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April 7, 2022

VIA EMAIL and RESS

Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Nancy Marconi:

Re: Enbridge Gas Inc.
Ontario Energy Board File: EB-2020-0293
St. Laurent Ottawa North Replacement Project
Reply Submission

In accordance with the OEB's Procedural Order No. 6, enclosed please find the reply submission from Enbridge Gas in the above noted proceeding.

Please contact the undersigned if you have any questions.

Yours truly,

Adam Stiers
Digitally signed by Adam Stiers
Date: 2022.04.07 11:16:46 -04'00'

Adam Stiers
Manager, Regulatory Applications – Leave to Construct

c.c. Guri Pannu (Enbridge Gas Counsel)
Charles Keizer (Torys)
Zora Crnojacki (OEB Staff)
Intervenors (EB-2020-0293)

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sched. B, as amended;

AND IN THE MATTER OF an Application by Enbridge Gas Inc. for an order granting leave to construct in the City of Ottawa, under section 90 of the Act.

AND IN THE MATTER OF an Application by Enbridge Gas Inc. for an order approving the forms of Working Area Agreement and Transfer of Easement agreement, under section 97 of the Act.

ENBRIDGE GAS INC.

REPLY ARGUMENT

Table of Contents

A. Introduction

1. These are the reply submissions of Enbridge Gas Inc. ("Enbridge Gas") in respect of leave to construct the St. Laurent Pipeline Project, which includes the abandonment and replacement of approximately 16 km of nominal pipe size (NPS) 12 inch extra high-pressure (XHP) steel (ST) natural gas main, approximately 400 m of NPS 16 XHP ST natural gas main and existing services of various smaller lengths and sizes, with 9 km of NPS 12 XHP ST, 2.4 km of NPS 16 XHP ST, 4.2 km of NPS 6 intermediate pressure (IP) polyethylene (PE); and 3.6 km of NPS 4 IP PE in the City of Ottawa, Ontario (the "Project"). The main driver of the Project is the integrity of Enbridge Gas's distribution system serving customers in Ottawa and Gatineau. The previous phases of the Project (Phases 1 and 2), which were also driven by integrity concerns, were reviewed and approved by the OEB in EB-2019-0006. Both Phases 1 and 2 were recently constructed and placed into service, replacing portions of the existing St. Laurent NPS 12 and NPS 16 XHP ST natural gas main (St. Laurent Pipeline or Pipeline).

2. The integrity of St. Laurent Pipeline and the need for its replacement has been properly assessed through a comprehensive review with substantial documented evidence and review by pipeline integrity experts. On this basis, the St. Laurent Pipeline must be replaced and leave to construct the Project granted. The Project scope ensures that Enbridge Gas can continue to meet its obligation to serve firm contractual customer needs on a design day, based upon existing operational parameters. As a result, based on its OEB-approved demand forecasting methodology and current contractual customer commitments, Enbridge Gas has identified the need to replace existing facilities on a like-for-like basis.

3. The St. Laurent Pipeline is considered critical infrastructure in the City of Ottawa as it is a single source XHP line, operating at 275 psig and serving 165,000 customers (directly and indirectly) ranging from homeowners, businesses, hospitals, TransAlta Cogen (serving the Ottawa Health Sciences Centre and supplying electricity to the provincial electricity grid), Parliament Hill, the Cliff Steet Heating Plant, RCMP

Headquarters, and the University of Ottawa, to name a few. A winter interruption of natural gas service of even a few days can have a significant impact on these customers. In the absence of replacing the pipeline, there is a risk that Enbridge Gas will be unable to reliably supply and meet the energy demands of its customers. Moreover, in the absence of the Project, the inherent risk of operating the St. Laurent Pipeline will remain inescapable and critical given its integrity concerns which will only worsen over time.

4. Much has been said by the parties as to Enbridge Gas's motivation for proposing the replacement of the St. Laurent Pipeline. In an attempt to suggest that the St. Laurent Pipeline was not an immediate concern and to call into question Enbridge Gas's sincerity about the risk posed to its customers and the general public by the existing St. Laurent Pipeline, assertions have been made that cost recovery in 2022 Rates is the issue. However, this is not founded in fact and it is a narrative that distracts from the central issue: the integrity of the pipeline and the ability for Enbridge Gas to safely and reliably deliver gas in the absence of a replacement. Enbridge Gas began planning for this Project in 2016 (all 4 phases) and commenced project execution and the process for seeking approvals in 2018, long before the amalgamation of Enbridge Gas Distribution Inc. and Union Gas Limited or the establishment of the current incentive ratemaking mechanism for Enbridge Gas. Enbridge Gas fundamentally believes that the St. Laurent Pipeline must be replaced for safety reasons as expeditiously as possible. One particular question raised in the proceeding related to Incremental Capital Module (ICM) funding. To be clear, Enbridge Gas will proceed with the Project and replace the St. Laurent Pipeline as promptly as possible since it believes that it is in the public interest and that the pipeline should not continue to be operated in its current condition.

5. The OEB should reject the proposal by some parties that endorse the reactive repair option for the St. Laurent Pipeline to "buy time" to permit for decarbonization efforts. None of the decarbonization efforts put forward will eliminate the pipeline's integrity issues and the risks that customers are subject to. In effect, by endorsing such a plan

parties are suggesting that customers undertake the risk of known concerns and the further latent concerns of this pipeline on the hope that one day an old and poorly conditioned single source XHP pipeline will not experience a material failure while attempts are made to implement decarbonization plans that are: (i) barely launched, (ii) complex, (iii) largely not yet funded, and (iv) dependent (in-part) upon unpredictable homeowner and business owner adoption. Such a gamble with public health and safety is not in the public interest. Additionally, energy security and reliability is becoming a more pronounced issue of public importance given ongoing supply chain disruptions resulting from the COVID-19 pandemic and current geopolitical events abroad impacting global energy supplies. Relying on hypothetical models that are yet to be funded, and that are not at a stage in technological development where their impacts are known, is impractical and lacks prudence. The City of Ottawa themselves acknowledge the importance of energy security, "Ottawa believes that energy security is of paramount concern as we implement Energy Evolution and would not support any actions that would put such energy security at significant risk."[1]

6. Rather, the public interest is best served if customers continue to have safe and reliable delivery of natural gas volumes while the technology and funding for decarbonization plans are further developed to a level that they can reliably work alongside other existing infrastructure (e.g., natural gas) in an integrated fashion to meet the demands of customers. Currently, replacing the St. Laurent Pipeline is the most effective option, allowing Enbridge Gas to: (i) proactively manage risk to the pipeline and the public; (ii) meet its obligation to deliver safe and reliable natural gas; and (iii) minimize economic disruptions to residents, businesses and institutions in Ottawa and Gatineau. As noted above, the St. Laurent Pipeline is a single feed system considered to be critical infrastructure. Accordingly, the integrity concerns identified by Enbridge Gas need to be viewed in the context of the magnitude of consequences to the pipeline and customers in the event of failure. When viewed in this context, replacement is the most reasonable option to mitigate risk to the public

[1] Exhibit I.M.2.1.Staff.2 g)

with minimal impact, and to ensure reliable delivery of energy (natural gas) to customers.

7. Enbridge Gas will not comment upon each specific argument raised by parties in their Submissions, but instead will limit this Reply Argument to those that are most critical from its perspective. The fact that Enbridge Gas chooses not to address an argument should not be interpreted as agreement with it.

B. <u>Critical Infrastructure - Key Project Characteristics</u>

8. When considering the replacement of the St. Laurent Pipeline, OEB staff and intervenors have misunderstood the integrity risks of the pipeline by ignoring key pipeline characteristics and drawing comparisons between the St. Laurent Pipeline and other pipelines which are not comparable. For example, SEC compares the St. Laurent Pipeline to the recently replaced London Lines. While the London Lines were older than the St. Laurent Pipeline before their replacement, they are fundamentally different since they were smaller lines operating at a lower pressure and were located primarily in a rural area. In this instance, solely focusing on age of the pipeline provides low value in assessing its overall condition, the risk associated with it, and the need to replace it. The St. Laurent Pipeline has to be viewed in light of its unique characteristics, such as its increased risk profile due to its location in one of Ontario's most densely populated urban areas where failures can lead to significant customer loss. This "all pipelines are alike" approach does not properly recognize the critical importance of the St. Laurent Pipeline or the risks related to the continued operation of the St. Laurent Pipeline without replacement. Not all pipelines are alike and their accompanying risks in operation are unique to their operating parameters, configuration, and location. Fundamental to OEB consideration should be those key characteristics that relate to the pipeline that is the subject of the leave to construct application in order to provide the appropriate lens through which the facts of this Application must be considered. To a large extent, as noted, intervenors have urged that the OEB focus its deliberation on the future as far out as 2050, including that the OEB make predictions regarding the nature and pace of energy transition in the City

of Ottawa and the City of Gatineau. However, the OEB must return to the central tenet of this "leave to construct" Application, which is fundamentally about the integrity of the St. Laurent Pipeline and the present safety and operational concerns for customers. In this regard, the characteristics of the St. Laurent Pipeline as critical infrastructure delivering reliable energy to the citizens, businesses and institutions of Ottawa and Gatineau are central.

9. These key characteristics are as follows:

   I. The St. Laurent Pipeline is supplied from a single source, the St. Laurent Control Station, and consists of steel mains primarily installed in 1958 by completing girth welds approximately every 12 m, using compression couplings, and subsequently welding main branches and customer services directly to the pipeline main, applying field coatings in each of these instances which number more than a thousand.[2] Further, the pipeline lacked any cathodic protection until the mid-1970's.

   II. The St. Laurent Pipeline is an XHP pipeline with an operating pressure of 1,896 kPa (275 psi).

   III. The St. Laurent Pipeline is critical infrastructure, being integral to the natural gas network that supplies, directly or indirectly, natural gas to approximately 165,000 customers in the City of Ottawa and in Gatineau, Québec, including St. Vincent Hospital, Montfort Hospital, TransAlta Cogen (supplying steam and hot water for Ottawa Health Sciences Centre and electricity to the Independent Electricity System Operator), Parliament Hill, the Government of Canada Public Works Cliff Street Heating Plant (serving 52 buildings),[3] RCMP Headquarters, and the University of Ottawa.

[2] Exhibit B, Tab 1, Schedule 1, pp. 6-7
[3] While much has been made of the fact that the Cliff Street Heating Plant is currently being renovated, Enbridge Gas has no reason to believe that the end result of that work will be a reduction of the peak natural gas demand contracted for that facility.

IV. The St. Laurent Pipeline feeds 10 district regulating stations, two large control stations, and several private header stations.

V. The St. Laurent Pipeline's location is a high consequence urban area, the City of Ottawa having been constructed around and above it, with wall-to-wall concrete, a densely populated downtown core, utility congested road allowances, and railways/public transit in close proximity to the pipeline.

VI. Pipeline damage or failure could result in the loss of gas distribution service for tens of thousands of customers and essential public services, or, in some cases, place public safety at risk (in the most severe conditions resulting in loss of life).

10. Enbridge Gas proposes to replace the St. Laurent Pipeline for integrity reasons and not demand growth. The Project scope ensures that Enbridge Gas can continue to meet its obligation to serve firm contractual customer needs on a design day, based upon existing operational parameters. As a result, based on its OEB-approved demand forecasting methodology and current contractual customer commitments, Enbridge Gas has identified the need to replace existing facilities as proposed (like-for-like).[4]

11. The key characteristics above are fundamental to the OEB's consideration of the question of the customer risk which is central to its determination in this proceeding.

C. <u>Replacement</u>

The Pipeline's Integrity is Compromised

12. No intervenor has suggested that the St. Laurent Pipeline does not have integrity issues. Energy Probe supports the replacement of the pipeline with the Project. Nevertheless, OEB staff and each of Schools Energy Coalition (SEC), Pollution Probe, Federation of Rental-housing Providers of Ontario (FRPO), and Environmental Defence (ED) (the "opposing intervenors") assert that leave to construct the Project

[4] Exhibit I.ED.6 a)

should be denied on the basis that replacement is not warranted. Their assertion is based on a selective and superficial review of the facts and a selective consideration of discrete indicators. In contrast, Enbridge Gas has provided a substantial and documented history (e.g., inspection reports, leak history, depth of cover surveys, integrity digs, asset health assessment) of the pipeline which as been reviewed by a variety of professional pipeline integrity engineering experts who have reached the conclusion that the pipeline has reached the end of its useful life and needs to be replaced in order to ensure continued safe and reliable delivery of natural gas to customers in Ottawa and Gatineau. On this basis, the St. Laurent Pipeline should be replaced and leave to construct the Project granted.

(i) Leaks

13. OEB Staff reached their conclusion only on the basis of a forecast of future corrosion-related leaks and ignored all evidence related to actual leaks on the Pipeline.[5] On a selective basis, in reference to the response at Exhibit I.FRPO.14, SEC referred only to one leak in the last 10 years as a basis to dismiss the replacement of the St. Laurent Pipeline.[6] However, Enbridge Gas indicated in that response that in 2013 a category A corrosion leak occurred on Tremblay Road and resulted in a cut-out of an 8 m segment of main due to corrosion. SEC also ignored the remainder of the interrogatory response, where Enbridge Gas indicated that two category A leaks were recorded on valves. One was located at 772 St. Laurent Boulevard in 2016. Another was located at 300 Tremblay Road in 2017. In addition, two category B leaks were recorded on valves. One was located at 1200 Vanier Parkway in 2012. Another was located at 24 Sandridge Road in 2020. Two additional B leaks on valves were discovered on February 17, 2022. One was located on St. Laurent Blvd, south of Industrial Ave. The other was located on Tremblay Rd, east of Avenue U.[7]

14. There was also a leak in 2019 at the intersection of Industrial Avenue and St. Laurent Boulevard. Because of the location of the pipeline and the condition of the soil, having

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[5] OEB staff Written Submission (March 24, 2022), p. 9
[6] SEC Written Submission (March 24, 2022), p. 8
[7] UPDATED (March 2, 2022) Exhibit I.FRPO.14 a)

had a major roadway built above it since its original installation, it could not be fully excavated without causing major impacts to residents and businesses, and thus the source of the leak was not determined. However, Enbridge Gas replaced the pipeline in that location and had to abandon the section of pipeline under roadway. Because of the aforementioned site challenges the cost of this repair was in excess of $3.0 million.[8]

15. It is important to place the 2013 Category A corrosion leak in context. In addition to the leak, there were nine areas of pitting and corrosion with reduced thickness over a 15-foot area.[9] Further, Enbridge Gas explains that certain of these leaks were directly related to field applied coatings, failed installation welds and poor internal fusion.[10] Field applied coatings are used in steel natural gas systems to coat weld joints, fittings, and risers. Field application of coatings is challenging relative to factory applied coatings since they are applied outside and are subject to non-ideal weather and/or environmental conditions, as well as quality of the pipeline preparation prior to application. If the quality of field applied coatings is compromised, pipe coatings can soften, flow or become cracked and brittle, resulting in disbonded and ineffective coating which would lead to corrosion problems.[11]

16. The St. Laurent Pipeline has 180 service connections (on the existing NPS 12 pipeline alone, there are many more connections when one considers the entirety of the St. Laurent Pipeline system proposed for replacement) of which there are 99 active services, 77 services cut off at main, 4 live stub services, 10 district stations, 2 large control stations and several header stations connecting directly to the pipeline, all of which required field applied coating following installation.[12] In addition, the St. Laurent Pipeline contains multiple girth welds and taps that have also required field applied coatings that may be subject to aforementioned challenges. The St. Laurent Pipeline

[8] Exhibit B, Tab 1, Schedule 1, pp. 44-45; TC TR v. 1, pp. 64-66
[9] Exhibit B, Tab 1, Schedule 1, Attachment 3 p. 3
[10] Exhibit B, Tab, 1, Schedule 1 p. 17
[11] Exhibit B. Tab 1, Schedule 1, p. 19
[12] Exhibit B. Tab 1, Schedule 1, pp. 19-20

was installed in segments. Assuming typical 12 m segment lengths, this equates to over 1,000 field applied coatings on the girth welds connecting each segment.

17. All of these key points of weakness for the St. Laurent Pipeline are susceptible to degradation and leaks as in the leak described above. A key risk that was either ignored or not understood by OEB staff and opposing intervenors.

(ii) Age

18. As early as within the Company's 2018-2027 Asset Management Plan (AMP), Enbridge Gas concluded that the St. Laurent Pipeline exhibits many of the characteristics of 'vintage steel mains'.[13] While much has been made by intervenors of Enbridge Gas's use of this terminology, its historic use and definition is not important. What is important to understand is that the use of this terminology is not an indication that Enbridge Gas is proposing to replace the Pipeline based on age as a single determining factor, as SEC and FRPO assert.[14] Rather, the Company is simply noting that the St. Laurent Pipeline exhibits characteristics that are consistent with other pipeline(s) of a similar vintage within its service territory, including: corrosion, dents, compression couplings on mains and services, reduced depth of cover, past deficient cathodic protection, live stubs, mitered bends, failed installation welds and poor internal fusion, stray current from hydro infrastructure, light rail transit, and contaminated soil. It is these characteristics that are most important, not only the age of the pipeline facilities since they are indicative of the pipeline(s) poor and rapidly degrading health.

19. Despite having provided evidence regarding these characteristics and Enbridge Gas's unique integrity concerns with regard to the St. Laurent Pipeline, SEC inappropriately attempts to compare the proposed Project to the London Lines project by concluding that "twenty years from now the pipeline would be more than 80 years old, or roughly the same age as London Lines was when it was finally replaced."[15] Enbridge Gas

[13] Exhibit I.PP.11 b)
[14] SEC Written Submission (March 24, 2022), pp. 10-11; FRPO Written Submission (March 21, 2022), p. 1
[15] Ibid., pp. 10, 23.

addressed the limitations of drawing such comparisons in isolation (without due consideration of the unique characteristics, features, and environments that each pipeline exhibits) in its response to Exhibit I.PP.11, where it stated,

> By contrast, while the St. Laurent pipeline(s) system is largely located in a heavily urban area including: wall-to-wall concrete, densely congested right of way (beneath or adjacent to arterial roads), exposure to road salt, and frequent damage from third party contractors (often unreported), the London Lines pipeline system was largely installed along rural county roads or within easements along empty fields which did not expose the pipelines to comparable environmental stresses. The consequence of the St. Laurent pipeline(s)' urban location combined with its age/vintage have ultimately exposed the pipeline(s) to greater damages to the pipeline coating and accelerated corrosion leading to a shorter useful life compared to other pipelines located in rural settings, such as the London Lines pipeline system.

20. To be clear, the relative vintage and useful life of the now replaced London Lines are not indicative in any way of the current state or condition of the existing St. Laurent Pipeline proposed for replacement. Any assertion that the London Lines' (or any other pipeline for that matter) useful life should be a determining factor in this proceeding is made without a basis in evidence.

(iii) Inspection History

21. Within Exhibit B, beginning at page 14, Enbridge Gas describes some of the historical reports completed which indicate the current condition of the St. Laurent Pipeline, including historical records, inspections and information obtained from actual integrity digs and repairs on the pipeline. Enbridge Gas attached reports spanning more than a decade to support the conclusions ultimately drawn by its pipeline operations, design and integrity engineering experts, that the pipeline: (i) has reached the end of its useful life; (ii) cannot be relied upon to safely deliver natural gas volumes to existing customers in Ottawa and Gatineau; and (iii) must be replaced as promptly as possible.

22. In response to this evidence, FRPO asserts that the OEB should ignore the conclusions of Enbridge Gas pipeline and integrity engineering experts and instead rely solely upon the "experienced observations, analysis and understanding" of FRPO's representative.[16] Mr. Quinn's submissions appear to be a cursory review of the materials with unsupported conclusions based on generalizations. Although FRPO admits that the evidence indicates that the St. Laurent Pipeline is in poor health and exhibits the characteristics of vintage steel pipeline, it concludes that the pipeline merely requires increased inspection and maintenance. This conclusion is without basis and ignores the fact that the OEB has very recently both approved similar applications to replace vintage steel pipelines and concluded that the safety and reliability of natural gas pipelines should remain paramount.[17] Accordingly, the OEB should not accept FRPO's conclusions or rely on them as the basis for its determinations in this current proceeding.

2006 Ground Penetrating Radar Integrity Project (2006 GPRIP)

23. Enbridge Gas completed a survey in 2006 of a segment of the St. Laurent Pipeline just south of Tremblay Road using ground penetrating radar technology and engaged a third-party expert to conduct an inspection of the subject pipeline. As a result of heavy pitting found on the pipeline segment inspected, it was cut out and replaced. In this regard, Enbridge Gas indicated in evidence that it expects there are other segments of the St. Laurent Pipeline that exhibit similar pitting/corrosion due to, for example, (i) poor quality field applied coatings (as described above), or (ii) latent third-party damage.

24. Focusing only on this conclusion and only on the fact that the subject pipeline segment had a casing in its vicinity, FRPO claims that Enbridge Gas's evidence is inaccurate and misleading.[18] However, FRPO has misinterpreted and mischaracterized Enbridge

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[16] FRPO Written Submission (March 21, 2022), p. 1
[17] EB-2019-0172 Decision and Order, April 1, 2020, p. 1; EB-2020-0136 Decision and Order, December 17, 2020, p. 1; EB-2020-0192 Decision and Order, January 28, 2021, p. 11; EB-2020-0091 Decision and Order, July 22, 2021, pp. 3-4.
[18] FRPO Written Submission (March 21, 2022), p. 2

Gas's statement. The pitting and corrosion shown in Figure 5 (also set out below) is the result of inadequate pipeline coating, but issues identified at this site also included mechanical damage (shallow scrapes/gouges), small arc strikes (in the vicinity of the girth weld), and a dent on the pipeline. It is in this regard that Enbridge Gas is making reference to other instances known to exist on the St. Laurent Pipeline system where there is expected to be inadequate pipeline coating, which is unable to prevent corrosion and/or pitting similar to that shown in Figure 5:

Figure 5: Example of Corrosion on the St. Laurent Pipeline

25. As stated above in the section related to Leaks, there are more than 1,000 girth weld locations and 180 service connection sites located along the St. Laurent Pipeline system where field applied coatings were used for decades and where Enbridge Gas expects there are failed installation welds and poor internal fusion as set out at Exhibit B, Tab 1, Schedule 1, page 17 regarding the 2013 Main Repairs and as displayed in Figure 7 of Exhibit B, Tab 1, Schedule 1 (see below).

Figure 7: Examples of Failed Installation Welds and Poor Internal Fusion

26. As stated at Exhibit B, paragraph 31, each of these sites has been at risk of similar corrosion damage and degradation since field application of coatings have quality issues relative to factory applied coatings because they are applied out-of-doors subject to environmental conditions and questionable pipe preparation prior to application. Compromised pipe coatings can soften, flow or become cracked and brittle, resulting in an ineffective coating leading to corrosion problems.

27. Regarding latent third-party damages, also referenced by Enbridge Gas above, given the location of the St. Laurent Pipeline, within one of Ontario's most densely developed urban settings, it is reasonable to expect that over its more than sixty-year lifetime, the St. Laurent Pipeline has experienced far more latent third-party damages than have been reported to Enbridge Gas that have not only damaged the pipeline coating, but also resulted in a series of other anomalies that threaten the pipeline's integrity. This is evident from the incident described by Enbridge Gas at Exhibit B, Tab 1, Schedule 1, pages 20-23. In this instance, out of pure luck, an excavator discovered extensive damage previously done by a third-party contractor that was never reported to Enbridge Gas (see Figure 9 below), including:

- Five dents to the gas main.

- Three of the dents had linear corrosion indications (cracks).
- 11 damaged features (gouges, scratches and/or metal loss).
- Six of the damaged features were found within the dents.

Anomalies of this nature are common in dense urban locations, especially where depth of cover is inadequate, and can lead to wall loss and leaks due to corrosion.

28. Not only has FRPO misinterpreted and mischaracterized the intent of the statement made by Enbridge Gas, FRPO has only focused on the singular aspect of the casing in the proximity. FRPO believes that this is the sole reason for the discovered corrosion. However, the Pipeline Integrity Report shown at Exhibit B, Tab 1, Schedule 1, Attachment 2, does not conclude that is the case. The only reference to casings is that portions of corroded casing were found on the excavation bank. This coupled with FRPO's attempt to use a variety of academic articles that are not evidence and upon which Mr. Quinn, as FRPO's representative, cannot make an expert opinion, amount to no more than speculation on FRPO's part that the casing was the singular case for the damage. As stated at the Technical Conference,[19]

> MR. MADRID: Byron Madrid. Yes, this evidence was included because, again, it is one input into the overall decision here as to the condition of the pipe.
>
> So whether, to your questioning here, the casing may have contributed to the corrosion or a number of factors contributed to that corrosion, the point of the matter here is that we've got a pipe that had degraded and it's corroded, and it is one additional input that we can identify that stresses the fact that the pipe needs to be replaced.

[19] TC TR v. 1, p. 14

Figure 9: Examples of Damage to the NPS 16 Gas Main

2014 Integrity Dig

29. In reference to the third-party incident discussed above related to damage to Enbridge Gas's NPS 16 XHP pipeline at St. Laurent Boulevard and Highway 417, FRPO points to the fact that the pipeline depth of cover was not insufficient.[20] FRPO relies on this single instance to draw the conclusion that third-party damage is neither unusual nor a result of insufficient depth of cover.

30. FRPO is correct in that third-party damage is common on the St. Laurent Pipeline system, including incidences that are not reported to the Company as discussed above. While the depth of cover in the instance cited by FRPO was not inadequate, Enbridge Gas has noted multiple known locations (see the depth of coverage discussion below) where depth of cover is insufficient and/or has changed because the pipeline is located in a dense urban environment that has been subject to constant change and development over the course of the pipeline's 60+ year useful life. It is reasonable to conclude that where depth of cover is inadequate and/or has changed

[20] FRPO Written Submission (March 21, 2022), p. 4

since installation, the probability and risk of third-party damage is even greater. Especially when one considers, as discussed above and acknowledged by FRPO, how common such events are to natural gas pipelines and how frequently they may occur without Enbridge Gas being notified.

31. FRPO also asserts that because the latent third-party damage identified in 2014 was found and permanently repaired, it does not impact the condition of the St. Laurent Pipeline. FRPO misses the point. The focus is not that there are known instances of damage, degradation and failure that have been repaired on small segments of the St. Laurent Pipeline system consistent with prevailing standards and codes. Instead, it is that the circumstances giving rise to the repairs are indicative of a much larger problem consistent with the vintage of this pipeline. Enbridge Gas has advanced extensive evidence gathered over time which when reviewed comprehensively and not selectively supports the conclusion that there are many other circumstances of degradation and damage elsewhere on the St. Laurent Pipeline.

2016 NPS 16 Bridge Crossing Inspection (2016 Bridge Inspection)

32. Enbridge Gas completed a visual inspection of the pipeline crossing just north of Highway 417 in 2016 and identified severe corrosion on the NPS 16 XHP pipeline at the north and south ends of that crossing. In Exhibit B, Enbridge Gas explained that a pipeline anchor is installed in these locations and it was unclear whether the anchor sleeves or the pipeline itself was corroding. However, through responses to interrogatories and testimony delivered at the Technical Conference Enbridge Gas clarified that after having completed excavation at either end of the crossing it had determined that the corrosion identified was on the anchor supports.[21]

33. FRPO implies that this clarification is evidence that the entirety of the Application should be discounted in some way and that the presence of corrosion on the NPS 16 XHP bridge crossing is irrelevant.[22] In fact, confirmation that corrosion is occurring on

[21] Exhibit I.FRPO.6 a), Exhibit I.Ottawa.9 and TC TR v. 1, pp. 20-21
[22] FRPO Written Submission (March 21, 2022), p. 5

the anchor supports remains concerning to Enbridge Gas, since the anchor supports are welded directly to the pipeline and exposed to the same environmental conditions.

34. It should not be lost after all, that corrosion of this nature (potentially accelerated due to environmental conditions, such as road salt accumulation) was also the cause for replacement of this bridge crossing in 2012, as further discussed in Exhibit I.Ottawa.9.

2017 Depth of Cover Survey (2017 Survey)

35. In 2017, Enbridge Gas hired G-Tel Engineering to complete a Depth of Cover Survey for the entirety of the St. Laurent Pipeline. The results of the survey indicated that depth of cover is a concern. Exhibit B, Tab 1, Schedule 1, Table 4 shows that there were 20 segments with an average length of 14.9 m that did not meet the minimum depth required pursuant to CSA Z662, and 56 segments with an average of 23.5 m that met the minimum depth pursuant to CSA Z662, but did not meet Enbridge Gas's minimum depth of cover requirements. There are two alternatives to address depth of cover issues: (i) to relocate the pipeline to a greater depth, or (ii) to add additional cover over top of the pipeline. Enbridge Gas has concluded that additional cover is not a feasible solution for the St. Laurent Pipeline.

36. FRPO asserts that based on Enbridge Gas's statement that there are no lengths of pipeline located underneath the roadway with less than 0.6 m depth of cover, additional cover could be used to remediate the depth of cover issues.[23] However, the Company's conclusion that additional cover is not a feasible solution for the St. Laurent Pipeline is based on a number of challenges that exist within the areas identified that FRPO has not considered, including: landscaped boulevards, trees, retaining walls and driveways, light standards, bike paths, drainage concerns, City-owned property, sidewalks, bus shelters, walking paths to building entrances, and snow removal. The Company stands by the assertion that additional cover cannot

[23] FRPO Written Submission (March 21, 2022), p. 5.

feasibly resolve the depth of cover issues for the St. Laurent Pipeline, particularly given its densely populated urban location.

2018 Indirect Inspection (2018 Inspection)

37. In 2018, Enbridge Gas commissioned an indirect inspection on segments of the St. Laurent Pipeline by PureHM. The results of the inspection: (i) identified several areas totaling approximately 97 m in length with cover less than the Company's minimum depth of cover standard; (ii) identified 15 pipeline coating anomalies; (iii) identified 3 cathodic protection anomalies; and (iv) made a variety of recommendations for additional actions Enbridge Gas could undertake to improve the integrity of the pipeline and improve correlation.

38. In reference to the PureHM inspection results, FRPO incorrectly infers that the recommended actions provided by PureHM as a result of the 2018 inspection are no more than standard activities that Enbridge Gas performs routinely on all steel pipelines. To support this inference, FRPO relies on a partial quote from the Technical Conference, taken from an exchange between Mr. Quinn and Mr. Madrid, in response to FRPO's question of whether the activities that Enbridge Gas is performing on the St. Laurent Pipeline are any different than what the Company would do for any steel pipeline in the Enbridge territory. In response, Mr. Madrid stated that they are "not any different than what our requirement is to protect our assets".[24] However, the context and entirety of this exchange omitted by FRPO is critically important in this instance.

> MR. MADRID: Byron Madrid, Enbridge. No, they're not any different than what our requirement is to protect our assets. So I wouldn't call them remediation activities. <u>These are simple cathodic protection processes and programs that need to be executed to maintain the pipeline at the current status. It is important to note, though, that even though we've got adequate cathodic protection today, that does</u>

[24] FRPO Written Submission (March 21, 2022), p. 6.

not resolve the degradation of the pipe that has been experienced since it was installed up to this date.[25]

39. FRPO's mischaracterization fails to acknowledge that Enbridge Gas will take action to protect its assets, but that does not resolve the degradation of the pipeline experienced to date.

(iv)Asset Health Index and Forecast Leak Rate Are Not Determining Factors

40. The opposing intervenors and OEB staff point to the Asset Health Index analysis (the AHI analysis) and the resulting corrosion-related leak forecast arising from that analysis to assert that there is no immediate need to replace the St. Laurent Pipeline. This was because the corrosion-related leaks were predicted to be 4 by 2041 and 40 by 2061.[26] However, the opposing intervenors and OEB staff have entirely taken the analysis out of context and have misapplied it in a manner that inappropriately exposes customers to risks if the OEB chooses to reject replacement and endorse repair on this basis.

41. Fundamental to this misapplication by the opposing intervenors and OEB staff is that they have failed to appreciate that the AHI analysis (and the resulting corrosion-related leak forecast) is derived not from known issues related to the St. Laurent Pipeline, but it is instead derived from a statistical analysis of a number of pipelines across Enbridge Gas's service territory and based upon a specific set of generalizing assumptions. In effect, the AHI analysis is an abstraction from the St. Laurent Pipeline and its real-life issues described above, and the analysis has instead been used by Enbridge Gas to establish a future corrosion-related leak rate to enable an estimate of the costs of the Repair Alternative (which Enbridge Gas has rejected).

42. Under the AHI analysis, asset health is determined using widely accepted and applied statistical principles that correlate the age (or usage) of an asset versus failures, that can then be used to produce a model to project future failures. This technique,

[25] TC TR v. 1, pp. 25-26
[26] Limited to corrosion-related leaks on the pipeline body only, does not include corrosion at connections, fittings etc.

commonly known as reliability engineering, is the probability that a material, component, or system will perform its intended function under defined operating conditions for a specified period of time. The reliability of an asset or system is determined by applying a statistical method to correlate the age of the asset with failures. This is accomplished using reliability software tools like ReliaSoft Weibull++ or Statistical Analysis System (SAS). Pipelines' intensity of failure models use a Non-Homogeneous Poisson Process (NHPP) Log-Linear method which allows for asset attributes and environmental factors to be directly incorporated into the intensity of failure formulas for the pipeline main asset subclasses. The NHPP analysis performed on each asset subclass determines statistically significant factors affecting the intensity of failure.[27] Further, the NHPP analysis modeled a non-linear trend (reflecting multiple future failure events), which means that the frequency between pipeline failure events becomes shorter over time, recognizing the ongoing degradation of the pipeline.

43. Enbridge Gas' reliability model technique used a failure dataset that included corrosion-related leak failures on all the gas distribution steel pipeline mains. In the failure dataset, there were no corrosion leaks on the St. Laurent Boulevard segment of the Project from 2007 to 2019. As a result, the AHI analysis is based on all steel pipeline mains and is not specific to the St. Laurent Pipeline. The accompanying corrosion-related leak forecast is a projection based upon a data set of other distribution steel pipelines. <u>It is in effect an indication of potential corrosion-related leaks, given the age and type of pipeline material (i.e., steel) and other aforementioned statistically significant factors, but it is not a prediction based on the unique circumstances or condition of the St. Laurent Pipeline that exist today or are likely to exist because of the field conditions in which the St. Laurent Pipeline exists.</u>[28]

[27] Exhibit I.EP.11 a)

[28] As described in Exhibit I.EP.11 a), For steel pipelines, the NHPP analysis identified five factors with a statistically significant contribution to the intensity of failure for the corrosion model, they are: i) length, ii) cathodic protection percentage of good readings, iii) wall thickness, iv) pressure class and v) total fittings.

44. Furthermore, the reliability engineering analysis (AHI) was completed to project the expected number of corrosion-related leaks over a 40-year horizon based on corrosion failure data only and as generally occurring. The analysis does not include consideration of any non-corrosion related pipeline failures or loss of containment that could result from the remaining integrity concerns known to impact the St. Laurent pipeline system, including but not limited to:[29]

- dents;
- deficient cathodic protection;
- coating degradation and damage;
- latent third-party (e.g. construction contractor) damages;
- manufacturing defects;
- poor internal fusion on seam welds and fittings (historic construction practices);
- multiple field applied coatings (of varied nature and vintage);
- shallow depth of cover;
- soil types (corrosive environments);
- unrestrained compression couplings; and/or
- degradation due to stray current from hydro infrastructure and contaminated soils.

45. Based on the foregoing it is inappropriate to use the AHI analysis in the manner suggested by the opposing intervenors and OEB staff. OEB staff stated that "based solely on the predicted likelihood of leaks", the urgency to address the integrity of the St. Laurent Pipeline is not warranted.[30] A similar conclusion was reached by SEC and other intervenors.[31] It is not appropriate to rely solely on one statistic and ignore all other physical factors and empirical evidence that govern the true health of the Pipeline and endorse an option based on a generalized model that could place tens of thousands of customers at risk in the event that pipeline failure occurs.

[29] Exhibit JT1.15
[30] OEB staff Written Submission (March 24, 2022), p. 9
[31] SEC Written Submission (March 24, 2022), p. 12

(v) Qualitative Risk Assessment

46. OEB staff and the opposing intervenors also misapplied the Qualitative Risk Assessment (QRA) performed by Enbridge Gas by extracting from that assessment one assessment component in isolation and applying it as an established fact when it was merely a tool used to assess risk.

47. A QRA is a way to assess uncertainties by recognizing the complexity of the operating environment and simplifying it through the application of a risk assessment methodology. This allows for the comparison of the result of the QRA against predefined risk evaluation criteria (such as Enbridge Gas's Standard Operational Risk Matrix).[32] OEB staff asked Enbridge Gas in an interrogatory to provide summary results of a QRA of risks associated with degrading conditions of the St. Laurent system using Enbridge Gas Operational Risk Matrix. Enbridge Gas advised in its response in Exhibit I.Staff.4 that at the time the risk assessment was conducted for the St. Laurent Pipeline, the Enbridge Standard Operational Risk Matrix was not yet established. Nevertheless, Enbridge Gas further noted that to be responsive, risks associated with scenarios described in the response were mapped to the Standard Operational Risk Matrix for illustrative purposes.

48. Two outcomes were considered: (i) a shut down of the pipeline to the facilitate repair, or (ii) repair of the pipeline without shutting it down in the event of a leak <u>because of corrosion only</u>. These scenarios focused on service shutdown along the pipeline segment between the St. Laurent Control Station and the Rockcliffe Control Station, which could lead to substantial customer loss.

49. The essence of the QRA is that the likelihood of a corrosion-related leak occurring leading to an adverse event is paired with the consequence that could arise from that event to identify the risk rating as represented in the Enbridge Gas Standard Operational Risk Matrix.[33] Under the limited circumstances set out above, the QRA showed for the winter scenario a high risk over the 20 years average risk and a very

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[32] Exhibit JT1.26
[33] TC TR v. 1, pp. 136-137

high risk over the 40 year average risk. Based on Enbridge Gas's Risk Evaluation criteria, risks (explained in the response at Exhibit I.STAFF.4 to include risk of customer loss, health and safety, financial and stakeholder) rated at or above "High" require risk mitigation to be undertaken, which Enbridge Gas determined was most effectively and efficiently accomplished via replacement of the St. Laurent Pipeline.

50. The forecast of leaks (corrosion related only) coming from the AHI analysis above informed the relative probability of adverse events, together with adjustments to account for the pipeline segment of interest, infrequent need to shut down to repair and seasonal changes to customer loss.[34] In being informed by the forecast of corrosion-related leaks this meant that the inherent limitations noted above related to the AHI analysis became part of the assessment. This introduced a conservative and limited consideration of immediate need reflected in the assumed relative probability of an event occurring employed as part of the QRA. As a result, for purposes of establishing a relative probability of an event where a leak repair would require an emergency shut down, Enbridge Gas assumed 1%.[35]

51. OEB staff inappropriately relies on this percentage as a basis to reject the replacement of the St. Laurent Pipeline and to assert a lack of urgency. OEB staff assigns a high level of predictive accuracy to the 1% by applying that percentage to the forecast corrosion-related leaks arising from the AHI analysis and asserting that if 4 leaks were to occur by 2041 only an estimated 1% would require pipeline isolation and a need for customer disconnection.[36] This is the primary basis for OEB staff's position that replacement is not needed. However, OEB staff's position is wholly based on the erroneous misapplication of the QRA. This also applies to a similar SEC assertion that relative risk used in the QRA is predictive of a near term event.[37] In fact, SEC readily

[34] Exhibit I.STAFF.4 a) & b)
[35] TC TR v. 1, pp. 209-212
[36] OEB staff Written Submission (March 24, 2022), p. 9
[37] SEC Written Submission (March 24, 2022), pp. 8-9

acknowledges in its submissions related to the QRA that "there does not appear to be any probabilistic assessment done as part of this process."[38]

52. OEB staff's error lies in misunderstanding the purpose of the event probability in the context of the QRA. As noted, the QRA is based on Enbridge Gas's Standard Operational Risk Matrix.[39] A comparable 7x7 risk matrix was referred to in the Enbridge Gas leave to construct application for the London Lines.[40] The matrix enables the intersection of likelihood and consequence to assign relative risk. The probability levels set a likelihood of an event relative to other likelihoods attached to other events. In effect, the 1% is no more than an order of magnitude, meaning a level which denotes its relative size of one event (a complete shutdown) to another occurrence (a repair without shutdown).[41] As such, it is inappropriate for OEB staff to take the 1% out of context and apply it as a predictive tool since it was not developed to perform such a function. OEB staff's conflating of the corrosion-related leak forecast arising from the AHI assessment and the 1% to reach a predictive conclusion is not appropriate. Different relative orders of magnitude of probability could have been assumed by Enbridge Gas while retaining the same relative probability rankings and still, ultimately, result in the same risk results. In that circumstance, using OEB staff's approach, the OEB staff assertion as to the outcome forecast to 2041 would have been different. As a result, the OEB should not rely on the submissions of OEB staff or the opposing intervenors in this regard.

53. In any event, it is important to understand the limitations of the QRA. The assessment only accounts for corrosion leaks at the pipeline body of the mains, other integrity issues and associated risks (including to Enbridge Gas personnel charged with completing repairs) are excluded from the analysis as they could not be reliably

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[38] SEC Written Submission (March 24, 2022), p. 12
[39] TC TR v. 1, p. 212
[40] EB-2020-0192 Exhibit B, Tab 2, Schedule 1 pp. 4-6; Exhibit I.ED.1 Attachment 1 pp. 57-60; Exhibit I.FRPO.1 Attachment 1 p. 8
[41] Exhibit I.JT1.26

translated into meaningful qualifiers at the time of assessments.[42] Some of these key risks include:

- Potential impact of TransAlta Cogen which supplies steam and hot water to the Ottawa Health Sciences Centre and electricity through the Independent Electricity System Operator (IESO), in case of outage south of the St. Laurent Control Station.[43]
- Potential service interruption and gas migration risks associated with corrosion at service connections (of which there are 180) and where field applied coatings were applied to girth weld locations, based on 12 m pipe segments that would equate to thousands of additional field applied coating locations.[44]
- Potential significant release of gas due to failure of compression couplings, particularly the ones which are not on record due to insufficient records identifying all fittings along the pipeline(s).[45]
- Increased risk of damages due to shallow depth of cover.[46]

(vi) The Risk Inherent in the St. Laurent Pipeline Cannot be Ignored

54. In effect, the position put forward by OEB staff and the opposing intervenors is that the OEB should ignore all of the physical integrity concerns of the St. Laurent Pipeline (based primarily upon the flawed reasoning of FRPO above) and rely on a distorted application of the likelihood of a failure to justify it. In doing this, parties are asking the OEB to commit customers (homeowners, businesses and institutions) in Ottawa and Gatineau to take on the probable risk of pipeline failures. At least, OEB staff acknowledges the risk that parties are asking customers to assume when OEB staff states that with respect to a pipeline failure "the consequences could be severe, due to the single-feed nature of the St. Laurent system".[47]

55. Parties have tried to diminish or ignore a fundamental component of a risk assessment. That fundament component is the magnitude of the consequences of a pipeline failure. In circumstances, where the degree of the consequence are

[42] Exhibit I.STAFF.4
[43] Exhibit B, Tab 1, Schedule 1 paras. 14-15
[44] Exhibit B, Tab 1, Schedule 1 para. 32
[45] Exhibit B, Tab 1, Schedule 1 para. 49
[46] Exhibit B, Tab 1, Schedule 1 paras. 38-39
[47] OEB staff Written Submission (March 24, 2022), p. 9

significant, actions must be taken even if the potential for the causal event is not an ordinary occurrence, especially where there is clear physical evidence that the event is probable. This particularly applies where the wellbeing of people, including Enbridge Gas employees, is at risk both physically and financially (e.g., as a result of a leak and subsequent repair on an XHP pipeline like St. Laurent). The opposing intervenors have attempted to diminish these aspects.

56. The key characteristics of the St. Laurent Pipeline set out above, together with its known condition, have an inherent risk that will be almost entirely eliminated through the construction of the Project. In the absence of the Project this same inherent risk, which remains inescapable and critical given its integrity concerns, can only worsen over time. The St. Laurent Pipeline is a single source XHP line serving approximately 165,000 customers (directly and indirectly) ranging from homeowners, hospitals and businesses. A winter interruption of natural gas service of even a few days can have a significant impact on people.

57. Should the St. Laurent Pipeline experience a defect or sustain damage, Enbridge Gas may need to temporarily reduce operating pressures in the pipeline or in the extreme scenario, shut down the pipeline entirely, depending on the severity of the defect or damage sustained. The potential consequences of a failure are amplified due to the location of the St. Laurent Pipeline. Any pipeline defects that could or do release gas into the atmosphere would most likely require a large emergency response and mitigation effort. Any emergency response and mitigation efforts will depend on the magnitude of the defect or damage and the time of year. In addition to the potential for customers losing gas supply, there would be the potential for traffic disruptions and public evacuations in and around the impacted area. Multiple visits to customer sites to “make safe” and restore service once the system issue is remedied could be required.

58. If the St. Laurent Pipeline is isolated due to damage in a situation where temperature in the day is -29°C (which is equivalent to 47 heating degree days), corresponding to design day conditions for Ottawa, gas supply to approximately 62,200 customer gas

meters would be interrupted.[48] As this relates to the number of customer gas meters, the number of gas users would be greater than the number of customer gas meters impacted (multiple customers can be served via a single meter). This situation would also interrupt natural gas supply to the Rockcliffe Control Station which is one of two supply sources for Gazifère.[49]

59. Pollution Probe attempted to diminish the risk to customers stating that an incident on a 47 heating degree design day is not a real or reasonable occurrence and is not likely to happen on the St. Laurent Pipeline or any other.[50] The design day standard used by Enbridge Gas is an appropriate standard accepted by the OEB and one to which Enbridge Gas must be able to provide service if necessary (in other words, one to which Enbridge Gas has historically designed to serve). As a result, it is appropriate to consider its ability to deliver gas in this event as it is ordinary and approved. In addition, Pollution Probe provide no evidence as to why this scenario is not appropriate.

60. Furthermore, Enbridge Gas notes that a temperature of -24° C (42 HDD) was reached on February 12, 2022, and a temperature of -27° C (45 HDD) on February 13, 2016.[51] Although not quite design day temperatures, interruptions on the cold days of winter such as these can cause similarly significant and material hardship for the customers served by the St. Laurent Pipeline.

61. Enbridge Gas estimates that it would cost approximately $54 million to repair the St. Laurent Pipeline, make safe and re-light affected customers in the Enbridge Gas franchise area, in a circumstance where the loss of containment required the isolation

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[48] As indicated in Exhibit JT1.23, following the Technical Conference Enbridge Gas discovered that the Design Day conditions for Ottawa should have been -30.2°C, which is equivalent to 48.2 HDD. Although modelled demands would increase if 48.2 HDD were used, there is no impact to Project need or scope as the difference is not material.
[49] Enbridge Gas also considered if the St. Laurent Pipeline is isolated due to damage in a situation where temperature in the day is 17°C (which is equivalent to 1 heating degree day). In this situation, gas supply to approximately 16,676 customer gas meters would be interrupted. This situation demonstrates that even under mild temperature conditions the St. Laurent Pipeline is critical to supplying thousands of customers. Exhibit B, Tab 1, Schedule 1 pp. 8-11
[50] Pollution Probe Written Submission (March 24, 2022), p. 7
[51] Exhibit I.M.1.PP.1

of the pipeline to facilitate the repair/replacement of the required section of pipe. [52] The complete assumptions underpinning this calculation are set out in detail in Exhibit I.FRPO.3 and Exhibit I.FRPO.25 and further detail was provided in Exhibit JT1.8. Enbridge Gas notes that the provision of these details is contrary to FRPO's assertion that Enbridge Gas was unwilling to provide information used to determine the numbers in question. As stated in Exhibit I.FRPO.25, the "entirety of the details of the assessments completed by Enbridge Gas in support of the conclusions drawn" were set out in that exhibit. Casting dispersions regarding disclosure is not an adequate response to the reasonable calculations and assumptions made by Enbridge Gas. In fact, in reply, other than disclosure, FRPO made no commentary as to the quality of the calculation in question.

62. A considerable part of the $54 million are Commercial/Industrial and Residential customer claims at an estimated cost of $42.8 million.[53] As noted in Exhibit JT1.8, the assumptions used in the cost estimate regarding potential claims was based on actual damage data from two incidents (Innes Rd in Ottawa and Agincourt Mall in Toronto). Based on the information from those two incidents, Enbridge Gas had previously established the assumption that 75% of Commercial customers would file claims with an average claim cost of $5,000 per day. However, for the purposes of establishing the current Project cost estimate of $54 million to repair, make safe, and re-light affected customers, Enbridge Gas conservatively assumed that only approximately 40% of Commercial customers would file a claim.

63. Pollution Probe disagreed with the premise of the calculation indicating that using a historical basis for the calculation was not appropriate.[54] However, this seems an impractical suggestion since historical assumptions provide the only appropriate reference on which to base a forecast. Pollution Probe also stresses that it "is also important to note that most of the costs from the calculation are claim costs which may

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[52] Exhibit B, Tab 1, Schedule 1 pp. 9-10; Enbridge Gas also estimated that it would cost approximately $37 million to make safe and re-light affected customers in the Gazifere franchise area in Gatineau.
[53] Exhibit I.FRPO.3 a)
[54] Pollution Probe Written Submission (March 24, 2022), p. 7

or may not occur and could even be covered by insurance, resulting in the monitor option being even more cost-effective".[55] In response, first, the nature of any forecast is that some consequences may or may not occur; that is why Enbridge Gas developed a conservative estimate. Second, Pollution Probe's view that insurance would deal with any claims demonstrates a clear lack of concern for the safety of customers and the consequences they may face. Whether made as a claim to Enbridge Gas or to their insurance company, a claim made represents a negative impact on customers which should not be diminished.

(vii) The Urgency is Real – Assertions regarding ICM and Schedule Are Not

64. In an attempt to suggest that the St. Laurent Pipeline was not an immediate concern and to indicate that Enbridge Gas was not sincere about the risk of not replacing the St. Laurent Pipeline, Pollution Probe suggested that Enbridge Gas has not decided whether or not to pursue the Project in the absence of ICM funding and that Enbridge Gas was motivated by economics and not out of concern for the integrity of the St. Laurent Pipeline and the risk it entails for its customers. The basis for Pollution Probe's assertion is an exchange during the Technical Conference where the question related as to what action Enbridge Gas would take in relation to an OEB decision related to capital recovery. Enbridge Gas indicated that they would have to understand the basis of the OEB's decision. At the time the question was posed by Pollution Probe, it was not clear as to the nature of the capital funding to which Pollution Probe was referencing.[56] Capital funding determinations may arise in various circumstances. It was not until Pollution Probe's submissions were provided was it clear that ICM funding was intended.[57]

65. To clarify, Enbridge Gas will proceed with the Project and replace the St. Laurent Pipeline since it believes that the St. Laurent Pipeline is no longer safe to be operated in its current condition and should be replaced. Whether a project is funded through ICM or base rates will drive capital budgeting and portfolio allocation decisions, it will

[55] Pollution Probe Written Submission (March 24, 2022), pp. 7-8
[56] TC TR v. 1, pp. 182-183
[57] Pollution Probe Written Submission (March 24, 2022), p. 8

not drive a decision on whether an integrity risk with significant implications will be mitigated.

66. Pollution Probe also asserted that there was a false sense of urgency with respect to the replacement of the St. Laurent Pipeline by indicating that if Enbridge Gas was denied it would assess its IRP options. This is not an accurate representation of the exchange at the Technical Conference.[58]

> MR. BROPHY: So you had indicated that the reason that you don't need to do a full IRP assessment is that it is planned to be constructed in the next three years. But if the OEB doesn't give you approval for a new pipeline within the next three years, then you are no longer exempt from an IRP assessment. Would that be accurate?
>
> MR. CLARK: Brad Clark, Enbridge. If that were to occur I think we would need to reassess. I mean, the company's position is that this pipeline does need to be replaced, and as soon as possible, and so I think we would need to seriously reassess if that was the decision.

Enbridge Gas remains dedicated to the replacement of the St. Laurent Pipeline and does not believe that IRP is an option.

67. Clearly if the OEB chooses to not grant leave to construct the project, Enbridge Gas will not be able to proceed, and it will have to reassess its next steps. But that is not an endorsement of IRP in this circumstance or a lessening in the belief that the St. Laurent Pipeline should be replaced. When pressed by Mr. Brophy further regarding pursing IRP, Mr. Clark responded:[59]

> MR. CLARK: I'm following you. However, the company's position still is that the risk on this pipeline and the integrity concerns with it are high enough and warrant

[58] TC TR v. 1, pp. 199-200
[59] TC TR v. 1, p. 201

> an immediate replacement. And while it is unfortunate that it has been delayed, we are still in that position.

68. Pollution Probe continued its theme of alleging that Enbridge Gas is creating a false sense of urgency by it suggesting various OEB approval dates in order for Enbridge Gas to meet its in-service date in December 2022.[60] What Pollution Probe fails to note is the evidence that Enbridge Gas remains committed to meeting its proposed in-service date and that it has considered strategies to accomplish that goal.[61]

> MR. MURDOCH: One of the possibilities that does present itself with a project of this size and magnitude is the overall length of construction, which means that we are able to add more and more crews. So we are currently making sure that we have -- we have that kind of plan planned out.
>
> But again, it is one of those things that until we know exactly when we will get a decision and when we are allowed to start construction, at this point it would be just to speculate on when we will be able to mobilize and start our construction

69. As noted, in Exhibit JT1.21,

> The Company's latest construction schedule assumes that the OEB will approve the Company's Application and all required permits will be granted (for Phase 3) for a construction start date of June 1, 2022. Enbridge Gas has reviewed the construction schedule weekly since late February 2022 to ensure all underlying assumptions remain valid and most recently validated all assumptions on March 3, 2022.

Attachment 1 of Exhibit JT1.21 also includes additional detail regarding: the number of construction crews required and their approximate work locations; and anticipated dates for construction activities deemed critical to meeting a 2022 Project in-service date.

(viii) Summary

70. Absent an order of the OEB for leave to construct the proposed replacement Project, the St. Laurent Pipeline will continue to deteriorate making the likelihood of a critical

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[60] Pollution Probe Written Submission (March 24, 2022), p. 3

[61] TC TR v. 1, pp. 149

failure increasingly probable. As the proposed Project is driven by the need to address the condition and integrity of the existing St. Laurent Pipeline system, the Company maintains that the current Application (similar to Phases 1 and 2 of the 4-Phase Project) should be approved by the OEB without delay and constructed as promptly as possible to facilitate the abandonment of the existing pipeline and its associated risks.

D. Repair/Retrofit Alternative

71. Enbridge Gas considered two alternatives to replacement of the St. Laurent Pipeline: (i) continued reactive repair of the existing pipeline; and (ii) retrofit of the existing pipeline (adding facilities such as launcher/receivers and replacing incompatible fittings) to permit in-line inspection (ILI) of the entire pipeline and complete the identified repairs. Enbridge Gas submits that neither alternative is acceptable and the OEB should grant leave to construct the Project enabling the replacement of the St. Laurent Pipeline.

72. Notwithstanding the existing integrity issues and based upon the flawed premise on which they consider risk and without any independent evidence or expert evidence in support of the alternatives, OEB staff and opposing intervenors endorse a range of options from just monitoring the Pipeline, to repair only, to retrofit and repair of the St. Laurent Pipeline.

(i) Reactive Repair

73. Given the known existing integrity concerns and the ongoing degradation of the existing 1958 St. Laurent Pipeline, continuing to manage pipeline failures and other integrity concerns in a reactive manner exposes ratepayers and the general public to an unacceptable level of risk. Since the St. Laurent Pipeline is almost entirely under the roadway, at a minimum, continued reactive repair of the pipeline means that the public is inconvenienced with a construction project for nearly each repair, requiring lane closures, restricted access to local businesses and residences. Frequent incidents of released natural gas in a densely populated area can lead to public safety concerns. Enbridge Gas must take the site of the repair as it finds it and depending

on the location, this could lead to significant costs that cannot be resolved through design. Operations and maintenance costs will increase as leaks become more common and the pipeline degrades further.

74. Most importantly, by continuing to reactively repair the Pipeline, the risks identified by Enbridge Gas will not be eliminated and will escalate over time. Security of supply will also be at risk as the St. Laurent pipeline system is a single-source network. The security of supply issue should not be minimized given the approximately 165,000 customers (direct and indirect) that depend on safe and reliable delivery of natural gas from these facilities. Depending on the cause of a pipeline failure event, pipeline operating pressures may need to be reduced, or the pipeline may have to be shutdown with consequences as noted above.[62]

75. OEB Staff has recognized the deficiency with the Reactive Repair Alternative, noting "that the rejection of the (reactive) repair option was appropriate as it fails to manage the increasing reliability risk of the existing pipeline".[63]

76. Both SEC and ED assert that the Reactive Repair Alternative is safe and do so based solely on Enbridge Gas's statement that the Repair Alternative is sufficient to meet the standards set out in CSA Z662.[64] SEC and ED have completely taken out of context the meaning of this statement. Enbridge Gas has an obligation to perform all work on its pipeline according to applicable codes and standards. As a result, any repair done would comply with the standard above, but that does not mean that all of the integrity issues identified above will not result in failures, including those related to safety. It must be remembered that repair is a reactive asset management practice. As a result, no matter what safety standard applies to repair, all of the risks and consequences associated with an event (e.g., pipeline rupture and leak) will occur as well as all the work and inconvenience that comes with completing the repair.

[62] Exhibit B, Tab 1, Schedule 1, p. 43; Exhibit JT1.15
[63] OEB staff Written Submission (March 24, 2022), p. 14
[64] SEC Written Submission (March 24, 2022), p. 24; ED Written Submission (March 24, 2022), p. 3; Exhibit I.ED.10 a)

77. SEC also points to the Emergent Safety Criteria within the Binary Screening Criteria Assessment included as Attachment 1 to Exhibit I.STAFF.6 as an indication that the Repair Alternative is sufficient to meet the need for the Project.[65] The IRP Assessment Process includes screening of identified system needs/constraints against 5 Binary Screening Criteria to determine whether further IRP evaluation is appropriate. The Binary Screening Criteria referenced by SEC is explained by the OEB in its IRP Framework as follows:[66]

> <u>Emergent Safety Issues</u>
>
> The first criterion deals with urgent or imminent issues. <u>The safety and reliability of the gas system is paramount.</u> Removing constraints that jeopardize this system performance does not allow time for the development and assessment of an IRP Plan.
>
> i. ***Emergent Safety Issues*** – *If an identified system constraint/need is determined to require a facility project for Enbridge Gas to offer safe and reliable service or to meet an applicable law, an IRP evaluation is not required. An example of such a system constraint/need, and an emergent safety issue, would be if an existing pipeline sustained unanticipated damage and needed to be replaced as quickly as possible to ensure the safety of local communities and Enbridge Gas's broader transmission and distribution systems. Longer-term safety related system constraints/needs may be appropriate for an IRP Plan and should be considered on a case-by-case basis.*

78. While SEC is correct in its conclusion that the replacement Project does not resemble an emergent event (e.g., a gas main that has been ruptured and is currently leaking or out of service due to third-party construction works) Enbridge Gas maintains that, given the known integrity concerns discussed and its ongoing degradation, the pipeline must be replaced as promptly as possible to ensure the Company is able to safely and reliably operate its system. As described in Enbridge Gas's response to Exhibit I.STAFF.6 b), the Project failed the Timing Binary Screening Criteria, since the underlying Project need must be addressed within 3 years or less. Enbridge Gas went on to explain the drivers for this conclusion, including: (i) projected leaks combined with ongoing pipeline degradation; (ii) other potential pipeline failures (such as third-

[65] SEC Written Submission (March 24, 2022), p. 24
[66] EB-2020-0091 OEB Decision and Order (July 22, 2021), p. 47 (emphasis added)

party damages, unrestrained compression couplings, failed installation welds and poor internal fusion and past deficient cathodic protection impacts); (iii) risk associated with consequence of failure in a highly urbanized setting; which includes customer outage and related safety risk; and (iv) security of supply. These same justifications explain why the Repair Alternative is not sufficient to meet the Project need. Further, absent approval to construct the Project, any pipeline failure event that were to occur in the future due to the numerous pipeline integrity concerns discussed, would in and of itself most certainly be considered "Emergent" and thus disqualified for further IRP assessment

79. ED also places uncommon faith in the opinion and views of Mr. Dwayne Quinn, representative for FRPO. Relying on FRPO's submissions, ED notes that Mr. Quinn is a professional engineer and former Union Gas Ltd. facilities planner.[67] However, Enbridge Gas notes that Mr. Quinn was not a witness in this proceeding, nor was he qualified as an expert of any kind. His submissions are not evidence and should not be taken as such. To the extent his submissions are his personal opinion in some professional capacity, they should be given no weight. In any event, ED's confidence is misplaced since as indicated above Mr. Quinn's interpretation of the integrity related evidence is unsupported.

80. Pollution Probe takes a much simpler approach and merely concludes that the integrity concerns "are some isolated portions of the existing pipeline that may require monitoring and potentially repair in the future. This is normal day to day activity and can be included in the regularly scheduled work approved in the capital and O&M envelopes reviewed by the OEB."[68] Pollution Probe gave no justification for its position.[69]

[67] ED Written Submission (March 24, 2022), p. 3
[68] Pollution Probe Written Submission (March 24, 2022), p. 6
[69] Pollution Probe referenced TC TR v. 1, p. 140 lines 25-28, but this deals with leak categorization and is unrelated to the proposition stated by Pollution Probe.

81. There is nothing put forward by the opposing intervenors to support the Reactive Repair Alternative.

(ii) Retrofit and Repair

82. Distribution pipelines like the St. Laurent Pipeline were not designed, constructed, or operated and maintained to allow for inline inspection. In the 1950's when the St. Laurent Pipeline was installed, in-line inspections were not a typical practice. At that time, the preferred installation method was to use smaller port valves to save costs as opposed to more expensive full port valves (the difference being the opening through the full port valve matches the internal diameter of the gas main). When an in-line inspection tool (pig) is launched into a gas main, the entire stretch of pipeline the tool travels through must have a similar internal diameter so the tool does not get stuck inside the pipeline. Similarly, any 3-Way tee's must be barred on one side so the tool doesn't get misaligned and stuck, which could result in a cut out if the in-line inspection tool can't be freed.[70]

83. Enbridge Gas analyzed the St. Laurent Pipeline to determine what retrofits would be required to make the pipeline in-line inspectable. This analysis determined that 28 retrofits were required in addition to 10 in-line filters needing to be installed (this estimate represented the minimum known number of retrofits required).[71] Regulation stations are extremely sensitive to dirt and debris, and in most instances if dirt enters the regulators or pilots (which operate the regulators), it will cause the equipment to fail. This can result in severe safety concerns, such as over-pressure situations on the downstream networks (lower pressure side of the stations), or under pressure situations resulting in outages. The purpose of in-line filter systems is to stop debris (which is stirred up from the in-line inspection & cleaning tool) from entering and

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[70] Exhibit B, Tab 1, Schedule 1 pp. 35-36

[71] Enbridge Gas did not include retrofits required for the many customer service branches that have been abandoned (pinned off service tees) over the pipelines' life, mitered bends or back-to-back elbows. Historical records of these items are limited, as a result Enbridge Gas would need to run a gauge plate tool through the entirety of the pipeline to determine the locations of these items and their impact on the ILI tool. While the precise location and quantity of these items is not known for the St. Laurent Pipeline, their existence will increase the cost associated with the Retrofit and Repair Alternative. As such, the $30.2 million cost should be considered as a minimum cost.

damaging the downstream regulation equipment. The high-level total cost estimate to retrofit the St. Laurent Pipeline was determined to be approximately $30.2 million.[72]

84. With regard to the Retrofit and Repair Alternative, the St. Laurent system would:[73]

(i) Require an immediate capital outlay of not less than $30.2 million to retrofit;

(ii) Expose ratepayers to ongoing repair costs that are not fully predictable at this time; and

(iii) Result in the accumulation of a great number of small segments being replaced over time until the pipeline is a patchwork of repair sleeves and joints. Each repair would have a different installation date/year that would need to be tracked and monitored and would present its own unique operational vulnerabilities compared to the proposed Project.

85. From a socio-economic and environmental perspective proceeding with the Retrofit and Repair Option would be extremely costly and disruptive to the public for many years to come as it would force Enbridge Gas to complete multiple planned and unplanned (potentially even emergency) construction projects mostly within roadways rather than the single two-phased Project proposed. Aside from cost, this approach introduces substantial risk to Enbridge Gas personnel each time a repair, whether planned or unplanned, is required on an XHP pipeline. Further, once the retrofits and ILI are completed it is expected that, given its age and associated known integrity issues, the ILI assessment results would likely only confirm the systemic nature of the integrity concerns/anomalies described, or worse.[74]

86. Based on the volume and severity of known integrity concerns and considering Enbridge Gas's experience with similarly aged steel natural gas mains (e.g., the NPS 20 Cherry to Bathurst project as discussed in the response at Exhibit JT1.12),

[72] Exhibit B, Tab 1, Schedule 1 pp. 36-39
[73] Exhibit JT1.16
[74] Exhibit JT1.16

retrofitting the St. Laurent pipeline system for ILI is redundant and unnecessary as the ILI results will trigger additional mitigative actions up to the full pipeline replacement that is the subject of the current Application. Accordingly, any such mitigative action except for the full replacement would needlessly expose ratepayers to both increased risk of outage in the interim as well as a greater cost burden in the longer-term, having paid for both the proposed Project and ILI (at a cost totaling more than $150 million), this approach is not in the best interest of ratepayers or the general public.[75]

87. SEC and ED appear to be indifferent between the Reactive Repair vs. Retrofit and Repair Alternatives, since in their view the suggested cost difference between these alternatives and the proposed replacement Project are sufficient to justify repair. As noted above, OEB staff rejected the Reactive Repair Alternative and endorsed the Retrofit and Repair Alternative.[76] This was premised on: (i) OEB staff's perception of risk, which as noted above is flawed and without support; (ii) the notion that resulting repairs would be guaranteed to be solely proactive if the pipeline was retrofitted, which is no way guaranteed to be the case, especially given the expected thousands of anomalies to be identified and ongoing degradation of the pipeline; and also (iii) upon the baseless notion that the costs of a future deferred replacement would be more economic when the St. Laurent Pipeline is ultimately replaced.

88. While inline inspection can provide for informed repair, the risk of reactive repair (found in the alternative that OEB staff rejected) remains. Furthermore, all of the consequences noted above under the Repair Alternative also remain. Very little is uniquely achieved by pursuing the alternative proposed by OEB staff. Furthermore, OEB staff's assertion as to the financial consequences of deferring replacement to sometime in the future is unsupported by any evidence and is pure speculation and should be disregarded.

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[75] Exhibit JT1.16
[76] OEB staff Written Submission (March 24, 2022), pp. 14-15

(iii) Costs

89. While OEB staff and opposing intervenors have incorrectly used the corrosion-related leak forecast derived from the AHI assessment as a basis to assess risk, Enbridge Gas has used the AHI analysis of projected leaks (based on corrosion failure data only) to provide a conservative cost estimate of the Reactive Repair Alternative.

90. For that cost estimate, repairs were assumed to be cut-outs that required a temporary bypass to be constructed to maintain gas supply downstream of the leak event. The estimate is conservative as there is no consideration of any specific locational complexities/challenges associated with excavation required to complete the cut outs of the impacted pipeline section(s) despite the pipeline(s) being located primarily within roadway and in densely urban areas. The cost per cut-out was estimated to be $420,000, which was calculated by using an estimated cost of $350,000 plus 20% contingency. This cost was multiplied by the leak projections per year and inflated at a rate of 2% per annum to determine the anticipated costs incurred each year between 2023-2062. The estimated costs were then discounted using methods prescribed in the OEB's E.B.O. 188, to arrive at an NPV.[77] The conservative basis of this estimate is apparent when compared to a leak repair in 2019 at the intersection of Industrial Avenue and St. Laurent Boulevard that cost $3,182,217 due to challenges associated with the specific location.[78]

91. Opposing intervenors endorse the Repair Alternative almost solely because of a lower cost level. In fact, ED believes that this alone is sufficient to endorse the repair option.[79]

92. However, it is also important to note that the Repair Alternative NPV does not include particular aspects that would in reality increase the cost estimate relative to the replacement cost which is a high-quality estimate. The Repair Alternative NPV:[80]

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[77] Exhibit JT1.15
[78] Exhibit B, Tab 1, Schedule 1, pp. 44-45
[79] ED Written Submission (March 24, 2022), p. 2
[80] Much of this is discussed in the response at Exhibit JT1.15

- does not include costs for any of the secondary impacts discussed in Exhibit B, Table 12 (e.g., the long term annual economic impacts to residents and local businesses resulting from nearly constant construction within roadways that would result);
- does not include any costs for repairs required as a result of ILI, which would be a far greater number than the predicted 40 corrosion-related leaks discussed above as it would include every integrity concern/anomaly identified (not just leaks);
- assumes that each of the corrosion and fitting leaks that will occur will not require large segments of pipeline to be replaced (which is not certain at this time and could drastically increase the cost of the Repair Alternative);
- does not include consideration of any non-corrosion related pipeline failures or loss of containment that could result from the remaining integrity concerns known to impact the St. Laurent pipeline system (as discussed at Exhibit B, Tab 1, Schedule 1, pp. 13-34).

93. Enbridge Gas does not consider investment in retrofitting the existing pipelines with ILI-compatible fittings, valves, and filter components to be prudent or reasonable. For all the above stated reasons, the Repair Alternative cost analysis is understated. The Company expects that the Retrofit and Repair Alternative will not be economic once all pipeline anomalies are addressed and will expose ratepayers to an unacceptable level of ongoing operational risk and uncertainty in the long-term compared to the proposed Replace Alternative (the Project) which establishes a firm end-date for the risk of outage at a known cost and in a manner that provides maximum certainty of effectiveness.[81]

(iv) Robotic Inline Inspection

94. With each asset, there are a number of functional considerations that need to be addressed. This can only be done on a case-by-case basis, often in consultation with vendors, to determine the applicability of the technology considered. Accordingly, Robotic ILI, for example, may not be feasible or appropriate to address every integrity concern.

[81] Exhibit JT1.16

95. Enbridge Gas considered robotic inline inspection of the St. Laurent Pipeline but chose not to pursue it for valid reasons. FRPO noted that Enbridge Gas did not pursue robotic ILI because the pipeline is located under the roadway.[82] Although related to this fact, the complete reason is that there must be sufficient space to locate and install launcher/receiver facilities and equipment set-up, charging station set-up, and supporting inspection crews and equipment.[83] The technical information gathered in support of this assessment and Enbridge Gas's conclusions are set out in Exhibit JT1.6 Attachment 1 (2016 Proposed Launcher Sites Review) and Attachment 2 (Existing Fitting Review for the ILI NPS 12 St. Laurent Pipeline). Enbridge Gas also completed analysis to determine the location of potential PipeTel ILI crawler tool charge points (required as the ILI crawler tool has limited battery capacity), and to determine whether the ILI tool was compatible with existing pipeline fittings (please see Exhibit JT1.6, Attachment 3 for details of this analysis). The PipeTel ILI crawler tool only has a battery capacity that allows it to travel approximately 350 m out and back in or approximately 700 m in total to another charge point.[84]

96. Because of the restrictions discussed above, only a small portion of the total St. Laurent Pipeline was seen as potentially viable for a robotic ILI by the PipeTel ILI crawler tool. Accordingly, Enbridge Gas tentatively scheduled robotic ILI for this segment of the St. Laurent pipeline (approximately 1.5 km depending upon the tool's ability to successfully pass through the two spherical 3-way tees and elbow fitting combinations at Blasdell Ave., otherwise it would only be approximately 1.2 km) with PipeTel for October 2019 if the PipeTel ILI crawler tool was actually able to pass through the existing pipeline and fittings.[85]

97. However, based on its recent experience with the Cherry to Bathurst pipeline and its knowledge of the St. Laurent Pipeline's condition and risk of incompatible fittings, Enbridge Gas made the decision to not proceed with the robotic ILI using the PipeTel

[82] FRPO Written Submission (March 21, 2022), p. 7
[83] Exhibit JT1.6; TC TR v. 1, pp. 37-41
[84] Exhibit JT1.6
[85] Exhibit JT1.6

crawler tool. Specifically, based on this information it was unnecessary to proceed with robotic ILI since it was very likely that the results of the inspection would (like Cherry to Bathurst) only confirm the need to replace the Pipeline and it was more prudent to avoid the additional expense of approximately $1.364 million ($614,000 for ILI + $750,000 for 3 estimated integrity digs resulting from the ILI).[86]

98. In November 2018, Enbridge Gas used the PipeTel ILI crawler tool on a section of the NPS 20 Lake Shore pipeline from Cherry St. to Bathurst St. in the City of Toronto. There were significant similarities between the existing Cherry to Bathurst pipeline and the St. Laurent pipeline, most notably that they were both 1950s steel pipelines located within densely populated urbanized environments with a history of failures and mounting integrity concerns.[87] The ILI completed on the Cherry to Bathurst pipeline confirmed expectations, which were reached using the same process applied to the St. Laurent Pipeline (e.g., inspections, surveys, review of historical records, integrity digs), that the pipeline needed to be replaced. As a result, ratepayers bore the cost of both the ILI as well as the replacement.[88]

99. Contrary to the views of FRPO, Enbridge Gas submits that it appropriately considered robotic ILI and the inherent limitations of that inspection relative to the cost. At FRPO's request, through undertaking Enbridge Gas re-confirmed with PipeTel that no substantial improvements have been made in either battery life or signal technology that would result in Enbridge Gas drawing a different conclusion regarding the appropriateness of or requirements for robotic ILI for the St. Laurent Pipeline.[89]

100. FRPO has referenced other robotic ILI technologies. These references are to websites and information that were not produced as evidence in these proceedings,

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[86] Exhibit JT1.12
[87] This segment of the NPS 20 Lake Shore pipeline (Cherry St. to Bathurst St.) and the St. Laurent Pipeline (Project) were both identified in Enbridge Gas's 2015/2016 asset health review exercise as high risk. However, the St. Laurent Pipeline is considered to have a higher potential for severe consequences of failure since it is a single feed system that operates at a higher pressure than the NPS Lake Shore pipeline (275 psig vs. 175 psig, respectively).
[88] Exhibit JT1.12
[89] Exhibit I JT1.13

and it is inappropriate to use submissions as a means to adduce evidence. Regarding robotic ILI technologies, Enbridge Gas notes that while robotic ILI crawler tools are suitable for the transmission integrity management program, there are a number of functional considerations that need to be addressed on a case-by-case basis (in consultation with tool vendors) before concluding that such ILI is appropriate for any application (whether transmission or distribution pipeline). Enbridge Gas historically utilized robotic ILI crawler tools solely in isolated pipelines, only recently (beginning in 2021) has it begun to use these tools more broadly in instances where Enbridge Gas has had the ability to easily isolate pipelines being inspected if necessary (thus mitigating some overall project risk). Utilizing ILI crawler tools in this manner has limitations, however, including:[90]

- Being limited to pipelines with a maximum operating pressure of 750 psi which can result in requiring pressure restrictions or having to shut pipelines down (further complicating inspections and operations). If a pipeline can't be shut down, the amount of flow bypass needs to be reviewed in the Company's network models to satisfy end loads.
- PipeTel also strongly recommends that operators perform an in-line cleaning prior to the inspection for the best chance at a successful inspection. This is rarely possible without retrofit work, which defeats the purpose of leveraging this technology in traditionally "unpiggable" pipelines.

101. Furthermore, in May 2021, while completing an inspection of the NPS 26 transmission pipeline between Parkway and Lisgar (approximately 2 km in an urban environment similar in some respects to the St. Laurent pipeline(s)), the communication link between the radio controller and the PipeTel crawler tool experienced unexplained interference resulting in a failed inspection. There was a concern that if the inspection continued, contact with the tool would have been lost, effectively stranding the tool in the pipeline. For this reason, PipeTel recommended that the inspection be aborted and the tool retracted. This was the second such incident of this nature experienced by the Company using these tools.[91] As a result, it is important to recognize that robotic ILI tools are not always reliable, and thus that

[90] Exhibit JT1.6
[91] Exhibit JT1.6

there was never a guarantee that the application of such tools to the St. Laurent Pipeline would have produced reliable results.

102. Finally, FRPO claims that Enbridge Inc. has been developing technology with a partner company for inline inspection which could be modified to be utilized for the St. Laurent Pipeline.[92] FRPO's claim is without basis and is inaccurate. The technology referenced is not in use in any way by Enbridge Gas as it is strictly designed for oil pipelines. Further, the technology is free swimming (requiring differential pressures to move) and is not a sell-propelled robotic crawler tool. The OEB should ignore FRPO's suggestion in this regard.

E. <u>Applicability of the City of Ottawa Energy Evolution Plan</u>

103. Because the replacement of the St. Laurent Pipeline is required for integrity reasons and not demand growth, Enbridge Gas must construct the Project to ensure it can continue to meet its obligation to serve the firm contractual needs of its customers on a design day, based upon existing operational parameters. As a result, based on its OEB-approved demand forecasting methodology and current contractual customer commitments, Enbridge Gas has identified the need to replace the existing facilities on a like-for-like basis.[93]

104. Much has been made in the submissions of OEB staff and the opposing intervenors of potential annual natural gas demand reductions, particularly in the context of the joint evidence of the City of Ottawa (Ottawa), Pollution Probe and SEC (collectively the Sponsors) premised upon the GHG reduction initiatives of Ottawa's Energy Evolution program and that of Ottawa Community Housing (OCH). It is important to note, however, that: (i) Ottawa staff acknowledges that they are not pipeline subject matter experts;[94] and (ii) Enbridge Gas does not design its system based on forecasted annual demands, but rather on a peak basis. When assessed on the basis of potential aggregate impact to peak design day demands, the potential

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[92] FRPO Written Submission (March 21, 2022), p. 8
[93] Exhibit I.ED.6
[94] Ottawa Letter (March 24, 2022), p. 1

reductions contemplated in the Sponsors' Evidence do not justify a reduction in Project scope by even a single pipeline size (representing approximately one third (⅓) of volumetric demand reductions required to justify reduction by a single pipeline size). Furthermore, the potential demand reductions cited, even if they were realized:[95]

(i) will in no way alter the operation of the St. Laurent pipeline system;

(ii) do nothing to enhance or make the repair option considered by Enbridge Gas more feasible;

(iii) do not change the fact that reactively repairing leaks/failures exposes ratepayers and the general public to an unacceptable level of risk; and

(iv) in no way mitigate the increasing probability of critical system failure or the severity of consequences, including risks to public health and safety, resulting from the ongoing deterioration of the St. Laurent pipeline system.

105. It is also important to note that Enbridge Gas contemplated IRP and applied the OEB-approved Binary Screening Criteria to the Project and determined that it is not appropriate to conduct further IRP assessment since the Project is driven by integrity concerns that must be addressed within three years and no demand or supply side solution can resolve the integrity concerns.[96] Enbridge Gas also retained a third-party consultant (Posterity Group) to evaluate the potential for targeted DSM (otherwise referred to as Enhanced Targeted Energy Efficiency (ETEE)) to provide material demand reductions to reduce the size of the Project (specifically to reduce the proposed 2.4 km of NPS 16 pipeline to NPS 12). DSM/ETEE potential was evaluated using a model based on the 2019 OEB Achievable Potential Study, specifically the Unconstrained Achievable Potential Scenario (Scenario B). This model was scaled to align with the specific customer types and demands connected to the existing facilities identified in the Project.[97] The Posterity report indicated that a reduction of 63,900

[95] Enbridge Gas Responding Evidence (January 27, 2022), pp. 6-7
[96] Exhibit B, Tab 1, Schedule 1 pp. 12-13; Exhibit I.STAFF.6
[97] Exhibit I.STAFF.6, Attachment 2

m^3/hr is necessary in the peak hour to reduce the pipeline by one size, while the model indicated that the maximum potential peak hour reduction from DSM is approximately 10,100 m^3/hour.[98] The results of that evaluation concluded that there is insufficient DSM/ETEE potential to reduce the sizing of the Project. Based on this and the integrity concerns, and contrary to the position of OEB staff, Enbridge Gas submits that combining IRP investment with the Retrofit and Repair Alternative would not in any way address the integrity concerns driving the need for the Project or affect the Project scope, including pipeline size.

106. This conclusion is consistent with the implications of the Sponsors' evidence. Based on the Sponsors' evidence, Ottawa's Buildings Renewal and Deep Retrofit program calls for renewals and deep retrofits of city buildings to reduce thermal energy demand by 60% to 70% and replace most existing gas heating systems with heat pumps. Set out at page 183 of the Sponsors' evidence is a list of buildings subject to this program and stated to be relevant to the St. Laurent area. Likewise, the Sponsors' evidence noted that OCH proposed to reduce to zero by 2040 the gas consumption of its 78 buildings.[99]

107. Using the address information provided by the Sponsors at Exhibit M.1/2.EGI.12 part (b) and through additional research to locate remaining City of Ottawa buildings, Enbridge Gas produced Table 1 below with its best estimate of the impacts of demand reductions cited by the Sponsors under peak design day conditions.[100]

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[98] The Posterity Report used 63,900 m^3/h as the reduction required to downsize the Project by a single size. This assumed targeted reductions in Ottawa with customers near the source of the pipeline (St Laurent Control). Enbridge Gas's response to I.ED.13 b) & c) as well as Enbridge Gas's Responding Evidence (filed January 27, 2022), used 32,500 m^3/h as the demand reduction required to downsize the Project by a single pipeline size. This represents the best-case scenario, with load reduction occurring at Rockcliffe Control. As such, the range of reductions required, depending on where the reductions occurred, could be from 32,500 m^3/h – 63,900 m^3/h. This does not change the outcome of the evaluation which concluded that there is insufficient DSM/ETEE potential to reduce the sizing of the Project.
[99] Sponsors' Evidence (January 17, 2022), pp. 7-8
[100] Exhibit I.M.2.1.STAFF.21 (UPDATED)

Table 1

Customer Group	Peak Design Day Demand (m^3/h)
Cliff St District Heating	7,565
City of Ottawa Sites	761
OHCH Sites	2,720
Total	**11,046**

108. The calculation applied in Table 1 assumes that demand reductions are 100% effective immediately with no use of methane (Natural Gas or RNG) and located in the most optimal part of the pipeline system for reducing system need/constraint (end of the system).[101] Using the best-case scenario of removing load from the end of the network/system, a reduction 32,500 m^3/h is required to downsize the NPS 16 portion of the Project (approximately 2.4 km) to NPS 12.[102] The potential demand reductions represent approximately one third (⅓) of the reductions required to downsize the proposed Project by a single pipeline size, let alone to eliminate the need for the St. Laurent pipeline system entirely (these demand reductions represent ~6% of the total capacity of the proposed replacement pipeline(s)).[103] Therefore, as in the case of IRP, there is no change in either need for or scope of the Project.

109. The Sponsors' Evidence summarizes Ottawa's and OCH's aspirational plans to reduce GHG emissions within the City via a variety of program and policy initiatives. By aspirational, Enbridge Gas means that, although the plans are laudable, much of the programming is yet to be developed, implemented or funded. This is clearly demonstrated by Table 2 below showing the claims made by Ottawa in the Sponsors' evidence and the corresponding clarifying information provided in the pre-filed evidence and subsequent interrogatory responses explaining current limitations.

[101] Exhibit I.M.2.1.STAFF.21
[102] Exhibit I.ED.13
[103] Enbridge Gas Responding Evidence (January 27, 2022), pp. 4-5

Table 2

Claims	**Clarifying Limitations**
Ottawa believes that energy security is of paramount concern as we implement Energy Evolution and would not support any actions that would put such energy security at significant risk.[104]	Ottawa has not assessed the risks to corporate City of Ottawa buildings or the Community if Enbridge Gas's St Laurent Pipeline is not replaced and a leak causes it to be temporarily taken out of service.[105]
The reproduction of Table 15 from Energy Evolution "shows the programs that are already or will be undertaken from 2020 to 2025 in the building sector."[106]	40% of the 2020-2025 period has now passed, of the 7 Programs identified that are intended to make meaningful progress toward a 100% reduction plan, only 2 have been implemented (one being a pilot, currently at the materials procurement stage).[107] "Staff have been working on developing and launching plans, policies, and programs that will directly impact or influence emission reductions; however, given that Energy Evolution was only approved one year ago and that many of these policies, programs, and plans are still in development, it will take time for these initiatives to have an effect. Staff do not expect to see a significant reduction in the next two to three GHG inventories, particularly on the community side. This is due to the number, scale and complexity of the projects required to achieve Council's targets, as well as factors outside the City's control, including policy decisions by senior levels of government and the availability of funding and market solutions."[108]

104 Exhibit 2.1-Staff-2 (SEC Interrogatory Responses, February 22, 2022)
105 Exhibit 2.1-Staff-2 g) (SEC Interrogatory Responses, February 22, 2022); Exhibit 2.1-Staff-3 d) (SEC Interrogatory Responses, February 22, 2022)
106 Sponsors' Evidence (January 17, 2022), pp. 5-6
107 Exhibit 1/2.EGI.3 (SEC Interrogatory Responses, February 22, 2022)
108 Sponsors' Evidence (January 17, 2022), pp. 32-33 (emphasis added)

"GHG reduction programs are already in action. The following table is a reproduction of Table 15 from Energy Evolution, which shows the programs that are already or will be undertaken from 2020 to 2025 in the building sector. More importantly, GHG reduction programs have already achieved noticeable results, at least in the context of corporate City of Ottawa reductions. Between 2012 and 2020, corporate emissions decreased by 43%, already exceeding the short-term target to reduce emissions by 30 per cent below 2012 baseline levels by 2025."[109]	"Corporate emissions decreased 43 per cent between 2012 and 2020, currently exceeding the short-term target to reduce emissions 30 per cent below 2012 baseline levels by 2025. <u>This decrease in emissions remains primarily due to the significant decline in emissions in the solid waste sector which can be attributed to the considerable efficiencies made at the Trail Road Waste Facility. The remaining emission reductions can be attributable to a decrease in fuel consumption within fleet, specifically transit fleet which saw a 20 per cent drop in diesel fuel consumption from busses between 2019 and 2020, and a reduction in emissions from facilities. The largest contributing sector to total corporate emissions was transit fleet,</u> which accounted for 44 per cent of the total (although emissions did decline in the transit fleet from 2019). Directly related, diesel consumption was the largest contributing source of emissions, accounting for 51 per cent of total corporate emissions."[110]
"In long run the City of Ottawa has identified and adopted 39 GHG reduction programs in order to achieve the 100% reduction objective."[111]	"One point <u>to clarify is that Mr. Fletcher refers to 39 reduction programs in the long run. This applies to all fossil fuels including gasoline and diesel, but as these programs are not relevant to gas consumption they are not discussed</u>."[112]

[109] Sponsors' Evidence (January 17, 2022), p. 5
[110] Sponsors' Evidence (January 17, 2022), pp. 18 (emphasis added)
[111] Sponsors' Evidence (January 17, 2022), p. 6
[112] Exhibit 1/2.EGI.2 a) (SEC Interrogatory Responses, February 22, 2022) (emphasis added)

"The City's Energy Evolution program, which is included in the filed materials at page 80, was passed unanimously by Ottawa City Council in October of 2020. It aims to reduce corporate city of Ottawa emissions to zero by 2040 and community wide emissions – that is, emissions from all entities within the City of Ottawa - to zero by 2050."[113]	Achieving the 100% scenario will require unprecedented investments from the City, senior levels of government, and the community in the next 10 years. Compared to the BAP, annual incremental community-wide investments of approximately $1.6 billion per year net present value would be required for the next decade (2020-2030) to achieve GHG reductions in line with the model. Of this, $581 million per year net present value would be required (2020-2030) for transit and active transportation infrastructure. An additional $41 million per year net present value would be required (2020-2030) for municipal building retrofits, transitioning to a zero emission municipal (non-transit) fleet, sewer heat capture, and renewable natural gas generation at wastewater and solid waste facilities. Annual incremental community-wide investments drop to around $782 million per year from 2031-2050.[114]
	Risks to Implementation Realizing this action and investment carries many risks. These risks may include: • Insufficient financial support from different levels of government and the private sector to meet the budgetary and staffing needs of the Action and Investment Plan and beyond … • Lack of uptake or buy-in from residents, businesses, industry or the municipality that impacts the viability of a new program or new standard …

[113] Sponsors' Evidence (January 17, 2022), p. 4
[114] Sponsors' Evidence (January 17, 2022), p. 145 (emphasis added)

	• Lack of alignment between what the Energy Evolution model calls for and recommendations that come forward for plans and strategies that directly relate to Energy Evolution. Note that although it is expected that the range of options evaluated will include one or more scenarios that achieve the GHG reductions required in the 100% scenario, those scenario(s) may not ultimately be recommended • Aggressive implementation timelines that may not account for typical City processes including capital budget approval, Long Range Financial Plan, planning, consultation, approvals, design, construction, and commissioning or account for provincial or federal approval processes that are out of the City's control[115]
Ottawa states their "role is to provide the Ontario Energy Board with information on the plans by major gas users in Ottawa to reduce their GHG emissions, and in order to do so to reduce their reliance on natural gas to a fraction of their current levels."[116] .	When asked what proportion of the GHG emission reductions within the Area of Benefit of the Project are from natural gas consumption, the City responded that they do not have the data or analysis. When asked to provide a breakdown of the various sources of GHG emissions reductions according to source (Natural Gas, Diesel, Fuel Oil etc). Ottawa judged that obtaining this level of data granularity for the 2020-2025 timeline was not worth the effort to achieve it in terms of refining planned programs.[117]

[115] Sponsors' Evidence (January 17, 2022), pp. 158-159 (emphasis added)
[116] Sponsors' Evidence (January 17, 2022), p. 3
[117] Exhibit 1/2.EGI.2 c) (SEC Interrogatory Responses, February 22, 2022) (emphasis added)

The City, part of the National Capital Region, acts in concert with the Federal Government's GHG reduction plan in the National Capital Region.[118]	In reality, there is no formal overarching agreement between Ottawa and the federal government regarding Energy Evolution.[119] ESAP is an activity of the federal government and while Ottawa liaises with ESAP, and is aware of its activities, it is basically independent of Ottawa. [120]
Ottawa buildings broadly speaking will have to follow the Energy Evolution high level plan, which calls for all City operations to be zero emissions by 2040.[121]	As an example, Ottawa cites Bruyere Continuing Care (BCC) (875,000 sq ft of space under their management) as one of the major gas users that will contribute to the emissions reduction targets. In reality, BCC is completely independent of Ottawa. Ottawa has no authority or accountability over BCC decisions regarding natural gas consumption. As is the case with many other natural gas consumers (incl. University of Ottawa) cited in the Sponsors' evidence.[122]

110. SEC has the view that there is "no doubt that fossil gas use is going to decline over the lifetime of the proposed new pipeline."[123] This opinion is also held by Pollution Probe and ED. However, based on the foregoing, the extent of the reduction and its impact on peak hour needs at this juncture is uncertain and there is no probative evidence that was filed on this assertion. Additionally, if the future occurs as Ottawa hopes, it does appear to a high likelihood that RNG is part of the plan and with no

[118] Sponsors' Evidence (January 17, 2022), p. 4
[119] Exhibit 1/2.EGI.4 (SEC Interrogatory Responses, February 22, 2022)
[120] Exhibit 1/2.EGI.5 (SEC Interrogatory Responses, February 22, 2022)
[121] Exhibit 2.1-Staff-2 a) (SEC Interrogatory Responses, February 22, 2022)
[122] Exhibit 1/2.EGI.14 (SEC Interrogatory Responses, February 22, 2022); Exhibit 1/2.EGI.15 (SEC Interrogatory Responses, February 22, 2022)
[123] SEC Written Submission (March 24, 2022), p. 20

other viable alternative distribution basis yet established, it is reasonable to believe that a pipeline will be used.

111. In any event, none of this has anything to do with the main issue before the OEB in the current leave to construct application, which is: Should the St. Laurent Pipeline be replaced on a like-for-like basis because of its clear and immediate integrity needs, ensuring the safe and reliable delivery of gas to meet Enbridge Gas's commitments to its customers in Ottawa and Gatineau? None of the evidence produced by the Sponsors touches in any way on that issue and instead looks to make inferences based on conjecture 20 – 30 years from now, not its immediate need. The information does not advance the OEB's consideration of this issue and is irrelevant.

112. On a related point, Enbridge Gas in its reply evidence made reference to the degree that electrification must occur to displace the energy provided over the course of 1 hour from natural gas. The calculation of 1.64 GW noted in Enbridge Gas's reply evidence was further qualified by its response in Exhibit I.M.1.ED.25 and, as stated in Exhibit JT1.27, that calculation was a direct energy conversion that did not incorporate many of the additional variables necessary (including those named by ED within its questions at Exhibit I.M.1.ED.25) to accurately determine the actual feasibility of fully electrifying Ottawa and Gatineau in place of natural gas service and the related electrical infrastructure. Although submissions on this aspect were made by some of the opposing intervenors, Enbridge Gas submits that the original information was provided for context only and it is no more relevant to the OEB's consideration of the approval sought than the Sponsors' evidence overall. ED did put various efficiency factors to the Ottawa witnesses.[124] In this regard, Enbridge Gas notes that the overall energy needed to displace the current natural gas delivered will have to be found through a combination of efficiencies or infrastructure, which is no small task. No certainty in this regard can be gained from the Ottawa witnesses since they are not experts and are self-declared fact-based witnesses only. In fact ED itself

[124] TC TR v. 2, pp. 35, 39-44

admits, that requesting insights on what Ottawa's electrical requirements will be in 2050 from the Ottawa witnesses, is "a fools errand".[125]

113. On the strength of the Sponsors evidence, SEC has proposed that the OEB impose certain conditions on a future leave to construct application in the event that the current application is rejected and ultimately Enbridge Gas is correct that replacement is required and a new leave to construct is sought.[126] The OEB should reject SEC's submissions. First, within the context of a leave to construct application, the OEB has no jurisdiction to impose IRP on Enbridge Gas and, in any event, there is no evidence in this proceeding on which to do so. Second, SEC's proposed conditions circumvent the OEB's IRP Framework and Binary Screening Criteria/IRP Assessment Process.

114. Based on the Sponsors' evidence as well as references to information drawn from articles and other jurisdictions (which are not evidence in this proceeding and should be given no weight),[127] OEB staff and opposing intervenors submit that the OEB should reject replacement and endorse repair of the St. Laurent Pipeline to "buy time" to permit for decarbonization efforts.[128] None of the decarbonization efforts put forward by the Sponsors will eliminate the pipeline's integrity issues and the risks that customers are subject to. In effect, OEB staff and opposing intervenors are endorsing a plan for customers to undertake the risk of known and the further latent integrity concerns of this pipeline on the hope that one day an old and poorly conditioned single source XHP pipeline will not experience a material failure while Ottawa attempts to implement a plan that is barely launched, complex and not yet funded. Such a bet is not in the public interest. The public interest would be better served if customers had safe and reliable gas delivery while Ottawa pursues its program. This can occur with the replacement of the St. Laurent Pipeline and the construction of the Project.

[125] TC TR v. 2, p. 44
[126] SEC Written Submission (March 24, 2022), p. 28
[127] ED Written Submission (March 24, 2022), pp. 2, 5, 8-9; FRPO Written Submission (March 21, 2022), pp. 2-4, 7-8; SEC Written Submission (March 24, 2022), pp. 16-17
[128] SEC Written Submission (March 24, 2022), p. 26

F. Disclosure

115. FRPO made various submissions regarding the willingness of Enbridge Gas to provide certain requested technical information. FRPO is incorrect in this regard. Enbridge Gas provided sufficient information in response to FRPO's inquiries. The requirement to provide a "full and adequate" response is the standard set out in the OEB's Rules of Practice and Procedure. The information may not have been in the exact form that FRPO requested, but the response provided was full and adequate based on the information available to Enbridge Gas.

(i) Simulation Study

116. According to FRPO, it sought the results of various simulations from Enbridge Gas. FRPO makes references to two letters in which the requests were made – January 6, 2022, and February 25, 2022. The questions posed in FRPO's January 6, 2022 correspondence were answered completely in Exhibit I.FRPO.23 through to Exhibit I.FRPO.27 which were filed on the record at the time of filing interrogatory responses in respect of Enbridge Gas's responding evidence and in advance of the Technical Conference. With respect to FRPO's February 25, 2022 correspondence, Enbridge Gas addresses FRPO's concerns in correspondence to the OEB which Enbridge Gas filed on March 1, 2022, also in advance of the Technical Conference. Enbridge Gas's March 1, 2022 correspondence is attached to these submissions as Attachment 1. In that correspondence, Enbridge Gas addressed each of FRPO's concerns, including that some of the scenarios sought by FRPO were not physically possible. Enbridge Gas responded fully and properly even though FRPO did not like or appreciate the response. FRPO had full opportunity to ask any follow-up questions at the Technical Conference.

(ii) Impacts of Casings

117. FRPO indicates that during the Technical Conference it had attempted to have the witnesses provide Enbridge Gas's understanding of the potential impacts of casings

but that it was refused. This is not an accurate representation of the record. Initially, FRPO had asked for an undertaking:[129]

> Can I ask by way of undertaking for you to check with your resources and determine if in the past casings were required, why that requirement for a casing has been eliminated from the code?

118. Although this request was initially refused, Enbridge Gas chose to seek clarification as to whether a response could be provided. After seeking further instructions and clarification, Enbridge Gas gave the response set out in Exhibit JT2.1 relating to the need for casings and to determine the reasons for the code change if possible. Exhibit JT2.1 provides the results of a CSA Code review back to CSA Code Z184-1968 and also reviewed Enbridge Gas's Standard Operating Manual from 1964. Among other details, Enbridge Gas noted:[130]

> In summary, uncased crossings have been allowed by Code, at least as early as 1968 (under certain design considerations). While the Company Operating practices at times may have differed from Code, it always met the minimum Code requirement (requiring railway crossings to be cased if the carrier pipe is larger than NPS 6).
>
> The Company was not able to find any information identifying the reasons or rationale for any specific changes in the Code updates within its records. While a record of such information may be informative, what is most important is having a record of prevailing Code to ensure compliance.

Enbridge Gas fulfilled the requested undertaking with a full and proper response.

119. FRPO further asserts that because of the initial refusal pending clarification, FRPO was somehow limited in its ability to get the witnesses input of the potential impacts of casings. This was not the case. In fact, in response to FRPO's questions, the witness responded:[131]

> So whether, to your questioning here, the casing may have contributed to the corrosion or a number of factors contributed to that corrosion, the point of the matter here is that we've got a pipe that had degraded and it's corroded, and it is

[129] TC TR v. 1, pp. 12-13
[130] Exhibit JT2.1
[131] TC TR v. 1, p. 14

> one additional input that we can identify that stresses the fact that the pipe needs to be replaced.

The witness also responded to questions about the nature of the repairs done and gave Undertaking JT1.2 relating to the proximity of those repairs to other repairs.[132]

(iii)Impact of Coating

120. FRPO asserts that they sought to have Enbridge Gas provide its views on pipeline coatings and their impact on asset health, and that FRPO's request for this comparison was refused. This is also not an accurate representation of the record. In Exhibit I.FRPO.13, FRPO requested an Asset Health Assessment for the Windsor and London Lines (both in the Union Rate Zone) in the same manner as done for the St. Laurent Pipeline and as out in Exhibit B-1-1, page 42. Enbridge Gas responded that:[133]

> This type of Asset Health and Reliability Engineering was not conducted on the Windsor Line and London Lines projects before their respective replacements, as the Company had not yet integrated the Asset Health Review process for Union Rate Zone assets at that time.

121. The exchange at the Technical Conference was as follows:[134]

> MR. QUINN: The question is, what -- we have heard that the St. Laurent line is coated. Was the Windsor line coated? And if so, how?
>
> If you need to take that away -- I thought this was a very preliminary question. We asked about asset health, and we didn't get what we were looking for, so I thought this is a different approach to try to give a relative comparison.
>
> MR. MADRID: We can take that back and confirm what exactly the Windsor line and London line had as far as coating.
>
> MR. QUINN: Okay. To be clear, and we got this in our recent technical conference, <u>the undertaking would be to compare the coatings of the St. Laurent line to the Windsor line and the London lines and differentiate the impacts on asset health from a current condition standpoint.</u> Is that sufficiently clear for Enbridge and the reporter?
>
> MR. MADRID: I believe the undertaking was for us to confirm what coating the Windsor and London line had. <u>We had already responded to FRPO's</u>

132 TC TR v. 1, pp. 16-18
133 Exhibit I.FRPO.13
134 TC TR v. 1, p. 6 (emphasis added)

> interrogatories with regards to the asset health review and a comparison between both those two pipelines and the St. Laurent, and I have communicated that as far as the asset health review we do not have the failure data as of yet. We are working on processing that data, and the modelling will be ready in 2023.

122. Enbridge Gas was not able to provide the information requested since analysis could not be done. Enbridge Gas confirmed what the Windsor and London Lines had regarding coating and did so as shown in Exhibit JT1.1.

(iv)Project Memo

123. FRPO asserted that notwithstanding that Enbridge Gas has indicated that no technical reports or documentation was relied upon by Enbridge Gas for the purposes of making its decision to proceed with the Project, Enbridge Gas had withheld a "project memo" referenced in the Board of Directors materials provided in these proceedings. FRPO requested that the document be produced as part of these reply submissions.

124. The Project Memo has already been disclosed. Enbridge Gas confirms that Attachment 3 of Exhibit I.FRPO.15 is the Project Memo that is referenced. Enbridge Gas's response to Exhibit JT2.2 remains correct:

> No additional technical reports or documentation was relied upon by Enbridge Gas for the purposes of forming its decision to proceed with the Project.

Enbridge Gas has made full and adequate responses to appropriate and relevant questions asked.

G. OEB Staff Support

125. Importantly, aside from the submissions of OEB staff addressed above, OEB staff draw the following conclusions regarding the proposed Project:

- OEB Staff submits that the Project is appropriately sized;[135]

[135] OEB staff Written Submission (March 24, 2022), pp. 16-17

- The IRP alternative assessed by Enbridge Gas (including targeted DSM) will not reduce the peak demand served by the St. Laurent Pipeline system on a scale sufficient to reduce the size of the proposed Project;[136]

- The Sponsors' evidence does not demonstrate that peak demand reductions of the required scale have been achieved or are likely to be achieved within the next few years due to Ottawa's Energy Evolution plan;[137]

- OEB Staff is not able to conclude that the proposed Project costs are in any way unreasonable;[138]

- Enbridge Gas has completed the Project Environmental Report in accordance with the OEB's Environmental Guidelines and OEB staff has not concerns with the environmental aspects of the Project;[139]

- The OEB should approve the proposed forms of Lands Rights agreements as both forms were previously approved by the OEB;[140] and

- That Enbridge Gas appears to have made efforts to engage with affected indigenous groups and no concerns that could materially affect the Project have been raised through its consultation (OEB staff is also not aware of any potential adverse impacts of the Project to any aboriginal or treaty rights).[141]

H. <u>Relief Requested</u>

126. Based on the foregoing, Enbridge Gas respectfully requests that the OEB, pursuant to section 90 of the Act, issue an Order granting leave to construct the pipelines and pursuant to section 97 of the Act, issue an Order approving the forms of

[136] OEB staff Written Submission (March 24, 2022), p. 17
[137] OEB staff Written Submission (March 24, 2022), p. 17
[138] OEB staff Written Submission (March 24, 2022), pp. 18-19
[139] OEB staff Written Submission (March 24, 2022), p. 20
[140] OEB staff Written Submission (March 24, 2022), p. 21
[141] OEB staff Written Submission (March 24, 2022), p. 22

Working Area Agreement and Transfer of Easement agreement set out at Exhibit E, Tab 1, Schedule 1, Attachments 1 and 2.

All of which is respectfully submitted this 7th day of April 2022.

____

Charles Keizer
Counsel to Enbridge Gas

Adam Stiers
Manager
Regulatory Applications
Leave to Construct
Regulatory Affairs

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Enbridge Gas Inc.
50 Keil Drive North,
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Canada

March 1, 2022

VIA EMAIL and RESS

Nancy Marconi
Acting Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Nancy Marconi:

Re: Enbridge Gas Inc. (Enbridge Gas)
Ontario Energy Board (OEB) File: EB-2020-0293
St. Laurent Ottawa North Replacement Project
Response to FRPO Correspondence February 25, 2022

Enbridge Gas Inc. ("Enbridge Gas" or the "Company") is submitting this correspondence in response to the Federation of Rental-housing Providers of Ontario's ("FRPO") letter of February 25, 2022 wherein FRPO asserted that Enbridge Gas did not provide complete and sufficient responses to particular FRPO interrogatories. Contrary to the assertions of FRPO, Enbridge Gas has provided complete responses to the interrogatories identified in FRPO's February 25, 2022 letter.

FRPO 23

FRPO indicates that Enbridge Gas failed to provide requested station inlet pressures on the design day in respect of the proposed replacement. However, in making its submission FRPO has only referred to one part of the question. In Exhibit I.FRPO.23 a) FRPO asked Enbridge Gas to confirm that Table 2 in Exhibit I.FRPO.2 provides simulated peak day station inlet pressures for 2021/22. In response, the Company indicated:

> The simulated inlet pressures are peak winter conditions at the time of analysis (2020/2021). The Company does not expect pressures for 2021/2022 to be materially different.

In Exhibit I.FRPO.23 c), FRPO asked for a second table showing the peak day inlet pressures for stations shown in Table 2 in a peak-day simulation after the proposed replacement. In response, the Company stated:

> The pipeline replacement was design to meet existing capacity requirements and as such **these station inlet pressures will not change materially** following the completion of construction of the Project. (emphasis added)

Based on this response, the inlet pressures are essentially the same as those already stated in Table 2 of Exhibit I.FRPO.2. Those inlet pressures are set out and the information requested by FRPO has been provided and the response complete. In support of this conclusion, Enbridge Gas will produce a table showing that peak day inlet pressures for stations shown in Table 2 of Exhibit I.FRPO.2 are not materially different. Enbridge Gas will file this additional table within an updated interrogatory response to Exhibit I.FRPO.23 c) in advance of the scheduled Technical Conference.

FRPO 24

According to FRPO, in Exhibit I.FRPO.24, FRPO requested the simulated outlet pressures and flows and asserted that those were not provided without justification. Enbridge Gas interpreted FRPO's sentence leading into the numbered part-questions posed by FRPO as providing context, together with FRPO's further qualification that:

> If the simulated setting was not 275 psig, please re-run the simulation using 275 psig and provide the resulting pressures and flows at the stations pre- and post-proposed replacement.

In response, Enbridge Gas stated that:

> The NPS 12 northbound line is limited by its MOP of 250 PSIG and cannot be raised to 275 psig.

As a result, the parameters of the request made by FRPO are not physically possible and the simulation was not provided. Accordingly, the Company provided complete responses to FRPO's inquiries for parts (i) and (ii) since those inquiries reflected scenarios that are contrary to reality.

FRPO appears to now indicate that the un-numbered lead-in sentence was meant to be a broad-based request for all outlet pressures and flows. In an effort to avoid further procedural delay and in the interest of regulatory efficiency, Enbridge Gas intends to file an updated response to Exhibit I.FRPO.24 providing peak day flows out and outlet pressures for each station (for the pre-and post-replacement scenarios) in advance of the scheduled Technical Conference.

FRPO 25

In Exhibit I.FRPO.25, which related to Exhibit I.FRPO.3 and Exhibit I.FRPO.5, FRPO sought the study, together with other aspects, that determined the number of customers lost on a 47 HDD and the cost to repair, make safe and relight. In response, Enbridge Gas provided the Schedules attached to this correspondence. This supplemented the information already provided in response to Exhibit I.FRPO.3 and Exhibit I.FRPO.5.

As indicated by Enbridge Gas in its response to Exhibit I.FRPO.25:

> The **entirety of the details of the assessments** completed by Enbridge Gas in support of the conclusions drawn within Exhibit B, which are based on the Company's historical experiences mitigating system outages, are set out in Tables 1 and 2 below for a 47 HDD and 1 HDD respectively. (emphasis added)

As noted, all of the details have been provided. There are no additional studies in addition to the information provided in Exhibit B-1-1 regarding customer loss and the information provided in the above responses.

FRPO 28

In Exhibit I.M.2.FRPO.28 b), FRPO requested that Enbridge Gas provide a map showing the locations of the stations including the Rockcliffe Control station. The Company referenced FRPO to Exhibit B-1-1, Figure 1 which is attached to this letter. As requested by FRPO the map shows the locations of the stations. It is important to note that FRPO did not in its original question indicate that cross-streets be identified or provide an explanation of the purpose of the map requested.

FRPO, in its February 25 letter, has now altered its request and is now inappropriately posing a new question while at the same time asserting that Enbridge Gas has not fully responded to the question asked. In an effort to avoid further procedural delay and in the interest of regulatory efficiency, Enbridge Gas intends to file an updated response to Exhibit I.M.2.FRPO.28 b) providing a legend for the map set out in Exhibit B-1-1 Figure 1.

Based on the foregoing, Enbridge has provided sufficient and complete responses to all of the original and additional questions asked by FRPO.

Please contact the undersigned if you have any questions.

Yours truly,

(Original Signed)

Adam Stiers
Manager, Regulatory Applications – Leave to Construct

c.c. Guri Pannu (Enbridge Gas Counsel)
Charles Keizer (Torys)
Zora Crnojacki (OEB Staff)
Intervenors (EB-2020-0293)

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

INTERROGATORY

Preamble:

In FRPO.3 and FRPO.5, we asked EGI to file the study(ies). Instead, we received assorted assumptions that answered a few of our questions. We ask again that EGI file:

Question:

a) The study(ies)
b) The report(s) to management
c) The technical analysis document(s) and
d) Whatever EGI would call the information sources provided by analysts to management that documents the methodologies and assumptions used to determine for both Enbridge Gas and Gazifere:
   i) the assumptions – e.g., static or transient simulation
   ii) minimum pressures deemed to prompt an outage
   iii) methodology and assumptions employed in estimating the costs of:
      (1) actions for mitigation
      (2) repair
      (3) make safe and relight
      (4) customer claims

Response

a) - d)
The entirety of the details of the assessments completed by Enbridge Gas in support of the conclusions drawn within Exhibit B, which are based on the Company's historical experiences mitigating system outages, are set out in Tables 1 and 2 below for a 47 HDD and 1 HDD respectively.[1]

[1] Total customers lost are set out at Exhibit B, Tab 1, Schedule 1, Tables 1 & 2 for Customer Loss at 47 Degree Day and 1 Degree Day, respectively.

Table 1 – 47 HDD

Category	Item	Qty
Service Visits	**MAKE SAFE COSTS**	
	Fitter Assumptions	
	Total Number of Customers (ON only)	31,623
	Fitter Cost ($/hr) – approximate	$100
	Fitter Supervisor Cost ($/hr)	$150
	Number of Make Safe per Hour	15
	Per Diems and Hotel per Day	$200
	Mileage ($/km)	$0.50
	Make Safe Assumptions	
	Number of Person-Hours Making Safe	2108
	Number of Person-Days Making Safe	210.8
	Number of Fitters to Make Safe in 48 Hrs	105.4
	Make Safe Costs	
	Cost for Fitters to Make Safe (Salary Only)	$252,984
	Per Diems for Fitters to Make Safe	$42,164
	Supervision for Fitters (1 Supervisor/10 Fitters)	$39,600
	TOTAL MAKE SAFE	**$334,748**
	RE-LIGHT COSTS	
	Re-Light Assumptions	
	Number of Re-Lights per Hour	5
	Number of Person-Hours Re-Light	6325
	Number of Person-Days Re-Light	632
	Number of Fitters to Re-Light in 5 Days	126.5
	Re-Light Costs	
	Cost for Fitters to Re-Light (Salary Only)	$758,952
	Per Diems for Fitters to Re-Light	$126,492
	Supervision for Fitters (1 Supervisor/10 Fitters)	$117,000
	TOTAL RE-LIGHT	**$1,002,444**
	COSTS FOR FITTER TRAVEL	
	Travel (Salary)	$202,387
	Travel (Mileage)	$56,921
	Travel (Per Diems)	$50,597
	TOTAL FITTER TRAVEL	**$309,905**
Service Visit Costs		**$1,647,097**
Replacement Costs (Contractor)	**REPLACEMENT COSTS – CONTRACTOR**	
	Replacement Assumptions	
	Cost assumed to be an average of a typical repair cost ($420,000) and actual 2018/2019 cost for replacement on St. Laurent ($3,182,417)	
	Replacement Cost – Contractor	$1,801,209
	TOTAL REPLACEMENT COST	**$1,801,209**
Replacement Costs (Contractor)		**$1,801,209**
Replacement Costs (Internal)	**REPLACEMENT COSTS – INTERNAL**	
	Replacement Assumptions – Field Staff	

	Number of Field Staff Responding Cost per Hour (OT Considered) Hours per Day Per Diem Hotel Number of Days **Replacement Assumptions – Supervision** Supervision (1 Supervisor/5 Staff) Cost per Supervisor per Day Number of Days **Replacement Assumptions – Liaison, Planning, Engineering** Number of EGI Liaisons Number of Planning/Engineering Support Number of Days Cost per Day Transportation per Employee **Replacement Costs** Field Staff Costs Supervisor Costs Liaison, Planning, Engineering Costs **TOTAL REPLACEMENT COST – INTERNAL**	25 $62 10 $75 $125 10 5 $500 10 20 20 10 $500 $450 $205,000 $35,000 $298,000 **$538,000**
Replacement Costs (Internal)		**$538,000**
Claims	**COST OF CLAIMS** **Commercial/Industrial Claims Assumptions** Total Commercial/Industrial Customers Impacted Percentage of Customers with Claims Cost of Commercial Claim per Day Average Number of Days to Make Safe, Re-Light **Residential Claims Assumptions** Total Residential Customers Impacted Percentage of Customers with Claims Cost of Residential Claim per Day Electric Heater Cost Percentage of Customers with Supplied Heat Average Number of Days to Make Safe, Re-Light **Claims Costs** Commercial/Industrial Claims Residential Claims **TOTAL CLAIMS COSTS**	 3,362 40% $5,000 5 28,261 30% $200 $250 10% 5 $33,619,992 $9,184,825 **$42,804,818**
Claims Costs		**$42,804,818**
Administrative	**ADMINISTRATIVE COSTS** **Administrative Cost Assumptions** Number of Staff Cost per Hour (OT Considered) Hours per Day Number of Days **Administrative Costs** Administrative Costs **TOTAL ADMINISTRATIVE COSTS**	 25 $62 10 10 $155,000 **$155,000**

Administrative Costs		**$155,000**
Temporary Facilities	**TEMPORARY FACILITIES COSTS** **Facilities Assumptions** Rental Trailers, Command Centers, Relief Centers **Facilities Costs** Facilities Costs **TOTAL FACILITIES COSTS**	 $200,000 **$200,000**
Temporary Facilities Costs		**$200,000**
Deferred Work	**DEFERRED MAINTENANCE/SERVICE WORK COST** **Deferred Work Assumptions** Total Hours Worked (Internal/Contractor) Percentage of Deferred Work Made-Up with OT OT Premium **Deferred Work Costs** Deferred Work Costs **TOTAL DEFERRED WORK COSTS**	 10,933 15% $31 $50,838 **$50,838**
Deferred Work Costs		**$50,838**
Contingency Costs (15%)		**$7,083,339**
TOTAL ESTIMATED COST		**$54,305,598**

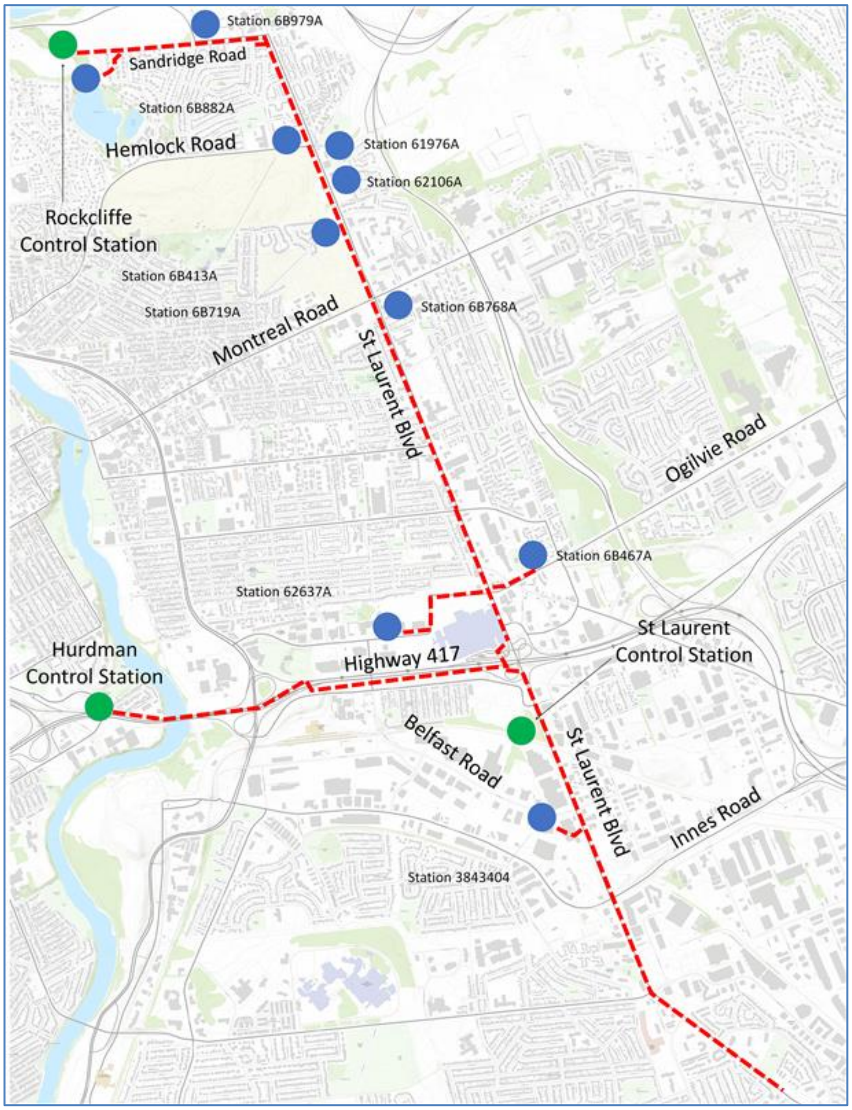
Table 2 – 1 HDD

Category	Item	Qty
Service Visits	**MAKE SAFE COSTS**	
	Fitter Assumptions	
	Total Number of Customers (ON only)	16,676
	Fitter Cost ($/hr) – approximate	$100
	Fitter Supervisor Cost ($/hr)	$150
	Number of Make Safe per Hour	15
	Per Diems and Hotel per Day	$200
	Mileage ($/km)	$0.50
	Make Safe Assumptions	
	Number of Person-Hours Making Safe	1112
	Number of Person-Days Making Safe (12 hr day)	111.2
	Number of Fitters to Make Safe in 48 Hrs	55.6
	Make Safe Costs	
	Cost for Fitters to Make Safe (Salary Only)	$133,408
	Per Diems for Fitters to Make Safe	$22,235
	Supervision for Fitters (1 Supervisor/10 Fitters)	$21,600
	TOTAL MAKE SAFE	**$177,243**
	RE-LIGHT COSTS	
	Re-Light Assumptions	
	Number of Re-Lights per Hour	5
	Number of Person-Hours Re-Light	3,335
	Number of Person-Days Re-Light (12 hr day)	334
	Number of Fitters to Re-Light in 5 Days	66.7
	Re-Light Costs	
	Cost for Fitters to Re-Light (Salary Only)	$400,224
	Per Diems for Fitters to Re-Light	$66,704
	Supervision for Fitters (1 Supervisor/10 Fitters)	$63,000
	TOTAL RE-LIGHT	**$529,928**
	COSTS FOR FITTER TRAVEL	
	Travel (Salary)	$106,726
	Travel (Mileage)	$30,017
	Travel (Per Diems)	$26,682
	TOTAL FITTER TRAVEL	**$163,425**
Service Visit Costs		**$870,595**
Replacement Costs (Contractor)	**REPLACEMENT COSTS – CONTRACTOR**	
	Replacement Assumptions	
	Cost assumed to be an average of a typical repair cost ($420,000) and actual 2018/2019 cost for replacement on St. Laurent ($3,182,417)	
	Replacement Cost – Contractor	$1,801,209
	TOTAL REPLACEMENT COST	**$1,801,209**
Replacement Costs (Contractor)		**$1,801,209**
Replacement Costs (Internal)	**REPLACEMENT COSTS – INTERNAL**	
	Replacement Assumptions – Field Staff	

	Number of Field Staff Responding Cost per Hour (OT Considered) Hours per Day Per Diem Hotel Number of Days **Replacement Assumptions – Supervision** Supervision (1 Supervisor/5 Staff) Cost per Supervisor per Day Number of Days **Replacement Assumptions – Liaison, Planning, Engineering** Number of EGI Liaisons Number of Planning/Engineering Support Number of Days Cost per Day Transportation per Employee **Replacement Costs** Field Staff Costs Supervisor Costs Liaison, Planning, Engineering Costs **TOTAL REPLACEMENT COST – INTERNAL**	25 $62 10 $75 $125 10 5 $500 10 20 20 10 $500 $450 $205,000 $35,000 $298,000 **$538,000**
Replacement Costs (Internal)		**$538,000**
Claims	**COST OF CLAIMS** **Commercial/Industrial Claims Assumptions** Total Commercial/Industrial Customers Impacted Percentage of Customers with Claims Cost of Commercial Claim per Day Average Number of Days to Make Safe, Re-Light **Residential Claims Assumptions** Total Residential Customers Impacted Percentage of Customers with Claims Cost of Residential Claim per Day Electric Heater Cost Percentage of Customers with Supplied Heat Average Number of Days to Make Safe, Re-Light **Claims Costs** Commercial/Industrial Claims Residential Claims **TOTAL CLAIMS COSTS**	 1,303 40% $5,000 5 15,373 15% $200 $250 10% 5 $13,029,959 $2,690,276 **$15,720,235**
Claims Costs		**$15,720,235**
Administrative	**ADMINISTRATIVE COSTS** **Administrative Cost Assumptions** Number of Staff Cost per Hour (OT Considered) Hours per Day Number of Days **Administrative Costs** Administrative Costs **TOTAL ADMINISTRATIVE COSTS**	 25 $62 10 10 $155,000 **$155,000**

Administrative Costs		**$155,000**
Temporary Facilities	**TEMPORARY FACILITIES COSTS** **Facilities Assumptions** Rental Trailers, Command Centers, Relief Centers **Facilities Costs** Facilities Costs **TOTAL FACILITIES COSTS**	 $200,000 **$200,000**
Temporary Facilities Costs		**$200,000**
Deferred Work	**DEFERRED MAINTENANCE/SERVICE WORK COST** **Deferred Work Assumptions** Total Hours Worked (Internal/Contractor) Percentage of Deferred Work Made-Up with OT OT Premium **Deferred Work Costs** Deferred Work Costs **TOTAL DEFERRED WORK COSTS**	 6,947 15% $31 $32,303 **$32,303**
Deferred Work Costs		**$32,303**
Contingency Costs (15%)		**$2,899,602**
TOTAL ESTIMATED COST		**$22,230,286**

Figure 1: St. Laurent Pipeline



4. The Project will be constructed in two Phases. Since filing its original Application, Enbridge Gas has refined and adjusted the Project construction schedule to accommodate the delay that resulted from the Ministry of Transportation's (MTO) objections to the original Phase 4 preferred route (PR) and the OEB's subsequent /U