1.25	1.00	1.00	1.25	1.00
Health Adjusted score	**32%**	**56%**	**66%**	**43%**	**52%**	**59%**	**53%**

3

*based on tacit knowledge, St. Laurent is picked over Ottawa Valley



Asset Renewal
Safety
Integrity
Reliability
Recommend pipelines (or segments) to further assess
Organization and people
Risk
Financial analysis
Operational performance
Asset health condition
Probability of failure
Consequence of failure
Repair as leaks come up
Inline retrofit and repair
Replace
ACT
PLAN
DO
CHECK
Life cycle analysis
Asset Information
Records
Tacit
Statistics
Industry
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Asset Information

– Available asset information collected

- Weekly meetings with Integrity, Engineering, Corrosion, Asset Analytics, Risk, Network analysis since September 2015
- Minutes are available
- All information has been uploaded to Asset Management SharePoint site

– Sources of information/ Knowledge and expertise collected

- Tacit knowledge
  - Workshops (e.g. Enbridge retirees)
  - Workshops with Operations AR&I
  - Interviews with Field Managers (e.g. Jim Miller, Mike McEwan, Vito Modugno etc.)
- Technical knowledge
  - Expert guidance and recommendations (e.g. Ken Ocean, Stephen Jehlicka, Brad Jefferies)
- Records
  - DSIMP
  - PMTS
  - GIS
  - Past Inline inspection data
  - Old engineering manuals / drawings
  - Past Enbridge studies
  - Missy tickets / field notes (where practical)
- Industry research

Stakeholders collaborative consultation / expertise

Core team from Integrity, Risk, Asset Analytics, Corrosion Prevention met on a weekly basis

Asset Analytics
- David Patfield
- Duminda Randeniya
- Catherine McCowan

Corrosion / Damage Prevention
- Brad Jefferies
- Jason Samara
- Steven Mott

Asset Management
- Deirdre Broude
- Ryan Tao
- Rachit Bhambri

Major Projects
- Bike Balkanci

Industry and EGD Research
- PHMSA
- Banak, Jana, Dynamic Risk etc.

Engineering
- MAOP Team
- Stephanie Pazuki
- Gonzalo Juarez

Risk Management
- Angela Wong
- Andy Ridpath
- Erik Naczynski

Integrity
- Ken Ocean
- Stephen Jehlicka
- Brad Patzer
- Daniel Zanini
- Fred Butrico

AR&I
- Monica Lavers
- David Marshall
- Tom Jedemann
- Mohamed Chebaro
- Kevin Bando

Enbridge Retirees
- Jim Tweedie
- Jim Miller
- Peter Malia
- Rick Logue

Network Analysis
- Elli Cristea

Interviews
- Mike McEwan
- Vito Modugno

Asset Health Index

Collect information, and relate to the current condition

– The purpose of Asset Condition Assessment is to detect and quantify long-term degradation factors using a multi-criteria assessment approach into a single indicator of the health of the asset, that impacts the asset life. The specific asset health or condition does not necessarily imply a set course of action or timing, without consideration of the operating context, risk, financial implications, and overall strategy for managing a particular asset.

– Methodology of developing Asset Health Index is consistent with the Asset Health Review that UMS Group is developing for GD

– Asset Health Index is widely used in industry
  - PHMSA
  - Horizon Utilities rate filing
  - Toronto Hydro Asset Condition Assessment
  - Hydro One Asset condition Assessment

– Approach has been accepted by SMA's

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Asset Health Index

This was an iterative process with many expert consultations

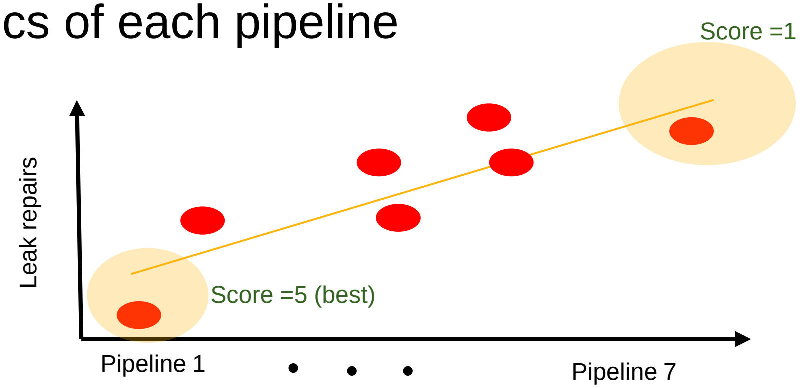
– Asset Health threats were determined
- Corrosion 60%
- Vintage 30%
- Design Index 10%

Supported by documented industry research, and various EGD studies – e.g. vintage pipeline reports, Jana laboratories field applied coating reports etc. An iterative process.

– Degradation characteristics causing the threats were collected
- Field applied coating type
- Cathodic protection survey results
- Activity around the pipeline etc.

This list was developed in consultation with various subject matter experts and industry studies. An iterative process.

– Scoring the characteristics of each pipeline
- Quantitative data
- Tacit knowledge
- Iterative process



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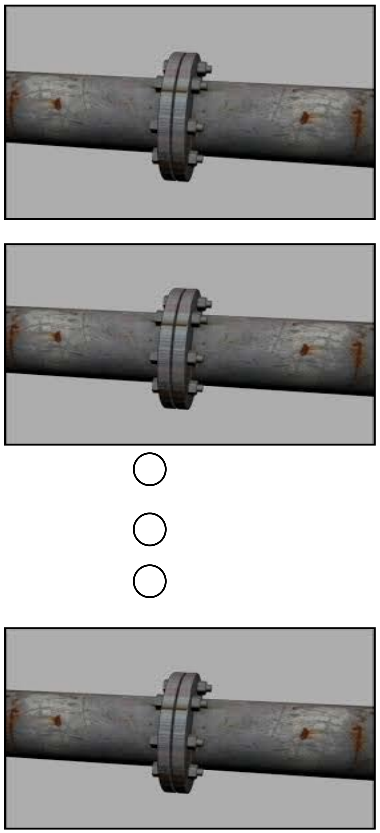
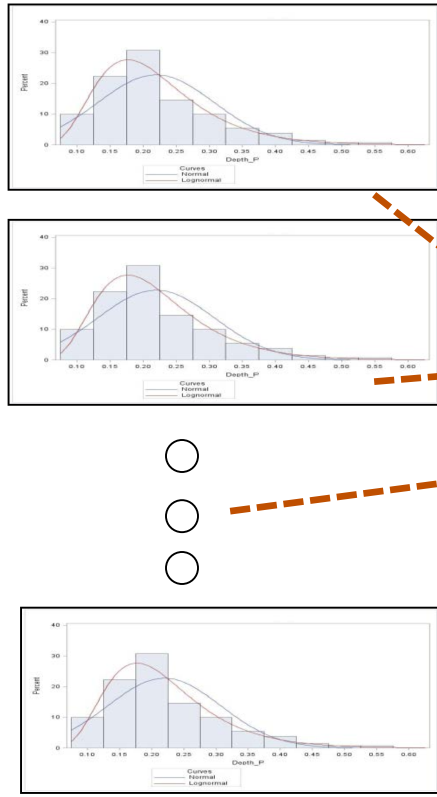
Probability – chance of an unwanted event using past observations

6 IL I'd lines

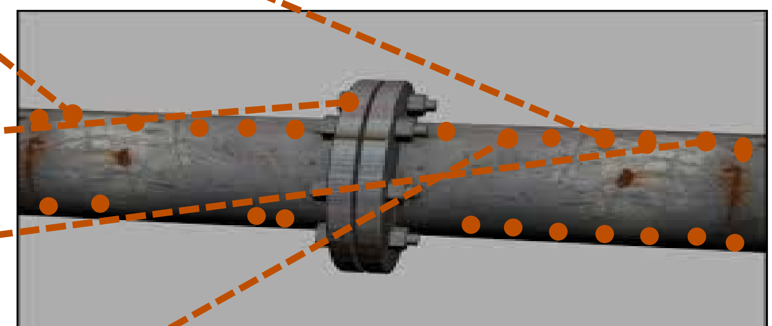


Observed features distribution



ARP pipeline, not ILI'd

On the non IL I'd line pick 10,000 points



Randomly apply the features from the ILI'd distributions to the ARP line to each of the 10,000 points

Repeated for all the non ILI'd ARP lines, to proximate the corrosion and damage rates from past ILI'd lines

ILI'd pipelines of similar vintage, coating

Distribution rates scaled back/forth to match age of ARP line

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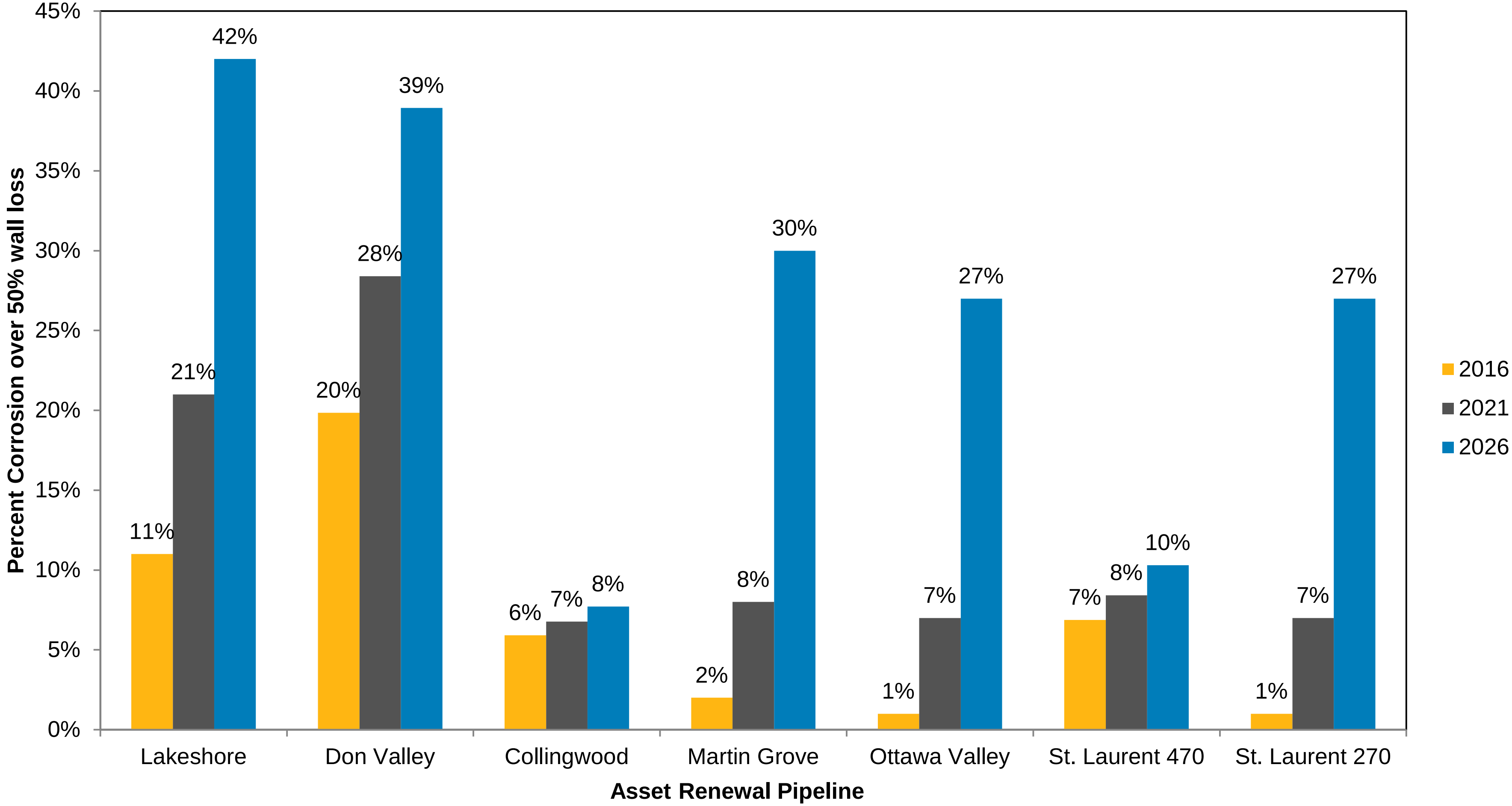
Percentage of corrosion features greater than 50% wall loss



Corrosion in the 50% bucket will grow over time, based on the corrosion rates, and the number of features falling in from the <50% wall loss bucket over time

Insights

Insight is relative to each pipeline in each category

- Lake Shore
  - Highest number of leak repairs (8 leak repairs – since 2011)
  - Most number of coating repairs (6 coating repairs since 2006)
  - Highest number of events (construction, equipment etc.) per kilometer (109 events/km)
  - High percentage in an urban area (100%)
  - High predicted latent third party damage rate (ILI statistics)
  - Sporadic periods with lack of, and unknown CP protection levels (data after 1999)
  - Possibility of high induced AC voltage levels (greater than 15V) (soil resistivity, and models)
  - Less than 1% of the line has In Line Inspected
- Don Valley
  - Pipe Bridge condition potentially compromises the pipe
  - High percentage in an urban area (100%) (80% in High Consequence Areas)
  - Highest number of non third party damage rate (rock impingement, padding practices etc.) (ILI statistics)
  - Lowest predicted latent third party damage rate (ILI statistics)
  - Sporadic periods with lack of / spotty CP protection
  - Highest percentage in AC corridor (65%)
  - Has been In Line Inspected (investigations: 1 immediate, 15 scheduled)

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Insights

Insight is relative to each pipeline in each category

- Collingwood
  - Highest number of possible corrosion repairs (no leak) (8)
  - High predicted latent third party damage rate (ILI statistics)
  - Highest rating for cathodic protection
  - Areas with Depth of Cover (DOC) concerns
  - Has been In Line Inspected (3 scheduled inspections in 2013)
  - MAOP study scaled back the supply pressure, limiting customer additions
- Martin grove
  - Unknown DOC, with a very high # of fittings per Km (e.g. blow off valves, compression couplings)
  - High percentage in an urban area (100%)
  - High predicted latent third party damage rate (ILI statistics)
  - Sporadic periods with lack of, and unknown CP protection levels (data after 2000)
- Ottawa Valley
  - Pipeline mostly in non urban area (88%)
  - Has elevated induced AC voltages
  - High predicted latent third party damage rate (ILI statistics)
  - High number of leak repairs (6)

Insights

Insight is relative to each pipeline in each category

- St. Laurent 470
  - High percentage in an urban area (100%)
  - Has been In Line Inspected (5 immediate and 9 scheduled inspections)
  - Tacit knowledge not supported by available data (gap)

- St. Laurent 270
  - High percentage in an urban area (100%)
  - High predicted latent third party damage rate (ILI statistics)
  - High # of fittings per Km (e.g. blow off valves, compression couplings) (6.9 fittings/Km)
  - Tacit knowledge not supported by available data (gap)

	Lakeshore	Don Valley	Collingwood	Martin Grove	Ottawa Valley	St. Laurent 470	St. Laurent 270
Length / Diameter	45Km	12.1 Km	69.4 Km	5.6 Km	233 Km	5.8 Km	13.3 Km
Diameter	NPS 20	NPS 30	NPS 8	NPS 12	NPS 8	NPS 12	NPS 12
Health Index (higher better)	32%	56%	66%	43%	52%	59%	53%
Option 1[(1,3)] repair as leaks found	$70M	$71M	$10M	$3M	$97M	$5M	$7M
Option 2 Retrofit, Pig line, dig, repair	$45M	$36M[(4)]	$5M	$5M	$55M	$3M	$8M
Option 3 Replace	$240M (5x pig, dig, repair)	$289M (8x pig, dig, repair)	$94M (19x pig, dig, repair)	$16M (3x pig, dig, repair)	$316 (6x pig, dig, repair)	$17M (6x pig, dig, repair)	$39M (5x pig, dig, repair)
Percentage of pipe within population center	100%	100%	18%	100%	12%	100%	100%
customers impacted with a full pipe failure (winter)[(2)]	53K 93% res. 2 hosp.	125K 85% res. 15 hosp.	43K 94% res.	38K 91% res.	48K 94% res. 20 hosp.	15K 90% res. 8 hosp.	30K 90% res. 5 hosp.

(1) Very rough estimates, for financial magnitude purposes only, not for regulatory usage (see assumptions in appendix)
(2) Customer impacted needs to be verified. Also depends on where the disruption occurs, and back feed capacity
(3) The repair estimates is only for the next 10 years. This amount will be much larger beyond the 10 year horizon
(4) Does not include cost of bridge repair

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Repair Vs. Replace

Pros/Cons

Repair

Pros	Cons
➢ For ILI pipe, repair program for each pipeline can be created	➢ Cathodic protection ineffective if there is shielding
➢ No significant up front capital outlay	➢ Increasing amount of leaks and repairs as pipeline ages (especially at field applied coatings)
➢ Improvement in pigging technology	➢ Higher security of supply threats
	➢ Higher operation and maintenance (O&M) costs
	➢ Potentially high number of Integrity digs (especially for non ILI lines), repair option may be cost prohibitive
	➢ Still have old pipe, increasing risk (don't know condition)
	➢ Continual coating degradation

Replace

Pros	Cons
➢ Construction of new asset using modern standards, materials, training etc.	➢ High initial capital outlay
➢ Possibly re-route to less consequence areas	➢ Public inconvenience during long construction (if in heavily populated area)
➢ Lower O&M costs	
➢ Possible increase in size to ensure future security of supply, i.e. reduce need for future reinforcements.	
➢ Reduce probability of failure	

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Recommendations

– ***Potential pipelines***

- Lakeshore / South DVP, Martin Grove, St. Laurent 270

– ***Recommendations:***

- Quantitative Risk Assessment (QRA)
  - Segmentation – based on probability of failure and consequence, may select segments of multiple lines
  - Combine with known issues, e.g. Don Valley bridge crossing remediation/replacement with Lakeshore
- Integrity
  - Perform Integrity digs / inline inspections or guided waves on the identified pipelines
  - Ensure alignment with the Asset Health Review work (life cycle curves, life cycle costing etc.)
- Records
  - Collect records prior to 2007
  - In depth review of Missy Tickets / field notes for the identified pipelines
  - Maximum Allowable Pressure studies on the pipelines that don’t have a full study
- Financial Analysis
  - Refine financial analysis
- Depth of cover
  - Martin Grove- conduct a DOC survey
  - Don Valley – investigate low DOC

Next Steps

1. Approval on the recommendations
2. Transition to ARP team – align with Asset Management project plan
3. Provide ongoing support

Appendix:

→ Financial estimating summary
→ Statistical analysis summary
→ Fortis BC application highlights (1958 vintage pipe)

Preliminary financial estimating methodology / assumptions

– Cost inputs (both capital & O&M considered)

- Major projects / GSTS
  - Pigging related retrofit costs (e.g. valves, back to back elbows, adding pig launchers/ receivers)
  - Digging costs with sleeve repair / digging costs with cut out and replace (using stopper fittings)
  - All costs are based on pipe diameter

– Assumptions

- Metal loss based on a statistical prediction, of greater than 50% wall loss will be dug/repaired
- For lines that need ILI retrofits – assumed 15% of all the fittings will need retrofits (valves, and back to back elbows)
- Option 1- each feature greater than 50% wall loss will be dug and repaired (sleeve or cut out & replace) individually
- Option 2- Retrofit the pipe to make it piggable (where required). The number of digs will be significantly reduced, as the in line inspection would typically identify wall loss at relatively close proximity to each other, resulting a coordinated dig schedule.
- Option 3: Replacement costs from (based on historically similar replacements)

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Statistical analysis summary

Pipeline	Metal loss	Number of Features 2016	Number of Features 2021	Number of Features 2026	Percentages 2016	Percentages 2021	Percentages 2026
Lakeshore	<10%	19	0	0	0.04	0	0
	10-30%	305	174	28	0.65	0.37	0.06
	30-50%	94	197	244	0.2	0.42	0.52
	50-70%	33	66	127	0.07	0.14	0.27
	70%>	19	33	70	0.04	0.07	0.15
Ottawa North 270	<10%	10	0	0	0.07	0	0
	10-30%	106	66	11	0.78	0.48	0.08
	30-50%	19	63	89	0.14	0.46	0.65
	50-70%	1	8	33	0.01	0.06	0.24
	70%>	0	1	4	0	0.01	0.03
Ottawa Valley	<10%	168	0	0	0.07	0	0
	10-30%	1869	1150	192	0.78	0.48	0.08
	30-50%	336	1079	1558	0.14	0.45	0.65
	50-70%	24	144	575	0.01	0.06	0.24
	70%>	0	24	72	0	0.01	0.03
Martingrove	<10%	3	0	0	0.06	0	0
	10-30%	44	25	4	0.76	0.44	0.07
	30-50%	9	28	36	0.16	0.48	0.63
	50-70%	1	4	15	0.02	0.07	0.26
	70%>	0	1	2	0	0.01	0.04
Ottawa North 470	<10%	18	18	18	0.07	0.07	0.07
	10-30%	150	132	109	0.58	0.51	0.42
	30-50%	73	88	105	0.28	0.34	0.41
	50-70%	13	17	21	0.05	0.07	0.08
	70%>	4	5	6	0.02	0.02	0.02
DVP	<10%	49	30	30	0.11	0.07	0.07
	10-30%	68	46	19	0.16	0.11	0.04
	30-50%	231	235	216	0.53	0.54	0.50
	50-70%	69	97	130	0.16	0.22	0.30
	70%>	17	26	39	0.04	0.06	0.09
Collingwood	<10%	164	164	164	0.19	0.19	0.19
	10-30%	510	478	440	0.60	0.56	0.51
	30-50%	132	157	187	0.15	0.18	0.22
	50-70%	32	36	42	0.04	0.04	0.05
	70%>	19	22	24	0.02	0.03	0.03

Depth Rates

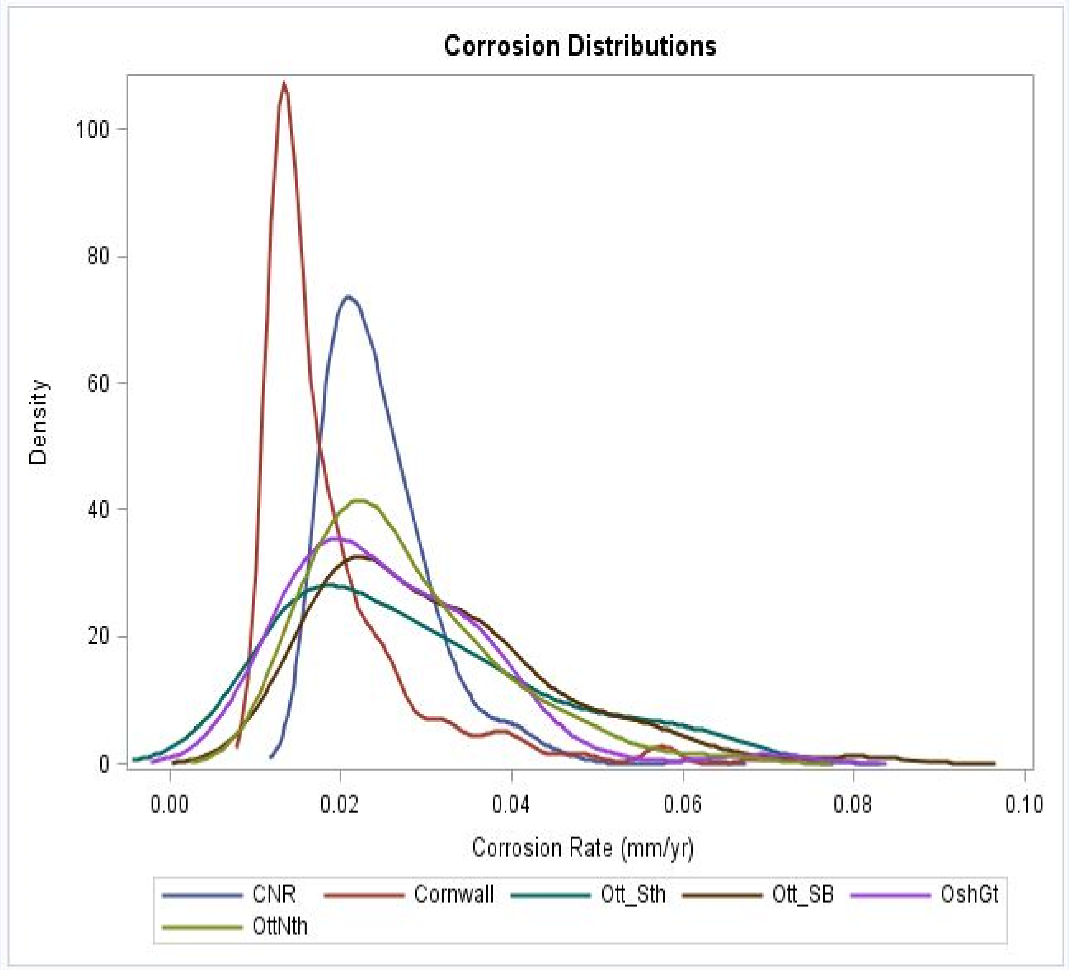
Pipeline Name	Type of damage	ILI Data Urban	ILI Data Rural	Length	P(rural)	P(urban)	Rate Urban	Rate Rural
Barrie - Collingwood	Third Party	14	36	55.4	0.18	0.82	0.25	0.65
	Non Third Party	12	26				0.22	0.47
DVP	Third Party	7	2	35	0.11	0.89	0.20	0.06
	Non Third Party	32	0				0.91	0.00
Ottawa North -470	Third Party	3	0	6	1.00	0.00	0.50	0.00
	Non Third Party	5	0				0.83	0.00
Ottawa North -270	Third Party			13.3	0.98	0.02	0.90	0.41
	Non Third Party						0.28	0.45
Lakeshore	Third Party			45.7	1.00	0.00	0.90	0.41
	Non Third Party						0.28	0.45
Ottawa Valley	Third Party			233.5	0.12	0.88	0.23	0.35
	Non Third Party						0.57	0.23
Martingrove	Third Party			5.6	1.00	0.00	0.90	0.41
	Non Third Party						0.28	0.45

Damage Rates

Pipeline Name	Corrosion Rate
Barrie - Collingwood	0.02
DVP	0.046
Ottawa North -470	0.031
Ottawa North -270	0.023
Lakeshore	0.025
Ottawa Valley	0.024
Martingrove	0.025

Corrosion Rates

Corrosion Distribution curves used for the Monte Carlo simulation



Approach to determine the number of features

	Metal loss	Number of Features			Percentages		
		2016	2021	2026	2016	2021	2026
Lakeshore	<10%	19	0	0	0.04	0	0
	10-30%	305	174	28	0.65	0.37	0.06
	30-50%	94	197	244	0.2	0.42	0.52
	50-70%	33	66	127	0.07	0.14	0.27
	70%>	19	33	70	0.04	0.07	0.15

# of corrosion features projected using the following approach

1) All the features the ILI data base were summed & allocated to the various buckets (<10%, 10-30% etc.)
2) The length of all the pipe that has been ILI'd were summed
3) The ratio of the features per kilometer was multiplied by the length of the non ILI'd pipeline, in a particular bucket

$$\left(\frac{\sum All\ ILI\ features}{\sum length\ of\ all\ ILI\ pipe}\right)$$ X length of non ILI'd pipe x Percentage

Comparison with Fortis BC application

- NPS 30, approximately 20Km
- Installed in 1958
- Replacement costs $243M (2014 dollars)
- Rehabilitation costs $154M (2014 dollars)
  - Based on 167 digs, every 12 meters at an average cost of $92,200 per dig
  - All leaks have been observed at field applied coatings on girth welds over the entire length of the pipeline
- Without excavating and inspecting the entire pipeline, there will be some remaining pipeline risk…..not a feasible solution
- Probability of rupture is insignificant, probability of failure by leak will escalate by 3.7 through the period of 2013-2033
- Disbonded coatings at girth welds renders CP ineffective
- The use of ILI is not viable because of inside diameter restrictions

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Mains – Distribution – Steel

Steel mains are an integral asset of EGD's natural gas distribution system. The steel pipeline system (over 12,000 kilometers in total) accounts for approximately 35% of all mains within the gas distribution system and includes critical infrastructure extending from gate stations to lower pressure systems. Between the early 1950s and early 1970s, steel mains were the only material used in the gas distribution system. They were installed for different pressure classes, from Low Pressure to Extra-High Pressure, and ranging from various sizes, from 1-inch distribution mains up to 36-inch trunk mains. Figure 5-10 illustrates the calendar age of the steel main population.

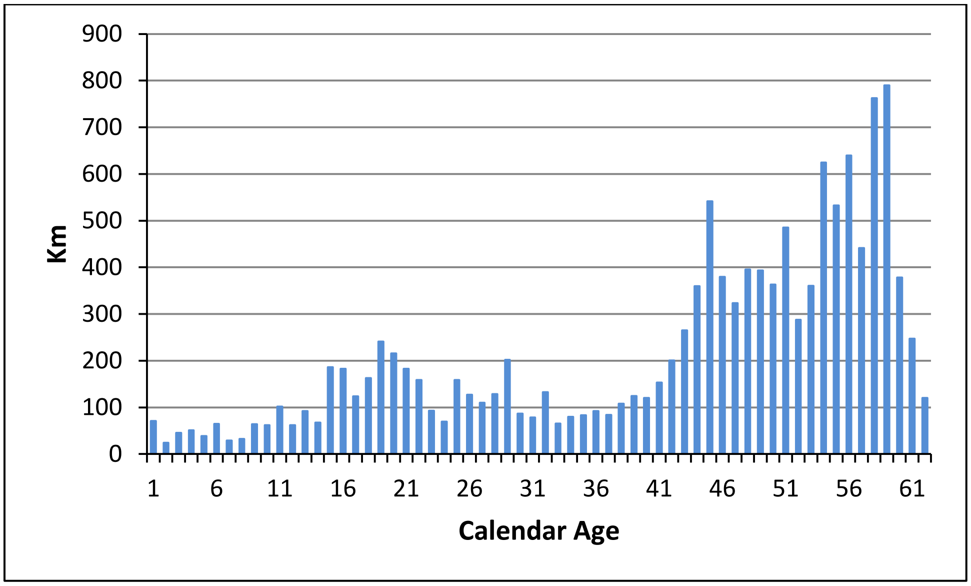

Figure 5-10: Steel Main Current Age Distribution (Based on 2017 Base Year)

This figure indicates that there is a higher kilometers count as you move across the x-axis in age. During the major system expansion from mid-1950s to early the 1970s across the entire EGD franchise, steel mains were installed at a rate over 440 km per year on average. Steel distribution mains that were installed in the early 1970's and prior are referred to as "vintage steel mains". Vintage steel mains account for over 50% (more than 7,000 kilometers) of the total steel mains population. These mains were installed using material, coatings, design requirements, and construction practices based on standards in place during that earlier time period. Similarly, protection programs such as locate and cathodic protection procedures were different from current day practices.

Distribution steel mains service some of the oldest and most populated parts of the EGD franchise area, including the downtown cores in Toronto and Ottawa. Over time, urban encroachment and the construction and infrastructure activities supporting municipal growth have impacted both the condition and the consequences associated with the potential failure of these gas mains. In urban areas there are challenges with ensuring adequate cathodic protection due to the interference caused by subway, streetcar and light-rail transit systems with existing underground infrastructure and hydro utility designs.

Evaluating Asset Health*:* A steel main failure projection model was developed to forecast the number of corrosion leaks in proceeding years based on statistical analysis of the corrosion leak history from the past nine years. Based on this model, the number of failures on distribution steel mains were projected as seen in Figure 5-11.

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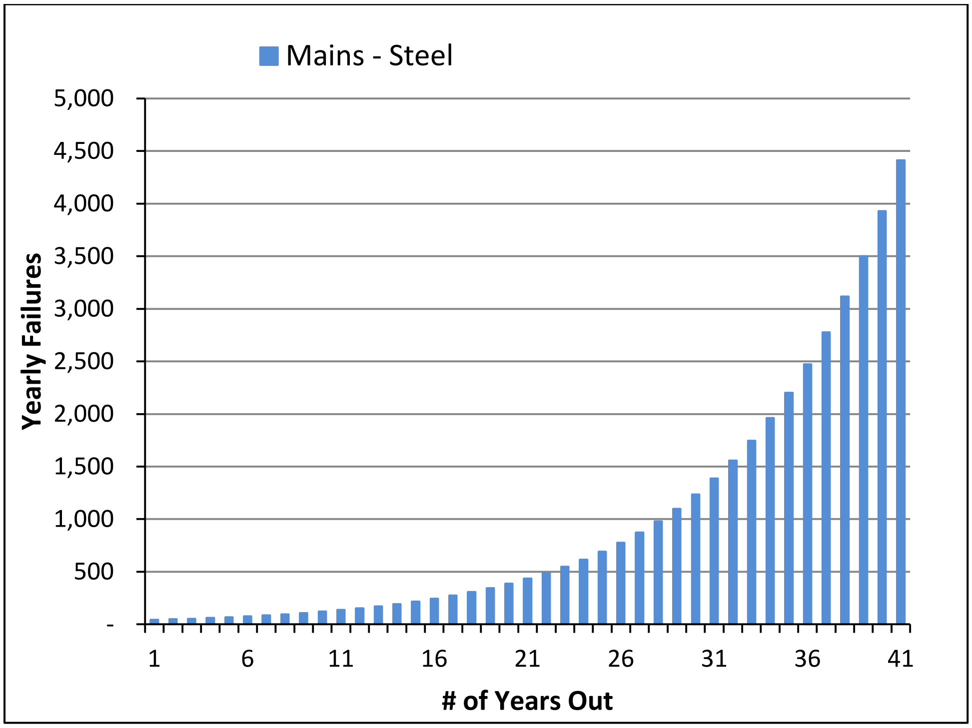

Figure 5-11: Steel Mains Corrosion Failure Projections (2017-2057)

The steel main failure projection model forecasts an exponential growth of leaks over the next 40 years. The resulting failure projection model shows a very strong correlation to the asset age, as well as a moderate correlation with other pipe attributes (covariates) such as manufactured coating type and location.

The current failure projection model does not consider other influencing parameters such as: CP history, field applied coating type, number of service connections, and soil type. Non-corrosion leaks have also not been considered at this time. These leaks (caused by mechanical fitting failures, metal cracking, defective pipes, etc) contribute to approximately 50% of the total non-third party leaks on steel mains. Therefore, it is reasonable to believe the current projection on number of failures is likely understated.

It can be seen that over time the failures associated with corrosion alone are expected to grow exponentially. This can be explained by the fact that a linear asset like steel mains can have multiple coating defects along the pipe body. These active corrosion sites all have similar corrosion rates, resulting in multiple leaks on the same asset within a similar time frame. This model has intrinsically incorporated historical practices in temporary repair and replacing some assets at a later time.

Condition rating charts (as seen in Figure 5-12) present the health index of the steel mains population in projected 10-year increments.

It should be noted that the intent of the Asset Health Index is to provide a general asset health overview of the entire population. It is not to be mistaken as an indicator for the health of any one asset. This is because there are many unique contributors that are not considered that could accelerate pipe degradation. These are independently studied during the risk assessments.

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Table 5-12: Probability of Failure by Asset Class Category

CATEGORY	DESCRIPTION	POF
HI5	Category V – Fails within 1-5 years	>=0.2
HI4	Category IV – Fails within 6-10-years	0.1 <= x < 0.2
HI3	Category III – Fails within 11-25 years	0.04 <= x < 0.1
HI2	Category II – Fails within 26-40 years	0.025 <= x <0.04
HI1	Category I – Fails greater than 40 years	<0.025

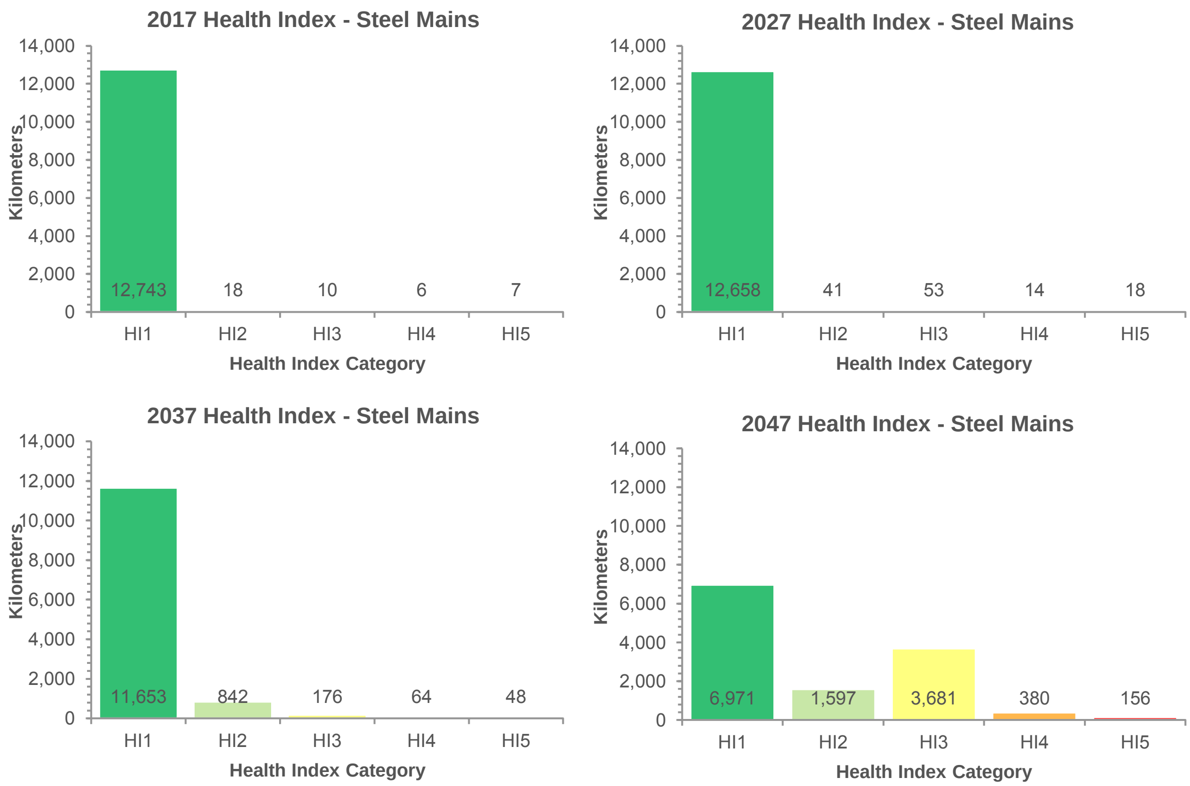

Figure 5-12: 2017 to 2047 Health Index for Steel Mains

The increase in failure probabilities is relatively stable and then takes a significant turn between the years 2037 and 2047, when the oldest vintage steel mains enter into the 80 to 90 year age range. By 2047, it is expected that over 25% of the steel main population will have started and continue to degrade at an accelerated rate, with over 500 km requiring immediate replacement at that time. A greater concern is that nearly 4,000 km will need to be addressed in years 2057 to 2082 (outside of the illustrated window).

To further verify the validity of the failure projection model, a statistical analysis was performed on the inline inspection data to better understand steel main corrosion rates. Through the statistical view of the corrosion rates, it was determined that the majority of the distribution steel mains would have experienced at least one corrosion leak before they reach the age of 100 years. The outcome of this analysis is consistent with the result from the steel main failure projection model. The first leak could occur well before the 100 year time frame. On the basis of long term corrosion leak mitigation, the useful life of a steel main is set at 100 years. EGD will continue to monitor asset health of steel mains to determine if this needs to be adjusted.

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Steel mains as a group are generally performing well at the current age over the next 10-years, though there are pipelines that individually are in poor condition, requiring mitigation. Through direct assessment and observations made during steel main repairs and other maintenance, it is observed that vintage steel mains have demonstrated declining health compared to steel mains installed after the 1970s. This could be the result of less advanced design, construction and damage prevention practices in the past comparing to today's practices, and latent damages from past third-party construction activities near the mains.

In addition to it age, vintage steel mains are also susceptible to accelerated degradation and/or higher risk of third party damage in the following ways:

- Compression couplings (mechanical fittings which are not welded onto the main) on steel mains that are not properly restrained or unrestrained could cause a loss of containment due to exposed points of thrust. In this case, the weight of the soil is required to hold the fittings in place. When the soil is disturbed, the pipe can pull out of the fitting, resulting in blowing gas through the open pipe end with the potential of full bore release of gas.
- Compression couplings on steel mains that are unknowingly isolated from the corrosion protection system could result in inadequate cathodic protection, leading to the assets' accelerated corrosion and potentially loss of containment.
- The existence of shallow blow-off valve assemblies that could be damaged during excavation activities.
- Reduction in the original depth of cover due to urban development could increase the potential of damages due to excavation activities and increased external loading. According to the codes and standards, a minimum depth of cover is needed to ensure the appropriate distribution of weight of transportation vehicles across pipelines is not exceeded. If the depth of cover is not appropriate, excessive stresses are introduced into the pipe, and failures could result.
- The continuous exposure of road salt and seasonal ground movement on bridge crossing assets that could result in accelerated corrosion and external loading/stresses.
- Lack of cathodic protection with pipe casings that could result in corrosion causing excessive stress or shorts on the carrier pipe that is in contact with the casing, which could lead to the loss of containment.
- Manufacturing defects associated with seam welds and fittings that are weak points in the distribution system and could result in a loss of containment due to prolonged exposure to stress and corrosion.
- Latent damages to pipe coatings that were never reported to EGD for repair and became active corrosion sites, which could hamper the effect of the corrosion protection system and result in accelerated corrosion and potentially loss of containment.

The Kipling-Oshawa-Loop (KOL) system in the Greater Toronto Area (GTA) is a vintage steel High Pressure network (HP) that is known to have most of the features mentioned above across the entire system. This system not only connects the high pressure network between the GTA and the Oshawa area, it also runs through the core of the city along major roadways to supply large businesses and feed into the Intermediate Pressure network (IP) delivering gas to commercial and residential customers. Areas of this system have undergone pressure increases over time in order to serve the increase in customer growth. Given the KOL's operating pressure, the highly populated areas this system was installed in, and the high consequence failure mechanisms such as full pull-out from compression couplings, the risk of the KOL vintage steel system is among the highest of the steel mains population. The cumulative effects of these factors create vulnerabilities with this asset, directly effecting its condition and result in an increasing numbers of leaks in early vintage steel mains as compared to those installed in the 1980's and beyond.

Risks and Consequences: Failures on steel mains in densely populated areas pose a greater risk than in suburban settings, as the ground surface is often paved across the entire width of the street, leaving no openings for escaping natural gas to vent to the atmosphere. With nearby underground infrastructures becoming the path of least resistance, gas can migrate through these channels and into buildings, creating a gaseous and potentially explosive environment for customers and the public. Corrosion leaks through pinholes are the general mode of failure for steel mains. However for the KOL network that was pressure elevated, an additional risk associated with failure of the compression couplings can potentially result in the full bore release of gas. This full bore release of gas into underground infrastructures can result in catastrophic consequences to workers as well as the public as high pressure travels into buildings. EGD has mitigation practices for the treatment of compression couplings where the locations are known, however for vintage gas mains such as the KOL, there are insufficient records identifying the existence of these fittings.

Steel main repairs usually require more planning and resources than plastic main repairs. In many instances, specialized skill sets are needed to install isolation fittings on the steel main and stop the flow of gas in order to facilitate the repair. This in turn adds to the repair duration, causing longer service disruptions, more gas loss, and higher total cost for the repair.

The risks associated with potential failures on these assets are as follows:

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Table 5-13: Risk and Consequences

RISK	EXPLANATION
Safety	Risks of underground gas leaks and migration through underground infrastructures into buildings, resulting in gas accumulation and explosion. Risk of above ground release of gas leading to potential fire.
Financial	Financial loss due to total repair costs, commodity loss, relighting customer gas appliances, regulatory penalties, and any property damages caused by the gas leak.
Customer Satisfaction	Risks associated with greenhouse gas (GHG) emissions, environmental impact, customer outages, and reputational damages.

In order to understand how risks are distributed across the entire steel main network and its long term projection, a system-wide risk assessment was conducted to quantify risk listed in **Table 5-13** over the next 40 years (2018 to 2057). The methodology used is aligned with the risk management bow-tie presented in Section 4 (Strategy & Planning).

Understanding the complexity of the system and the use of best available data, the current scope focuses on risks due to loss of containment attributed by the following threats:

Non-third party damages: In addition to corrosion leaks as predicted by the steel main failure projection model, the following threats are being considered in the risk model:

- Fittings and connectors failures: Does not include instances where another primary cause exists (e.g. ground movement or excavation activities).
- Defective pipe body: Defects from manufacturing.
- Defective joining method: Defects caused by improper welds and mechanical fitting due to improper installation.
- Improper construction method: Leaks caused by human error during construction.

Third party damages: Damages caused by third parties defined as contractor, home owner, landowner, other utility etc. This is typically due to excavation activities.

Since this is the first version of the risk quantification model, complexities listed below have not been implemented and will be considered in the future development of the risk model as part of continuous improvement:

- Location-specific corrosion factors such as stray current, specific soil conditions (such as contaminated soil, poor backfill materials), types of field applied coating, soil type etc.
- Interaction between multiple threats, such as combined effects of dented pipes due to excavation activities and corrosion.
- Failure of compression couplings leading to significant release of gas and pressure due to exposed points of thrust or ground movement.
- Inadvertent damage of pipe fittings and valves which have shallow depth of cover during excavation activities.
- Reduction of original depth of cover due to urban development.
- Variation of population densities due to growth and non-residential purposed areas.
- Constructability issues during repair and replacement activities.

40 Year Risk Projection – 2018 to 2057

The following graph (**Figure 5-13**) illustrates safety and customer satisfaction risk projections over the next 40 years in five year intervals without proactive risk control measures. The distribution between EGD-defined intolerable and conditionally tolerable risk levels is represented by kilometers of pipe in each risk level. Financial risk is excluded from the graph as the main risk drivers for steel mains are safety and customer satisfaction risks. Also shown in the graph is the projected total number of leaks per year based on non-third party damage threats. The leak projection includes both corrosion and non-corrosion failures, but excludes third party damage as it is considered to be a time-independent threat. All values presented in **Figure 5-13** are five year averages.

It is important to note that the projection is a partial view of system wide risk. Further work will be required to account for complexities that are excluded from the current model in order to provide a more comprehensive view on risk.

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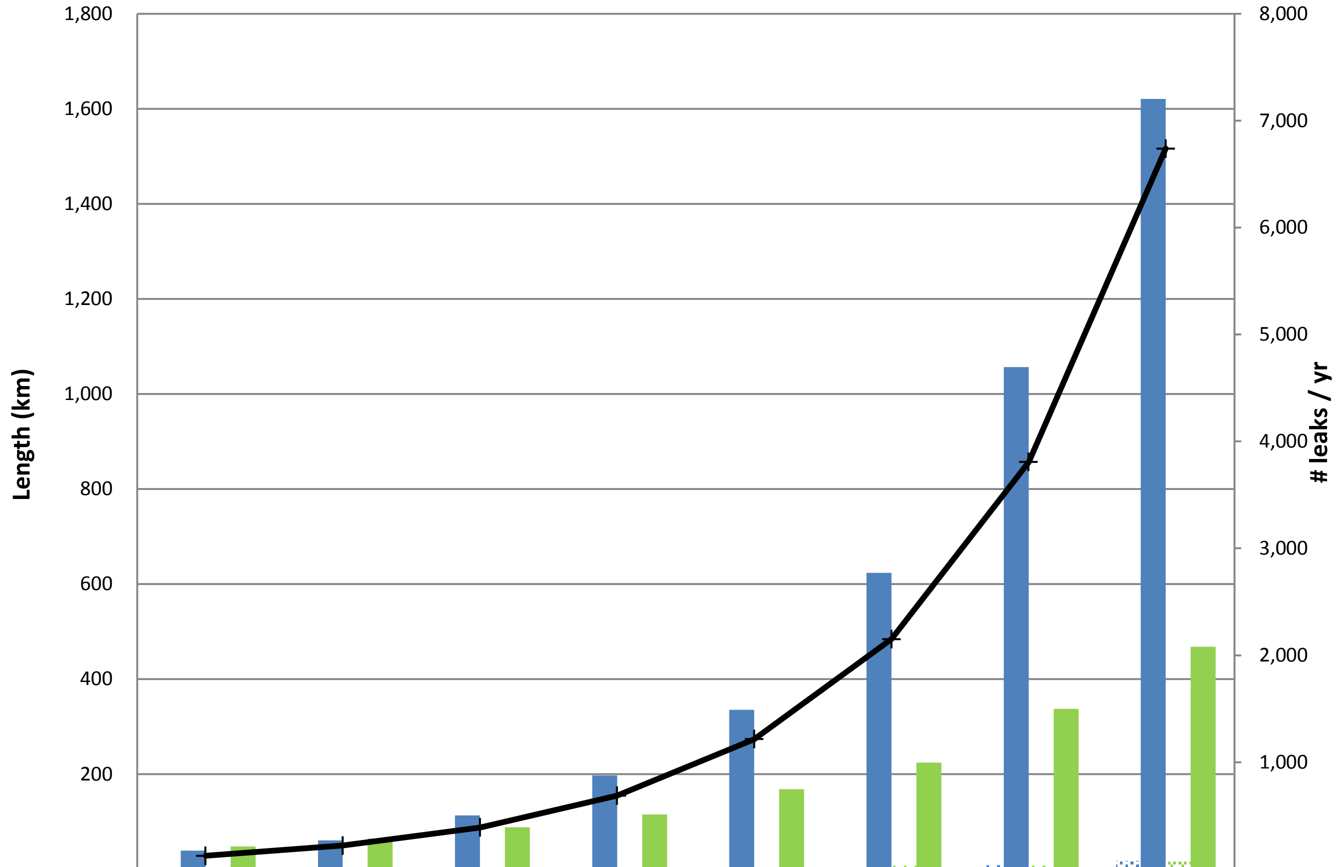

	1 - 01/01/2018 - 12/31/2022	2 - 01/01/2023 - 12/31/2027	3 - 01/01/2028 - 12/31/2032	4 - 01/01/2033 - 12/31/2037	5 - 01/01/2038 - 12/31/2042	6 - 01/01/2043 - 12/31/2047	7 - 01/01/2048 - 12/31/2052	8 - 01/01/2053 - 12/31/2057
Safety - Intolerable	0.03	0.04	0.10	0.13	1.29	3.83	8.80	17.35
Safety - Conditionally Tolerable	38.7	60.2	113.2	197.0	335.3	623.2	1056.7	1620.5
Customer Satisfaction - Intolerable	-	-	-	-	-	7	7	16
Customer Satisfaction - Conditionally Tolerable	47.7	64.5	87.8	114.8	168.5	224.0	336.9	468.0
# leaks / yr	124	220	389	687	1,216	2,151	3,808	6,739

Figure 5-13: Steel Mains Risk Distribution – Safety and Customer Satisfaction Risks

Safety risk is shown to have the most aggressive increase in the next 40 years followed by customer satisfaction risks. Safety risk starts to accelerate in 2028 where the risk has increased three-fold compared to the first five year average. This projection shows that the current risk control strategy will not be able to effectively manage the accelerating risk in the next 40 years to EGD's established risk target. These risks are only tolerable if they can be managed through reasonable and practicable measures (as discussed in **Section 4.1.3.4**). Safety is a corporate priority for the Company and is embedded as a goal within EGD's Asset Management Policy; therefore, in addition to current reactive measures responding to leaks, a proactive risk control strategy needs to be in place to effectively manage risks towards EGD risk target.

Development of Proactive Risk Control Strategy

In order to develop a proactive risk control strategy, the developed risk model was used to investigate risk distribution across the steel main system in 2028 (at the end of a 10 year span). As seen in **Figure 5-14**, out of the population of pipes within intolerable and conditionally tolerable levels, 48% of pipes (in length) are from the KOL system, 24% are from the 20% - 30% SMYS pipe system, while the rest are attributed across the network. The majority of these pipes are vintage steel mains located in populated areas. The outcome aligns well with EGD's experience on vintage steel mains, and in particular with concerns regarding the KOL system.

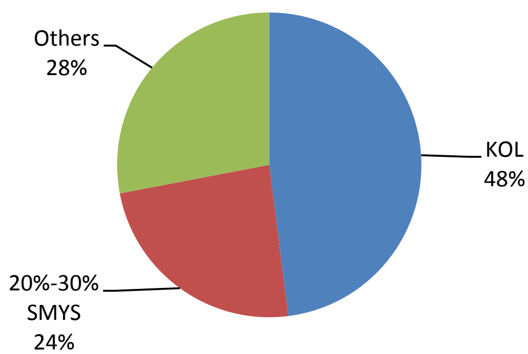

Figure 5-14: Year 2028 Safety Risk of Steel Mains

Since the risk model does not address location-specific issues, inputs from Operations and Integrity subject matter advisors were also considered in developing risk control strategies for vintage steel mains. This includes system wide and location-specific issues such as lack of depth of cover, suspected locations for compression coupling, potential exposure to stray current, and constructability in determining replacement or repair strategies. In order to manage current risks towards EGD's risk target, a proactive risk control strategy to target the vintage KOL system, the 20%-30% SMYS pipelines, and other problematic areas based on inputs from operations and integrity have been formulated and discussed in the following section.

Life Cycle Management: Strategies are required to manage the emerging safety and customer satisfaction risks from vintage steel mains as well as the escalating leak growth in the future due to the deteriorating condition of aging assets.

For the next 10-years, the following short term strategic alternatives are proposed to address these assets' risks:

1. Continue to replace steel mains once they have experienced failure and integrity issues and implement a risk control strategy for pipes with intolerable risks (reactive program).
2. In addition to #1, proactively manage the risks associated with vintage steel mains identified as conditionally tolerable through various risk control strategies ranging from replacement to retrofitting pipes for inline inspection and mitigation (proactive program).

An analysis was completed that shows a replacement rate of 140 km per year is required in order to manage the steel mains to an asset life of 100 years. The illustration below shows the effect of various replacement strategies on the forecasted number of leaks.

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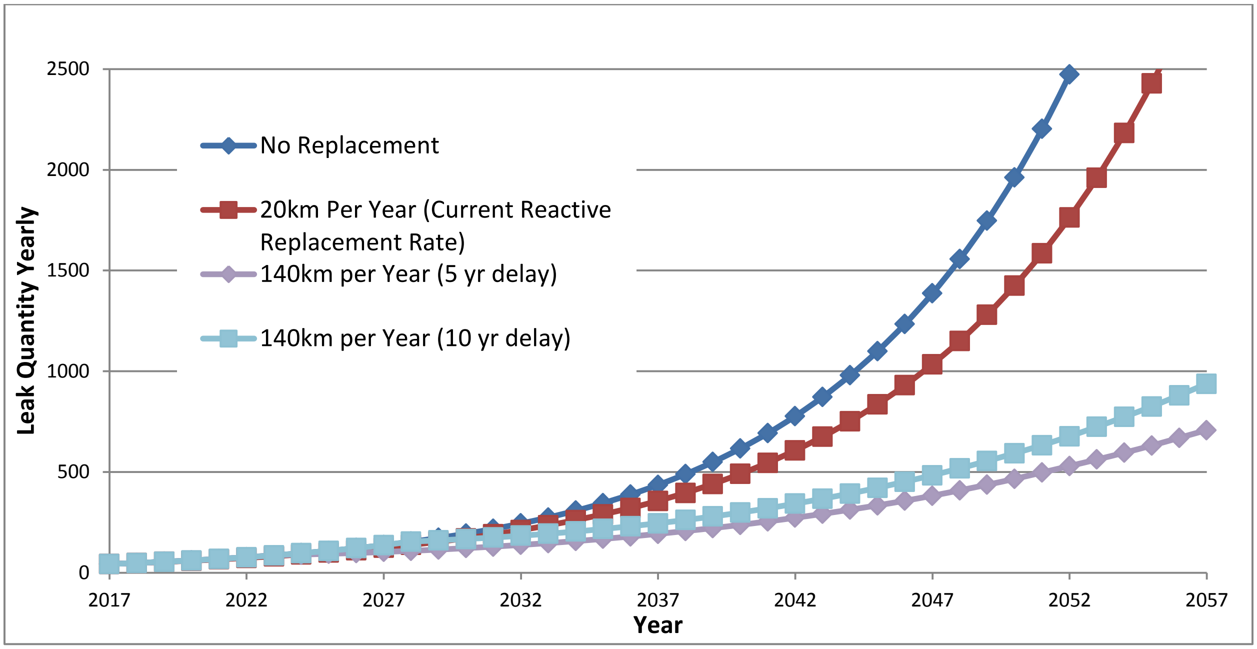

Figure 5-15: Steel Mains Corrosion Failure Projection – Replacement Rate Options

At the current rate of replacement (approximately 20 km per year) it would take over 100 years to address the 1950's pipe alone. By 2047, EGD is projected to experience a steep acceleration of annual leak rates on this asset. If EGD maintains current replacement rate over the next 40 years, it would still see significant increases in corrosion leaks. This level of leak increases will eventually overwhelm the current emergency response capacity and compromise the ability to maintain a safe and reliable distribution system.

To this end, over the longer term, the strategy of managing risk must be augmented to ensure that risk is managed over the long term and that replacement programs can be adequately resourced. This means proactive planned replacements of these assets, at 140 km per year, should be implemented and paced to ensure that these assets are replaced before they reach end of life. Understanding this is seven times the current replacement rate, it is appropriate to start to increase the replacement rates in a thoughtful manner, reducing ratepayer impact while balancing risk, cost, and resource capacity.

EGD evaluates the alternatives using safety, financial, and customer satisfaction criteria.

From a safety perspective, the short term focus of the vintage steel main replacement program is to address the known pipeline integrity concerns and compliance issues as they arise in the field. By addressing steel mains with intolerable risk, and replacing failing and poor condition pipes, it essentially prevents the future failures of these assets. In order to manage the increasing safety risk in the next 40 years, the proactive program targets pipes which could expose the general public to increasing safety risks. This includes the KOL system, part of the 20%-30% SMYS system, and various locations across the network. The intent of this program is to maintain safety risk towards EGD's risk target and reduce the accelerated growth of safety risk beyond 2028. In the longer term, the leak projection forecasts the steel mains leak rate growing close to 10 times over the next 20 years. At such high leak rates, the emergency response capacity will be challenged and will affect the safe and reliable delivery of natural gas, and expose customers, the public, and the employees to higher risk. This long term challenge has not been addressed by the proposed short term strategy.

From a financial perspective, repairing steel mains requires a long planning cycle and extensive coordination of specialized skill sets. In light of accelerating leak growth rate projections, it is financially inefficient to perform large numbers of steel main repairs on an emergency response basis rather than a planned proactive replacement basis, since the emergency repairs only improve the condition of very small sections of the affected mains, leaving the overall system still in a generally poor condition. Planned replacements essentially eliminate all other active corrosion sites that have not failed yet and avoid the need for multiple leak repairs along the same steel system. It also provides opportunities to optimize financial resources to be more cost effective.

From a customer satisfaction perspective, with the projected growth in customer satisfaction risk, the risk of interrupting supply to customers and greenhouse gas emissions associated with uncontrolled gas release would increase in the next 40 years. Addressing the leaks alone through the reactive program would not effectively reduce the risk to EGD's target. In order to

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ensure a satisfactory customer experience, a proactive program needs to be in place to actively manage potentially failing pipes.

Preferred Strategy*:* To ensure the safe and reliable delivery of natural gas, EGD will continue to focus on addressing existing pipeline integrity concerns and compliance issues as they are being identified. Based on the short term leak rate projections shown in **Figure 5-13** Steel Mains Risk Distribution, EGD should plan for an increase in its reactive replacement program as part of the reactive program to account for the growing leak rates.

In order to manage the accelerating risk in safety and customer satisfaction, the proactive risk management program proposed above will be brought forward, ensuring that risks are managed towards EGD's risk target.

As described above, the steel main failure projection model points to an asset life of 100 years. It is expected that in the next 40 years the long term challenge for EGD is to manage the acceleration of leaks in the steel main system when the majority of the population is approaching its end of useful life. This will put a lot of stress on EGD resources in responding to failures and planning and executing replacement or repair activities.

Although the proposed short term strategy (both reactive and proactive programs) can manage safety and customer satisfaction risks in the next 10-years, it is not designed to address potential logistic and resource constraints in the future. To address the long term challenge, EGD will:

- Start evaluating potential logistic and resource constraints based on current leak projections.
- Closely monitor leak rates as part of the validation process for both the steel main failure projection model and risk models.
- Improve data collection on location-specific information to advance predictability of current steel main failure projection and risk models.
- Evaluate EGD's steel main replacement strategy regularly to determine if the replacement rate as proposed in **Figure 5-15** Steel Mains Corrosion Failure Projections – Replacement Rate Options (increasing the replacement rate to 140 km per year) must be implemented.

In the short term, the preferred replacement strategy is to continue the current reactive replacement program and augment this with the proactive risk management program to address risk associated with pipes such as those in the KOL system and part of the 20%-30% SMYS system through reasonable and practical measures. The preferred strategy is Option 2.

The preferred strategy has the following benefits:

- Addresses reactive work for the short term, while initializing a proactive replacement strategy.
- Manages the longer term risk associated with aging assets.
- Helps EGD manage operating and maintenance costs effectively.

EGD will continually monitor the performance of the assets and refine the analytical models based on best available data. As the quality of models and data improve according to Plan-Do-Check-Act, EGD can better predict asset condition and support the longer term replacement plan and modify the replacement strategy.

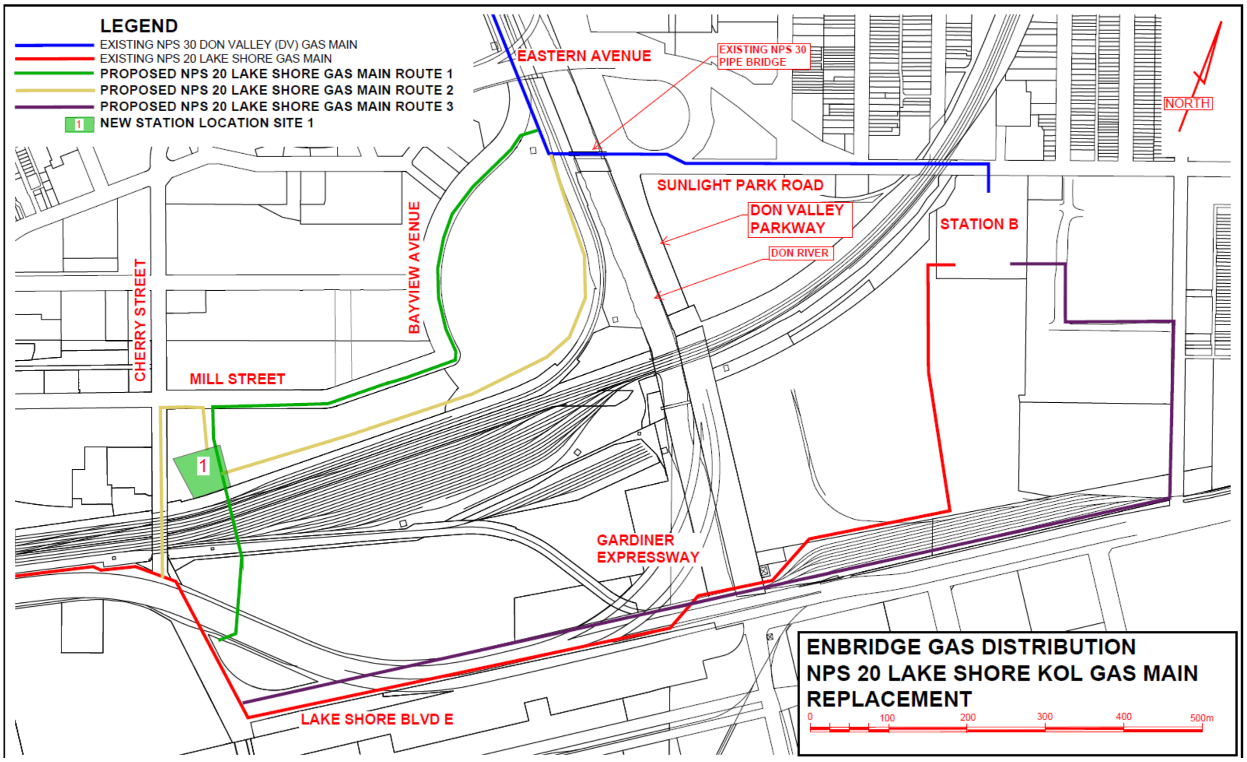

Figure 5-25: Segment B – Existing NPS 20 HP Gas Main and Proposed Route Alternatives

NPS 20 LAKESHORE KIPLING OSHAWA LOOP (KOL) REPLACEMENT PROJECT

The NPS 20 Lakeshore KOL replacement Project spans 46 km from Lisgar Station on the north-west side of the GTA to Station B on the southeast side of the GTA. This replacement Project has been divided into 5 phases and prioritized using the results from the Asset Health Review (AHR), QRA and tacit knowledge. The 5 phases for the replacement of the NPS 20 HP KOL pipeline will span over numerous years with Phase 1 and 2 captured within the 10-year Asset Management Plan.

Phase 1 is currently in the planning stage. Phase 2 is in the screening stage while Phase 3-5 are still in the preliminary screening stages and as such, do not have well-defined Project scopes identified at this time.

Figure 5-26: NPS 20 Lakeshore KOL Replacement Phases

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Scope

The Project scope for Phase 1 and Phase 2, as well as anticipated construction timing is described below.

Phase 1 (Cherry Street to Bathurst Street) - NPS 20 Lakeshore KOL Replacement Project:

The NPS 20 Lakeshore Kipling Oshawa Loop (KOL) replacement Project addresses vintage steel mains installed in 1954. This Project was assessed through the use of the AHR methodology, QRA, tacit knowledge from a variety of internal stakeholders and ILI/Integrity dig results. In addition to the declining health demonstrated by vintage steel mains, this pipeline is part of the KOL system in the Toronto area and is known to have a number of features that make it more susceptible to accelerated degradation and/or higher risk of third party damage. These features include but are not limited to compression couplings on mains and services, reduced depth of cover, shallow blow-off valves, drips/syphons, lack of cathodic protection, live stubs, stray current from hydro infrastructure and possible contaminated soils. The assessment of Phase 1 has identified risk results that exceed the Company's risk tolerance and supports the replacement of the pipeline.

The NPS 20 KOL Phase 1 Cherry to Bathurst Project is a size for size replacement of NPS 20 HP steel main on Lakeshore Blvd. The first phase addresses a section of the KOL pipeline identified to be above the acceptable risk tolerance and has been scheduled in the first half of the 10-year Asset Management Plan. The replacement of the NPS 20 Lakeshore KOL Phase 1 vintage steel main addresses known pipeline integrity and operational field concerns by proactively replacing steel mains approaching intolerable risk due to failing and/or poor condition pipes. This results in the prevention of the future failures of these critical distribution system assets.

Scope

The scope of this Project includes the replacement of the existing NPS 20 HP KOL steel natural gas main (Segment A) on Lake Shore Blvd from Cherry Street to Remembrance Drive. Approximately 4.4 km of NPS 20 HP steel main will be installed and approximately 4.5 km of the existing NPS 20 HP gas main will be retired.

In addition, the scope of this Project includes the replacement of the existing NPS 20 HP KOL steel natural gas main (Segment B) on Parliament Street from Lake Shore Blvd E to Mill Street. Approximately 500 m of NPS 16 HP steel main will be installed on Mill Street, between Tannery Road and Trinity Street, and approximately 300 m of the existing NPS 20 HP gas main on Parliament Street will be retired. The Project will consist of the planning and engineering in 2018/2019, with construction to begin in 2020.

Expenditures

A Class 5 estimate was completed for Phase 1 and the total capital expenditure to replace the 4.5 km of NPS 20 HP main will be approximately $145M as illustrated in **Table 5-16**. This cost was determined by Regional Construction and Major Projects Planning using the cost estimating tool.

Resources

These larger main replacement Projects are traditionally planned and designed by the Planning & Major Projects department. Planning has a team of dedicated full time employees that will continue to manage and execute the major pipeline replacement Projects. The construction work will be managed by the Major Projects group while the contractor executes the work. Depending on the scope and complexity of the replacement Project, the construction contractor resourcing will be managed through a combination of existing EA Contractors and bid process to source out additional contractor resources where required.

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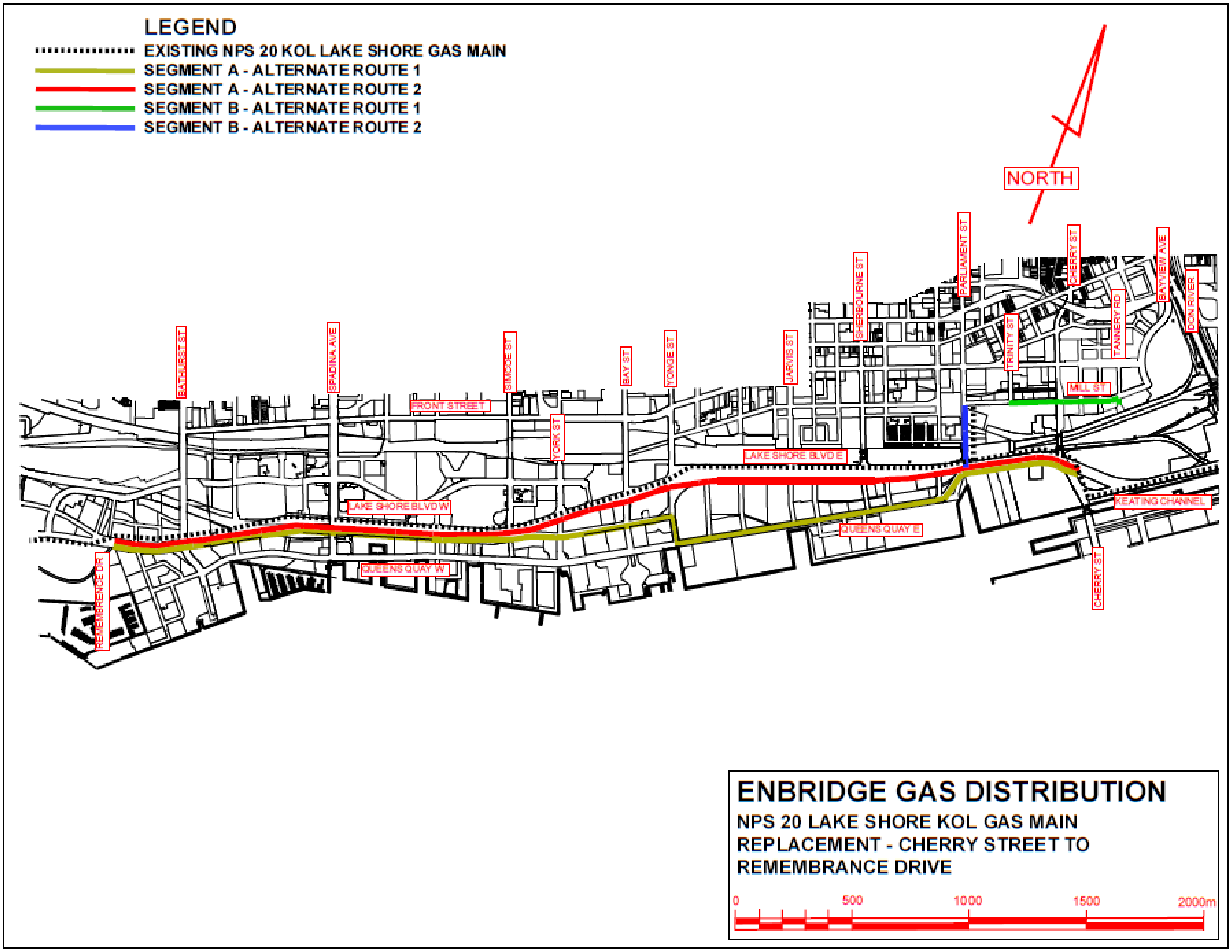
Leave to Construct

A LTC will be requested. This Project is a like-for-like replacement however there is a possibility that the new main may require a land easement for a short section of the proposed alignment. In addition, in the interest of the public and in an effort to review, discuss and coordinate the Project scope/complexity with all external stakeholders that may be directly or indirectly impacted by the construction of the Project, it is the position of the Company that a LTC would be beneficial.



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Phase 2 (Winston Churchill) - NPS 20 Lakeshore KOL Replacement Project:

NPS 20 Lakeshore KOL replacement Project addresses vintage steel mains installed in 1954. This Project was assessed through the use of the AHR methodology, QRA, a collection of tacit knowledge from a variety of internal stakeholders and ILI/Integrity dig results. In addition to the declining health demonstrated by vintage steel mains, this pipeline is part of the KOL system in the Toronto area and is known to have a number of features that make it more susceptible to accelerated degradation and/or higher risk of third party damage. These features include but are not limited to compression couplings on mains and services, reduced depth of cover, shallow blow-off valves, lack of cathodic protection, live stubs, stray current from hydro infrastructure and possible contaminated soils. The assessment of Phase 2 has identified risk results that are approaching the Company's intolerable risk region and support that this section of the NPS 20 pipeline that requires replacement.

The NPS 20 KOL Phase 2 Winston Churchill Blvd Project is a size for size replacement of NPS 20 HP steel main from Lisgar Station to Sheridan Park Dr. The second phase is addressing a section of the pipeline identified to be approaching the intolerable risk tolerance and has been scheduled in the second half of the 10-year Asset Management Plan. This phase requires some additional investigation to confirm the pipe condition status with the identification of the appropriate scope and replacement timing. The replacement of the NPS 20 KOL Phase 2 (Winston Churchill Blvd) vintage steel main addresses known pipeline integrity and operational field concerns by proactively replacing steel mains approaching intolerable risk due to failing and/or poor condition pipes. This results in the prevention of the future failures of these critical distribution system assets.

Scope

The scope of this Project includes the replacement of the existing NPS 20 HP KOL steel natural gas main on Winston Churchill Blvd. from Lisgar Gate Station to Sheridan Park Dr. (former Sheridan Gate Station site). Approximately 10.7 km of NPS 20 HP steel main will be installed and approximately 10.7 km of the existing NPS 20 HP gas main will be retired. The new pipeline route will follow the Municipal Right of Way where possible and is planned for construction in 2024. The planning and engineering will take place in 2022/2023.

Expenditures

A Class 5 estimate was completed for Phase 2 and the total capital expenditure to replace the 10.7 km of NPS 20 HP main will be approximately $298.5M as illustrated in **Table 5-16.** This cost was determined by Regional Construction and Major Projects Planning using the cost estimating tool.

Resources

These larger main replacement Projects are traditionally planned and designed by the Planning & Major Projects department. Planning has a team of dedicated full time employees that will continue to manage and execute the major pipeline replacement Projects. The construction work will be managed by the Major Projects group while the contractor executes the work. Depending on the scope and complexity of the replacement Project, the construction contractor resourcing will be managed through a combination of existing EA Contractors and bid process to source out additional contractor resources where required.

Leave to Construct

A LTC will be requested. This Project is a like-for-like replacement however there is a possibility that the new main may require a land easement for a short section of the proposed alignment. In addition, in the interest of the public and in an effort to review, discuss and coordinate the Project scope/complexity with all external stakeholders that may be directly or indirectly impacted by the construction of the Project, it is the position of the Company that a LTC may be considered.

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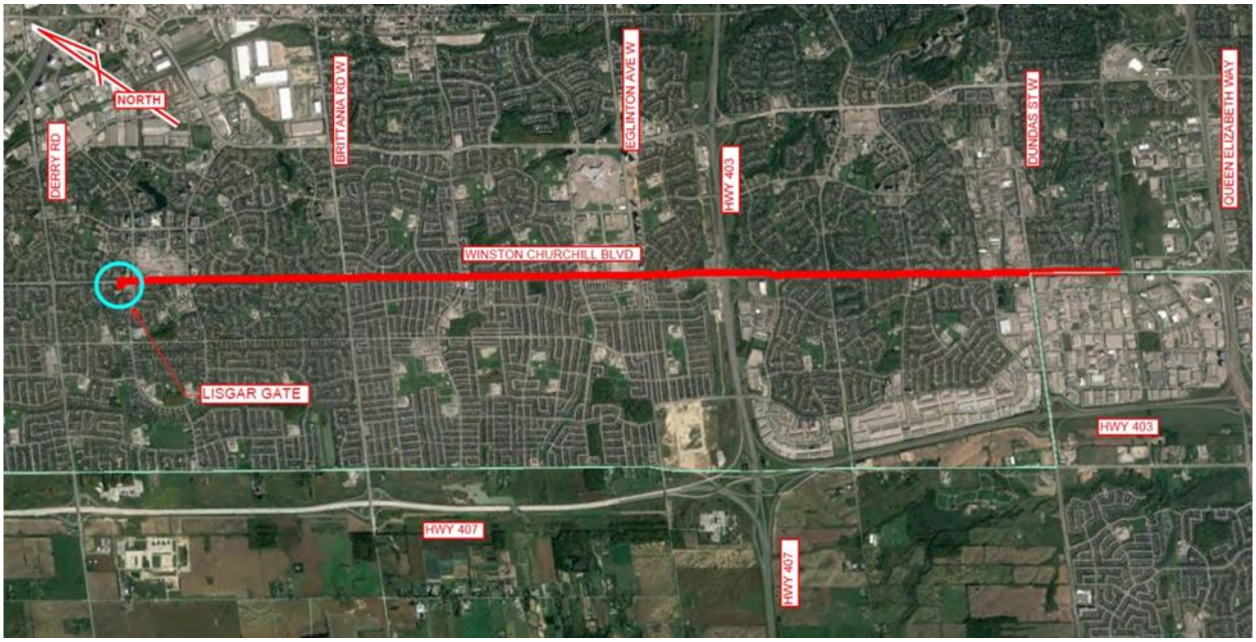

Figure 5-28: Phase 2 - Winston Churchill Blvd – NPS 20 Lakeshore KOL Replacement

NPS 12 ST. LAURENT REPLACEMENT PROJECT

NPS 12 St Laurent XHP replacement Project addresses vintage steel mains installed in 1958. This Project was assessed through the use of the AHR methodology, QRA and a collection of tacit knowledge from a variety of internal stakeholders. In addition to the declining health demonstrated by vintage steel mains, this pipeline is located in downtown Ottawa and is known to have a number of features that make it more susceptible to accelerated degradation and/or higher risk of third party damage. These features include but are not limited to compression couplings, reduced depth of cover, shallow blow-off valves, lack of cathodic protection, live stubs, stray current from railway and hydro infrastructure and possible contaminated soils. The assessment has identified risk results that exceed the Company’s risk tolerance and support that this section of the NPS 12 XHP pipeline requires replacement.

This replacement Project has been split into four phases, with the first two phases scheduled for 2018 and 2019 and the remaining two phases identified for 2021 & 2022 within the 10-year Asset Management Plan.

The NPS 12 St Laurent Project is a size for size replacement of NPS 12 XHP steel main. The replacement Project is addressing sections of the pipeline identified to be in poor condition and has been scheduled in the first half of the 10-year Asset Management Plan. The third and fourth phases require some additional investigation to confirm the pipe condition status, and then identify the appropriate scope and the replacement timing.

The replacement of the NPS 12 XHP vintage steel main helps address known pipeline integrity and operational field concerns by proactively replacing steel mains approaching intolerable risk due to failing and/or poor condition pipes. This results in the prevention of the future failures of these critical distribution system assets.

The lateral to Trans Alta was installed in 1992 and the main that is crossing the Rideau River to Hurdman Station was installed in 1985, 1986 and 1998. As such, these mains will not be included in this replacement Project. Both the AHR and QRA results support the decision to exclude these mains from the replacement Project.

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Asset Management

Asset Replacement Strategy

Legacy EGD

AM Principles & Governance

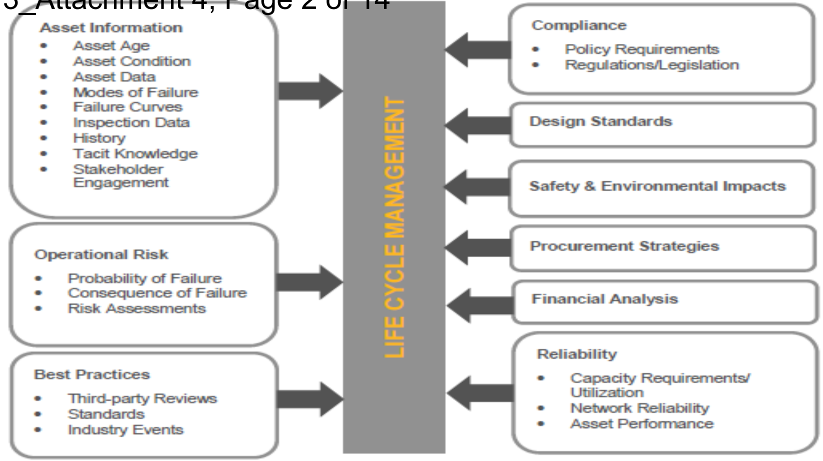


Figure 4.1-6: Life Cycle Management Inputs

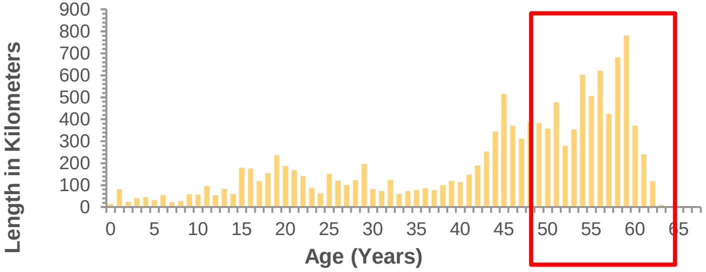
EGD is committed to:

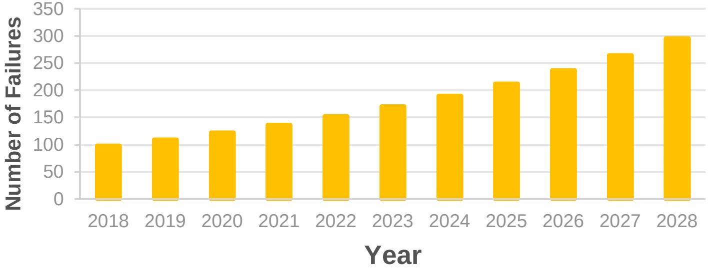
- ❑ Value-based decision-making for all asset-related investments on a holistic evaluation of:
  - Cost,
  - Risk, and
  - Performance
- ❑ Continual comprehensive condition assessment and risk review.
- ❑ Understanding of the asset’s life cycle which is critical for decision-making and the safe and reliable delivery of natural gas.
- ❑ Balancing data & tacit (quantitative / qualitative)
- ❑ Ensuring its processes, systems, and controls collectively strive to deliver verifiable, traceable, complete, timely, accurate, and accessible asset information

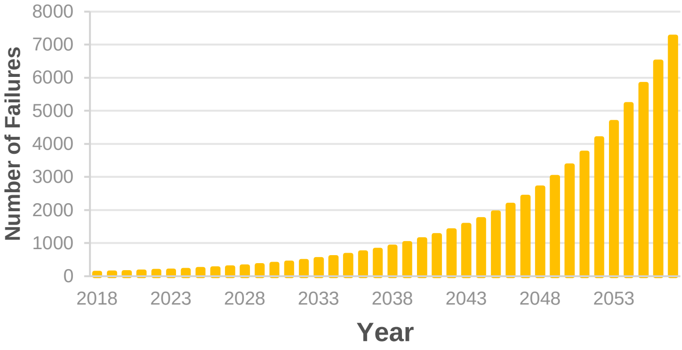
These principles need to be transparent and demonstrated to ensure prudency of capital spend while maintaining safety and reliability, and credibility with our internal and external stakeholders (Customers, OEB, Industry)

Vintage Steel Understanding

- Over 13,000 km of Steel pipe in inventory
- Vintage: installed before 1970 and accounts for 7,000 km
- Services the oldest and most densely populated areas
- Impacted by urban encroachment and municipal infrastructure growth & renewal programs
- Asset Health impacted by:
  - Materials, coatings, design requirements and construction practices based on standards of the time
  - Protection programs such as utility locates and cathodic protection differed from current practices
- Assets found to have varying degrees of corrosion due to historic cathodic protection practices and coating standards
- Failure rates are expected to increase over time
- Expected Life - 100 yrs to first failure
- By 2050, > 2,000 km will be at or above 100 yrs old
- Current Replacement rate – 9 km/yr
  - translates to 200+ yrs to replace 2,200 km of 1950's pipe
- A higher replacement rate is needed to manage the long term health of the assets







Demonstrating the need

Do we have the information needed to demonstrate the need for broad system replacement? If not, what else is needed, and how can we get there?

Life Cycle Strategy:

To support a broad replacement program, a robust life-cycle strategy needs to be developed and matured, which include the following components of cost, risk and performance:

- Full Life Cycle cost (Capital / O&M)
- Total cost of ownership
- Asset performance, condition and end of life (Data driven, balanced with tacit)
- Impact of repair, replace and run to failure decisions
- Forecasted risk over time
- Maximizing financial performance without increasing risk
- Resource capacity
- Long term use of gas

These elements are currently under development, but are not mature enough to be used as the basis for decision making.

The current Vintage steel replacement program has been designed to address the pacing required to address the increasing leaks anticipated over time, as well as the known poorly performing assets, driven by tacit knowledge.

Recommendation & Path Forward

End Goal (Longer term 2-5 yrs.)

Mature the AM foundation through Value-based Decision making focused on Asset Lifecycle Management (ALM)

- ❑ **Asset Performance** (Value of Ownership)
  - Enhanced focus on Asset performance and customer outcomes
  - Improved sustainability through short and long term investments focused on system performance
- ❑ **Cost of Ownership**
  - More effective investment decisions and trade-offs between CAPEX / OPEX across the lifecycle
  - Optimized maintenance strategies with understanding of impact on useful life
  - Improved operational efficiency through better asset performance with managed cost / risk
- ❑ **Risk of Ownership**
  - Improved stakeholder confidence through reduced risk and compliance assurance
  - Improved decision credibility / accountability with a clear audit trail for decision making across the lifecycle
  - Improved delivery of governance outcomes

Vintage Steel Mains (VSM) Plan – Next Steps

Themes	Next 6 Months	6 Months to 1 year	1 to 2 years
Integration Activities	• Develop integrated Asset Management plan across EGI	• Targeted training for improved AM Practice across EGI. • Integration planning of EGI asset data, knowledge, and systems	• Combined asset platform
Asset Performance (Value of Ownership)	Development of: • Acceptable asset performance standards and measures • Criteria for making decisions - 'what is good enough' in terms of analysis, and understanding of condition degradation • Asset performance analysis at the system/network level.	Development of Decision Support framework that: • incorporates tacit knowledge and data to support a prioritized replacement plan • considers observed condition, operability, maintainability and consequence • broader analysis of risk and performance scenarios (maintenance strategy, spares, redundancy, etc.) • Establish the role of IRP in system planning and demand side management	• Detailed next steps for the proactive program • Execute asset investments and maintenance to maintain short/long-term system performance • Methodology to make repeatable and traceable asset investment decisions supported with quantitative/qualitative knowledge
Cost of Ownership	• Replace vintage steel main based on leak projections and tacit information	• Develop lifecycle costing analysis	• Development of a proactive strategy to replace VSM before end of life in keeping with performance standards
Risk of Ownership	• Mitigate risk and condition issues as identified in the field to maintain safe and reliable operations • Manage risks of larger diameter pipelines to prevent intolerable risks • Continue to collect and analyze pipe condition data through field activities and tacit input • Set up team with specific objectives & timelines to identify proactive replacement program	• Research industry and regulatory practices • Identify clear drivers for proactive program and confirm segments/projects to send for solution planning • Ensure engagement of internal stakeholders on identified segments/projects	• Enhance AHR predictive analysis and risk models with pipe condition data & include other influencing factors • Start proactive program in 2020 • Continue sustainment of proactive program

Timeline Overview – Major Pipelines

	2015 - 2016 – Risk Ranking	2017 – 2018 Asset Analytics Introduced	2018 to Present - Value Based Decision Making
Analytical Activity	• Asset Health Review (AHR) exercise conducted on vintage steel mains (13 major pipelines) based on tacit knowledge • AHR exercise condition ranked & prioritized three pipelines for replacement (vetted with AR&I) 1. NPS 20 Lakeshore KOL Pipeline (45.7km) 2. NPS 12 Martin Grove KOL Pipeline (5.6km) 3. NPS 12 St Laurent (270 psi) Pipeline, Ottawa North (13.3km)	**Asset Information:** • Collection of information/knowledge & expertise on the major pipelines including: 1. Predicted latent third party damage rates (ILI statistics) 2. DOC concerns 3. Number of fittings and service branches • MOP studies & record research • Crawler ILI segments of NPS 20 Lake Shore • Execution of integrity digs from ILI results • DOC surveys completed on all 3 pipelines • ECDA and Pipe Wall Assessment (PWA) activities completed on segments of NPS 20 Lake Shore and NPS 12 St. Laurent • 3rd Party Damage impact on risk assessment results	**Operational Risk:** • Completion of QRAs for the identified pipelines (including engagement of internal stakeholders) • Address immediate risk identified with NPS 30 XHP Don River Pipe Bridge – 1929 structure • Address immediate risk identified with NPS 12 St Laurent (Tremblay) • Metal loss feature growth projections & metal loss estimates for similar pipes in geographic area • Value based decision on a holistic review of cost, risk and performance

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Major Pipelines – Summary

Pipeline / Project	NPS 20 KOL Lake Shore Phase 2 - 5	NPS 20 KOL Lake Shore Phase 1	NPS 20 Don River Relocaton	NPS 12 KOL Martin Grove	NPS 12 St Laurent	NPS 30 Don River Replacement
Cost						
Retrofit, ILI and Integrity Dig Option Estimate (*Entire length of NPS 20 KOL)	$266.7 M*	NA	NA	$9.8 M	$16 M	NA
Replacement High Level Estimated Cost	$1.2 B	$150.7 M	$41.4 M	$27.5 M	$57.1 M	$25.4 M
Risk						
Does the Initial QRA substantiate replacement?			NA			
Does the purpose, need and timing substantiate replacement?						
Is the cost proportionate to the risk reduction?			NA			
Performance						
Safety						
Wall to Wall (Approximate %)	5%	50%	NA	0%	1%	NA
High Level Buildings			NA			NA
Reliability						
Vital Main?						
Customer Impact with Pipe Failure at Peak	49,462	-	-	1,831	61,412	92,500
Is there repair history?						
Condition						
Does DOC Survey confirm locations below code or EGD guideline?			NA			NA
Metal Loss features identified by ILI of 1500m & 413m on NPS 20 KOL pipe segments & estimated from ILI results on NPS 12 Ottawa North IMP	TBD/Estimated	**735 + 348**	NA	NA	321	NA
-Metal Loss >=70% WT (Immediate digs)	TBD/Estimated	**0 + 0**	NA	NA	11	NA
-Metal Loss >=60% WT <70% WT (Scheduled digs)	TBD/Estimated	**0 + 3**	NA	NA	0	NA
-Metal Loss 50% WT - 60% WT (Scheduled digs)	TBD/Estimated	**3 + 4**	NA	NA	26	NA
-Metal Loss 30% WT - 50% WT	TBD/Estimated	69 + 43	NA	NA	0	NA
Dents identified by ILI of 1500m pipe segment	TBD/Estimated	**16 + 0**	NA	NA	13	NA
-Dents >=2% OD (Scheduled digs)	TBD/Estimated	**2 + 0**	NA	NA	4	NA
-Dents <2% OD >=1% OD	TBD/Estimated	3 + 0	NA	NA	7	NA
How much life do we expect on this pipeline (wall loss growth projection)	TBD	TBD	NA	TBD	TBD	NA
Do we have field or failure data and/or Eng. studies to substantiate replacement?			If Stakeholder Conflict is Confirmed			
What additional data or work is recommended for decision? Note: Crawler ILI estimated cost is $650K (O&M)	- Metal loss feature growth projections -3rd Party QRA component	- Metal loss feature growth projections -3rd Party QRA component	NA	-3rd Party Damage QRA component -Evaluate options to address DOC concerns	-3rd Party Damage QRA component -Crawler ILI 2019 -Metal loss feature growth prjections	NA
Recommendation	Keep Phase 2-5 Beyond 10 YR Plan	Keep Phase 1 to 2025+	Proceed with Stakeholder Confirmation Only	Proceed per Two Phases	Proceed per Four Phases	Procced 2019

Legend	**Yes**	**No**	**Partially**	**Moving to Yes**

Major Pipelines – Next Steps

Vintage Steel Main Plan

Next 6 months
- Develop acceptable asset performance standards and measures
- Decision making criteria

6 Months to 1 year
- Decision support framework development

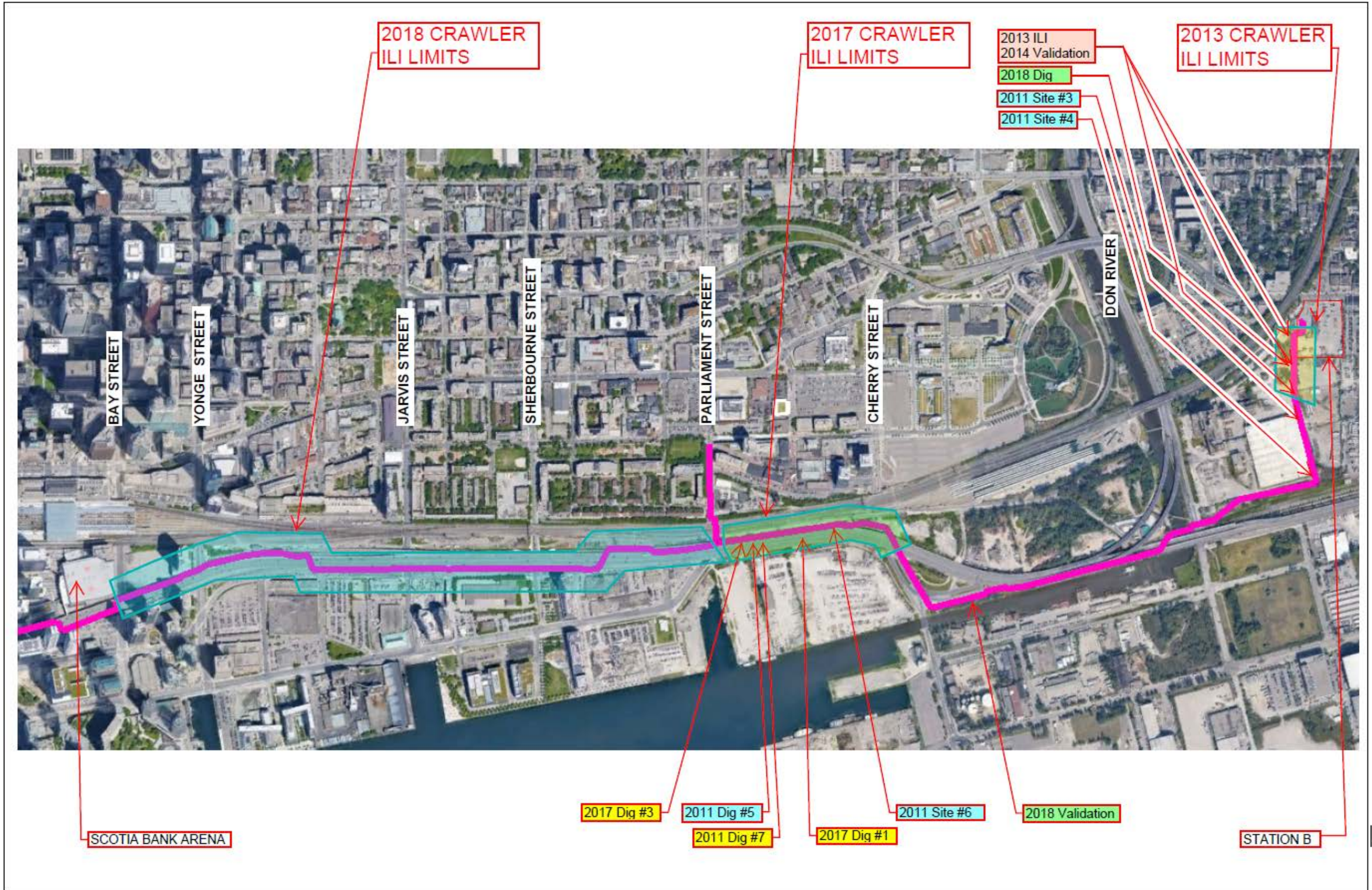
1 to 2 years
- Development of proactive strategy to replace VSM aligned with performance standards, enhance AHR

2 to 5 years
- Value based decision making focused on Asset Lifecycle Management

	Next 6 Months	6 Months to 1 year	1 to 2 years	2 to 5 years
NPS 30 Don River Replacement	Obtain permit & easement approval for construction execution in 2019			
NPS 20 Don River Relocation	Confirmation from stakeholder to proceed	- Finalize route option - Continue with EA and LTC Process	Continue planning, pre-engineering and detail engineering for construction in 2020	
NPS 12 St Laurent & NPS 20 Lake Shore	Explore other methods to identify integrity dig locations: - Use of PipeTel ILI Crawler Tool - Use of PureHM Pipe Wall Assessment Tool (PWA) - Regional tacit knowledge Wall loss growth projections	- Execution of identified methods - Work with GSTS Integrity to project growth of corrosion features from ILI results	Continue planning, pre-engineering and detail engineering for: - NPS 12 construction in 2021 & 2022 -NPS 20 Phase 1 construction 2025	- Work with municipal & external stakeholders to address conflicts with future developments - Continue identifying NPS 20 Phase 2-5 scope and timing
Asset Management Evolution Activities	Incorporate 3rd Party Damage component (DOC survey results) in QRA	- Utilize field data from integrity digs in QRA - Utilize tacit knowledge in QRA (quantify)		

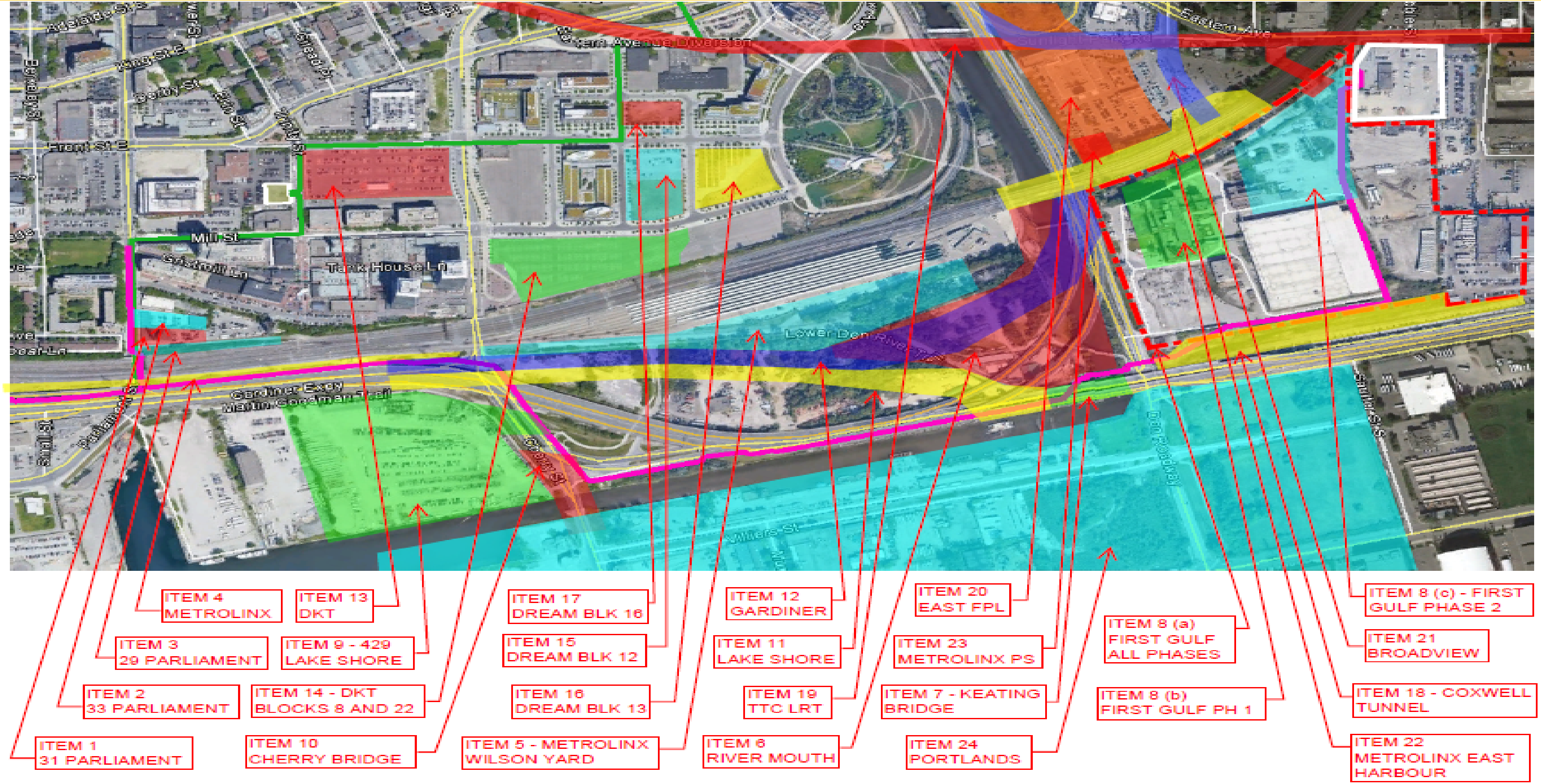
Back Up Slides

NPS 20 Lake Shore ILI & Integrity Dig Overview



Shows existing Station B and the proposed station location

NPS 20 Supply/Don River Replacement – Other Concurrent Projects



Proposed Phases

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ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe (EP)

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, Page 7

Preamble:

"Based on the data gathered through the completed ILIs, Enbridge Gas forecasts that around 72 integrity digs would have to be conducted on the inspected sections of the C2B segment in the next 40 years (taking into account that required digs could be combined where close to one another)."

Question**:**

a) Please explain why the OEB should be concerned about 72 "integrity digs" in the next 40 years.

b) Please confirm that an integrity dig is an excavation that Enbridge management decides to do.

c) How many integrity digs does Enbridge Gas do each year?

d) Please provide the number of integrity digs per year per km for each diameter of steel pipe in the Enbridge Gas system for the last five years.

Response:

a) The quantity and costs of these digs make it unreasonable to continue to perform integrity digs. There is also a potential public safety impact as ILI tools are not perfect (+-10% @ 80% confidence). The features identified during an ILI may be located in an area requiring a complicated excavation or requiring significant public and social disruptions (i.e. multiple lane closures). A replacement pipeline can be designed to minimize these impacts during installation. Additionally, many repair methods require welding on a live gas pipeline which introduces risk to the work performed.

b) An integrity dig is an excavation that is required due to a concern on the pipeline condition, in order to ensure the safety and reliability of the Enbridge Gas system. Some of these integrity digs are prescribed by standards, whereas other integrity digs are professional judgments made by Enbridge Gas personnel.

c) Enbridge Gas completed 71 integrity digs in 2020 and 69 integrity digs in 2019. These digs were completed across approximately 3,600km of Transmission Integrity Management Program gas mains, of which 80% have a designated ILI inspection frequency.

d) Enbridge Gas can provide this information for the Legacy EGD network only. Please refer to the table below for the total number of integrity digs in the last five years in the legacy EGD service territory for mains that are part of the Transmission Integrity Management Program.

Pipe Size	# Digs	# Digs per Year per KM
NPS 8	10	0.034135187
NPS 10	6	0.169598794
NPS 12	53	0.099780829
NPS 16	7	0.026547463
NPS 20	8	0.05582331
NPS 24	19	0.047160924
NPS 26	0	0
NPS 30	9	0.024519627
NPS 36	4	0.008758185

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe (EP)

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, Pages 7 and 10

Preamble:

"This model is used by Enbridge Gas's Integrity Management department to determine expected corrosion growth rates on existing features identified by ILIs."

Question:

a) Please provide all assumptions regarding the forecast of expected corrosion rates including cathodic protection pipe to soil potentials over the next 40 years.

b) Please describe cathodic protection actions that Enbridge could take over the next 40 years to ensure that pipe to soil potentials remained in the range that would protect the pipe from corrosion.

Response:

a) PiMSlider corrosion projections do not integrate cathodic protection potentials. Corrosion rates are determined based on the size of the defect and the age of the pipe segment.

b) Cathodic protection is not a solution that could ensure the Cherry to Bathurst segment of the KOL is completely protected against further corrosion for the next 40 years. Enbridge Gas presently applies cathodic protection using rectifiers combined with 24/7 remote monitoring in levels that are generally considered sufficient to protect the main according to the annual test point survey. Unfortunately, there are areas where coating degradation, soil contamination, and stray current may cause additional risks to pipeline integrity that cathodic protection would not be able to fully protect against. The specific location where these risks present themselves are difficult to diagnose and mitigate. Aboveground surveys, for example, were not perceived to be reliable in accounting for the myriad of interference/coating issues in the area when attempting to identify integrity problems, and were consequently not accepted as reliable indicators of integrity issues. As such, although it is deemed feasible to maintain cathodic protection levels above protection criteria similar to the methods used at present, this protection can only be confirmed at the test point locations.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe (EP)

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, Page 10

Question:

a) Please provide the location of the 3 locations totalling 6.1 metres that have less than 60 cm of cover than required by the CSAZ662 standard.

b) For how long has Enbridge Gas been aware that these three locations do not meet the requirements of the CSAZ662 standard.

c) Has Enbridge Gas informed the TSSA that its NPS 20 does not have adequate cover at three locations? If the answer is yes, please file the report that Enbridge sent to the TSSA regarding this non-compliance with CSAZ662. If the answer is no, please explain why not.

d) Can additional cover be placed at these three locations or can the pipe be lowered?

Response:

a) Location 1 is approximately 15m east of Parliament Street along the north Boulevard of the Lake Shore Boulevard East westbound lanes.

   Location 2 is approximately 19m east of the Parliament Street along the north Boulevard of the Lake Shore Boulevard East westbound lanes.

   Location 3 is approximately 40m east of Bonnycastle Street under the north curb of the east bound traffic lane of Lake Shore Boulevard East.

b) The Depth of Cover survey was conducted on this pipeline in December of 2015.

c) There is no requirement for Enbridge Gas to report to the TSSA depth of cover issues for its pipelines. When depth of cover issues are identified the expectation is that the operator deals with those issues. The Project will alleviate these known depth of cover issues.

d) For locations 1 and 2, the pipeline is directly adjacent to the Metrolinx fence. No change of grade or excavation to lower the pipeline is permissible this close to the main line tracks. For location 3, being in the east bound lanes of Lake Shore Boulevard East the change of grade isn't possible at this location.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Energy Probe (EP)

INTERROGATORY

Reference:

Exhibit C, Tab 1, Schedule 1, Page 3

Preamble:

"Golder's evaluation and recommendations were developed using their proprietary "GoldSET" methodology."

Question:

a) Please explain what GoldSET methodology does.

b) Please explain why the OEB should have confidence in Golder's evaluation using its GoldSET methodology considering that there was no input from the City of Toronto or TRCA.

Response:

a) Enbridge Gas retained Golder to assess proposed routes, that satisfied network analysis, in a highly urbanized area using their Goldset method. The Goldset method uses geospatial data as a base set. Multiple scenarios are run to identify the most suitable corridor (i.e. route). The work done by Golder helped to ensure that an appropriate range of potential routes were brought forward to be assessed as part of the Environmental Report (ER) under the OEB Environmental Guidelines.

   A description of the GoldSET methodology can be found on the Golder website (https://golder.goldset.com/portal/downloads/GoldSET%20Brochure.pdf). For ease of reference an explanation of the GoldSET methodology from the Golder website is reproduced below.

   > Integrating a rigorous multicriteria analysis (MCA) approach, geospatial information management and the ability to forecast project performance, GoldSET is an innovative set of web-based tools that provide a simple, systematic process to evaluate alternatives or to monitor on-going projects. This is achieved by using geospatial, qualitative and quantitative data from environmental, social, economic and technical dimensions GoldSET provides an effective process for quickly identifying the most sustainable corridor for linear projects and selecting the best

> sites for plants and installations. In addition, GoldSET allows for a comprehensive evaluation and comparison of project alternatives.

b) The work undertaken by Golder and by Dillon (the author of the Environmental Report) is appropriate and useful in identifying the most appropriate routing for the Project. In this case, the most suitable corridor for the Project identified by Golder was the proposed corridor, and this suitability was very strong even when factoring environmental and socio-economic factors. Combining the work done by Golder and Dillon with the experience that Enbridge Gas has building pipelines in the City of Toronto and the comments received during the open houses, Enbridge Gas is confident that the proposed route is the most suitable for the Project.

The ER requires input from stakeholders as part of a comprehensive consultation program. Feedback from the City of Toronto was sought as part of the ER, where a range of potential routes identified by Golder were considered.

In the ER, Dillon noted the work completed by Golder, and how it contributed to the ER:

> Dillon understands that Golder conducted a thorough review of potential pipeline corridor options, considering available technical and non-technical spatial information; suitable environmental, social, and technical decision criteria; the OEB regulatory process for LTC applications; and other provincial and municipal and permitting processes. As such, Dillon did not conduct a separate routing constraints analysis/evaluation for the Project. However, Dillon reviewed Golder’s routing evaluation and confirmed the following:
>
> - It meets the objectives of the OEB Guidelines;
> - It can be reasonably discussed with stakeholders during the engagement cycle of the Project; and,
> - There are no gaps in information that may materially impact the final routing options, including information gathered from stakeholder engagement activities.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Federation of Rental-housing Providers in Ontario (FRPO)

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, Pages 19-25

Preamble:

In the above reference, EGI provides that NPS 16 was simulated as a replacement size and it provided pressures over 100 psig. However, EGI presents three different scenarios to establish some risk to customers if an additional scenario occurs. We would like to understand the potential impact of NPS 16 sizing.

Question**:**

Please provide a high-level cost estimate for NPS 16 for the 4.5km project.

a) For each of the scenarios, please provide a cost estimate to modify the station(s) that would project to have inlet pressure reductions to ensure continuity of service to customers.
   i) For each scenario, please describe the required modification (i.e., upgrade regulators and relief) and the cost for each station that requires modification.

Response:

a) The NPS 16 option was determined not to be a viable option by Enbridge Gas therefore the Company did not develop a cost estimate for this option. Absent a detailed cost estimate for the NPS 16 option, Enbridge Gas estimates that the cost of a downsized replacement pipeline would be reduced by approximately 5% to 10%. A key reason why the cost reduction is so low is due to the fact that the construction method for an NPS 20 pipeline is the same for an NPS 16 pipeline. The reduction in pipe size would impact only materials costs, drill size (a slightly smaller drill would be required) and welding (welding times are slightly shorter due to circumference of the pipeline). No station modification work would be required.

ENBRIDGE GAS INC.
Answer to Interrogatory from
Pollution Probe (PP)

INTERROGATORY

Reference:

[Exhibit D, Tab 1, Sch. 1]

Question:

a) Please provide a copy of Enbridge's Feasibility Policy.

b) Please describe how this project's financial treatment aligns with EBO 188.

c) Please provide a table showing the contingency percentages used on the last ten Leave to Construct projects approved by the OEB.

d) Please explain the methodology Enbridge uses to assign a contingency percentage to projects like the one proposed and please provide a copy of reference materials from relevant policies, guidelines and manuals.

e) Please provide and populate a copy of Table 3: Estimated Project Costs and add a column for the proposed new pipeline and a column for the proposed abandonment inserted before the total cost column.

f) Please provide a copy of the materials used (including contractor courtesy quotes) to calculate and provide confidence that these costs are an accurate estimate.

Response:

a) Please refer to the latest Enbridge's Feasibility Policy filed with the Board as part of EB-2020-0094 Filing (Exhibit C/Tab 2/Schedule1). Also please refer to EB-2011-0354/Exhibit B2/Tab 1/Schedule 1 for the Economic Feasibility Procedure and Policy approved by the Board for the EGD rate zone. For ease of reference both documents are included as attachments to this response.

b) The financial assessment of the Project has been completed using a DCF analysis, comparing the NPV cost of repair vs. replacement option over the asset life cycle (40-Year horizon). This DCF method is in accordance with EBO 188 principles, as listed in Schedule 1, Discounted Cash Flow Methodology, Appendix B, EBO 188 by the Board. Please refer to Exhibit I.Staff.3 b) for the DCF schedules.

c) Please refer to the table below for a list of contingency percentages used for recently approved Enbridge Gas LTC applications.

Proceeding	**Name**	**Contingency Percentage**
EB-2019-0183	Owen Sound Reinforcement	14% contingency applied to materials, construction and labour
EB-2019-0188	North Bay Community Expansion	10% contingency applied to materials, construction and labour
EB-2019-0172	Windsor Pipeline Replacement Project	15% contingency applied to materials, construction and labour
EB-2019-0218	Sarnia Industrial Line Reinforcement	20% contingency applied to materials, construction and labour
EB-2019-0187	Saugeen First Nation Expansion Project	10% contingency applied to materials, construction and labour
EB-2019-0006	St. Laurent Pipeline Replacement Project	25% contingency applied to the Project with exception of Consultant Costs. A 10% contingency is applied to Consultant Costs as a large portion of this work was already completed
EB-2018-0226	Georgian Sands Pipeline Project	20% contingency applied to all construction, material and External/Internal overhead costs.
EB-2018-0188	Chatham-Kent Rural Project	15% contingency applied to materials, construction and labour

EB-2018-0306	Stratford Reinforcement Project	15% contingency applied to materials, construction and labour
EB-2018-0097	Bathurst Reinforcement Project	30% contingency applied to all direct costs
EB-2018-0108	Don River 30" Pipeline Project	30% contingency applied to all direct costs
EB-2018-0096	Liberty Village Project	25% contingency applied to all construction, material and external/internal overhead costs

d) The contingency applied to this project conforms to Enbridge Gas's Guidelines for a project at this stage of scope development and risk profile. At the time the estimate was prepared the project maturity level was at the planning stage and drawings were preliminary. The contingency funding for the project is required to cover the costs of known risks that cannot be estimated at the time the estimate is prepared including underground issues (e.g., utility conflicts, subsurface conditions such as rock and soil quality), working space requirements (e.g. easement costs, temporary working easements, width of right of way and congestion of utilities) and the possibility of delays due to weather. Additional project specific risks include working in the vicinity of the Gardiner Expressway and other main traffic arteries.

e) Please refer to Exhibit I.ED.10 b).

f) Exhibit D, Tab 1, Schedule 1, Table 3 has been populated with the best of Enbridge Gas's knowledge at this time and constitutes an accurate estimate with respect to the Project maturity and level of risk. Further details about the line items in Table 3 can be found at Exhibit I.EP.23.

PROPOSED REVISIONS TO EGD RATE ZONE ECONOMIC FEASIBILITY PROCEDURE AND POLICY

Introduction

1. The purpose of this evidence is to present the proposed revisions to the Company's current procedures and policies for determining the feasibility of the Company's system expansion and community expansion projects in the EGD rate zone. These procedures and policies are adopted to comply with the *Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario* of the Ontario Energy Board ("Board"), reported under EBO 188 dated January 30, 1998.

2. This evidence includes an overview of the Company's Customer Connection Policy, Customer Contribution and Refund Policy, Method for Economic Feasibility Assessment, and Procedure for Capital Expenditure Approval. It has been expanded to include key elements of the Company policy under the Community Expansion framework as approved by the Board in EB-2016-0004 dated November 17, 2016 and refined for this Application. The new framework applies to all qualifying Community Expansion ("CE") Projects and Small Main Extension ("SME") and Customer Attachment Projects, as defined in the EGD rate zone Rate Handbook, Rider I.

Customer Connection Policy

3. The Company uses a portfolio approach to manage its system expansion activities and ensures that the required profitability standards are achieved at both the individual project and the portfolio level. Investment Portfolio and Rolling Project Portfolio are two Board-prescribed portfolio approaches and are discussed in paragraph 15 and 16 of this evidence.

4. The Company manages both of its portfolio approaches to achieve a Profitability Index ("PI") of greater than 1.0 as required by the Board under EBO 188.

5. Individual projects are required to achieve a PI of 1.0 or the customer shall be required to pay a Contribution-in-Aid-of-Construction ("CIAC") to bring the project up to the required PI level. In exceptional circumstances, a project may be authorized at a lower PI levels (i.e. between 1.0 and greater than 0.8) as long the Company maintains its overall portfolio PI above 1.0.

6. During construction and operation of each project, the Company will comply with the OEB's *Environmental Guidelines for HydroCarbon Pipelines and Facilities in Ontario*.

Customer Contribution and Refund Policy

7. CIAC may be obtained for projects having a negative Net Present Value ("NPV") or a PI less than 1.0. The contribution should be sufficient to bring the project PI up to a required level. Harmonized Sales Tax ("HST") is added to contribution payments.

8. New residential customers connecting to the existing mains are provided, at no cost, with a service connection up to a maximum of 20 meters. Any service length beyond 20 meters is charged to the customer at a rate $32 per metre as prescribed in Rider G of the Rate Handbook.

9. The length of service for feasibility assessment is measured from the customer property line to the location on the front wall of the building where the meter will be installed.

10. Where the use of a proposed facility is dominated by a single large volume customer, it is considered a dedicated facility for CIAC purposes. The dominant customer may be required to pay a CIAC to result in a project NPV of zero or a PI of 1.0. CIAC amounts are subject to added HST.

11. Refunds of CIAC may be requested by customers when the actual customer count on the system expansion exceeds the original forecast. For Rate 1 and Rate 6 customers, these refunds are processed at the end of five years from the date of construction. The system expansion project is then re-evaluated with the actual customer count to determine a revised contribution that is required to bring the NPV to the original targeted level. The difference between the revised contribution amount and the actual contribution paid by customers is the total amount to be refunded to original customers. Refunds are made based on the proportionate contribution of customers.

12. These refunds do not apply to the mains wheres SES and TCS rate riders have been applied in lieu of CIAC. The refunds are made only for the specific piece of main put into service; no refunds are payable for customers added downstream of the specific piece of main. No interest is payable, and only customers who made a contribution are eligible for a refund.

13. In order to be eligible for a refund, the customer must be consuming natural gas at the address for which refund is being claimed. If the customer moves, he or she is responsible for notifying the Company of the new address.

14. Refunds for large volume customers will be determined based on a re-evaluation of the system expansion project, taking into consideration extra investment and

additional load brought on within five years to the specific piece of main constructed to serve the initial customer(s). Similar to system expansions, refunds for large volume customers will be evaluated subject to customer request. This policy is not available to large volume customers in Development Projects where an Hourly Allocation Factor process has been used for allocating project cost amongst the prospective customers.

System Expansion Portfolios – Accountability

15. Investment Portfolio: The Company evaluates all system expansion projects in a test year and ensures they are designed to achieve a portfolio PI of at least 1.1. All new customers attaching to new and existing mains are included in this portfolio.

16. Rolling Project Portfolio ("RPP"): The Company also maintains a rolling 12-month distribution expansion portfolio including the cumulative result of project-specific Discounted Cash Flow ("DCF") analyses. The RPP does not include customer attachments from existing mains constructed in prior years. The Company maintains RPP at a PI level greater than 1.0.

Estimating Inputs for Economic Feasibility Assessment

17. This section provides the method used to determine the parameters that make up the economic feasibility assessment. It includes capital cost, O&M expenses, and distribution revenues associated with a system expansion project. These inputs are discounted at the Utility's Weighted Average Cost of Capital ("WACC") to carry out the DCF analysis which measures Economic Feasibility of a project based on NPV and PI.

Capital Cost Estimation

18. The Company uses various approaches for estimating capital cost for different types of projects. The objective is to derive estimates that are closely aligned to costs that are reflective of the unique parameters of each project, and those cost differences are typically delineated by geographic area.

19. The following is a summary of various estimation techniques and the project types to which they are applied:

- For new subdivisions where Joint Utility Trenching ("JUT") is often used to construct natural gas infrastructure, unit rates prescribed in the underlying contracts are used for estimating capital cost for mains and services.
- For subdivisions where JUT is not an option, or for commercial and industrial connections, field estimates are used for capital costing.
- For large volume customers field estimates are used to estimate mains and service cost. /U

20. If a main is oversized to meet future growth potential, it may be re-priced at the size required to meet customers' load requirements for feasibility calculations. The actual cost of the main must be shown on the Authorization for Expenditure ("AFE").

21. An incremental overhead allowance is added to the cost of mains and services and is incorporated in the feasibility analysis of all projects.

Consumption and Revenue

22. For subdivision and residential connections, consumption is estimated based on building type (single, semi-detached, townhouse) and configuration (bungalow, split or two-story). The Capital Project Feasibility ("CAPF") program calculates customer revenue based on consumption levels input by the Customer Connections Representative ("CCR").

23. A load sheet is used to estimate consumption of commercial and industrial connections. The load sheet information is provided by the customer and contains consumption of various appliances installed at the premises.

24. For large volume connections, consumption information should include monthly volumes and the customer's contract daily demand.

25. The Investment Review group calculates revenue, based on the input consumption profiles and the most recent Board-approved rates.

System Expansion Surcharge ("SES") and Temporary Connection Surcharge ("TCS")

26. As set out in Rider I of the Company's Rate Handbook, the Company may apply an SES or TCS to Rate 1 and Rate 6 customers receiving gas distribution services as part of a CE project, SME or Customer Attachment Project. The Company may apply the SES or TCS if the project PI is less than 1.0. The terms and conditions applicable to the SES and TCS are set out in Rider I.

(a) SES

27. The SES is used for CE Projects, having 50 or more potential customers. Unlike approved distribution rates, the SES will not change over time and will appear as a separate line item on a customer's monthly gas bill.

28. The SES will be treated as a revenue for the purpose of the Company's economic feasibility analsysis of the project. The SES will be charged to all Rate 1 and 6 customers who consume an estimated volume of gas less than 50,000 m^3 in the project area for a period of up to 40 years. The term of the SES for each project will be set at the minimum term required for the project to achieve a PI of at least 1.0 or 40 years, whichever is less.

29. Customers attaching after the start of the initial SES term will also be required to pay the SES for the remainder of the initial SES term for that project. The ongoing payment obligation of the SES will attach to the property for the balance of its term should the property change ownership or occupancy during this time.

30. Municipal contributions may be collected by way of up front lump sum or annual payments for up to 10 years subject to municipal commitment for such contributions to qualifying projects.

31. Large volume customers within the CE Project area, who consume more than 50,000 m^3 per year may pay either the SES and/or the CIAC. This will be addressed separately or as part of the customer contracts.

(b) TCS

32. The TCS is used for SME and Customer Attachment Projects, having less than 50 potential customers. The TCS is used as an alternative to CIAC to achieve a PI of 1.0, or in addition to CIAC for a project to achieve a minimum PI of 1.0.

33. These projects include the extension of mains, the related service attachments, as well as any service lines to individual customers connecting to pre-existing mains.

34. Similar to the SES, the TCS is charged at the same rate, is in addition to approved distribution rates and is treated as revenue for the Company's economic feasibility analysis of the project. TCS appears on a customer's gas bill as a separate line item.

35. The TCS term will be determined on a project specific basis and will be restricted to a minimum of one year to a maximum of 20 years from the project's in-service date. The term will be based on the number of years it takes for the project to achieve a PI of 1.0.

36. Similar to SES, customers attaching after the start of the initial TCS term will also be required to pay the SES for the remainder of the initial TCS term for that project. The ongoing payment of the TCS will attach to the property for the balance of its term should the property change ownership or occupancy during this time.

37. If a project is not economically viable after applying 20 years of TCS, CIAC may be used in addition to the TCS to achieve a PI of 1.0.

38. For the purpose of governance and reporting, all projects where TCS is applied will be included in the Company's Rolling Project Portfolio and Investment Portfolio

alongside other system expansion projects.

Hourly Allocation Factor ("HAF")

39. The HAF process is a method of allocating the capital cost of a Development Project between forecast large volume customers requiring incremental firm capacity within an identified Area of Benefit. The HAF is applied as a capital cost in addition to the capital cost of customer specific facilities (i.e. dedicated distribution main, service line, customer station, meter) to the individual economic analysis of customers receiving incremental firm capacity in the Area of Benefit as they commit or contract for gas service. /U

40. The HAF is calculated by dividing the net capital cost of a Development Project by the sum of the forecast firm hourly large volume customer demand (regardless of seasonality) that the project serves within the Area of Benefit and is expressed in dollars per m3/hour. /U

41. The threshold of eligibility of the HAF for all Development Projects will be 50 m^3/h /U
and greater /U

Customer Attachment and Revenue Horizon

42. The maximum customer attachment horizon for small volume customers (including residential, commercial and industrial connections with annual consumption of no more than 50 000 m^3) is 10 years. The revenue horizon is 40 years from the in-service date of the initial mainline. For large volume customers, the maximum customer attachment horizon is 10 years. The maximum revenue horizon is 20 years from the customers' initial service date.

43. A project specific revenue horizon is used when the project life cycle is deemed shorter than 20 years.

Marginal Operating and Maintenance (“O&M”) Expenses

44. The Company’s incremental operating and maintenance (“O&M”) cost is based on an annual study that is aligned with cost allocation principles and is included in assessing project feasibility.

Procedure for Capital Expenditure Approval

45. Enbridge's procedure for obtaining management approval to make a capital expenditure for distribution system expansion is known as the Authorization for Expenditure ("AFE"), and is outlined in the AFE manual. A system expansion project is typically initiated by a Customer Connections Representative ("CCR"), who identifies potential new customers. The CCR will assess the required amount of plant additions to provide service and will initiate an AFE for approval.

46. A feasibility assessment is required to be attached to an AFE as part of the approval process. Feasibility assessment is done based on the estimated revenue and benefits of connecting new customers against the total cost of attaching and serving them. The Capital Project Feasibility ("CAPF") program is an online IT tool used for evaluating all projects except for residential infills connections and Large Volume projects. All Large-volume projects are separately evaluated by the Investment Review group using Excel based feasibility tools.

47. CCRs provide inputs for the CAPF tool, which include estimates of capital cost, customer additions and timing, and annual consumptions of new customers. The Investment Review group uses Excel based feasibility tools for assessing large-volume and more complex projects with inputs from the Special Projects and Key Accounts groups.

48. All AFEs are approved by the appropriate level of authority including managers, directors, VPs and President as set out in the workflows based on capital approval authority.

ECONOMIC FEASIBILITY PROCEDURE AND POLICY

Introduction

1. The purpose of this evidence is to present the current procedures and policies for determining feasibility of Enbridge Gas Distribution Inc's ("Enbridge" or the "Company") system expansion projects. These procedures and policies are adopted to comply with the Ontario Energy Board's (the "Board") "*Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario*", reported under EBO 188 dated January 30, 1998.

2. This evidence includes an overview of the Company's Customer Connection Policy, Customer Contribution and Refund Policy, Procedure for Capital Expenditure Approval and Method for Economic Feasibility Assessment.

3. The most recent feasibility parameters are used in this evidence, which are based on 2011 system expansion portfolio and are updated to reflect EB-2011-0051 Decision with Reasons.

Customer Connection Policy

4. The Company uses a portfolio approach to manage the system expansion activities and ensures that the required profitability standards are achieved at both the individual project and the portfolio level. Investment Portfolio and Rolling Project Portfolio are two Board prescribed portfolio approaches and are discussed on page 3 of this schedule. The Company manages to achieve a Profitability Index ("PI") of greater than 1.0 for both portfolios as required by the Board under EBO 188.

Witnesses: F. Ahmad
P. Squires

5. The minimum PI required for individual projects is 0.80. For projects with a PI less than 0.80, the customer shall be required to pay a Contribution-in-Aid-of-Construction ("CIAC") to bring the project up to the required PI level.

6. Customers connecting to the existing mains are provided, at no cost, with a service connection up to a maximum of 20 meters. Any service length beyond 20 meters is charged to the customer at a rate prescribed in Rider G.

7. The length of service for feasibility assessment is measured from the customer property line to the meter.

8. Requests for exceptions to the minimum PI must be authorized by the Manager, Customer Portfolio and Policy.

9. During construction and operation of each project, the Company will comply with the "*OEB Environment Guidelines for HydroCarbon Pipelines and Facilities in Ontario*".

Customer Contribution and Refund Policy

10. CIAC may be obtained for projects having a negative NPV. The contribution should be sufficient to bring the project NPV up to a viable level as assessed by the Customer Portfolio and Policy group from time to time. Harmonized Sales Tax ("HST") is added to contribution payments.

11. Where the use of a proposed facility is dominated by a single large volume customer, it is considered a dedicated facility for CIAC purposes. The dominant customer may be required to pay a contribution to result in a project NPV of zero or a PI of 1.0. Contribution amounts are subject to added HST.

Witnesses: F. Ahmad
P. Squires

12. Refunds of CIAC may be requested when the actual customer count on the system expansion exceeds the original forecast. For general service customers, these refunds are processed at the end of five years from the date of construction. The system expansion project is then re-evaluated with the actual customer count to determine a revised contribution that is required to bring the NPV to the original targeted level. The difference between this and the actual contribution paid by customers is the total amount to be refunded. Refunds are made based on the proportionate contribution of the customers.

13. Refunds for large volume customers will be determined based on a re-evaluation of the system expansion project taking into consideration extra investment and additional load brought on within five years to the specific piece of main constructed to serve the initial customer(s).

14. These refunds are made only for the specific piece of main put into service and no refunds are payable for customers added downstream of this piece of main. No interest is payable, and only customers who made a contribution are eligible for a refund. In order to be eligible for a refund, the customer must be consuming natural gas at the address for which refund is being claimed. If the customer moves, he or she is responsible for notifying the Company of the new address. Records of contributions are maintained by the Business Performance group at Enbridge.

System Expansion Portfolios – Accountability

15. Investment Portfolio: The Company evaluates all system expansion projects in a test year and ensures they achieve a portfolio PI threshold of 1.1. All new customers attaching to new and existing mains are included in this portfolio. The

Manger, Customer Portfolio and Policy is accountable for ensuring that the required PI threshold is achieved.

16. Rolling Project Portfolio ("RPP"): The Company also maintains a rolling 12-month distribution expansion portfolio including the cumulative result of project-specific Discounted Cash Flow ("DCF") analyses. The RPP does not include customer attachments from existing mains constructed in prior years. The company maintains RPP at a PI level greater than 1.0 and the Manager, Business Performance is accountable for maintaining this level.

Procedure for Capital Expenditure Approval

17. Enbridge's procedure for obtaining management approval to make a capital expenditure for distribution system expansion is known as the Authorization for Expenditure ("AFE"), and is outlined in the AFE manual. A system expansion project is typically initiated by a Regional Customer Connections Field Representative, who identifies potential new customers. He or she will assess the required amount of plant additions to provide service and will initiate an AFE for approval.

18. A feasibility calculation is required with an AFE, which assesses the estimated revenue and benefits of attaching these new customers against the cost of serving them. The Capital Project Feasibility ("CAPF") program is an IT tool used for evaluating all projects except for Large Volume Customer additions. Large volume projects are separately evaluated by Enbridge's Investment Review group with inputs from the special project group. All calculations related to project feasibility assessment are attached to an AFE as part of the approval process.

Witnesses: F. Ahmad
P. Squires

19. The Customer Connections representative inputs information on plant requirements, customer additions and timing, and volumetric data for Subdivision/Residential and Commercial/Industrial connections. For large-volume connections, the inputs are completed by the Investment Review group.

20. All AFEs are reviewed by the Manager, Business Performance who obtains approval from the appropriate management levels. The Manager Business Performance also ensures compliance with the Company's Connection Polices.

Method for Economic Feasibility Assessment

21. This section provides the method used to determine the input parameters including cost and revenues associated with a system expansion project. These parameters are discounted at the Utility's Weighted Average Cost of Capital ("WACC") to perform a discounted cash flow ("DCF") analysis. The Economic Feasibility of a project is measured using a NPV and PI.

22. Capital Cost: Budgeted average unit prices are used to estimate capital cost for mains and services based on the required pipe size and ground conditions. This procedure is used to develop capital estimates for all residential, commercial and industrial connections. For large volume connections (i.e., above 340 000 m^3 annual consumption), field estimates are used to estimate mains and service cost.

23. If a main is oversized to meet future growth potential, it may be re-priced at the size required to meet customers' load requirements for feasibility calculations. The actual cost of the main must be shown on the AFE.

24. An incremental overhead allowance is added to the cost of mains and services and is incorporated in the CAPF program for feasibility analysis.

Witnesses: F. Ahmad
P. Squires

25. Consumption and Revenue: For subdivision and residential connections, consumption is estimated based on building type (single, semi-detached, townhouse) and configuration (bungalow, split or two-storey). The CAPF program calculates customer revenue based on consumption levels input by the local Customer Connections representative.

26. A load sheet is used to estimate consumption of commercial and industrial connections. The load sheet information is provided by the customer and contains consumption of various appliances installed at the premises.

27. For large volume connections, consumption information should include monthly volumes and the customer's contract daily demand. The Investment Review group calculates revenue, based on the input consumption profiles and the most recent Board Approved revenue rates.

28. Customer Attachment and Revenue Horizon: The maximum customer attachment horizon for regular residential, commercial and industrial connections is 10 years. The revenue horizon is 40 years from the in-service date of the initial mains.

29. For large volume customers, the customer attachment horizon is 10 years. The maximum revenue horizon is 20 years from the customers' initial service date if this is a reasonable expectation.

30. Marginal Operating and Maintenance ("O&M) Expenses: According to the most recent feasibility parameters, the incremental O&M cost for adding residential connections is estimated to be $70.11 per customer.

Witnesses: F. Ahmad
P. Squires

31. For commercial and industrial connections, the incremental O&M cost is $190.14 per customer.

32. For large volume connections, incremental O&M is determined based on the average annual expense for various rate classes except for rate 125 and is shown in Table1 provided below. For rate 125 customers, marginal O&M is determined on a case by case basis.

Table 1
Marginal O&M Expense per Customer

Rate Class	R9	R110	R115	R135	R145	R170	R300
Marginal O&M per customer	$4,586	$5,230	$6,694	$3,521	$4,082	$5,306	$4,994

33. Gas Costs: Gas costs are based on the Weighted Average Cost of Gas ("WACOG") less the commodity component. Currently the WACOG (excluding commodity) is $.0794/m^3 for conventional heating and water heating loads at residential, commercial and industrial facilities.

34. For large volume connections, gas costs are based on the customer's load profile characteristics which will typically warrant a customized gas cost calculation consisting of four components including: 1) Unbilled and Unaccounted for Gas ("UUF"), 2) transportation, 3) annual storage and 4) peak day delivery. The Investment Review group calculates gas cost based on the customers' monthly volumes, contract demand and service requirement (Western or Ontario). All gas costs include UUF, but only Western contracts include transportation costs. The customers' load profile dictates the amount of load balancing, storage, and peak day costs/credits are included in gas costs. Firm customers will incur peak day

Witnesses: F. Ahmad
P. Squires

costs, while interruptible customers will receive peak day credits. UUF and transportation costs will be applied to the customers' load, storage costs to the customers' stored gas, and peak day costs to the customers' peak day storage requirement if the customer is firm. Peak day credits will be applied to interruptible customers' average daily volume. The formula used for calculating amounts of stored gas and peak day storage requirements are included with the table of costs found in Table 2 on the following page.

35. The interruptible gas cost categories are: (a) Rate 145 customers with a minimum 16 hour curtailment notice; and (b) Rate 170 customers with 4 hours curtailment notice.

Table 2

Gas Cost for Large Volume Customers

		UUF ($/m^3)	Transportation (Western Only) ($/m^3)	Annual Storage ($/m^3)	Peak Day Delivery ($/m^{3}d)
Firm	Rates 100, 110,115, 135				
	a) Volume	Annual load	Annual load	Stored gas[1]	Excess on peak day over average daily
	b) Cost				
	Rates 100,110,115	0.00064	0.05727	0.01095	1.00573
	Rate 135	0.00064	0.05727	0.00000	(1.19730)[3]
Interruptible	Rates 145 and 170				
	a) Rate 145 with 72 hour curtailment	0.00064	0.05727	0.01095[2]	(1.19730)[3]
	b) Rate 145 with 16 hour curtailment	0.00064	0.05727	0.00881[2]	(0.17067)[3]
	c) Rate 170[4]	0.00064	0.05727	0.00881[2]	(0.17067)[3]

1 (Volume from November to April/181 days – Annual Load/365 days)*181 days
2 Applied to uncurtailed volumes.
3 Applied as a credit based on the customers' average daily volume
4 If Enbridge Gas Distribution is restricted in utilizing its interruption rights a custom calculation should be performed by the Investment Review group.

Witnesses: F. Ahmad
P. Squires

ENBRIDGE GAS INC.
Answer to Interrogatory from
OEB Staff (STAFF)

INTERROGATORY

Reference:

Exhibit D, Tab 1, Schedule 1, page 5
Exhibit B, Tab 1, Schedule 1, pages 28 to 29

Preamble:

The application states that overall estimated costs of the Project are approximately $133 million, which includes indirect overheads of $24.1 million and a contingency of 30% applied to all direct capital costs. The estimated cost covers materials, construction and labour and land costs.

Enbridge Gas conducted an analysis to compare the costs of repairing the pipeline versus replacing it, using a 40 year time horizon and discounting the costs using the methods prescribed in EBO 188 to arrive at a net present value (NPV). While the NPV of the repair option is slightly lower than that of the replacement option, Enbridge Gas rejected the repair option as the total cost of a replacement is much lower ($107 million) than the total cost of repairs ($262 million).

Question**:**

a) Please provide an estimate of the costs of consultation for the Project. Please confirm whether consultation costs have been included in the total estimated costs of the Project. If this is not included in the Project costs, please explain how Enbridge Gas intends to fund the costs of consultation.

b) Please explain why the NPV of the repair option is lower than the NPV of the replacement option, when the total costs of the repair option are higher, and provide the DCF analysis reports used to support the cost comparison.

c) Please confirm that the total costs also include the environmental costs of the Project.

d) Please confirm whether Enbridge Gas expects to recover the costs of the Project through an Incremental Capital Module (ICM) request in its 2021 rates application.

e) Please confirm whether this specific Project, on this segment of the KOL, is included in Enbridge Gas's Utility System Plan and Asset Management Plan that has been approved by the OEB.

f) Please provide a table, similar to the table below, comparing the costs of the Project to three or more comparable projects completed by Enbridge Gas in recent years broken down by pipe size, length, material, pressure class, material cost, construction/labour cost, other cost (i.e. land, legal, regulatory etc.), contingency, total project cost and year of construction.

<table>
<tr><th>Project</th><th>Pipe size</th><th>Length</th><th>Material</th><th>Pressure class</th><th>Material cost</th><th>Construction / labour</th><th>Other cost</th><th>Project Contingency</th><th>Total Project Cost</th><th>Construction year</th></tr>
<tr><td rowspan="2">XYZ</td><td>NPS 4</td><td>2 Km</td><td>Plastic</td><td>LP</td><td>$ XX</td><td>$ XX</td><td rowspan="2">$ XX</td><td rowspan="2">$ XX</td><td rowspan="2">$ XX</td><td rowspan="2">20XX</td></tr>
<tr><td>NPS 8</td><td>4.3 Km</td><td>Steel</td><td>XHP</td><td>$ XX</td><td>$ XX</td></tr>
<tr><td>YYZ</td><td>NPS 6</td><td>2 Km</td><td>Steel</td><td>HP</td><td>$ XX</td><td>$ XX</td><td>$ XX</td><td>$ XX</td><td>$ XX</td><td>20XX</td></tr>
</table>

Response:

a) Outside Services, which include environmental, engineering, and other consulting costs, are estimated at $5,199,780. Please refer to Exhibit D, Tab 1, Schedule 1, Table 3. Also, please see Exhibit I.EP.23.

b) The difference in NPV arises because of the time value of money.

The total capital cost of the repair option ($262 million) is forecasted based on multiple integrity digs spread over the next 40 years. More integrity digs than indicated may be required over the next 40 years and even more thereafter.

The total capital cost of the replacement option ($107 million) is the capital investment for the Project over 2020-2022.

The DCF analysis for cost comparison on an NPV basis adopts the same method as listed in Schedule 1, Discounted Cash Flow Methodology, reference to EBO 188 Appendix B by the Board.

The NPV of the repair option is ($74 million) and the NPV of the replacement option is ($84 million). Please see the DCF schedules below for both options.

DCF Analysis - 40 Year Horizon

NPS 20 Repair Option - Cherry to Bathurst

Project Year ($000's)	Project Total	1	2	3	4	5	6	7	8	9	10
Operating Cash Flow											
Revenue	-	-	-	-	-	-	-	-	-	-	-
Expenses:											
O & M Expense	(16,493)	(1,020)	-	(318)	-	(552)	-	-	(1,172)	-	(366)
Municipal Tax	(841)	(15)	(15)	(15)	(15)	(16)	(16)	(16)	(16)	(17)	(17)
Income Tax	4,594	274	4	88	4	150	4	4	315	4	101
Net Operating Cash Flow	(12,741)	(760)	(11)	(245)	(11)	(417)	(12)	(12)	(873)	(12)	(281)
Capital											
Incremental Capital	(262,058)	(1,260)	(1,323)	(2,084)	(1,459)	(1,532)	(1,608)	(1,689)	(2,659)	(1,862)	(1,955)
Change in Working Capital	-	-	-	-	-	-	-	-	-	-	-
Total Capital	(262,058)	(1,260)	(1,323)	(2,084)	(1,459)	(1,532)	(1,608)	(1,689)	(2,659)	(1,862)	(1,955)
CCA Tax Shield											
CCA Tax Shield	52,885	30	50	86	87	107	126	145	157	184	203
Net Present Value											
PV of Operating Cash Flow	(5,238)	(743)	(10)	(218)	(10)	(338)	(9)	(9)	(614)	(8)	(180)
PV of Capital	(81,330)	(1,231)	(1,233)	(1,853)	(1,238)	(1,240)	(1,242)	(1,244)	(1,870)	(1,249)	(1,251)
PV of CCA Tax Shield	12,302	29	46	76	74	86	97	107	111	123	130
Total NPV by Year	(74,266)	(1,944)	(1,197)	(1,994)	(1,173)	(1,491)	(1,154)	(1,146)	(2,374)	(1,134)	(1,301)
Project NPV	**(74,266)**										

Note: The discount rate is 4.8%, the same as EGI 2020 feasibility parameters for system expansion projects.

DCF Analysis - 40 Year Horizon

NPS 20 Repair Option - Cherry to Bathurst

Project Year ($000's)	Project Total	11	12	13	14	15	16	17	18	19	20
Operating Cash Flow											
Revenue	-	-	-	-	-	-	-	-	-	-	-
Expenses:											
O & M Expense	(16,493)	-	(634)	-	-	(1,346)	-	(420)	-	(728)	-
Municipal Tax	(841)	(17)	(18)	(18)	(18)	(19)	(19)	(19)	(20)	(20)	(20)
Income Tax	4,594	5	173	5	5	362	5	116	5	198	5
Net Operating Cash Flow	(12,741)	(13)	(479)	(13)	(13)	(1,003)	(14)	(323)	(14)	(550)	(15)
Capital											
Incremental Capital	(262,058)	(2,737)	(4,669)	(3,017)	(3,960)	(4,574)	(3,493)	(4,584)	(3,851)	(6,570)	(4,245)
Change in Working Capital	-	-	-	-	-	-	-	-	-	-	-
Total Capital	(262,058)	(2,737)	(4,669)	(3,017)	(3,960)	(4,574)	(3,493)	(4,584)	(3,851)	(6,570)	(4,245)
CCA Tax Shield											
CCA Tax Shield	52,885	228	274	318	355	401	441	479	517	569	621
Net Present Value											
PV of Operating Cash Flow	(5,238)	(8)	(279)	(7)	(7)	(508)	(7)	(149)	(6)	(231)	(6)
PV of Capital	(81,330)	(1,672)	(2,721)	(1,678)	(2,101)	(2,315)	(1,687)	(2,113)	(1,693)	(2,757)	(1,700)
PV of CCA Tax Shield	12,302	139	159	177	188	203	213	221	227	239	249
Total NPV by Year	(74,266)	(1,540)	(2,841)	(1,508)	(1,920)	(2,620)	(1,481)	(2,041)	(1,472)	(2,749)	(1,457)

Project NPV	**(74,266)**

DCF Analysis - 40 Year Horizon

NPS 20 Repair Option - Cherry to Bathurst

Project Year ($000's)	Project Total	21	22	23	24	25	26	27	28	29	30
Operating Cash Flow											
Revenue	-	-	-	-	-	-	-	-	-	-	-
Expenses:											
O & M Expense	(16,493)	-	(1,546)	-	(483)	-	(837)	-	-	(1,776)	-
Municipal Tax	(841)	(21)	(21)	(22)	(22)	(22)	(23)	(23)	(24)	(24)	(24)
Income Tax	4,594	6	415	6	134	6	228	6	6	477	6
Net Operating Cash Flow	(12,741)	(15)	(1,152)	(16)	(371)	(16)	(632)	(17)	(17)	(1,323)	(18)
Capital											
Incremental Capital	(262,058)	(5,572)	(6,436)	(6,143)	(7,095)	(6,773)	(7,111)	(8,214)	(7,840)	(9,055)	(8,644)
Change in Working Capital	-	-	-	-	-	-	-	-	-	-	-
Total Capital	(262,058)	(5,572)	(6,436)	(6,143)	(7,095)	(6,773)	(7,111)	(8,214)	(7,840)	(9,055)	(8,644)
CCA Tax Shield											
CCA Tax Shield	52,885	662	717	774	833	893	950	1,015	1,082	1,151	1,223
Net Present Value											
PV of Operating Cash Flow	(5,238)	(6)	(420)	(6)	(123)	(5)	(191)	(5)	(5)	(347)	(4)
PV of Capital	(81,330)	(2,128)	(2,346)	(2,136)	(2,354)	(2,144)	(2,148)	(2,367)	(2,156)	(2,376)	(2,164)
PV of CCA Tax Shield	12,302	253	261	269	276	283	287	293	297	302	306
Total NPV by Year	(74,266)	(1,881)	(2,504)	(1,872)	(2,201)	(1,866)	(2,052)	(2,080)	(1,863)	(2,421)	(1,862)
Project NPV	(74,266)										

DCF Analysis - 40 Year Horizon

NPS 20 Repair Option - Cherry to Bathurst

Project Year ($000's)	Project Total	31	32	33	34	35	36	37	38	39	40
Operating Cash Flow											
Revenue	-	-	-	-	-	-	-	-	-	-	-
Expenses:											
O & M Expense	(16,493)	(554)	-	(961)	-	-	(2,040)	-	(637)	-	(1,104)
Municipal Tax	(841)	(25)	(25)	(26)	(26)	(27)	(27)	(28)	(28)	(29)	(29)
Income Tax	4,594	153	7	262	7	7	548	7	176	8	300
Net Operating Cash Flow	(12,741)	(426)	(19)	(725)	(19)	(20)	(1,519)	(20)	(489)	(21)	(833)
Capital											
Incremental Capital	(262,058)	(9,076)	(12,389)	(10,006)	(13,659)	(13,238)	(11,584)	(15,812)	(12,771)	(17,432)	(14,080)
Change in Working Capital	-	-	-	-	-	-	-	-	-	-	-
Total Capital	(262,058)	(9,076)	(12,389)	(10,006)	(13,659)	(13,238)	(11,584)	(15,812)	(12,771)	(17,432)	(14,080)
CCA Tax Shield											
CCA Tax Shield	52,885	1,290	1,384	1,479	1,578	1,697	1,793	1,903	2,016	2,135	22,931
Net Present Value											
PV of Operating Cash Flow	(5,238)	(102)	(4)	(158)	(4)	(4)	(287)	(4)	(84)	(3)	(130)
PV of Capital	(81,330)	(2,168)	(2,824)	(2,176)	(2,834)	(2,621)	(2,188)	(2,850)	(2,196)	(2,860)	(2,204)
PV of CCA Tax Shield	12,302	308	315	322	327	336	339	343	347	350	3,590
Total NPV by Year	(74,266)	(1,961)	(2,513)	(2,012)	(2,511)	(2,289)	(2,136)	(2,511)	(1,934)	(2,513)	1,255
Project NPV	**(74,266)**										

DCF Analysis - 40 Year Horizon

NPS 20 Replacement Option - Cherry to Bathurst
InService Date: August - 2022

Project Year ($000's)	Project Total	1	2	3	4	5	6	7	8	9	10
Operating Cash Flow											
Revenue	-	-	-	-	-	-	-	-	-	-	-
Expenses:											
O & M Expense	-	-	-	-	-	-	-	-	-	-	-
Municipal Tax	(2,380)	-	-	(15)	(47)	(48)	(48)	(49)	(50)	(51)	(52)
Income Tax	631	-	-	4	12	13	13	13	13	13	14
Net Operating Cash Flow	(1,749)	-	-	(11)	(34)	(35)	(36)	(36)	(37)	(37)	(38)
Capital											
Incremental Capital	(107,268)	(2,460)	(62,873)	(41,935)	-	-	-	-	-	-	-
Change in Working Capital	-	-	-	-	-	-	-	-	-	-	-
Total Capital	(107,268)	(2,460)	(62,873)	(41,935)	-	-	-	-	-	-	-
CCA Tax Shield											
CCA Tax Shield	27,279	-	-	3,180	1,511	1,421	1,336	1,256	1,181	1,110	1,043
Net Present Value											
PV of Operating Cash Flow	(667)	-	-	(10)	(29)	(28)	(27)	(27)	(26)	(25)	(24)
PV of Capital	(98,292)	(2,402)	(58,598)	(37,291)	-	-	-	-	-	-	-
PV of CCA Tax Shield	15,279	-	-	2,828	1,282	1,150	1,032	926	830	745	668
Total NPV by Year	(83,680)	(2,402)	(58,598)	(34,474)	1,253	1,122	1,004	899	804	720	644
Project NPV	**(83,680)**										

Note: The discount rate is 4.8%, the same as EGI 2020 feasibility parameters for system expansion projects.

DCF Analysis - 40 Year Horizon

NPS 20 Replacement Option - Cherry to Bathurst
InService Date: August - 2022

Project Year ($000's)	Project Total	11	12	13	14	15	16	17	18	19	20
Operating Cash Flow											
Revenue	-	-	-	-	-	-	-	-	-	-	-
Expenses:											
O & M Expense	-	-	-	-	-	-	-	-	-	-	-
Municipal Tax	(2,380)	(53)	(53)	(54)	(55)	(56)	(57)	(58)	(59)	(60)	(61)
Income Tax	631	14	14	14	15	15	15	15	16	16	16
Net Operating Cash Flow	(1,749)	(39)	(39)	(40)	(41)	(41)	(42)	(43)	(43)	(44)	(45)
Capital											
Incremental Capital	(107,268)	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	-	-	-	-	-	-	-	-	-	-	-
Total Capital	(107,268)	-	-	-	-	-	-	-	-	-	-
CCA Tax Shield											
CCA Tax Shield	27,279	981	922	867	815	766	720	677	637	599	563
Net Present Value											
PV of Operating Cash Flow	(667)	(24)	(23)	(22)	(22)	(21)	(20)	(20)	(19)	(18)	(18)
PV of Capital	(98,292)	-	-	-	-	-	-	-	-	-	-
PV of CCA Tax Shield	15,279	599	537	482	432	388	348	312	280	251	225
Total NPV by Year	(83,680)	576	515	460	411	367	328	293	261	233	207

Project NPV	**(83,680)**

DCF Analysis - 40 Year Horizon

NPS 20 Replacement Option - Cherry to Bathurst
InService Date: August - 2022

Project Year ($000's)	Project Total	21	22	23	24	25	26	27	28	29	30
Operating Cash Flow											
Revenue	-	-	-	-	-	-	-	-	-	-	-
Expenses:											
O & M Expense	-	-	-	-	-	-	-	-	-	-	-
Municipal Tax	(2,380)	(62)	(63)	(64)	(65)	(66)	(67)	(68)	(69)	(71)	(72)
Income Tax	631	16	17	17	17	18	18	18	18	19	19
Net Operating Cash Flow	(1,749)	(45)	(46)	(47)	(48)	(49)	(49)	(50)	(51)	(52)	(53)
Capital											
Incremental Capital	(107,268)	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	-	-	-	-	-	-	-	-	-	-	-
Total Capital	(107,268)	-	-	-	-	-	-	-	-	-	-
CCA Tax Shield											
CCA Tax Shield	27,279	529	497	468	440	413	389	365	343	323	304
Net Present Value											
PV of Operating Cash Flow	(667)	(17)	(17)	(16)	(16)	(15)	(15)	(14)	(14)	(14)	(13)
PV of Capital	(98,292)	-	-	-	-	-	-	-	-	-	-
PV of CCA Tax Shield	15,279	202	181	163	146	131	117	105	94	85	76
Total NPV by Year	(83,680)	185	164	146	130	115	102	91	80	71	63
Project NPV	**(83,680)**										

DCF Analysis - 40 Year Horizon

NPS 20 Replacement Option - Cherry to Bathurst
InService Date: August - 2022

Project Year ($000's)	Project Total	31	32	33	34	35	36	37	38	39	40
Operating Cash Flow											
Revenue	-	-	-	-	-	-	-	-	-	-	-
Expenses:											
O & M Expense	-	-	-	-	-	-	-	-	-	-	-
Municipal Tax	(2,380)	(73)	(74)	(75)	(77)	(78)	(79)	(81)	(82)	(83)	(85)
Income Tax	631	19	20	20	20	21	21	21	22	22	22
Net Operating Cash Flow	(1,749)	(54)	(55)	(55)	(56)	(57)	(58)	(59)	(60)	(61)	(62)
Capital											
Incremental Capital	(107,268)	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	-	-	-	-	-	-	-	-	-	-	-
Total Capital	(107,268)	-	-	-	-	-	-	-	-	-	-
CCA Tax Shield											
CCA Tax Shield	27,279	285	268	252	237	223	210	197	185	174	1,591
Net Present Value											
PV of Operating Cash Flow	(667)	(13)	(12)	(12)	(12)	(11)	(11)	(11)	(10)	(10)	(10)
PV of Capital	(98,292)	-	-	-	-	-	-	-	-	-	-
PV of CCA Tax Shield	15,279	68	61	55	49	44	40	36	32	29	249
Total NPV by Year	(83,680)	55	49	43	38	33	29	25	22	19	239
Project NPV	(83,680)										

c) Confirmed.

d) Not confirmed. Enbridge Gas expects to request ICM treatment for the Project in its 2022 rates application.

e) Enbridge Gas confirms that the Project has been included in its Utility System Plans and Asset Management Plans that have been filed with the Board. The Project is discussed in Section 5.2.5.2 – Condition Findings of the EGD Asset Management Plan 2019 – 2028 (EB-2018-0305) and more recently in Section 5.2.6.1.2 – Condition Findings of the EGI Asset Management Plan 2021-2025, which was submitted to the OEB on 10/15/2020 as part of the Company's 2021 rates application (EB-2020-0095). The OEB does not approve utility system plans and asset management plans but does review and reference these documents in response to ICM requests.

f) A comparison of the total project costs to three comparable projects is shown in the table below. Costs have not been adjusted for inflation, and do not include IDC or indirect overheads.

Project	City	Work Year	Pipe Size	Length	Estimated cost	Estimated cost per meter	Assumed Contingency	Actual Total Costs	Actual cost per meter
GTA Project - WC21 & Hydro Tower HDD	Markham	2015	36"	354 m	$1,827,114	$5,155	16% ** (Project)	$3,860,982*	$10,894
Keele & CNR	Vaughan	2016 - 2018	26" ST	327 m	$5,614,030	$17,168	30%	$4,979,098	$15,227
NPS 30 Don River Replacement	Toronto	2019	30" ST	326 m	$25,597,539	$78,762	30%	$23,517,742***	$72,140
NPS 20 Replacement Cherry to Bathurst	Toronto	2021 - 2022	20" ST	4380 m	$107,267,556	$24,490	30%	TBD	TBD

*Cost is for HDD crossing work only and does not include costs associated with construction pigging, hydrostatic testing, drying, tie-ins, pipe energization, backfilling and site restoration.
**Overall project contingency approximately 16%
***Estimated actual total costs to date, finalized completion costs will be submitted to the OEB in the Final Cost Report

The Project is similar in some ways to the projects listed above. However, it is a much longer project in terms of pipeline length and is located in the core of downtown Toronto and the estimated cost of the Project takes these increased costs into account.

The NPS 30 project was completed in Toronto, however, it utilized an alternate method of construction called micro-tunneling. The NPS 30 project had the additional complexity of being located in close proximity to the Toronto Regional Conservation Authority flood protection landform feature.

The Project will utilize open cut and Horizontal Directional Drilling (HDD) construction methodologies. The Project is not in close proximity to the Toronto Regional Conservation Authority flood protection landform feature. The Project does include a Metrolinx railway crossing on Parliament Street, which adds project complexity. Given the high traffic congestion in the area, construction hours for the Project may be limited based on allowable working hours in the City of Toronto, which adds to the Project cost.

The Keele & CNR project was done utilizing HDD in the city of Vaughn. It was also completed in the Right of Way (ROW) similar to the Project. The Project has a greater contingency than the Keele & CNR project as it is a longer installation length and is located in the core of downtown Toronto, therefore resulting in a higher level of risk related to overall project cost. Increased expected costs come from utility congestion, lack of working space (which leads to inefficiencies on construction), restricted hours of work, potential night-time work activities, complex traffic plans, reduced margins for installation tolerances and additional project coordination with third party projects.