Ontario Energy Board | Commission de l'énergie de l'Ontario

BY EMAIL

January 24, 2025

Ms. Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor Toronto,
ON M4P 1E4 registrar@oeb.ca

Dear Ms. Marconi:

Re: Ontario Energy Board (OEB) Staff Submission Enbridge Gas Inc. – St. Laurent Replacement Project Application OEB File Number: EB-2024-0200

In accordance with Procedural Order No. 6, please find attached the OEB staff submission in the above proceeding. The attached document has been forwarded to Enbridge Gas Inc. and to all other registered parties to this proceeding.

Yours truly,
Zora Crnojacki
Digitally signed by Zora Crnojacki
Date: 2025.01.31 16:15:09 -05'00'
Zora Crnojacki
Senior Advisor, Natural Gas Applications

Encl.

ONTARIO ENERGY BOARD

OEB Staff Submission

Enbridge Gas Inc.
St. Laurent Replacement Project
Application

Application for Leave to Construct

EB-2024-0200

January 24, 2025

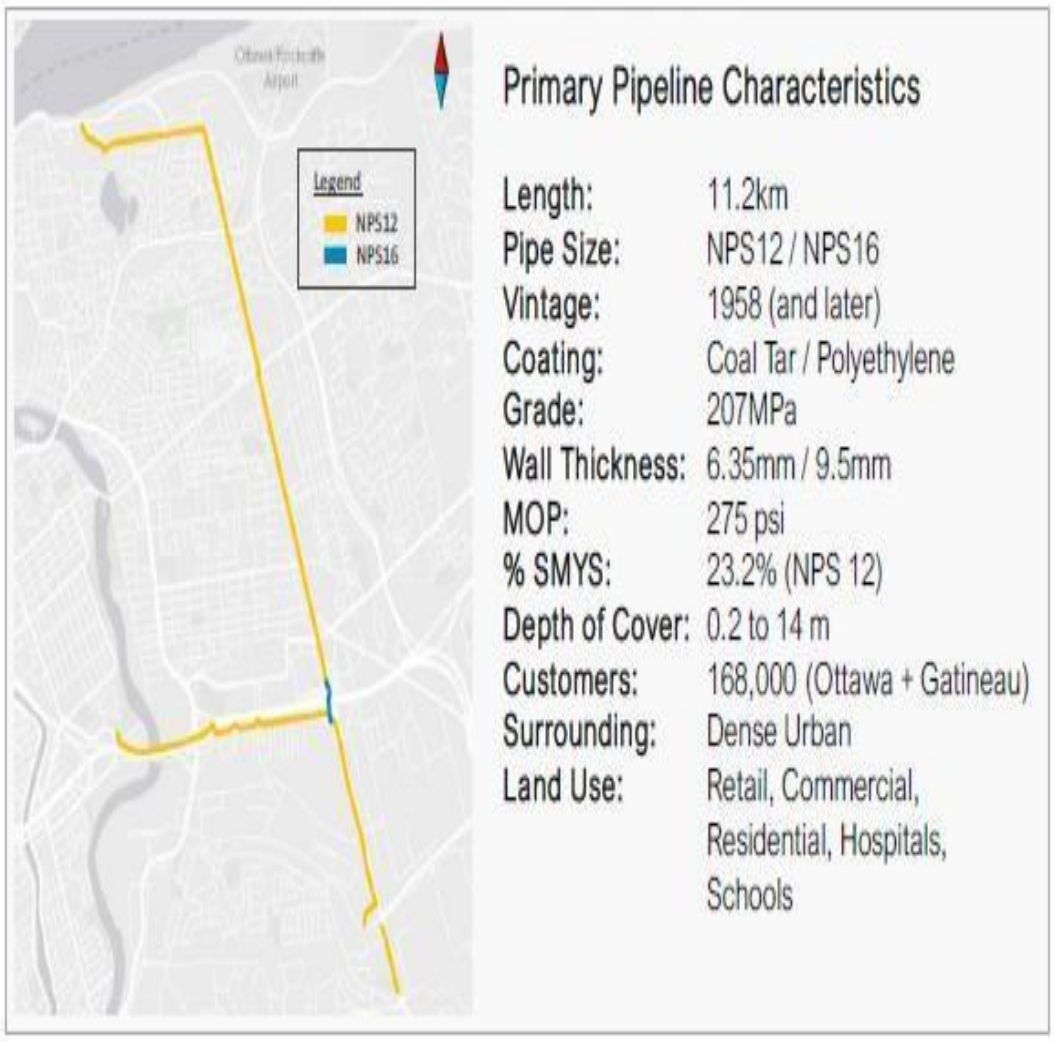
Table of Contents

1.0 Introduction and Application Overview

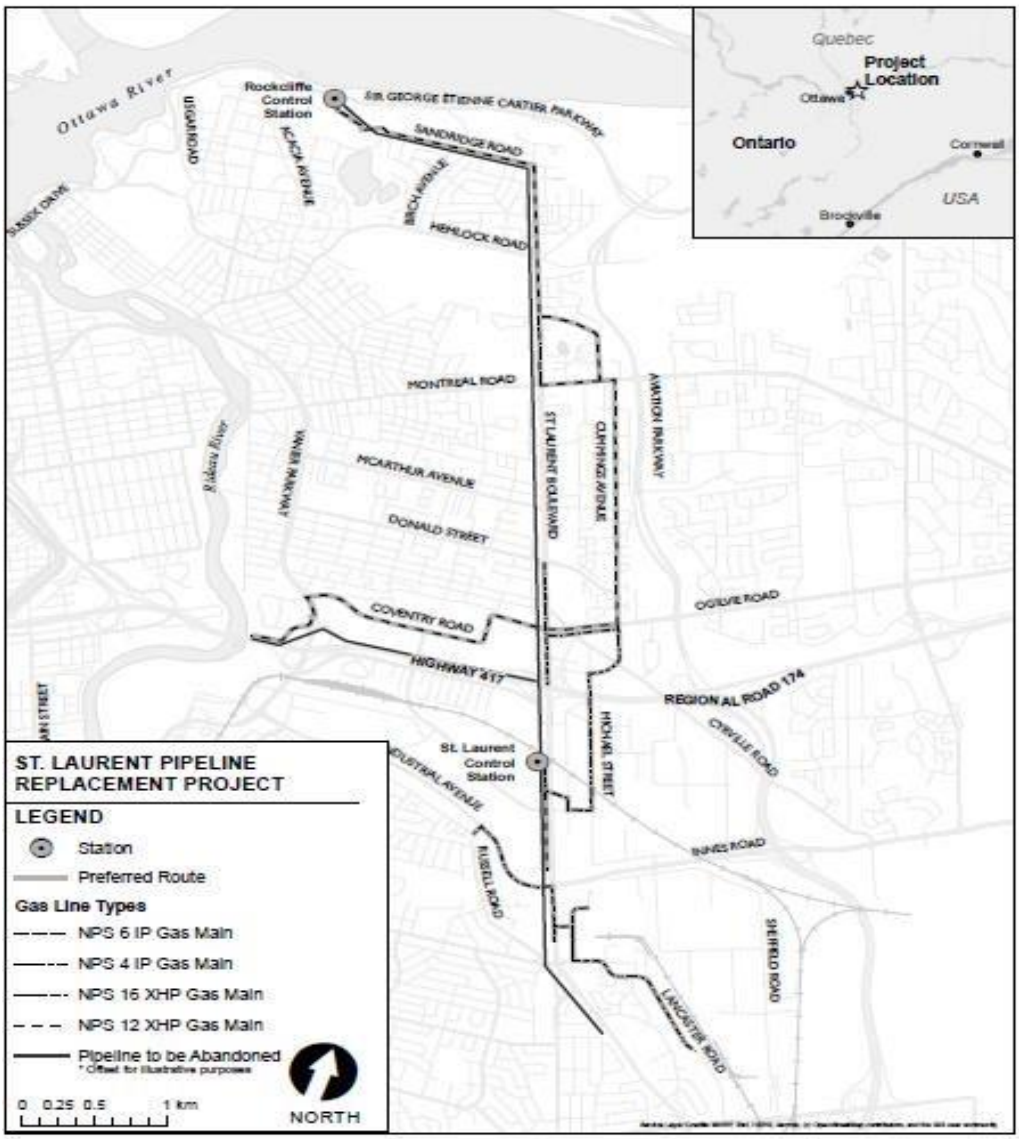
Enbridge Gas Inc. (Enbridge Gas) applied to the Ontario Energy Board (OEB) on June 17, 2024, under sections 90 and 97 of the *Ontario Energy Board Act*, *1998*, for an order granting leave to construct approximately 17.6 kilometers of natural gas pipeline and associated facilities along St. Laurent Boulevard, Sandridge Road and Tremblay Road in the City of Ottawa (St. Laurent Pipeline Replacement or Project). Enbridge Gas stated that the proposed natural gas pipeline will address risks to safety and operational reliability on the St. Laurent Pipeline System (SLP).

The existing SLP and its operational parameters and surrounding land uses are shown on the map below.

Figure 1: St. Laurent Pipeline Map



The Enbridge Gas Project's general location is represented on the map below.



Enbridge Gas has also applied under section 97 of the OEB Act for approval of the form of land-use agreements it has offered or will offer to landowners affected by the project route.

According to Enbridge Gas's proposed construction schedule, Project construction is anticipated to take approximately 21 months, starting in April 2025. The SLP is expected to be in service by December 2026.

The SLP System serves a total of 167,500 customers, approximately Enbridge Gas's 126,200 customers in the City of Ottawa, and about 40,700 Gazifère customers in Gatineau and 600 Gazifère customers outside of Gatineau. According to Enbridge Gas, the replacement of the SLP is needed to manage the risk to safe and reliable natural gas service to customers in the City of Ottawa and Gatineau.

The Project is designed to replace approximately 14.4 km of existing extra high pressure (XHP) steel pipeline with 12.8 km of XHP steel pipeline and 4.8 km of intermediate pressure pipeline.

The SLP system is comprised of 10.8 km of NPS 12 coated steel pipe and 0.4 km of NPS 16 coated steel pipe[1]. The SLP was originally commissioned between 1958 and 1959 at a pressure of 1,200 kPa (175 psi). Due to the increase in demand from new and existing customers fed by this pipeline, a pressure elevation was completed in 1985 to increase the pressure of the pipeline to 1,900 kPa (275 psi). This pressure increase was based on Clause 9.13 of the 1983 edition of CSA Z184 Gas Pipeline Systems standard (CSA Z184-M1983). This clause permits the increase of a pipeline's Maximum Operating Pressure (MOP) to 80% of its design pressure, as opposed to relying on an established pressure test.

In terms of the timeline for commissioning the existing SLP segments, 70.9% of the SLP was commissioned between 1958-1959 and 81.5% of the SLP was commissioned between 1958-1962. The other SLP pipeline sections were constructed after 1972.[2]

This is Enbridge Gas's second application for leave to construct the SLP replacement project. The first application[3] was denied on May 3, 2022. The OEB found that there was not sufficient evidence to approve the project. Specifically, the OEB found that Enbridge did not demonstrate that the integrity of the SLP system was compromised to the extent that it required replacement. In the current proceeding, Enbridge Gas has provided evidence on its Targeted Inspection Program (TIP) including Quantitative Risk Assessment (QRA) to support the need to replace the existing SLP based on its declining integrity.

[1] Exhibit B Tab 1 Schedule 1 Plus Attachments page 3.

[2] Response to I.1- CAFES-Ottawa.17, (a) and (b), Table 1 SLP Lengths Constructed by Vintage [3] EB-2020-0293

OEB staff recognizes the need to address the integrity related risks of the St. Laurent Pipeline. OEB staff submits that Enbridge Gas's evidence supports its proposal for an immediate pipeline replacement; and that the OEB should approve the application. OEB staff addresses the rationale for this position in sections 3.1 – Need for the Project; and 3.2 – Alternatives to the Project.

OEB staff has no significant concerns with other aspects of Enbridge Gas's application. OEB staff submits that, should the OEB grant leave to construct the Project, the approval should be subject to Conditions of Approval contained in Appendix A of this submission.

2.0 The Proceeding

A Notice of Hearing was issued on July 12, 2024. The following parties applied for intervenor status:

- City of Ottawa
- Community Association for Environmental Sustainability (CAFES Ottawa)
- Environmental Defence (ED)
- Energy Probe (EP)
- Federation of Rental-housing Providers of Ontario (FRPO)
- Independent Electricity System Operator (IESO)
- Industrial Gas Users Association (IGUA)
- Pollution Probe
- School Energy Coalition (SEC)

CAFES Ottawa, ED, EP, FRPO, IGUA, Pollution Probe, and SEC applied for and were granted eligibility to apply for cost awards.

The OEB has issued six procedural orders. The procedural orders have addressed a variety of matters, including setting the procedural schedule; deciding on Environmental Defence's proposal to file intervenor evidence; deciding on a request that Enbridge Gas file additional information related to certain undertakings; and determining to proceed by way of a written hearing.

The proceeding included discovery by written interrogatories, Enbridge Gas' responses, a transcribed virtual technical conference, and the filing of undertaking responses from the technical conference. The technical conference was originally scheduled for two days and took place on October 30 and 31, 2024. The OEB convened an additional virtual, transcribed half-day technical conference session on November 13, 2024. Enbridge Gas

filed written responses to all undertakings arising out of the technical conference and served them on all intervenors on November 27, 2024.

The OEB also provided for a process for submissions by the parties on Environmental Defence's proposed intervenor evidence. On October 1, 2024, by way of Decision on Proposed Intervenor Evidence and Procedural Order No. 2, the OEB denied Environmental Defence's request to file evidence. In Procedural Order No. 5, the OEB set the schedule for submissions on the need for an oral hearing. Parties were to file submissions by December 18, 2024, and Enbridge Gas to file its reply by December 20, 2024. On January 3, 2025, by way of Procedural Order No. 6 the OEB decided to proceed by way of written hearing.

OEB staff and intervenor submissions are due by January 24, 2025. Enbridge Gas' reply submission is due by February 7, 2025. This will close the record of the proceeding.

3.0 OEB Staff Submission

Consistent with the standard Issues List for natural gas leave to construct applications, the OEB staff submission is structured to address the following issues:

1. Need for the Project
2. Project Alternatives
3. Project Cost and Economics
4. Environmental Matters
5. Land Matters
6. Indigenous Consultation
7. Conditions of Approval

3.1 Need for the Project

Enbridge Gas submitted that the need for the Project is underpinned by the declining and ongoing integrity decline of vintage steel distribution pipelines in the St. Laurent Pipeline system (SLP). OEB staff supports Enbridge Gas's proposal that the evidence demonstrates that a replacement of the SLP pipeline is needed to mitigate the risks associated with declining condition of the SLP.

Section 3.1 Need for the Project is organized as follows:

- 2021 St. Laurent Ottawa North Replacement Project Application

- New Approach - Total Integrity Program Overview
- Targeted Inspection Program – Testing and Inspection Techniques
- Quantitative Risk Assessment
- DNV Validation of the Quantitative Risk Assessment
- TSSA's Fitness-for-service Review

2021 St. Laurent Ottawa North Replacement Project Application

On May 3, 2022, the OEB denied the application for the reason that the evidence on SLP pipeline condition and associated risk did not support the replacement of the pipeline at the time. The OEB found:

> *…the need for the Project and the alternatives to the Project have not been appropriately assessed. Enbridge has not demonstrated that the pipeline integrity is compromised, and that pipeline replacement is required at this time. The OEB urges Enbridge to thoroughly examine other alternatives such as the development and implementation of an in-line inspection and maintenance program using available modern technology...*[3]

In its evidence filed in 2021, Enbridge Gas indicated that the declining condition of the pipelines was assessed using the results of past system surveys and inspections, conducted at various locations of the SLP between 2006 and 2018. These surveys and inspections included a ground penetrating radar integrity project (2006); field work on leak repairs (2013); integrity dig (2014); bridge crossing inspection (2016); depth of cover surveys (2017); and indirect inspection to assess cathodic protection, coating, and depth of cover (2018).

Enbridge Gas used its Asset Health Index (AHI) methodology to predict how the condition of the existing SLP would change over a forty-year time frame (if not replaced), and to project the number of leaks that may occur. The Enbridge Gas AHI model predicted 4.3 cumulative leaks by 2041, 13 cumulative leaks by 2051, and 36.8 cumulative leaks by 2061.

Enbridge Gas's evidence on risk assessment for the 2021 St. Laurent Ottawa North Replacement Project was not based on current data gathered systematically by direct testing of the current condition of the SLP. At that time Enbridge Gas submitted that it did not have infrastructure to conduct an in-line inspection of the SLP to further assess its

[3] EB-2020-0293 Decision and Order, dated May 3, 2022, page 3

condition. In terms of risk assessment, Enbridge Gas conducted qualitative risk assessment using its Standard Operational Risk Assessment Matrix.[4] QRA was not performed.

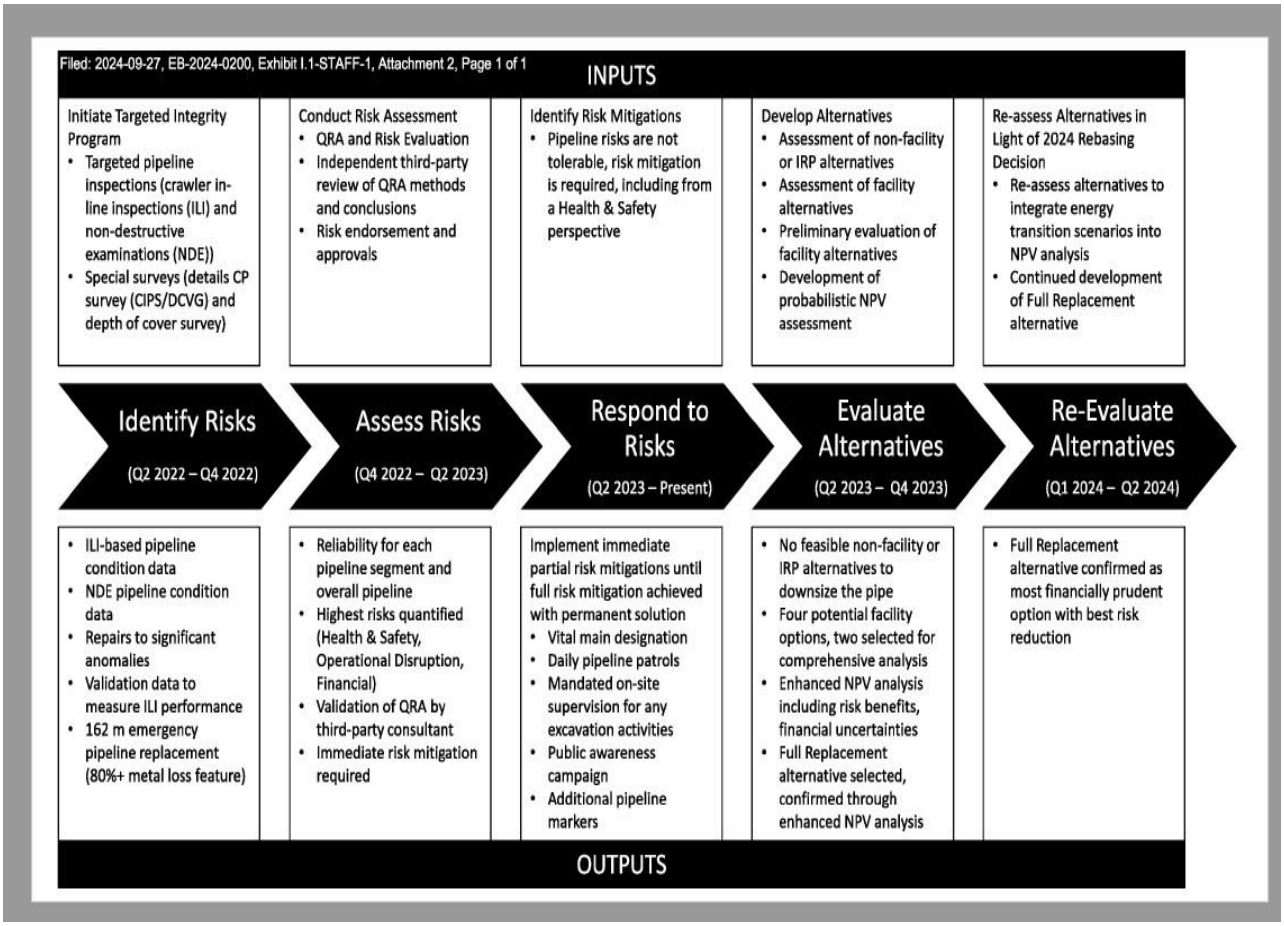
New Approach to Total Integrity Program Overview[5]

In the current proceeding, Enbridge Gas advised that it has undertaken a full re-examination of the condition of the existing SLP using available technology and risk assessment techniques and has conducted a new approach to evaluate alternative actions to mitigate the condition of the pipeline. In the beginning of June 2022, Enbridge Gas commenced the TIP. The TIP is a comprehensive assessment of the reliability and condition of the SLP. An important improvement over earlier integrity monitoring approach is that the TIP applies QRA and field inspection of the current condition of the SLP pipeline as opposed to mostly historical data, including more modern approach to in-depth technical assessment in conjunction with a review of the historical SLP condition records. The TIP approach encompassed:

- SLP's operating history data
- Assessment of current condition applying the following methods to collect pipeline-specific data by: ○ In-line inspection (ILI) ○ Field excavations
    - Non-destructive examinations (NDE)
- Quantitative Risk Assessment ○ Risk modelling
    - Reliability modelling

In response to OEB staff interrogatories[6] Enbridge Gas filed a schematic TIP process:

[4] EB-2020-0293 Enbridge Gas Inc. response to interrogatory I.STAFF.4
[5] St. Laurent Replacement Project Application, EB-2024-0200
[6] Exhibit I.1-STAFF.1, Attachment 2, page 1



The above schematic shows five phases in Enbridge Gas's TIP model with a timeline, inputs and outputs. It illustrates how Enbridge Gas applied a comprehensive approach and current methods to identify risks, assess risks, respond to risks, evaluate alternatives, and re-evaluated the alternatives. The TIP activities cover a two-year period between Q2 2022 and Q2 2024. In the last phase of the TIP approach Enbridge Gas concluded that a full replacement of the SLP is most financially prudent option with the best risk reduction[7].

Enbridge Gas asserted that it used modern technology to in-line inspect portions of the pipeline to detect and size measurable pipeline defects that exist on the SLP. In addition, Enbridge Gas emphasized that it supplemented the in-line inspection with in-field nondestructive examination (NDE), lab in-line inspection (ILI) validation testing, and lab evaluations of pipe material samples. Enbridge Gas also highlighted that it conducted the

[7] Additional description and submissions on the evaluation of alternatives will be covered in the chapter on Project Alternatives

Quantitative Risk Assessment and stated that it had the QRA results validated by the third-party consulting company, DNV.

Targeted Inspection Program – Testing and Inspection Techniques

According to Enbridge Gas, the TIP aims to determine the safety and reliability of the pipeline's operability, identify immediate mitigation measures, and assess asset management requirements for remaining life options, including safety, reliability, and economic considerations (e.g., repairs, replacement).[8] The on-site inspection methods completed on the SLP by Enbridge Gas, since June 2022, include:

- In-line Inspection – Robotic Crawler Tool – Magnetic Flux Leakage (MFL)
- In-line Inspection – Robotic Crawler Tool – Laser
- Opportunistic Excavations with Non-Destructive Excavations (NDE)
- CP Survey – Close Interval Potential Survey (CIPS)
- Direct Current Voltage Gradient (DCVG)
- Depth of Cover measuring
- Leak and Odorant Surveys

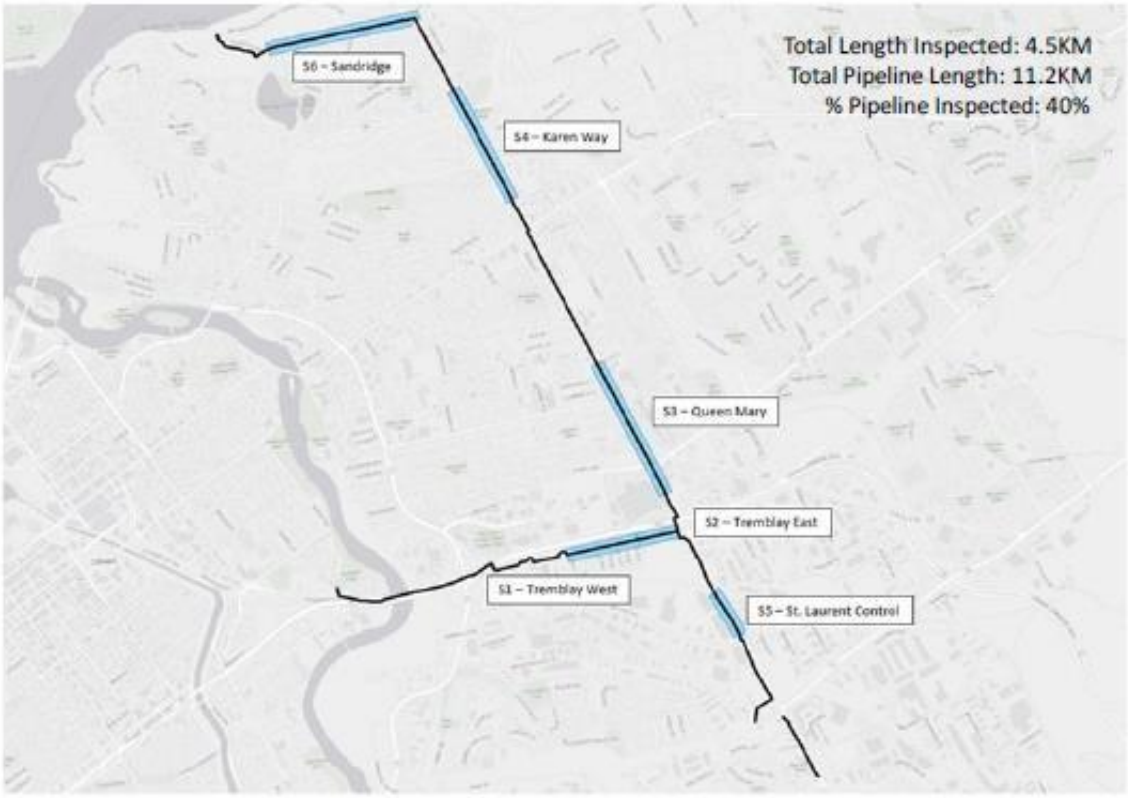
In-Line Inspection Results

The concrete on location inspection results came from In-line Inspection (ILI) and subsequent field NDEs (through excavation). ILI using an MFL-LDS inspection tool, was used to cover 4.5 km (40%) of the SLP system. These sites were selected based on access, CIPS, location and other surveys, assuming the main load is the internal pressure. The diagram below shows the location and extent of the ILI inspection. The location and length of the SLP pipeline tested by ILI is shown in the map below. [9]

[8] Exhibit B Tab 1 Schedule 1 Plus Attachments, page 6, Table 1

[9] Exhibit B, Tab 1, Schedule 1, paragraph 14, page 6, Table 1. Inspections and Surveys and Figure 2. Robotic Crawler ILI Extents and Locations

Figure 2: Robotic Crawler ILI Extents and Locations



Integrity Digs

Enbridge Gas conducted Non-Destructive Excavations at 13 locations (including one where NDE assessment was not completed). These locations were at ILI launch sites or ILI driven except for five where operational concerns were determined). A total of 212 anomalies were found (e.g. corrosion, gouging, arc burns, welding defects). Enbridge Gas stated that over one hundred of the anomalies were significant enough to require pipeline repairs in compliance with Enbridge Gas's Operating Standards and CSA Z662 Oil and Gas Pipeline Systems (CSA Z662-19).[10]

Dents and Metal Loss Tests Results

[10] Exhibit B, Tab 1, Schedule 1 paragraphs 31-33, pages 16-17, and page 17, Table 3: Integrity Dig Findings

A total of 611 metal loss features identified by Enbridge Gas along the inspected portion of the pipeline indicate possible corrosion or gouging, with 12 significant features reported with depths greater than 40% of the wall thickness. A total of 386 dent features from third-party damage with a depth greater than 0.5% of the pipeline diameter were identified along the inspected portion of the pipeline, using In-line Inspection with laser measurement.

The statistical sampling[11] used for assessment of the corrosion threat indicates sufficient sampling was used to conclude the corrosion susceptibility of the pipeline with a 99% confidence level and a 5% margin of error.

Charpy Toughness Test Results

As Enbridge Gas stated,[13] Charpy toughness test results it conducted for the SLP showed significantly lower values than the conservative lower bound estimate Enbridge Gas typically assumes for vintage steels,[12] with a lower bound of 2/3CVN = 5.3J for Grade 207, compared to a likely 400% higher toughness for new carbon steel material than the toughness of the existing SLP pipeline. The minimum acceptable toughness value per CSA Z662 was not calculated (~20J). Enbridge Gas has provided the toughness criterion per CSA Z662.[13]

Reported Leaks between 2007 and 2023

Enbridge Gas reported ten leaks which were repaired between 2007 and 2023. Nine of the leaks were at valves, fittings and service connections which Enbridge Gas assessed represent no potential hazard. One leak was on a pipeline and Enbridge Gas assigned the highest risk level to the potential hazard of this fault. Enbridge Gas further noted that in urban environments, hard surfaces and buildings represent a higher risk of a gas leaks in confined spaces and increased risk of a build-up to explosive levels.[14]

Quantitative Risk Assessment

Enbridge Gas conducted a Quantitative Risk Assessment (QRA), using the gathered data inspection and survey data and information to assess the level of risk of the SLP

[11] Exhibit B, Tab 1, Schedule 1, Attachment 2 - Quantitative Risk Assessment (QRA) - Appendix B [13] Exhibit I.1-SEC-6, Page 1 of 1
[12] Exhibit B, Tab 1, Schedule 1, Attachment 2, Page 63 of 91
[13] UNDERTAKING JT2.25 – Technical Conference, Day 2, EB-2024-0200
[14] Exhibit B, Tab 1, Schedule 1, paragraph 46, pages 28-29, Table 6: Leak/Repair Summary

system, considering different elements such as potential failure modes and consequences on health and safety, operational disruption, and financial impacts related to the frequency of these failures.

The QRA of the SLP pipeline took into consideration all quantified hazards and

potential risks. This assessment was then measured against three distinct evaluation criteria to determine SPL pipe feasibility for continued safe operation. The evaluation criteria included:

- CSA Z662-19 Annex O Reliability Targets
- USA Pipeline and Hazardous Material Safety Administration (PHMSA) Distribution Pipeline Significant Incidents Benchmark
- Enbridge Standard Operational Risk Assessment Matrix (ORAM)

CSA Z662-19 Annex O Reliability Targets

CSA Z662-19 Annex O sets target reliability thresholds for the Leakage Limit State (LLS), which addresses small leaks, and the Ultimate Limit State (ULS), which concerns larger leaks and ruptures [Canadian Standards Association (CSA) Z66219: Annex O – O.1.5.2 & O.1.5.3]. These reliability targets are designed for gas transmission pipelines and align with the standards for U.S. transmission pipelines following American Society of Mechanical Engineers (ASME) B31.8 standard. The St. Laurent pipeline, operating at 23.2% Specified Minimum Yield Strength (SMYS), falls under the U.S. classification for transmission pipelines.

Based on assessment against CSA Z662-19 Annex O Reliability Targets, Enbridge Gas concluded:

- 3.6 km of the 11.2 km pipeline (32%) was assessed to have a small leak failure rate above the 1E-3 incidents per km/yr, which is the LLS limit described by CSA Z662 - Annex O.[15]

- Seven km of the 11.2 km pipeline (62%) was assessed to have a large leak or rupture failure rate above the 5.8E-5 incidents per km/yr, which is the ULS limit described by CSA Z662 – Annex O for a NPS 12 pipeline at 275 psi MOP in a Class 3 (urban) location.

[15] Exhibit B, Tab 1, Schedule 1, Attachment 2, page 37

- Integrating the Leakage Limit State (LLS) and Ultimate Limit State (ULS) approaches, results in a conclusion that 8.8 km of the 11.2 km pipeline (79%) fails one or both reliability limits. OEB staff notes that TSSA correspondence (Work Order No.: 14370698)[16] on September 20, 2024, indicated that Enbridge Gas complied with the intent of clauses 3, 10, and 12 of CSA Z662-

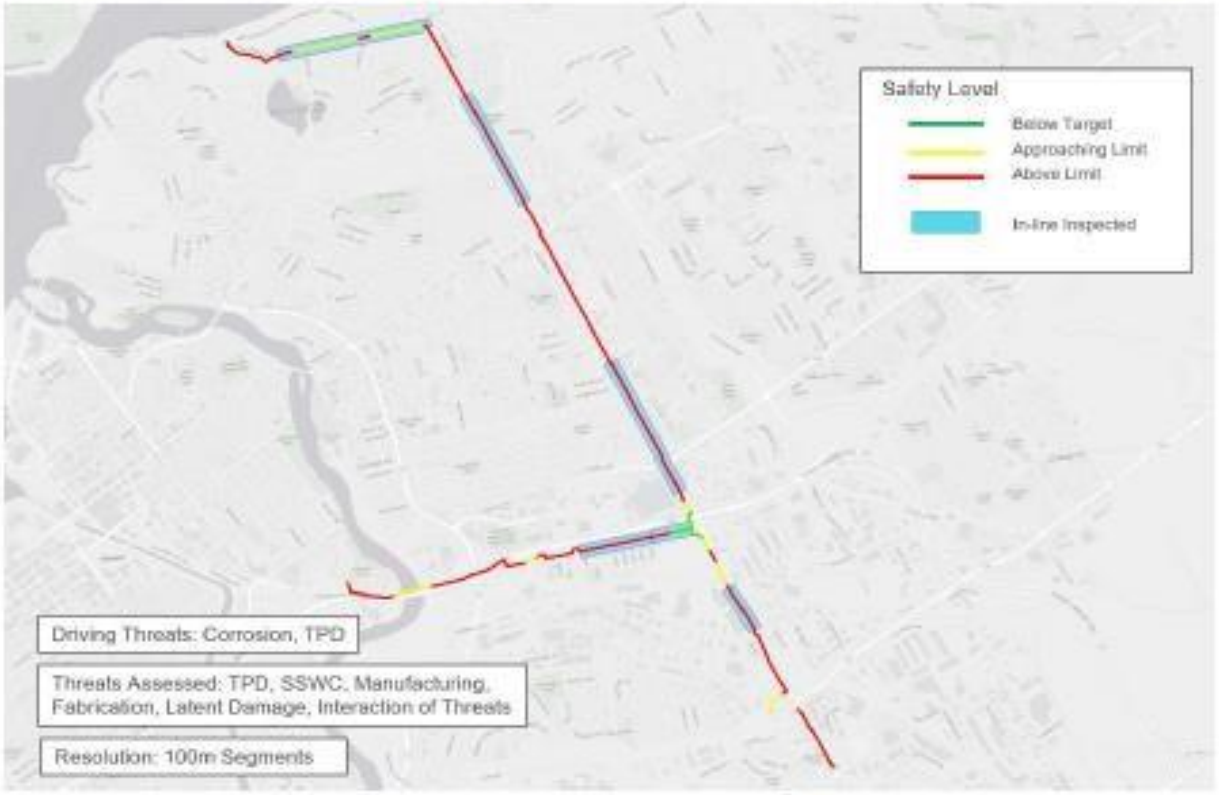
19. It also recommended that the risks need to be properly managed by Enbridge Gas to remain in compliance with CSA Z662-19 and actions should be taken by Enbridge to remediate the condition of the SLP. Enbridge noted that the segments that fail the Leakage Limit State (LLS) and Ultimate Limit State (ULS) along the SLP pipeline are non-continuous.

SLP Reliability vs Reliability Targets is illustrated in the map below.[17]

[16] EB-2024-0200 Exhibit I.1-STAFF-12, plus Attachments

[17] Exhibit B, Tab 1, Schedule 1, paragraphs 49-54, pages 33-37, Figure 17: SLP Reliability versus Targets (LLS and ULS targets combined)

Figure 17: SLP Reliability vs. Targets (LLS and ULS targets combined)



PHMSA Distribution Pipeline Significant Incidents Benchmark

A significant incident benchmark is defined by PHMSA [US 49 CFR § 191.3] as the historical average of significant incidents. Enbridge Gas used this benchmark value for a comparison of the estimated number of significant incidents on SLP compared to the average observed in the industry.

Enbridge Gas applied, as a benchmark value, a hazard rate of approximately 1.73E-5 per km/yr of significant incidents which meets PHMSA's reporting thresholds.[18] The combined failure rate from all sources, converted to equivalent significant incident rate, is 4.6E-2 incidents per km/yr, with corrosion and TPD being the highest contribution.

[18] Exhibit B, Tab 1, Schedule 1, Attachment 2, page 45

Enbridge Standard Operational Risk Assessment Matrix (ORAM)

ORAM is an Enbridge Gas-wide measure of risk acceptance that is used to support riskinformed decision making in all Enbridge Gas business units. This risk matrix is intended to be applied to the assessment of scenarios or events that could result in health or safety impacts to the Enbridge Gas workforce or the public, damage to the environment, impacts to the reliability of Enbridge Gas's assets, reputational damage, or financial losses. The key risks on the SLP that were mapped to the ORAM were Health & Safety, Financial, and Operational Reliability risks.

Considering the overall risks of a failure on the pipeline system, the QRA was supplemented with consequences of various outcomes and mapped to the Enbridge Standard ORAM. This exercise concluded that various risk scenarios meet the Enbridge Operational Risk Matrix definitions of "High Risk" or "Very High Risk".

DNV Validation of the Quantitative Risk Assessment

To enhance the level of confidence in the results, Enbridge Gas sought the expertise of DNV, an internationally recognized consulting firm with a specialization in quantitative risk assessments.

DNV performed a qualitative review of the approach used by Enbridge Gas and its evaluation of the reliability and risk assessment methodologies employed in the QRA, as well as the application of various risk tolerance thresholds. DNV's review concluded that the methodologies applied were consistent with standard industry practices.[19]

DNV agreed with the conclusion made by Enbridge Gas that the risk analysis with the matrix resulted in scenarios with "High Risk" or "Very High Risk" and that additional remedial action to improve the reliability of 8.8 km of the pipeline should be considered.

DNV noted that the use of sub-segmentation of the pipeline into sub-scenarios may give better probability risk values as the application of summed-scenario pipeline frequencies for use in the risk matrix may be considered conservative (i.e., overrepresenting the risk). [20]

[19] Exhibit B, Tab 1, Schedule 1, Attachment 3, page 1
[20] Response to interrogatory Exhibit I.1-PP-24, Attachment 5, page 3

DNV suggested additional calculations of gas release sub-scenarios and sub-segmentation would not change the assessment risk outcome and/or conclusion by Enbridge Gas that the replacement is the optimal option to manage the risk.

TSSA's Fitness-for-service Review

In response to an interrogatory from OEB staff [21], Enbridge Gas advised that it requested the TSSA to perform an Engineering Consultation and provide comments on the fitnessfor-service, integrity, and risk assessments completed by Enbridge Gas for the existing St. Laurent pipeline. The TSSA issued a letter (Work Order No. 14370698) on September 20, 2024 to Enbridge Gas indicating that Enbridge Gas complied with the intent of clauses 3, 10, and 12 of CSA Z662-19. However, the TSSA also recommended that the risks need to be properly managed by Enbridge Gas to remain in compliance with CSA Z662-19 and actions should be taken by Enbridge Gas to remediate the condition of the SLP. The TSSA letter to Enbridge Gas did not recommend the specific actions in this regard but concluded that "the risks now need to be properly managed by Enbridge to remain in compliance with the CSA Z662-2019 [and that] actions shall be taken by Enbridge to remediate the condition of the St. Laurent pipeline."

OEB Staff Submissions – Need for Replacement

Starting in June 2022, Enbridge Gas implemented the new Targeted Inspection Program. This program is a comprehensive approach and modern methods to inspect the current condition of the pipeline, identify risks, assess risks, respond to risks, evaluate alternatives and re-evaluated the alternatives. Enbridge Gas implemented on-site inspection methods which indicated that the condition of the SLP is declining.

Enbridge Gas implemented a Quantitative Risk Assessment using the inputs it acquired through inspection and testing. The Quantitative Risk Assessment approach involved applying three sets of standards to assess the risk associated with the current condition of the SLP and to assess the risk to reliability and safety:

1. CSA Z662-19 Annex O Reliability Targets
2. PHMSA Distribution Pipeline Significant Incidents Benchmark

[21] Response to interrogatory Exhibit I.1-STAFF-12, Attachment

3. Enbridge Standard Operational Risk Assessment Matrix

OEB staff submits that the QRA approach, combining the three sets of standards, and targets, seems adequate and valid. OEB staff agrees with Enbridge Gas that given the absence of specific reliability targets for distribution pipelines in Canada, along with the increased risks associated with the pipeline's location in urban areas, the CSA Z662 Annex O reliability targets can serve as a crucial benchmark for assessing the pipeline's reliability under these conditions. Although CSA Z662 Annex O is an informative (non-mandatory) part of the standard, it is considered to provide a level of rigor for engineering assessments for safety consideration (CSA Z662 Annex O Clause 3.4).

As noted above, the TSSA evaluated Enbridge Gas's report on the SLP's fitness-forservice and recommended that the risks need to be properly managed by Enbridge Gas to remain in compliance with the CSA Z662-19 and actions should be taken by Enbridge Gas to remediate the condition of the SLP. The TSSA did not recommend any specific action (replacement, ongoing monitoring, inspection and repair or any other option) to address those recommendations regarding the fitness-for-service, integrity and risk assessment of the SLP, but OEB staff understands that the TSSA does not typically recommend specific actions.

OEB staff has no concerns with the DNV valuation of Enbridge Gas's Quantitative Risk Assessment results applied as part of the TIP. OEB staff notes that DNV pointed to certain actions to refine the accuracy of the reliability of risk value but remarked that these actions would not change the assessment risk outcome and/or conclusion by Enbridge Gas that replacement is the optimal option to manage the risk.

In conclusion, OEB staff submits that Enbridge Gas has demonstrated the need to take corrective action to address the condition of the existing SLP.

3.2 Project Alternatives

In order to determine the best alternative to reduce the risk associated with the integrity and declining condition of the SLP, Enbridge Gas evaluated integrity program and facility alternatives, and non-facility alternatives including Integrated Resources Planning Alternatives (IRPA). In the outcome of alternatives assessment and selection process, Enbridge Gas has concluded that full replacement is the best alternative to address the need for the Project.

Integrity Program and Facility Alternatives

The evaluation process for determining the most suitable risk mitigation action for the SLP began with a review of six distinct alternatives:[22]

Alternative 1: No additional actions, continuing with third-party damage mitigation—rejected as the pipeline risk, safety and reliability cannot be mitigated without additional actions

Alternative 2: Permanent pressure reduction—rejected as loss of capacity is not acceptable

Alternative 3: Extensive Inspection and Repair with Crawler ILI

Alternative 4: Extensive Inspection and Repair with Free-Flow In-line Inspection (ILI)—rejected as insufficient to reduce risk on a longer run, could meet risk thresholds temporarily

Alternative 5: Full Replacement. Full replacement of the SLP

Alternative 6: Partial Replacement. This alternative is a combination of Alternative 3 and Alternative 5

Alternative 1 and Alternative 2 were eliminated initially as the risk reduction effectiveness is inadequate for both. Alternatives 3 and 4 are variations of Extensive Inspection and Repair while Alternatives 5 and 6 are replacement alternatives.

The four risk mitigation alternatives were assessed after analysis to evaluate the residual risks after mitigation and to determine the constructability of the facilities.

Enbridge Gas identified Alternative A- Full Replacement and Alternative B-Extensive Inspection and Repair as two feasible risk reduction strategies. Enbridge Gas selected Alternative A – Full Replacement as the preferred option.

Alternative A: Full Replacement – proposed Project Alternative
B: Extensive Inspection and Repair

[22] Exhibit C, Tab 1, Schedule 1, pages 1-7

These two alternatives were comparatively assessed based on: approximate reduction of health and safety risk, operational reliability risk, and financial risks (i.e., cost of property damage, emergency repair, restoring service to customers).

Enbridge Gas applied the following criteria in its comparative assessment of risk mitigation alternatives:

- Public Safety and Residual Risks
- Public Disruption and Nuisance
- Uncertainty of Plan and Outcomes
- Other Considerations (i.e., long-term uncertainty impacts, potential for using the pipeline for future low-carbon initiatives etc.)
- Financial Assessment (NPV)

Technical Aspects of Alternative A and Alternative B

Enbridge Gas selected the full replacement as its preferred approach based on the risk assessment and the high estimated failure rate of the existing SLP. Considering the current degradation of the SLP pipe, the amount of required repair and inspection for continued safe operation and the added risk of low toughness and potential pipe material lamination replacement (Alternative A) seems to have an advantage over extensive inspection and repairs (Alternative B).

OEB Staff Submissions – Technical Aspects of Alternative A and Alternative B

OEB staff submits that in terms of risk management and repair, Alternative A – replacement, is favorable. OEB staff points out that Enbridge Gas should ensure the reliability and integrity of the existing SLP until the replacement is completed, estimated in 2026.

OEB staff notes that the replacement pipes proposed in the Project are of higher wall thickness and acceptable material toughness compared to those of vintage pipes. For that reason, it is expected that future maintenance will be much lower compared to the existing vintage pipes of the same operational life.

OEB staff notes that no slabs were installed as a measure to prevent Third-Party Damage (TPD). OEB staff submits that during the construction of the replacement pipeline, the current mitigation measures should continue and should be enhanced. For example, installation of slabs is recommended to prevent TPD which is one of

the highest-consequence risks. Enbridge Gas has so far implemented the following mitigations activities to manage the risks of the existing SLP:

- periodic inspection
- cathodic inspection with monitoring
- soft mitigation of TPD

Enbridge Gas's risk management measures include increasing awareness of the risk of TPD. OEB staff submits that these measures should continue but also may be enhanced.

OEB staff submits that replacement of the existing pipeline is the best alternative to manage integrity and safety risks compared to intensive inspections and repairs.

OEB staff recommends that, should the OEB approve the replacement, Enbridge Gas should be required to continue to implement the existing and enhanced risk mitigation measures to continue reliable and safe service until the new pipeline is inservice, estimated in 2026. Should the OEB deny the replacement, Enbridge Gas should be required to formulate enhanced monitoring and mitigation programs to manage the declining integrity of the existing pipeline with time. If the pipeline replacement is not approved, OEB staff suggests that Enbridge Gas should improve its Targeted Inspection Program by adding considerations and testing of time dependent future metal loss and impacts of pipeline material toughness.

OEB staff notes that Enbridge Gas's reported material toughness of the vintage SLP pipes constitutes an added risk not reflected in repair costs and delays. Enbridge Gas also stated that pipe wall lamination was a challenge in some areas where repair was conducted. OEB staff suggests that although this can be considered a fabrication matter that Enbridge Gas was not able to control/detect 60 years ago, it should be viewed as a high-risk for repair considering the reported low toughness.

OEB staff observes that Enbridge Gas does not use the EGI Distribution Steel Pipeline Repair Standard Criteria to determine excavation sites for repair. Enbridge Gas uses EGI Distribution Steel Pipeline Repair Standard Criteria for repair upon excavation.[23] OEB staff notes that this approach could inflate the repair cost for shortto-medium operational life.

When assessing the condition of the SLP, Enbridge Gas accounted for the effect of probability of the impact of future inspection, detection, repair on the failure rate and required repair. OEB staff suggests that a few additional parameters that were not assessed may improve Enbridge Gas's future Targeted Inspection Program. These additional parameters and criteria may include[24]:

[23] Exhibit I.1-STAFF-6

[24] Technical Conference Transcript Vol. 2, October 31, 2024, pages 142-143 and page 162 , lines 13-18 and

- Time dependent future metal loss (Linear metal loss rate was assumed which is not conservative)

- Impact of material toughness on highly corroded regions and pin-holes (not just Third-Party Damage) as well as on repair of material toughness on highly corroded regions and pin-holes (not just Third-Party Damage) as well as on repair

Should the OEB not approve Alternative A – replacement, Enbridge Gas would need to take steps to safely extend the operational life of the existing SLP. OEB staff suggests that Enbridge Gas may consider risk assessment and inspection/repair plans including:

- Better understanding of corrosion mechanism and future metal loss projection
- Better inspection techniques
- Revision of repair procedures and associated cost based on existence of lamination defects and low toughness
- Potential future impact on internal pipe corrosion due to potential use for hydrogen blending
- Control of the Cathodic Protection and monitoring and ensuring this does not cause additional risk due to hydrogen embrittlement

OEB staff notes that the above considerations and actions were discussed with Enbridge Gas in the technical conference on October 31, 2024. More detail on Enbridge Gas's comments may be found in the transcript of the technical conference.[25]

Economic Comparison of Alternative A and Alternative B

Enbridge Gas conducted an economic Net Present Value (NPV) assessment comparing Alternative A and Alternative B.

Enbridge Gas compared the NPV of Alternatives A and B under three different time horizons:

- Case A: 63 years (61 years from the projected in-service date of 2026), matching the OEB-approved depreciation rate for this asset category (steel mains)

[25] Technical Conference Transcript Volume 2, October 31, 2024, pages 132, 144-146 and 153

- Case B: 42 years (40 years from the projected in-service date), matching the typical time horizon Enbridge Gas has used in economic feasibility assessments in previous Leave to Construct applications.
- Case C: 31 years. This useful life was selected to match the most aggressive electrification scenario from Enbridge Gas's energy transition scenario modelling (discussed in more detail below). This scenario projects that no gas customers will remain in 2055 (31 years), such that the SLP would have reached its economic end-of-life.

Table 7

Summary of NPVs for Alternative A and B with Various Useful Lives

NPV ($ millions)	A – Full Replacement	B - Extensive Inspection and Repair	$ Difference (A – B)
Case A (63 years)	$(134)	$(253)	+$119
Case B (42 years)	$(134)	$(179)	+$45
Case C (31 years)	$(134)	$(140)	+$6

Cost Assumptions Used in NPV Analysis[26]

The costs associated with Alternative A are $155 million, while the costs associated with Alternative B are $298 million. In this analysis, Enbridge Gas excluded past costs already incurred for the SLP replacement and potential future costs expected to be common to both alternatives. [29]

The activities and costs associated with Alternative A used in the NPV analysis are:

- Full pipeline replacement ($151.3 million)
- Interest during construction ($3.7 million)

[26] All costs quoted in this section are from Exhibit I.2-Staff-17, attachment 4, and are in 2024 dollars. [29] For this reason and due to discounting of all costs to 2024 dollars, the costs for Alternative A are not identical to those described for the Project in the "Project costs and economics" section of this submission.

The activities and costs associated with Alternative B are:

- Upfront targeted replacements to replace 1.9 km of the pipeline ($41.5 million) and replace a section of NPS 16 pipe with an identified corrosion issue ($2.7 million)
- Upfront measures to:
    - inspect the uninspected portion of the pipeline with crawler in-line inspection tool ($3.9 million);
    - inspect and mitigate remaining critical features already identified from inspected sections of the pipeline ($12.5 million), and inspect and mitigate critical features expected to be identified from the uninspected sections (following crawler in-line inspection) ($16.3 million); ○ implement measures to reduce the threat of third-party damage ($11.8 million)
- Ongoing inspection and repair of the 7.8 km of the existing pipeline that was installed prior to 1978, on a 7-year cycle[27] ○ Crawler in-line inspections, including site preparation ($42.7 million) ○ Inspection and mitigation of identified critical features identified from the crawler in-line inspections ($160.6 million)
    - Possible stuck crawler tool retrieval ($1.8 million)
- Interest during construction ($4.5 million)

Three key input assumptions impacting Enbridge Gas's assessment of the ongoing costs associated with Alternative B are:

- **Frequency of inspection**. Enbridge Gas assumed a 7-year re-inspection interval.
- **The assumed level of identified critical features identified from the ILI inspections that require further inspection and mitigation**. After the initial rounds of mitigation based on the first crawler in-line inspection (which would identify a higher number of critical features), Enbridge Gas estimated the number of digs needed in future inspection cycles based on trend data for similar pipelines from its Transmission Integrity Program.
- **The cost escalator for future costs**. Enbridge Gas used an inflation rate of 3% for most cost categories (based on non-residential construction CPI index), but escalated inspection and mitigation costs at a rate of 6% based on cost trending of integrity digs over the previous 10 years.

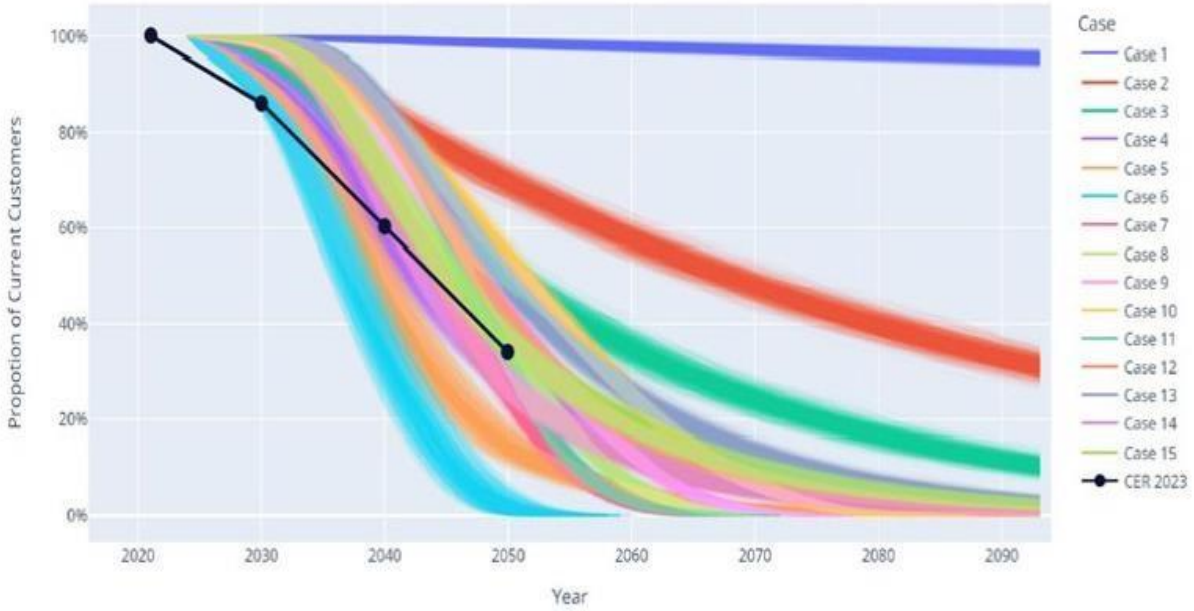
[27] Costs shown for these actions are based on case A, which has inspection and repair measures continuing through 2085.

Energy Transition Analysis and Stranded Asset Risk

Enbridge Gas assessed the potential impacts of energy transition on the SLP Project. The primary purpose of this analysis was to assess the risk of stranded assets associated with the Project. This information was used to inform time horizons used in Enbridge Gas's NPV analysis (i.e., by choosing a time horizon shorter than the technical life of the asset).

Enbridge Gas engaged Integral Engineering to perform probabilistic modeling to estimate the rate at which general service customers might choose to exit the gas system. Integral Engineering modeled multiple scenarios, based on different assumptions around the rate of electric heat pump adoption and customer decisions as to whether and when to disconnect from the gas system following heat pump adoption, and compared the scenario results to the Canadian Energy Regulator's Energy Future 2023 Global Net-Zero Scenario.[28] The model results indicated that under 14 of the 15 scenarios, customers would remain on the system beyond 2060, while under the 15th scenario (with the most aggressive electrification and gas disconnection assumptions), the most likely year in which no general service customer would be present is 2055.

Figure 2 Summary of analysis results: Proportion of Remaining Customers



[28] Application Evidence, Exhibit B, Tab 3, Schedule 1, page 15, Figure 2

Enbridge Gas's energy transition analysis also included a review of current federal, provincial and municipal climate policies (including the City of Ottawa's Climate Plan and the status of its Energy Evolution Plan), an analysis of the energy needs of local Large Volume Contract Demand customers, and the state of electricity system planning in the Ottawa area. Enbridge Gas indicated that these reviews provided additional support for its conclusions that there was low risk of the Project's assets being stranded, and that the capacity provided by the Project would be needed well into the future.

OEB Staff Submission – Economic Comparison of Alternative A and Alternative B

OEB staff notes that Enbridge Gas's NPV analysis showed that Alternative A is economically preferable to Alternative B, with a higher (less negative) NPV in all cases. The difference between the two options narrows as the time horizon of the NPV analysis decreases, with both alternatives having the same NPV at a useful life of approximately 30 years.

While Enbridge Gas's NPV analysis shows Alternative A to be preferable to Alternative B

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under all modeled time horizons, with a change in the economic input assumptions related to cost escalation (discussed further below), the NPV of Alternative A and Alternative B becomes similar.

However, as discussed earlier, additional actions are likely needed to make Alternatives A and Alternative B comparable from a risk and safety profile. This would increase the cost of Alternative B.

OEB staff submits that the economic comparison of Alternatives A and B, at a minimum, does not favour Alternative B to a degree that would override the technical advantages of Alternative A. Therefore, OEB staff considers Alternative A to be the preferred alternative. OEB staff provides additional submissions on two aspects of Enbridge Gas's economic analysis: cost escalation assumptions and the assumed time horizon/useful asset life used for the NPV analysis, taking account of energy transition considerations.

OEB Staff Submission - Cost Escalation Assumptions

OEB staff notes that given the high costs of ongoing inspection and mitigation efforts in Alternative B ($160.6 million) and the long time horizon of these activities, the NPV results are very sensitive to assumptions around cost escalation and discount rate, in particular, the assumption of a 6% annual cost escalator for these activities.

Enbridge Gas provided several reasons why these costs were increasing faster than other construction costs, and indicated that a 6% rate was actually a conservative assessment as its analysis of historical cost data for integrity digs showed an 8-10% increase per year.[29]

Were Enbridge Gas to use a consistent 2% cost escalator for all project costs in both Alternative A and Alternative B, consistent with its cost escalator for its Asset Management Plan, the NPV results change significantly, with Alternative B being economically preferable to Alternative A under cases B and C, and only slightly more expensive in case A.[30]

Table 1
Summary of NPVs for Alternative A and B with Various Useful Lives
with Modified 2% Constant Escalation Rate

NPV ($ millions)	A – Full Replacement	B – Extensive Inspection and Repair	$ Difference (A - B)
Case A (63 years)	$(130)	$(134)	+$4
Case B (42 years)	$(130)	$(123)	-$7
Case C (31 years)	$(130)	$(113)	-$17

Integrated resource planning for Enbridge Gas is heavily dependent on the benefits associated with deferral of capital spending. The higher the cost escalation rate, the lower these benefits will be. In this case, the use of a cost escalation rate of 6% for ongoing inspection and mitigation costs is higher than Enbridge Gas's discount rate of the time

[29] JT 1.1
[30] OEB Staff Submission

value of money (its weighted average cost of capital of 5.75%). A cost escalation rate higher than the discount rate has the counterintuitive implication that deferring capital expenditures actually increases costs on a net present value basis.[31] This would make it challenging for any asset life extension activities to pass a cost-effectiveness analysis. OEB staff does not believe that the use of a cost escalator that is materially higher than both the inflation rate and the cost escalator for general construction costs, over the long time horizon associated with the Project, is appropriate.

OEB staff notes that, under the IRP framework, Enbridge Gas will be filing an enhanced Discounted Cash Flow-plus (DCF+) test with the OEB for approval.[32] OEB staff recommends that Enbridge Gas provide a proposal for the appropriate treatment of cost escalation of project costs as part of this enhanced DCF+ test.

OEB Staff Submission - Useful Asset Life Under Energy Transition

Based on the energy transition information filed in the proceeding (Integral Engineering analysis, City of Ottawa Energy Evolution, long-term electricity planning), OEB staff believes that the useful asset life of the project is unlikely to be less than the 31-year asset life (2055) assumed in case C, and that this serves as a reasonable time horizon for the NPV analysis. The SLP is a major pipeline serving approximately 168,000 customers and OEB staff believes that the likelihood of the Project having few or no remaining customers before 2055 is low.

OEB staff does have a concern that Enbridge Gas's definition of useful asset life in its energy transition scenario modeling is likely too conservative. Enbridge Gas's definition assumes that an asset remains useful so long as any customers remain, noting that its obligation to serve means that it cannot discontinue service to customers that would like to remain.[33]

However, the obligation to serve cannot mean service at any cost. Should Enbridge Gas undertake Alternative B and customer disconnections reach high levels, the OEB would need to look at eliminating the obligation to serve or changing cost allocation policies (to make remaining customers on the underutilized asset pay more of the cost of subsequent inspections and repairs).

[31] Technical Conference transcript day 1, pp. 11-12
[32] EB-2020-0091 Decision and Order, July 22, 2021, p. 57

The use of a customer number threshold higher than zero to set the estimated asset life for the purpose of economic evaluation is therefore more appropriate. OEB staff notes that the use of a 31-year asset life (2055) is roughly aligned with when customer numbers decline to 25% of current levels (in an extrapolation of the Canadian Energy Regulator's Energy Future 2023 Global Net-Zero Scenario, and in an average of Integral Engineering's modelling scenarios).

Should the useful asset life of the Project be 31 years, there would still be undepreciated assets at the end of the Project's life, given the longer depreciation period of 61 years. Enbridge Gas is already required to examine options to ensure its depreciation policy addresses the risk of stranded asset costs appropriately as part of its next rebasing.[34]

Non-Facility Alternatives, including Integrated Resource Planning Alternatives

Enbridge Gas indicated that it reviewed potential non-facility/integrated resource planning (IRP) alternatives to the Project as required by the IRP Framework.

Enbridge Gas submitted that implementation of IRP alternatives would not address the risks associated with the condition of the SLP, as both supply-side alternatives and demand-side alternatives would still require making use of the existing SLP. Therefore, Enbridge Gas submitted that the scope of its IRP alternatives assessment was limited to assessing whether the proposed Project pipeline size could be reduced, rather than avoided entirely.

Enbridge Gas indicated that a peak hour demand reduction of between 13,300 m^3/hr and 25,100 m^3/hr (depending on the location of demand reduction) would be required by winter 2025/2026 to allow Enbridge Gas to downsize the Project's 2.4 km of NPS 16 to NPS 12. Downsizing this segment would provide Enbridge Gas with a cost saving of approximately $1.3 million.[35]

Enbridge Gas assessed four IRP alternatives (two supply-side alternatives and two demand-side alternatives) that could enable pipeline downsizing, but rejected all four, as described below.

- **Incremental Gas Supply** – rejected for technical reasons as there are no additional interconnects in the area to provide incremental supply.

[34] EB-2022-0200, Decision and Order, December 21, 2022, pp. 140-141.
[35] JT1.20 provides additional detail on this cost estimate.

- **Compressed Natural Gas** – rejected for economic reasons as the cost of the compressed natural gas alternative is approximately $1.2 million every year, thus the lifetime cost of this alternative is significantly higher than the savings resulting from downsizing the pipe.
- **Enhanced Targeted Energy Efficiency** - rejected for technical and economic reasons. Enbridge Gas indicated (based on an evaluation of energy efficiency potential from the Posterity Group) that the maximum peak hour reduction potential from enhanced targeted energy efficiency for its general service customers was less than the peak hour demand reduction required for pipe downsizing, and the full potential could not be achieved until 2042, long after the date of winter 2025/26 by which Enbridge Gas submitted that the pipeline would need to be replaced or repaired due to condition risks. The cost of enhanced targeted energy efficiency (approximately $77 million) would also be much higher than the cost savings associated with pipeline downsizing.
- **De-Contracting Capacity of Existing Contract Customers** – rejected for technical reasons. Enbridge Gas sent out a binding reverse open season document to all existing distribution contract rate customers in the proposed project service area, which gave the customers the opportunity to de-contract existing distribution capacity, or to convert existing firm distribution service to interruptible service (with negotiated interruptible rates). Uptake by customers of these options would reduce the peak hour demand Enbridge Gas would be required to serve, however, no bids were received.

Enbridge Gas also indirectly considered the impact of the City of Ottawa's Energy Evolution Plan in reducing natural gas use, through potential (downward) adjustments to its demand forecast. Enbridge Gas concluded that the status of the priority projects within the Energy Evolution Plan that could impact natural gas demand shows that the majority are currently off track and, therefore, the timing of when the reductions could occur cannot be determined. As a result, no adjustments to the demand forecast were made.[36]

OEB Staff Submission – IRP Alternatives

OEB staff submits that none of the IRP alternatives examined are preferable to the proposed Project. There is no feasible IRP alternative that entirely avoids the need for

[36] Exhibit I.3.PD-13(i)

repair or replacement of the SLP, and the minor cost savings from downsizing the NPS 16 segment are far outweighed by the cost of IRP alternatives.

In OEB staff's submission on Enbridge Gas's previous St. Laurent Ottawa North Replacement Project application, OEB staff submitted that, should the OEB accept that a full pipeline replacement is required in the near future, then the Project is appropriately sized, as neither the IRP alternative, nor the City of Ottawa's efforts through Energy Evolution, will feasibly reduce the peak demand served by the St. Laurent system on a scale sufficient to reduce the sizing of the proposed Project in the near term.[37]

OEB staff submits that this conclusion is still applicable to demand-side IRP alternatives in this proceeding, taking account of the updated evidence on the proposed Project and IRP alternatives. An updated status report from the City of Ottawa on the progress of the Energy Evolution plan indicates challenges with many of the projects in the Energy Evolution plan and does not provide evidence of significant expected near-term gas peak demand reductions.[38]

OEB staff has some concerns about Enbridge Gas and Posterity's methodology for assessing enhanced targeted energy efficiency as a demand-side IRP alternative. These concerns include the lack of consideration of the energy efficiency potential from contract customers (aside from the potential use of interruptible rates) or demand reductions from Gazifère customers,[39] and an economic analysis that only reports the direct program costs of demand-side IRP alternatives, not the potential energy cost savings to participating customers. However, OEB staff does not believe that addressing these issues would change its conclusion that a demand-side IRP alternative (in combination with pipeline downsizing) is not preferable to the proposed Project, due to the very high program costs for demand-side alternatives relative to the cost savings associated with pipeline downsizing, and the large amount of demand reduction that would need to be acquired in a short period of time.

OEB staff also agrees with Enbridge Gas that the supply-side IRP alternatives examined are not preferable to the proposed Project.

[37] EB-2020-0293, OEB Staff Submission, March 24, 2022, pp. 16-17
[38] Application and Evidence, Exhibit B, Tab 3, Schedule 1, pp. 2-7
[39] Residential customers account for approximately 43% of peak demand (Exhibit I.2-ED-21(b))

3.3 Project Cost and Economics

The total estimated construction cost of project is estimated at $216 million which includes approximately $7.35 million of investigation costs of Targeted Integrity Program to assess the reliability and condition of the existing pipeline (not included in the leave to construct application) and approximately $208.7 million for construction of the project.

Enbridge Gas estimated the Project costs as shown in the table below to be approximately $216.07 million. Enbridge Gas noted it seeks approval for $208.72 million. The differential of $7.35 million is the estimated cost related to implementation of the Targeted Integrity Program to assess the reliability and condition of the SLP beginning in June 2022. Table below itemizes the forecast Project cost:[40]

Table 1

Estimated Project Costs

Item #	Description	Pipeline Costs	Ancillary Costs(1)	Total Costs
1	Materials	$5,713,679	$565,089	$6,278,768
2	Construction & Labour	$105,789,143	$10,462,663	$116,251,806
3	External Permitting & Lands	$1,712,979	$169,416	$1,882,395
4	Outside Services	$16,632,354	$1,644,958	$18,277,312
5	Direct Overheads	$4,209,912	$416,365	$4,626,276
6	Contingency	$19,840,594	$1,962,257	$21,802,850
7	IDC	$3,711,276	$367,049	$4,078,325
8	Project Cost	$157,609,937	$15,587,796	$173,197,733
9	Indirect Overheads & Loadings	$32,321,125	$3,196,595	$35,517,720
10 (2)	Total Project Costs	$189,931,062	$18,784,391	$208,715,452
11	Incremental Investigation Costs	$4,767,202 (3)	$2,582,527 (4)	$7,349,729
12 (5)	Total Project Costs including Incremental Investigation Costs	$194,698,264	$21,366,917	$216,065,181

Project costs set out in table above include: (1) materials; (2) construction and labour; (3) external permitting and lands; (4) outside services; (5) direct overheads; (6) contingencies; (7) interest during construction (IDC); (9) indirect overheads and loadings; and (11) incremental investigation costs. Enbridge Gas noted that excluding indirect overheads, loadings, and incremental investigation costs, the total estimated cost of the Project is $173.2 million. Contingency of 14.8% is applied to direct capital costs. Enbridge Gas stated that the contingency is based on the current design stage of the Project and was calculated using the risk profile of the Project.

[40] Exhibit B, Tab 1, Schedule 1, page 2, Table 1

In the table below Enbridge Gas provided a comparison of the forecasted project cost with the cost of two recently completed projects. [41]

Table 2
Project Cost Comparison – Pipeline Costs ($ millions)

Description	SLP Replacement Project	NPS 20 Replacement Cherry to Bathurst Project (1)	NPS 20 Waterfront Relocation Project (2)
Facility Description	0.3 km of NPS 6 ST XHP; 10 km of NPS 12 ST XHP; 2.5 km of NPS 16 ST XHP; and 4.8 km of IP PE.	4.5 km of NPS 20 ST HP	Temporary Bypass: 0.2 km of NPS 20 ST HP; Permanent Relocation: 0.2 km of NPS 20 ST HP
Materials	6.3	3.5	2.5
Construction & Labour	116.3	71.8	10.2
External Permitting & Lands	1.9	1.1	0.02
Outside Services	18.3	5.2	2.2
Direct Overheads	4.6	1.0	0.3
Contingency	21.8	24.8	4.6
IDC	4.1	1.7	0.4
Project Cost	173.2	107.3	20.2
Indirect Overheads & Loadings	35.5	24.4	3.3
Total Project Costs	208.7	133.0	23.5
Incremental Investigation Costs	7.3	N/A	N/A
Total Project Costs including Incremental Investigation Costs	216.1	N/A	N/A

Enbridge Gas did not propose a unique rate recovery treatment for the capital costs of the Project. Enbridge Gas stated that if the Project is approved and it qualifies for Incremental Capital Module (ICM) recovery, Enbridge Gas will apply for cost recovery in the rate year in which the project goes into service (2025 or 2026). Enbridge Gas further stated that if there is no ICM recovery, the Project will not be included in rate-base for rate setting purposes until the next rebasing application following the proposed in-service date.[42] **OEB Staff Submission – Forecast Capital Cost**

OEB staff has no concern with the forecast cost for the Project. Comparison of cost with the two similar projects was not meaningful because these are not comparable to SLP Project. OEB staff submits that were the OEB to approve the SLP Replacement Project with Standard Conditions of Approval agreed upon by Enbridge Gas, Condition No. 6 (see Schedule A of this submission), agreed upon by Enbridge Gas, would require

[41] Application Exhibit E, Tab 1, Schedule 1, page 3, Table 2
[42] Enbridge Response to OEB staff interrogatory I.1-STAFF-2 b)

that Enbridge Gas file with the OEB the actual capital cost of the Project and explain variances and the use of contingencies.

3.4 Environmental Matters

Enbridge Gas retained Dillon Consulting Limited (Dillon) to complete an Environmental Report (ER), which assessed the existing bio-physical and socio-economic environment in the study area, the alternative routes, the proposed preferred route, public consultation program, impact assessment, and proposed mitigation measures to minimize the impacts of the project.

The Project's ER was finalized in June 2020 and ER Amendment 1 was completed in November 2020.

ER Amendment 2 was completed in January 2024 and provides an additional assessment on the additional segments added to the proposed pipeline routes.

The ER amendment was submitted to the Ontario Pipeline Coordinating Committee (OPCC) and other stakeholders for review and comment on October 27, 2023. Enbridge Gas provided an updated consultation log.

The description of consultation activity with the federal National Capital Commission (NCC) provided in Appendix D of the ER notes that federal approval is required for the project and that a Federal Land Use, Design and Transaction Approval (FLUDTA) level 1 or 2 application is required prior to a decision and a federal determination under the Impact Assessment Act (IAA). Enbridge notes that the IAA and FLUDTA have been accepted.

In its response to OEB staff interrogatories, Enbridge Gas provided an updated consultation log. Enbridge Gas stated that a federal determination under the IAA is expected in early 2025 and that no other part of the project requires determination under the IAA.[43]

Enbridge Gas states that it is looking at site options for replacing the Rockliffe Control Station and that the exact route for the pipeline at Rockliffe Park is subject to change

[43] Enbridge Gas Response to OEB Staff 20-b), September 27, 2024

pending the outcome of the site selection process for the replacement station. Enbridge Gas also states that at the time of filing, the locations under consideration fall within the study area of the Environmental Report.

In its response to OEB staff interrogatories, Enbridge Gas stated that the environmental assessment includes the areas that are under consideration for any changes to the pipeline route and that if additional changes are required to the Project Route to address the potential relocation of the Rockcliffe Control Station, those locations will be assessed in accordance with the OEB's Environmental Guidelines.[44]

OEB Staff Submission

OEB staff submits that Enbridge Gas has completed the ER in accordance with the OEB'S *Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario*. OEB staff has no concerns with the environmental aspects of the Project, based on Enbridge Gas's commitment to implement the mitigation measures set out in the ER.

OEB staff submits that Enbridge Gas's compliance with the conditions of approval outlined in Schedule A will ensure that impacts of pipeline construction are mitigated and monitored. OEB staff notes the site options for the relocation of the Rockclife Control Station are included in the study area of the ER.

3.5 Land Matters

The proposed route for the Project follows the public road allowance for most of the proposed pipeline. Enbridge Gas notes that both permanent and temporary easements are required for the Project.

Enbridge Gas also states that an easement for segments of the existing pipeline through Rockcliffe Park on lands owned by the National Capital Commission has expired and that Enbridge Gas will engage with the National Capital Commission to renegotiate any required easement for the preferred pipeline route prior to replacement.

In response to OEB staff interrogatories, Enbridge Gas stated that it anticipates that agreement will be reached with all landowners where required.[45] Enbridge Gas also stated that if the Rockcliffe Control Station is relocated, all sites being considered are

[44] Enbridge Gas Response to OEB Staff 21-d) and 21-f), September 27, 2024
[45] Enbridge Gas Response to OEB Staff 22-a), September 27, 2024

located on federal lands owned by the National Capital Commission (NCC), and are subject to the NCC's Federal Land Use and Transaction Approval (FLUDTA) process. Enbridge Gas notes that the FLUDTA is currently in the consultation phase and that the NCC's approval period is usually two to four months.[46]

OEB Staff Submission

OEB staff submits that the OEB should approve the proposed forms of easement and temporary land use agreements as both were previously approved by the OEB.

OEB Staff currently has no concerns with the relocation of Rockcliffe Station as the

proposed conditions of approval require Enbridge Gas to obtain all necessary approvals, permits, licences, and certificates needed to construct, operate and maintain the Project.

3.6 Indigenous Consultation

Enbridge Gas conducted consultation with the Indigenous communities potentially affected by the St. Laurent Replacement Project as required by OEB *Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Projects and Facilities in Ontario* (Guidelines).The Indigenous consultation started in 2020 for the St. Laurent Ottawa North Project.[47] On January 30, 2020, the Ministry of Energy and Electrification (Ministry) delegated procedural aspects of Indigenous consultation related to St. Laurent Ottawa North Replacement Project. The Ministry identified that Enbridge Gas should consult with Algonquins of Ontario and Mohawks of Akwesasne.[48]

On November 7, 2023 Enbridge Gas sent an update to Project description, subject to this application. Enbridge Gas received a letter from Ministry of Energy on December 21, 2023 (2023 Delegation Letter), indicating that, consistent with the Ministry of Energy's previous delegation letter issued January 30, 2020, the consultation list will continue to include Algonquins of Ontario and Mohawks of Akwesasne. With respect to consultation with the Algonquins of Ontario, the Ministry indicated that the Algonquins of Pikwakanagan First Nation is one of the communities that comprise the Algonquins of Ontario and should be notified separately for consultation and engagement purposes. Enbridge Gas proceeded as directed in the 2023 Delegation Letter. On September 15, 2023, Enbridge Gas

[46] Enbridge Gas Response to OEB Staff 23-a) and 23-b), September 27, 2024

[47] EB-2020-0293 application for the St. Laurent replacement by Enbridge Gas was denied by the OEB by Decision and Order dated Mar 3, 2022.

[48] The Indigenous consultation process and outcomes for the EB-2-2020-0293 is described in EB-20240200 Exhibit I, Tab 4, Schedule 1

informed the communities identified in 2023 Delegation Letter of the changes to Project scope and of its intent to file a new application to construct the replacement pipeline.

The evidence on Indigenous consultation for the current application includes updated Indigenous Consultation Report (ICR) as of April 8, 2024 and updated correspondence logs updated as of April 8, 2024. In response to OEB staff interrogatories Enbridge Gas filed further updates to the ICR and consultation log to cover period between April 8, 2024 and September 13, 2024. [49] Enbridge Gas noted that there have been no outstanding issues or concerns raised by the Indigenous communities.[50] The Algonquins of Ontario expressed the importance of environmental and archaeological impacts of the Project and requested ongoing consultation on the Project. Enbridge Gas stated it would be providing a field site visit requested by Algonquins of Pikwakanagan First Nation.

On November 8, 2024 the Ministry issued a Letter of Opinion to Enbridge Gas, which Enbridge Gas filed on the record of the case. The Ministry's Letter of Opinion stated "…based on this review of materials and our outreach to Indigenous communities, ENERGY is of the opinion that the procedural aspects of consultation undertaken by Enbridge to-date for the purposes of the Ontario Energy Board's Leave to Construct for the Project are satisfactory."[51]

Enbridge Gas stated that "…will continue to engage throughout the life of the Project to ensure any impacts on Aboriginal or treaty rights are addressed, as appropriate."

OEB Staff Submission

OEB staff notes that the Letter of Opinion has been filed and that the Ministry expressed its satisfaction with the procedural aspects of the consultation. OEB staff submits that Enbridge Gas appears to have made efforts to engage with potentially affected Indigenous groups and no concerns that could materially affect the Project have been raised through its consultation to date. OEB staff observes that Enbridge Gas appears to be cooperating with the Indigenous communities during the consultation process and

[49] Exhibit H, Tab 1, Schedule 1,Attachment 6 Updated Summary of Indigenous Consultation Report; and Attachment 7 Consultation Log Updated as of April 8, 2024 and Response to OEB staff interrogatory I.5STAFF-24 Attachment 1(updated summary ICR and consultation, log between April 8,2-24 and September 13, 2024)

[50] Exhibit H, Tab 1, Schedule 1, page 5, paragraph 15

[51] Exhibit H, Tab 1, Schedule 1, Attachment 4, page 1 [55] Exhibit H, Tab 1, Schedule 1, paragraph 15, page 5

that it made commitments to the Indigenous communities related to the Project. OEB staff is not aware of any potential adverse impacts of the Project to any Aboriginal or treaty rights. OEB staff notes that Enbridge Gas stated it would "…continue to engage throughout the life of the Project to ensure any impacts on Aboriginal or treaty rights are addressed as appropriate."[55]

3.7 Conditions of Approval

OEB staff sought comments from Enbridge Gas on the OEB's Standard Conditions of Approval for leave to construct applications. In response, Enbridge Gas agreed with the Standard Conditions of Approval.

Section 23 of the OEB Act permits the OEB, when making an order, to impose such conditions as it considers appropriate.

Should the OEB grant leave to construct the Project, OEB staff submits that the approval should be subject to the Conditions of Approval contained in Appendix A of this submission.

3.8 Conclusion

OEB staff submits that the OEB should approve the Project, subject to the Conditions of Approval attached as Appendix A to this submission.

All of which is respectfully submitted.

Appendix A: Conditions of Approval

Leave to Construct Application under
Section 90 of the OEB Act

Enbridge Gas Inc.
EB-2024-0200
Standard Conditions of Approval

1. Enbridge Gas Inc. shall construct the facilities and restore the land in accordance with the OEB's Decision and Order in EB-2024-0200 and these Conditions of Approval.

2. (a) Authorization for leave to construct shall terminate 12 months after the decision is issued, unless construction has commenced prior to that date. (b) Enbridge Gas Inc. shall give the OEB notice in writing:
   i. of the commencement of construction, at least 10 days prior to the date construction commences
   ii. of the planned in-service date, at least 10 days prior to the date the facilities go into service
   iii. of the date on which construction was completed, no later than 10 days following the completion of construction
   iv. of the in-service date, no later than 10 days after the facilities go into service

3. Enbridge Gas Inc. shall obtain all necessary approvals, permits, licences, certificates, agreements and rights required to construct, operate and maintain the Project.

4. Enbridge Gas Inc. shall implement all the recommendations of the Environmental Report filed in the proceeding, and all the recommendations and directives identified by the Ontario Pipeline Coordinating Committee review.

5. Enbridge Gas Inc. shall advise the OEB of any proposed change to OEB-approved construction or restoration procedures. Except in an emergency, Enbridge Gas Inc. shall not make any such change without prior notice to and written approval of the OEB. In the event of an emergency, the OEB shall be informed immediately after the fact.
6. Concurrent with the final monitoring report referred to in Condition 6(b), Enbridge Gas Inc. shall file a Post Construction Financial Report, which shall provide a variance analysis of project cost, schedule and scope compared to the estimates

filed in this proceeding, including the extent to which the project contingency was utilized. Enbridge Gas Inc. shall also file a copy of the Post Construction Financial Report in the proceeding where the actual capital costs of the project are proposed to be included in rate base or any proceeding where Enbridge Gas Inc. proposes to start collecting revenues associated with the Project, whichever is earlier. Both during and after construction, Enbridge Gas Inc. shall monitor the impacts of construction, and shall file with the OEB one electronic (searchable PDF) version of each of the following reports:

a) A post construction report, within three months of the in-service date, which shall:
   i. provide a certification, by a senior executive of the company, of Enbridge Gas Inc. adherence to Condition 1 ii. describe any impacts and outstanding concerns identified during construction
   iii. describe the actions taken or planned to be taken to prevent or mitigate any identified impacts of construction
   iv. include a log of all complaints received by Enbridge Gas Inc., including the date/time the complaint was received, a description of the complaint, any actions taken to address the complaint, the rationale for taking such actions
   v. provide a certification, by a senior executive of the company, that the company has obtained all other approvals, permits, licenses, and certificates required to construct, operate, and maintain the proposed project
b) A final monitoring report, no later than fifteen months after the in-service date, or, where the deadline falls between December 1 and May 31, the following June 1, which shall:
   i. provide a certification, by a senior executive of the company, of Enbridge Gas Inc. adherence to Condition 4 ii. describe the condition of any rehabilitated land
   describe the effectiveness of any actions taken to prevent or mitigate
   i. any identified impacts of construction
   ii. include the results of analyses and monitoring programs and any recommendations arising therefrom
   iii. include a log of all complaints received by Enbridge Gas Inc., including the date/time the complaint was received; a description of the complaint; any actions taken to address the complaint; and the rationale for taking such actions

7. Enbridge Gas Inc. shall designate one of their employees as project manager who will be the point of contact for these conditions and shall provide the employee's name and contact information to the OEB and to all affected landowners, and shall clearly post the project manager's contact information in a prominent place at the construction site.