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VIA RESS and EMAIL

January 21, 2022

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 No.: EB-2021-0148
2022 Rates (Phase 2)
Interrogatory Responses and Updated/Corrected Exhibits

In accordance with Procedural Order No. 1 dated November 29, 2021, enclosed please find interrogatory responses from Enbridge Gas in the above noted proceeding.

In accordance with the OEB's revised Practice Direction on Confidential Filings effective December 17,2021, Enbridge Gas is requesting confidential treatment of the following exhibits – details of the specific confidential information for which confidential treatment is sought (all of which fits within the OEB's "presumptively confidential" category) are set out below:

Exhibit	Description of Document	Confidential Information Location	Brief Description	Basis for Confidentiality Claim
Exhibit I.FRPO.15, Attachment 1	Powerpoint Report re. Byron Transmission Station	Page 5	Customer Names	Information that would disclose load profiles, energy usage and billing information of a specific customer that is not personal information.[1]

[1] This is item #3 in the "Categories of Information that Will Presumptively Be Considered Confidential", as found at Appendix B to the OEB's Practice Direction on Confidential Filings, December 17, 2021.

Exhibit I.PP.9, Attachment 1	Gas Distribution Contract between Enbridge Gas and Kirkland Lake Gold Ltd.	Pages 2 and 5	Contribution in Aid of Construction amount and timing	Information that would disclose load profiles, energy usage and billing information of a specific customer that is not personal information.[2]
		Page 9	Termination payments schedule	Information that would disclose load profiles, energy usage and billing information of a specific customer that is not personal information.[3]
		Pages 10, 11 and 12	Contract parameters, including Minimum Annual Volume, Contract Demand and customer-specific rates	Information that would disclose load profiles, energy usage and billing information of a specific customer that is not personal information.[4]

In addition to the interrogatory responses, Enbridge Gas is also filing updates/corrections to the following exhibits:

Exhibit	**Updates /Corrections**
Exhibit B, Tab 2, Schedule 1, pages 22 and 23	Par 35 – Changed 2021 to 2022 Table 10, line 1 – Changes 2021 to 2022
Exhibit B, Tab 2, Schedule 1, pages 32-33 and page 35	Par 57 – the description of the allocator was updated to reflect the assets being installed with the St. Laurent Ottawa North Replacement Phase 3 project.

[2] This is item #3 in the “Categories of Information that Will Presumptively Be Considered Confidential”, as found at Appendix B to the OEB’s Practice Direction on Confidential Filings, December 17, 2021. Note also that the OEB permitted confidential filing of similar information in the EB-2021-0205 Leave to Construct proceeding (Enbridge Gas re. Greenstone Gold Mines).
[3] See note 1.
[4] See note 2.

	Par 65 – the bill impact for a typical residential customer in the EGD rate zone was updated to reflect the revised project allocation.
Exhibit B, Tab 2, Schedule 1, Attachment 1, page 3	Table C Line 1 – Changed 2021 to 2022
Exhibit B, Tab 2, Schedule 1 Appendix F, page 1	The allocator for the St. Laurent Ottawa North Replacement Phase 3 project was updated to the Delivery Demand TP>4" to reflect the assets being installed with the project.
Exhibit B, Tab 2, Schedule 1 Appendix G, page 1	The ICM revenue requirement and unit rates were updated to reflect the allocation changes made to Appendix F.
Exhibit B, Tab 2, Schedule 1 Appendix H	The ICM bill impacts were updated to reflect the allocation changes made to Appendix F.
Exhibit B, Tab 2, Schedule 2, pages 7 and 10	Page 7 - removed abandonment reference for NPS 20 Replacement Cherry to Bathurst Page 10 – removed abandonement reference for Dawn-Cuthbert Replacement and Retrofits

Please contact the undersigned if you have any questions.

Yours truly,

(Original Digitally Signed)

Rakesh Torul
Technical Manager, Regulatory Applications

cc: Intervenors (EB-2021-0148)
David Stevens, Aird and Berlis LLP

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, pp. 28-29 of 35.

Preamble:

Enbridge Gas is seeking ICM funding for three projects that do not require Leave to Construct (LTC) approval from the OEB. The three projects are the Dawn to Cuthbert pipeline (ICM funding request - $23.5 million), Byron Transmission Station Replacement (ICM funding request - $20.4 million) and the Kirkland Lake Lateral Replacement (ICM funding request - $20.7 million).

Question(s):

a) In support of the 2022 ICM funding request, Enbridge Gas has filed an Asset Management Plan (AMP) addendum. The addendum provides an update for the 2022 budget year with respect to the 2020 AMP. Please provide the list of 2022 capital projects that Enbridge Gas considered for deferral, cancellation, or change in scope in order to accommodate the three projects (noted above) within Enbridge Gas's materiality threshold for 2022.

b) Please indicate whether there are any incremental revenues associated with the three non-LTC projects noted above. If yes, please provide the incremental revenue amounts for each of these projects. Please also include any incremental revenue for each of the projects that require LTC.

c) In the event that the OEB does not approve ICM funding for the three non-LTC capital projects, how does Enbridge Gas intend to move forward on these projects?

d) Please outline all capital spending related to synergy/integration projects in 2022 and confirm if they are included in the 2022 capital budget. Please indicate if any 2022 spending related to synergy/integration can be postponed to a later year.

Response:

a) The full list of investments would be considered in order to accommodate the three ICM projects below the materiality threshold. The following investments were reduced or deferred in the Union rate zone.

Investment ID	Investment Name	Reason for deferral/reduction	Amount of in-service capital reduction
502916	Hagar LNG Tank Boil Off Gas Recovery System	Initially considered compliance, work will be deferred until 2024	$8.9M
48757	HAMI: Dunnville Line Reinforcement	Work initially expected to extend to 2022 in-service was brought forward to be completed in 2021	$1.6M
1264	2022 Integrity Dig Program	Specific projects had not been identified to fully use the program spend	$1.5M
1263	2022 Depth of Cover Mitigation Program	Specific projects had not been identified to fully use the program spend	$1.3M
1790	Coniston Lateral Replacement	Project cost reduction identified and reflected in 2022 Budget	$1.1M
2142 & 1795	Sudbury Section 1: Sturgeon River North Side & South Side & River Crossing	Projects combined and deferred to 2023	$1.5M
49166	TIMM: 45-20-500 Hwy 655 NPS 6 HP Reinforcement (~860m) Murphy Rd Phase 1	Deferred to 2023	$1.0M
101371	Hagar Solar 1 Control Panel Upgrade	Defer to 2023	$1.0M
102820	MOP Verification Program S&T	Specific projects had not been identified to fully use the program spend	$1.2M

100774	50 Keil Renovations – Phase 5	Defer to 2024	$2.4M
	Efficiencies and workplan reductions	To be achieved through deferrals and efficiencies	$14.6M

Please note that only projects with a reduction of more than $1M are identified in the table above.

Having gone through this exercise, and recognizing that the asset needs still exceeded the materiality threshold, Enbridge Gas reviewed each Asset Class Program to see if it could be further reduced through efficiencies, work deferrals or other means. Looking across all asset classes this led to a further reduction of $14.6M as noted above.

b) There are no incremental revenues associated with any of the non-LTC or LTC related projects included in this application.

c) Enbridge Gas will consider the OEB's 2022 Rates decision in its entirety in determining the impacts to its capital budget and how it will proceed with the ICM Projects.

d) Capital spending related to synergy/integration projects are not included in the 2022 AMP Addendum and are not part of the 2022 in-service capital for ICM determination.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, pp. 25-26 of 35.

Preamble:

ICM funding requests must be based on discrete, material projects. As defined in the OEB ACM report, “amounts must be based on discrete projects, and should be directly related to the claimed driver. The amount must be clearly outside of the base upon which the rates were derived”.[1] As per the MAADs Decision, any individual project for which ICM funding is sought must have an in-service capital addition of at least $10 million.[2]

Each eligible capital project as identified for the EGD rate zone and Union rate zones in Enbridge Gas’s 2022 ICM application and evidence is a discrete project that exceeds the materiality level of $10 million. However, exceeding the threshold of $10 million does not necessarily imply that all projects over the threshold are eligible for ICM funding. The OEB’s filing requirements for utilities state that minor expenditures in comparison to the overall capital budget should be considered ineligible for ACM or ICM treatment. A certain degree of project expenditure over and above the OEB-defined threshold calculation is expected to be absorbed within the total capital budget.[3]

Question(s):

Please explain why Enbridge Gas considers that the three projects which do not require LTC would not be considered minor expenditures in comparison to the overall capital budget.

[1] EB-2014-0219 Report of the Board New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, p. 17
[2] EB-2017-0306 / EB-2017-0307 Decision and Order, August 30, 2018, pp. 32-33
[3] OEB Filing Requirements for Electricity Distribution Rate Applications, Chapter 3: Incentive Rate-Setting Applications, p. 24

Response:

Enbridge Gas believes that these projects are not minor expenditures. The capital cost of each is more than twice the materiality level that the OEB established for Enbridge Gas in the MAADs decision. These three projects are incremental to a capital need that is already above the materiality threshold. As noted in the response at Exhibit I.STAFF.1 a), Enbridge Gas has taken steps to reduce some areas of spend in 2022, bringing spend forward into 2021, and deferring it to 2023 and beyond. However, the asset needs are significant, and these projects are considered essential for the ongoing safety and reliability of the distribution system. Also, see the response at Exhibit I.EP.4 c).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, Attachment 1, Table D, page 4 of 5.

Preamble:

Enbridge Gas has identified the eligible capital projects and total in-service capital amounts for the ICM funding requests based on the previously OEB-approved capitalization policy.

Question(s):

Please provide overhead amounts, as outlined in Table D (columns 'd' and 'e', "New Harmonized Overhead Capitalization Policy") broken down by year.

Response:

Please find the overhead amounts by year including IDC supporting the 2022 in-service capital for the ICM funding requests:

Project Name	2019	2020	2021	2022
St. Laurent Ottawa North Replacement Phase 3	$113,101	$46,905	$118,195	$15,772,013
NPS 20 Replacement Cherry to Bathurst	$25,692	$197,221	$6,275,666	$17,333,406
Dawn to Cuthbert Replacement and Retrofits			$266,775	$4,127,182
Byron Transmission Station			$3,060,881	$649,947
Kirkland Lake Lateral Replacement			$132,601	$3,733,738

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Appendix A, Page 439 of 471
Dawn-Cuthbert NPS 42 Replacement and Retrofits

Preamble:

A previous ECDA survey completed in 2005 showed that the NPS 42 pipe showed areas of coating disbondment with minor to moderate pitting corrosion with up to 16% wall loss and predicted that further pitting would not exceed a total of 80 mils until year 2025.

Question(s):

a) Please explain the significance of the 80 mil threshold.

b) If corrosion pitting is not expected to exceed a total of 80 mils until year 2025, why does Enbridge Gas believe it must complete this project before that time?

Response:

a) Exhibit B, Tab 2, Schedule 2, Appendix A, page 439 of 471 refers to the predicted depth of external corrosion features in 2025 as calculated by EGI's ECDA vendor in 2005.

b) External corrosion is one of the threats active on the pipeline. The ECDA vendor calculation is based on an opportunistically discovered feature since, due to the presence of shielding pipeline coating, investigative dig site locations cannot reliably predict where the most severe corrosion is likely to occur. However, the known time-dependent threat of SCC is the primary integrity driver of the project, specifically because of the inability to reliably detect the areas with the most severe SCC. See Exhibit B, Tab 2, Schedule 2, Appendix A, pages 5 to 10 of 471.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Appendix A, Page 464 of 471
Dawn-Cuthbert NPS 42 Replacement and Retrofits

Preamble:

Enbridge Gas considered the option of running an Electro Magnetic Acoustic Transducer (EMAT) in-line inspection tool on the NPS 42 Dawn to Cuthbert pipeline to detect SCC and defer replacement of the pipeline until 2031. This option considered the long-term capital and O&M costs resulting from deferring the replacement until 2031 by modifying the pipeline to accept ILI tools, performing periodic EMAT and Magnetic Flux Leakage inspections and subsequent integrity digs.

Question(s):

Please explain the significance of the year 2031. Why could this option not defer pipeline replacement beyond that year?

Response:

2031 represents the year which EGI believes that SCC severity will increase to the point where monitoring and dig programs are required to occur more frequently. The economics of deferring the replacement and completing such programs at the anticipated frequency are less favorable than the preferred option.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Appendix A, Page 470 of 471
Dawn-Cuthbert NPS 42 Replacement and Retrofits

Preamble:

Table 1 provides a summary of the NPV assessment for Option A – Inspect/Maintain & Replace in 2031 and Option B – Replace Now.

Table 1: NPV Analysis Results

$Millions	Option A (Inspect/Maintain, Replace in 2031)	Option B (Replace)
Net Present Value (Life Cycle)	(20.21)	(20.13)

Question(s):

Given that the NPV of both options are approximately equal (less than 0.4% difference), did Enbridge Gas use any additional quantitative analysis (e.g., Profitability Index) to further assess the options? If so, please provide the results of that additional analysis. If not, please explain why not.

Response:

Enbridge Gas did not complete any further quantitative analysis. Profitability Index would only be used as a means of analysis if the investment was expected to generate new revenue through additional services provided. This investment is intended solely to manage the integrity of the pipeline system. Therefore, a NPV analysis was selected as the appropriate means to compare total lifecycle capital and O&M costs associated with each alternative.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Appendix A, Page 471 of 471
Dawn-Cuthbert NPS 42 Replacement and Retrofits

Preamble:

Table 1 provides the estimated project costs. At approximately $10.35 million, Contract Labour is approximately 43% of the total project costs.

Table 1: Estimated Project Costs

Dawn-Cuthbert Project Costs in $	
Internal Labour	180,000
Contract Labour	10,350,000
Third Party Services	3,300,000
Materials	3,600,000
Lands	10,000
Contingency	2,180,000
Project Costs	**19,620,000**
IDC	150,000
Indirect Overheads	4,390,000
Total Project Costs	**24,160,000**

Question(s):

a) Please explain the methodology used by Enbridge Gas to estimate the contract labour costs.

b) Using a summary table like Table 1, please compare the actual costs of three other projects that Enbridge Gas has completed in the last year to the estimated costs for the Dawn-Cuthbert project.

Response:

a) The contract labour cost was internally estimated by subject matter experts and validated with courtesy quotes from third party vendors.

b) There were three short segments of NPS 42 pipe replaced in 2020 as part of the integrity dig program (see response at Exhibit I.VECC.5) but because the segments were very short they are not comparable to the scope of this project.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Appendix B, Pages 1, 5 and 7 of 32
Byron Transmission Station

Preamble:

Enbridge Gas states that the station supplies natural gas to a majority of the London, St. Thomas and Port Stanley systems. As early as 2018, Enbridge Gas identified a number of integrity, safety, reliability, maintenance and operational concerns that supported a rebuild of the Station.

Enbridge Gas states that the heating system has degraded over time and is now only capable of operating at approximately 50% of its original rated output capability. In the event of a heater failure at the Station, Enbridge Gas estimates that there is potential that more than 5,000 customers in the London area alone could be impacted.

Enbridge Gas states that the Station inlet valve is seized in a position that is approximately 90% open due to the deteriorated state of the valve. As such, the Station inlet valve is no longer considered reliable and requires replacement.

Question(s):

a) Please explain why Enbridge Gas's station inspection and maintenance program did not identify and resolve the heating capacity issue before 2018.

b) Please explain why Enbridge Gas's valve inspection and maintenance program did not identify and resolve the inlet valve issue before 2018.

Response:

a) Based on the rating plates these heaters are adequately sized to support the station capacity until 2022. These heaters will not be able to deliver the required heat at design day serving the expected growth in the region beyond 2022 which was identified in 2018.

The inspection of these heaters has been completed following EGI procedures. However, these are combustion assets that are subject to wear and tear over years of operations, and appropriate repairs have been deployed to keep these heaters operational to 2022.

b) The inlet valve issue was identified prior to 2018 during inspections and servicing that identified that it could not be fully operated. It was decided to leave the valve as is until it could be included as part of a larger station rebuild because of the high complexity involved in replacing it. Other valves within the station, or an upstream mainline valve, would be used if there was an emergency requiring the operation of the inlet valve at the station.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Appendix B, Figure 2, Pages 5 of 32
Exhibit B, Tab 2, Schedule 2, Appendix B, Pages 32 of 32
Byron Transmission Station

Preamble:

Enbridge Gas states that an existing 18.5 wide pipeline easement will be “conceded back” to “Softon Developments” and the abandoned pipelines will be removed.

Question(s):

What does the term “conceded back” mean in this context?

Response:

Enbridge Gas had an 18.5m wide easement rights through Sifton Development’s land adjacent to the existing Byron Transmission station for pipelines that had since been taken out of service. As part of the land acquisition agreement with Sifton Development, Enbridge Gas agreed to remove the abandoned pipelines and release the easement rights.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Appendix B, Figure 2, Page 7 of 32
Byron Transmission Station

Preamble:

Due to projected growth in downstream general service markets fed by the Station, in 2018 Enbridge Gas projected that the Station could reach capacity by the end of 2022. Specifically, Enbridge Gas concluded that the regulation system and the heating system at the existing Station would be incapable of meeting system demand projected by winter 2022/23.

Rebuilding the entirety of the station will have added benefit of providing increased certainty for customers' planning purposes. The new station will have adequate capacity to support a minimum of 225,000 m3/hr flow in the future (as compared to its current capacity of 170,000 m3/hr which is limited by heating systems). OEB staff notes that this approximately a 30% increase in station capacity.

Question(s):

a) Please provide a 10-year demand forecast for the downstream general service markets.

b) Please explain how the 10-year forecast was determined, including any key assumptions and the sources of information upon which it was based (e.g., municipal growth plans).

Response:

a) The forecasted customer attachments (residential and Commercial/Industrial) for 2022 to 2031 are provided in the table below for the system primarily downstream of Byron Transmission Station.

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
RES	1,778	1,758	1,734	1,698	1,664	1,587	1,500	1,433	1,354	1,293
COM/IND	98	109	107	104	101	97	92	89	85	83

Also, see the response at Exhibit I.FRPO.15.

b) EGI’s customer additions forecast is developed using an economic and grass roots approach. The economic forecast is developed using the relationship between historical customer additions and housing starts and then further assessed by the regional sales/operation teams and adjusted as needed.

Since the majority of total customer additions consist of residential customer additions (approximately 94%), the economic forecast of total customer additions mostly follows the same trends as the housing market. EGI's consensus housing starts forecast is prepared using housing forecast from various bank/financial institutes and Bank of Canada.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Appendix B, Figure 1, Page 12 of 32
Byron Transmission Station

Preamble:

Figure 1 is a satellite image showing the location of the Byron Transmission Station. OEB staff notes the appearance of residential development encroachment on the station.

Question(s):

a) What was the CSA Z662 class location of the Byron Baseline Road and Wickerson Road at the time that the Byron Transmission Station was constructed? What is the class location now?

b) If there has been a change in the class location, please confirm that the Byron Transmission Station meets the requirements of the current class location.

c) If there has been a change in the class location, when did Enbridge Gas first become aware of the change?

Response:

a - c)

The requirements for class location 1, 2, and 3, are the same. As such EGI treats the class location for all stations equally unless the station is in a class 4 location. Byron Station is not in a class 4 location, and therefore, there has been no change in the class location requirement for Byron station.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Association of Power Producers of Ontario (APPrO)

Interrogatory

References:

Exhibit B, Tab 2, Schedule 2, Appendix A, Page 4 of 471

Preamble:

“Enbridge Gas’s Transmission Integrity Management Program (“TIMP”) periodically evaluates assets to identify hazards and determine the condition and risk of pipelines in the transmission network. An integrity assessment was recently conducted on the NPS 42 Dawn to Cuthbert pipeline as part of the scheduled condition monitoring program. The integrity assessment confirmed that the pipeline coating has degraded, allowing for the formation of time dependent pipeline threats which cannot reliably be detected using condition monitoring methods available on this pipeline. Enbridge Gas has determined that the pipeline condition represents an intolerable risk, to be mitigated through replacement of the 650 m segment of the Dawn to Cuthbert pipeline.”

Question:

a) In the evidence at Attachments 3 to 9 Enbridge Gas filed integrity assessment/inspection reports ranging from August 27, 2001 to March 14, 2021. Please confirm that this is everything Enbridge Gas considers as in the scope of its TIMP evaluation for the NPS 42 Dawn to Cuthbert pipeline. If not confirmed, please file all other evidence that Enbridge Gas does consider as part of its TIMP evaluation.

b) The issues outlined in Attachments 3 to 9, began to be identified in 2005. What changed to make the 650 m segment of the Dawn to Cuthbert pipeline an “intolerable risk” in 2022 but not in prior years?

Response

a) Confirmed.

b) Risk has increased due to the confirmation of the presence of Stress Corrosion Cracking (SCC) via excavations completed in 2019. The assessment methods employed to date for the External Corrosion Direct Assessment (ECDA) are not capable of identifying the areas likely to have the most severe SCC.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Association of Power Producers of Ontario (APPrO)

Interrogatory

References:

Reference 1: Exhibit B, Tab 2, Schedule 2, Appendix A, Page 8 of 471
Reference 2: Exhibit B, Tab 2, Schedule 2, Appendix A, Page 12 of 471
Reference 3: Exhibit B, Tab 2, Schedule 2, Appendix A, Page 6 of 471

Preamble:

Reference 1: "Based on the inspection methodologies used, it could not be determined whether the most severe SCC features have been discovered on the Dawn to Cuthbert segment and as a result, it is imperative that mitigative action be taken to proactively manage this critical asset."

Reference 2: "In addition to the guidance on Integrity Management Programs in CSA Z662, the Canada Energy Pipeline Association ("CEPA") documents guidance for pipeline operators experiencing SCC in the CEPA Recommended Practices for Managing Near-Neutral Stress Corrosion Cracking, 3rd Edition. Depending on the severity of the SCC, various mitigation activities are recommended including, but not limited to, inspecting the pipeline with an ILI tool capable of detecting SCC (e.g. EMAT), restriction of operating pressure, 100% surface nondestructive testing or pipe segment replacement."

Reference 3: "Some downstream segments of the NPS 42 Dawn to Kirkwall portion of the Dawn Parkway System were constructed at the same time and with the same materials as the NPS 42 Dawn to Cuthbert pipeline, including polyken tape coating. These segments have been monitored closely through in-line inspections (ILI), targeted integrity dig programs and engineering analysis to quantify the severity and growth rates of these pipeline threats. The NPS 42 Dawn to Cuthbert pipeline, however, does not currently have ILI tool launching and receiving facilities to permit any ILI tools, including ones capable of detecting Stress Corrosion Cracking (SCC)."

Question:

a) Given the SCC issues spotted in 2019 and corrosion issues spotted in 2005 why was the in-line inspection tool not added to the NPS 42 Dawn to Cuthbert pipeline earlier?

b) What other methodologies are capable of determining whether the most severe SCC features have been discovered on the Dawn to Cuthbert segment?

c) Why was the methodology in response to (b) above not used?

d) Is it Enbridge Gas' approach that any feature of SCC (even if minor) would lead to mitigative action? What other mitigative action(s) would have been contemplated (e.g.ILI) and which ones has Enbridge Gas considered for NPS 42 Dawn to Cuthbert pipeline?

e) In Reference 2, Enbridge Gas mentions that the type of mitigation activities recommended depend on the severity of the SCC, but in Reference 1, it appears that the severity of the SCC could not be determined. Please explain and reconcile.

Response

a) SCC was confirmed from the 2019 pipeline excavations. 2022 is the earliest date this project can be executed given the amount of time required to analyze the findings and develop plans.

b) Methods capable of determining whether the most severe cracks have been discovered are limited to inline inspection technologies detecting cracks and direct examination of the pipe surface. These technologies include EMAT (refer to Exhibit B, Tab 2, Schedule 2, Appendix A, page 6 of 471) and ultrasonic (UTCD) tools. The UTCD tools cannot be used in gaseous environments as it requires a liquid couplant.

   As stated in Exhibit B, Tab 2, Schedule 2, Appendix A, page 12 of 471, par 23, 100% surface non-destructive testing (NDT) is also capable of determining whether the most severe cracks have been discovered. This involves excavation, coating removal, and surface preparation of the pipeline for NDT.

c) Ultrasonic crack detection tools (UTCD) require a liquid couplant and cannot be used in a gaseous environment.

   Performing 100% surface NDT on a segment of this length is not a typical or practical construction methodology due to the time required to perform manual non-destructive examination techniques and associated repairs, which may still result in portions of the pipeline requiring replacement.

d) Per CSA Z662-19 Section 10.3.1, EGI is obligated to "monitor for conditions that can lead to failures, to eliminate or mitigate such conditions, and to manage integrity data." Where pipelines containing SCC can be reliably monitored and managed, such pipelines can remain in service. The inability to reliably monitor the NPS 42 Dawn-Cuthbert pipeline for SCC necessitates elimination or mitigation of the hazard.

EMAT ILI has been considered as a condition monitoring action and is addressed in Exhibit B, Tab 2, Schedule 2, Appendix A, pages 463-471.

e) Please refer to Exhibit B, Tab 2, Schedule 2, Appendix A, page 8 of 471, par 17. The assessment of severity (CEPA categorization) is based on physical examination of the SCC feature during an integrity dig. It cannot be confirmed that the most severe SCC has been discovered because EGI cannot determine such feature locations due to the inability to reliably monitor this pipeline segment for SCC.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Association of Power Producers of Ontario (APPrO)

Interrogatory

References:

Exhibit B, Tab 2, Schedule 2, Appendix A, Page 468 of 471

Preamble:

"Enbridge Gas is planning to construct the Project between June and September 2022, with and in-service date of September 30, 2022. Site restoration would occur between May and July of 2023. See Exhibit B, Schedule 1, Attachment 10 for a detailed Project schedule."

Question:

a) Is the site restoration cost included in the project estimate cost of $24.2 million? If not, what are the costs for site restoration and how will these costs be funded?

Response

a) The cost estimate of $24.2M includes $600k in site restoration or clean up costs which are expected to be spent in 2023. Since these costs will be incurred in the year after the project goes into service, the costs are treated as base capital in 2023 and are not recovered through the ICM mechanism.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Association of Power Producers of Ontario (APPrO)

Interrogatory

References:

Exhibit B, Tab 2, Schedule 2, Appendix A, Page 471 of 471

Preamble:

"The total estimated cost of the Project is $24.2 million as shown in the Table 1 below. This cost includes: (i) materials; (ii) construction and labour; (iii) environmental protection measures; (iv) contingencies; (v) interest during construction ("IDC"); and (vi) indirect overheads.

Table 1: Estimated Project Costs

Dawn-Cuthbert Project Costs in $	
Internal Labour	180,000
Contract Labour	10,350,000
Third Party Services	3,300,000
Materials	3,600,000
Lands	10,000
Contingency	2,180,000
Project Costs	**19,620,000**
IDC	150,000
Indirect Overheads	4,390,000
Total Project Costs	**24,160,000**

The cost estimates set out in Table 1 include an 11.4% contingency applied to all direct capital costs."

Question:

a) How were the contractors and third parties selected to perform the Contract Labour and Third Party Services as listed in Table 1? Did Enbridge Gas run a competitive procurement process for all these services and materials?

b) What type of work is included in "Third Party Services"? Were any of the "Third Party Services" sole sourced? If so, please provide the sole source justification.

c) How was the 11.4% contingency determined?

d) Please list each of the anticipated risks associated with achieving the estimated project cost and describe how each of those risks have been managed to date. Please quantify, if possible, the remaining risks. Does this show the contingency of $2.18 million is sufficient?

e) Are any COVID-19 related costs included in this cost estimate (including incremental material costs or incremental labour costs arising from shortages or delays related to the COVID-19 pandemic)? If not, does Enbridge Gas anticipate any COVID-19 related costs, to be incurred on top of this estimated project cost of $24.2 million?

<u>Response:</u>

a) Sourcing for Contract Labour and Third Party Services will be completed for through the Supply Chain Management department which is governed by stringent internal policies and procedures. Also, see the response at Exhibit I.FRPO.16.

b) Third party services refer to services to support construction, outside of prime contractor. All third party services will be sourced and acquired per Enbridge's Supply Chain sourcing policy.

c) The 11.4% contingency was determined based on the level of certainty of scope and consideration of risks at the time the estimate was created.

d) Risks are continually evaluated and are ever-changing through the lifecycle of the project. The contingency amount of $2.18 million is based on the consideration of risks at the time the estimate was created.

e) Enbridge has COVID-19 procedures and policies in place that contractors are aware of and expected to follow throughout the execution of the project. Based on the current global pandemic conditions, Enbridge Gas does not anticipate any additional COVID-19 costs to be incurred above the estimated project costs.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Association of Power Producers of Ontario (APPrO)

Interrogatory

References:

Reference 1: Exhibit B, Tab 2, Schedule 2, Appendix B, Page 6 of 32
Reference 2: Exhibit B, Tab 2, Schedule 2, Appendix B, Page 8 of 32

Preamble:

Reference 1: "In late 2018, Enbridge Gas conducted a system-wide indirect heater assessment (including size, condition and operation of heater systems) and identified both of the heaters at the Station as Risk Rank 2 (L3 C4). The assessment recommended that the heaters be replaced in 2021."

Reference 2: "In April 2021, the Project ISD was updated to August 31, 2022 due to several factors including: delays in securing site plan approvals and building permits, additional construction scope arising from the site plan consultation process with the City of London, and industry wide material procurement delays largely related to the unprecedented and ongoing COVID-19 pandemic."

Question:

a) Please provide a copy of the system-wide indirect heater assessment.

b) Were there any other heaters, apart from the two heaters at the Station that were at Risk Rank 2

c) The assessment recommended that the heaters be replaced in 2021, but due to delays the project's in-service date was pushed to August 31, 2022. How has the delay impacted the functionality of the heaters.

d) Given that there has been a series of delays, including reasons due to the ongoing COVID-19 pandemic, what is the probability of this project being delayed to 2023?

Response:

a) The indirect heater assessments were done individually. See Attachment 1 for an assessment related to the heaters at Byron Transmission Station. The heater assessments on the other sites are not relevant to this proceeding.

b) Through the indirect heater assessment there are 8 sites with Risk Rank 2 projects. Of these, 4 were replaced in 2019, 2 in 2020, and the last 2 are scheduled to be completed in 2022.

c) Supplemental inspection and maintenance have been conducted on the heaters at both the Byron Transmission and Baseline stations arising from the delay on the in-service date from August 21, 2021 to 2022.

   The delay does not impact the functionality of the heaters because they are adequately sized to support demand through the 2021/2022 winter season. Maintenance of the heaters was completed to ensure optimal combustion efficiency and reduce the likelihood of a combustion equipment failure.

d) Please see the response at Exhibit I.CCC.5.

2019 Byron Trans South Heater Repair Update & Proposed Plan Moving Forward

January 25th, 2019
Stations Engineering

ENBRIDGE

Daniel Blata
Stations Engineering EIT II

ENBRIDGE

Background

Byron Trans currently has two indirect line heaters on site. Both heaters will be replaced at the time of a Byron Trans rebuild by a boiler system with heat exchangers; however, due to the calculated heat required on site, the station requires both heaters to be operational until a full rebuild of Byron Trans is completed (estimated 2020-2021). As a result of the age and performance of the heaters, CIMCO (HVAC contractor) was brought on site through the Aecon help desk to ensure the existing heating equipment was acceptable for use in Ontario and performing at an optimal level.

Work Completed to Date

BYRON TRANS NORTH HEATER REPAIRS – MECHANICAL ISSUES ONLY

This heater was serviced in 2018 by CIMCO and was adjusted so that the heater was in the proper range for combustion. The holes in the bottom of the vent stack were a concern and as such, the stack was replaced prior to the heating season. No additional concerns have been brought up by CIMCO or the site technician regarding the North heater.

BYRON TRANS SOUTH HEATER REPAIRS – MECHANICAL ISSUES ONLY

This heater was inspected by CIMCO in 2018. Upon inspection, it was determined that 1 of the 3 burners was disconnected and a regulator was installed on the fuel gas line to reduce pressure. These modifications were done 10 to 20 years ago and were not well documented; however, it was confirmed that these modifications were completed after discussing this situation with the district as a result of the heater over-firing. The heater received a 'B' infraction based on the fact that modifications were completed to the heater without being approved by TSSA.

In discussion with CIMCO, it was concluded that if the heater was brought back to the original condition and the third burner was connected, the 'B' infraction on the heater would be lifted. In December of 2018, CIMCO connected the third burner; however, they still experienced over-firing and as a result, left the heater in the condition it was in.

On January 17th 2019, CIMCO was called back to get the heater up and running for the colder winter temperatures that were ahead. The details below outline the work that was completed to get the heater operational for the current heating season (2018/2019).

Lock out tag out was completed on the heater and the flame arrestor was removed in order to gain access to the burners.

Figure 1: Flame Arrestor

Figure 2: Three burners connected without throttle valves

The plan to get the heater running was to install a throttling valve on the fuel line to the third burner. This would essentially allow CIMCO to test the heater by turning off the third burner and then allow fuel regulation to the third burner.

Figure 3: Three burners with throttle valve on 3rd burner (OFF)

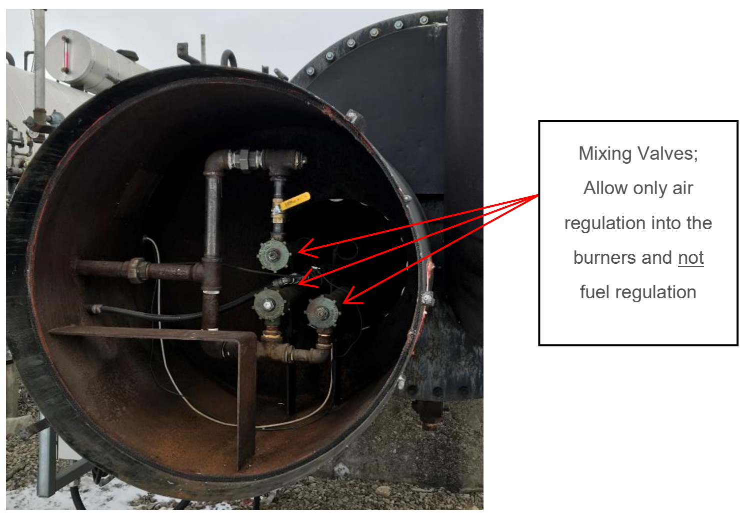

Figure 4: Three burners with valve on 3rd burner throttled

ENBRIDGE

With the throttling valve installed and in the OFF position, the heater was tested and a fairly blue flame was evident after slight adjustment of the mixing valves which could only adjust air into the burner. The pressure during operation at the manifold was determined to be 5 psi with only two burners operational.

Since the flue gas test came back within specification for CO, CIMCO slightly turned the throttling valve on the third burner to a location where it would be just open, minimizing the amount of combustion produced from the third burner. The mixing valve on the third burner was also adjusted to ensure a fairly blue flame. Once CIMCO was satisfied with the flame, testing on the combustion began as now the heater had all 3 burners connected as per original design specifications. The valve handle was removed from the throttling valve to ensure no adjustments were made to it; however, due to code requirements, the valve handle was left within the chamber as it contained all of the certifications.

By calculating the pressure correction factor using pressure at meter inlet, and obtaining the temperature correction factor on the meter along with the uncorrected flow rate, the corrected flow rate was calculated. The corrected flow rate was then used to obtain the heating input (MMBTU) to ensure alignment with designed heating input.

Applying the basic gas laws, the following formula may be used to size a rotary meter:

$$Q_s = Q_d \times F_p \times F_t$$

where:

Q_s = Standard or corrected volume

Q_d = Displaced or uncorrected volume

F_p = Pressure correction factor =

$$\frac{\text{Gauge Pressure + Atmospheric Pressure}}{14.73 \text{ psia}}$$

F_t = Temperature Correction Factor =

$$\frac{520°R}{460°R + \text{Gas Temperature}}$$

The first calculation that was completed with the throttling valve on the third burner at 50% open resulted in a corrected flow rate of 126 m^3/hr, which resulted in an approximate heating input of 4.5 MMBTU. The CO was also tested to be off scale. This essentially meant that the heater was still over-firing with the third burner connected. The only way to reduce heating input was to adjust the fuel input to the burners. A throttling valve could have been installed on each of the burners which would allow CIMCO to adjust the fuel input to each of the burners individually; however, the corrosion on the other two mixing valves was severe and as a result, CIMCO determined that they would rather adjust the fuel to all three burners than to install additional throttling valves on the other two burners.

The fuel supply valve in Figure 5 was throttled to adjust the fuel pressure into the burners until testing showed that CO was within spec and the corrected volume resulted in a heating input of approximately 3 MMBTU. Once CIMCO was confident that the heater could achieve a clean burn at a lowered inlet pressure to the burners, the throttling valve in Figure 5 was fully opened and the PFM regulator feeding the manifold was adjusted to 5 psi so that similar combustion results could be obtained. Ultimately, the heater had to be set up with a PFM set pressure of 4.3 psi which resulted in a manifold pressure of 3.4 psi.

Figure 5: Valve used to throttle pressure to inlet of burners

At these pressures, the corrected flow rate was determined to be 90.9 m^3/hr which results in an input of 3.2 MMBTU, within TSSA specifications. According to TSSA, equipment must be re-approved when fuel input changes are in excess of plus or minus 20%. The original approved rating on the arrestor was listed as 3 MMBTU. Thus, the heater was left over-firing at +6.7%, within TSSA specifications.

All appropriate tests were completed (see Figure 6 below) and within specifications as per CIMCO.

Figure 6: Test Results from Final Combustion Analysis

Way Forward

With modifications to operation pressure detailed above which are below original operating pressure, but within mixing head design, boiler is now deemed safe to use with the burners firing as intended and approximately at the designed firing rate (3.2 MMBTU vs. design of 3 MMBTU). ‘B’ Infraction will be cleared by CIMCO. Work completed by Marc and Dave from CIMCO.

The current set-up will provide adequate heat through the heating season; however, there are still a few outstanding items that should be completed as per CIMCO to ensure optimal performance of this heater:

1) *January 2019* – CIMCO to provide an appliance regulator to fine tune expected gas delivery and reduce pressure losses in piping due to excessive flow rates. This will allow the existing PFM regulator to be set up at its intended pressure of 10 psi and a manifold pressure of 5-10 psi feeding the appliance regulator. **Moving forward with recommendation.**

2) *January 2019* - Order in new mixing valves with fuel adjustment valves and pressure gauges so that manifold pressure can be increased back to original (5 psi). The current mixing valves only allow for intake air adjustment. CIMCO had spoken to Honeywell which had informed them that the lead time may be lengthy; however, they are able to source new mixing valve heads for the burners with an additional valve that can regulate the fuel into each burner. Installation for Spring 2019. **Moving forward with recommendation.**

3) *January 2019* - Order in blank orifices and drill a smaller hole for finer control. The current orifices are over-sized as the heater over-fires at a manifold delivery of 5 psi with all three burners on. The original orifices would have been replaced when the third burner was disconnected to ensure adequate firing and as a result they are now over-sized. Installation for Spring 2019. **Moving forward with recommendation.**

4) *Spring 2019* – Recommendation to bring in TSSA for field approval for the South heater due to poor documentation and discrepancies between control panel and arrestor (heat input of 4.8 MMBTU listed on control panel, 3 MMBTU on arrestor). This will ensure safe and reliable operation until the proposed rebuild is complete. **Not moving forward with recommendation at this time.**

Note – After setting up the 2nd heater, the South heater was made the primary heater to sustain an outlet of 70ºF and the back-up was set to 65 ºF. Because of the reduced pressure into the heater, the noise was significantly reduced which should avoid further noise complaints. Furthermore, by making the South heater the primary heater, heat loss as a result of travelling through a 2nd cold heater which was on standby prior to entering the pipeline is avoided.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Association of Power Producers of Ontario (APPrO)

Interrogatory

References:

Reference 1: Exhibit B, Tab 2, Schedule 1, Page 11 of 35
Reference 2: EB-2020-0095 - Enbridge Gas Inc. 2021 Rates Application

Preamble:

Reference 1:

"DP/TPS Replacements - reclassed from System Renewal $13M and variance in replacement and class location programs due to pacing and scope $5M

Growth – Byron Transmission Station project delayed to 2022 in-service $20M offset by change in reinforcement timing and scope due to changes in the growth forecast ($10M)"

Question:

a) As stated in Reference 1, the Byron Transmission Station project was delayed from 2021. Why did Enbridge Gas not bring an ICM application for the Byron Transmission Station project in its 2021 Rates Application (Reference 2)?

Response:

a) In preparing the 2021 Budget, Enbridge Gas attempted to accommodate all the required capital spend below the materiality threshold for each rate zone. Where this was not feasible, two projects (Sarnia Industrial Line Reinforcement and London Line Replacement Project) were proposed for ICM treatment; all other projects (including Byron Transmission Station) were accommodated below the materiality threshold at that time. In its Decision and Order, the OEB granted ICM treatment only for London Line Replacement Project.[1]

   However, when developing the 2022 Budget, it was not possible to accommodate the Byron Transmission Station below the materiality threshold and it was put forward for ICM treatment. Also, see response at Exhibit I.CCC.3 for an explanation on how Enbridge Gas selects ICM capital projects.

[1] EB-2020-0181, Decision and Order, page 1, dated May 6, 2021.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Association of Power Producers of Ontario (APPrO)

Interrogatory

References:

Exhibit B, Tab 2, Schedule 2, Appendix B, Page 7 of 32

Preamble:

"Due to projected growth in downstream general service markets fed by the Station, in 2018 Enbridge Gas projected that the Station could reach capacity by the end of 2022."

Question:

a) Please update the projection in Reference 1 with the best available information as at the date these interrogatory responses are filed.

b) When is the Station expected to reach capacity using this updated projection?

Response:

a) The projected flow rate in 2022 for the station is approximately 184,300 m3/hr.

b) The station is expected to reach its capacity in 2022.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Association of Power Producers of Ontario (APPrO)

Interrogatory

References:

Reference 1: Exhibit B, Tab 2, Schedule 2, Appendix B, Page 32 of 32
Reference 2: Exhibit C, Tab 2, Schedule 1

Preamble:

Reference 1: "The project cost has increased from the previous estimate reported in the Asset Management Plan. This is largely due to: (i) reclassification of the cost estimate from a Class 5 estimate (based on historical project costs and rangeability of -50% to +100%) to a Class 1 estimate, (ii) increased civil scope based on Site Plan Approval consultations, (iii) increased scope due to land acquisition agreement; and (iv) increased construction labour costs as a result of project construction being spread over two years."

The project cost of the Byron Transmission Station in the Asset Management Plan at Reference 2 was $8.05 million and the project cost in this application is $16.7 million (not including indirect overheads and IDC), which means it has more than doubled because of the identified factors Enbridge Gas identified in Reference 1.

Question:

a) Are any COVID-19 related costs included in this cost estimate (including incremental material costs or incremental labour costs arising from shortages or delays related to the COVID-19 pandemic)? If not, does Enbridge Gas anticipate any COVID-19 related costs, to be incurred on top of this estimated project cost of $20.4 million?

b) What are the risk mitigation measures that Enbridge Gas has implemented to avoid a further significant cost increase like that which is mentioned in the preamble?

Response:

a) COVID-19 related costs have been included in the $ 20.4 million cost estimate and no further additional cost related to COVID-19 is expected at this point.

b) The cost estimate of $16.7 million (not including indirect overheads and IDC) is a Class 1 Estimate which is the forecast/estimate at completion based on ongoing detailed cost tracking and actual invoices.

Based on the current project progress and schedule, Enbridge Gas is currently on track to commission the upgraded Byron Transmission Station in 2022 with minimal risk of significant cost increase. Enbridge Gas has received all necessary permits to proceed with construction, land acquisition has been completed, no further change in scope is anticipated, and most of the material procurement has been received. Also, see response at Exhibit I.APPrO.5 d).

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Association of Power Producers of Ontario (APPrO)

Interrogatory

References:

Exhibit B, Tab 2, Schedule 2, Appendix C, Page 147 of 147

Preamble:

Table 1: Estimated Project Costs

Item No.	Description	Cost
1.0	Material Costs	$1,982,400
2.0	Labour Costs	$7,728,000
3.0	External Permitting, Land	$168,000
4.0	Outside Services	$3,074,400
5.0	Direct Overheads	$487,200
6.0	Contingency Costs	$3,360,000
7.0	**Project Cost**	**$16,800,000**
8.0	Indirect Overheads	$ 3,750,059
9.0	IDC	$116,281
10.0	**Total Project Costs**	**$20,666,340**

"The cost estimates set out in Table 1 include a 25% contingency applied to all direct capital costs to reflect the preliminary design stage of this Project."

Question:

a) What type of work is included in "Outside Services"? If the "Outside Services" are performed by third parties, how are the third parties selected to perform those services? Did Enbridge Gas run a competitive procurement process for these services?

b) Were any of the "Outside Services" sole sourced? If so, please provide the sole source justification.

c) How is the 25% contingency determined?

d) Are any COVID-19 related costs included in this cost estimate? If not, does Enbridge Gas anticipate any COVID-19 related costs, such as costs related to supply chain issues, to be incurred on top of this total estimated project cost of $20.7 million?

Response:

a) Outside Services costs are budgeted to cover all consulting services and other vendor costs that are not related to Construction Contractor costs such as Survey/Topographical studies, Drafting, Environmental Assessment, Environmental Protection, Engineering, Geotechnical, NDE, Regulatory, Hydrostatic Testing and Legal. Enbridge Gas's procurement standard includes guidelines for a competitive procurement process if the total value of services provided exceeds a specified threshold.

b) One outside service was sole sourced that involved brush clearing of Enbridge Gas's existing easement due to proximity and machinery required to complete the job.

c) Contingency is defined as cost added to an estimate to allow for known risks (known unknowns) that are likely to result as refinement of scope is defined. A 25% contingency for Kirkland Lake was chosen which was built as a Class 5 estimate following the EGI System Improvement Cost Estimating and Management Standard.

d) Enbridge has COVID-19 procedures and policies in place that contractors are aware of and expected to follow throughout the execution of the project. Based on the current global pandemic conditions, Enbridge Gas does not anticipate any additional COVID-19 costs to be incurred above the estimated project costs.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Association of Power Producers of Ontario (APPrO)

Interrogatory

References:

EB-2014-0219, Report of the OEB: New Policy Options for Funding of Capital Investments: The Advanced Capital Module, September 18, 2014, Pages 16-17

Preamble:

The *Report of the OEB: New Policy Options for Funding of Capital Investments: The Advanced Capital Module* (ACM Report) states that distributors must meet an OEB-defined materiality threshold and a project-specific materiality threshold. It states:

> "A capital budget will be deemed to be material, and as such reflect eligible projects, if it exceeds the OEB-defined materiality threshold. Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount (as defined in this ACM Report) and must clearly have a significant influence on the operation of the distributor; otherwise, they should be dealt with at rebasing.
>
> Minor expenditures in comparison to the overall capital budget should be considered ineligible for ACM or ICM treatment. A certain degree of project expenditure over and above the OEB-defined threshold calculation is expected to be absorbed within the total capital budget."

Question:

a) Please provide the 2019 to 2022 total capital budget amounts for the combined utility (i.e. both Enbridge Gas Distribution and Union Gas rate zones combined).

b) Please calculate the value of each of the ICM projects that Enbridge Gas is requesting funding for in this 2022 Rates Application as a percentage of the total capital budget identified in (a) above.

c) For each of the ICM projects that Enbridge Gas is requesting funding for in this 2022 Rates Application, please explain why Enbridge Gas believes it meets the OEB's project specific materiality test, as set out in the Reference.

Response:

a) Please refer to the table below for the requested budgeted amounts:

Rate Zone $M	2019	2020	2021	2022
EGD	481.7	517.2	580.3	734.3
UG	527.5	528.3	627.0	543.1
Total	1,009.2	1,045.5	1,207.3	1,277.4

Budget amounts are in-service capital expenditures as presented in EB-2018-0305, EB-2019-0194, EB-2020-0181 and EB-2021-0148 Exhibit B, Tab 2, Schedule 1, Tables 1 & 2.

b) Based on a combined EGI budget of 1,277.4M, the ICM projects have the following % value as a proportion of the total capital budget:

- St. Laurent Ottawa North Replacement (Phase 3) – 6.7%
- NPS 20 Replacement Cherry to Bathurst – 9.9%
- Dawn to Cuthbert Replacement and Retrofits – 1.8%
- Byron Transmission Station – 1.6%
- Kirkland Lake Lateral Replacement – 1.6%

c) As noted in the pre-filed evidence, the proposed ICM projects meet the ICM materiality threshold as well as the project specific materiality. Please see Exhibit B, Tab 2, Schedule 1, paragraphs 21 to 49 for Enbridge Gas evidence on the Materiality threshold test.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. B//T2/S1/p. 3

Question:

Please explain what relief, if any, EGI is seeking from the OEB with respect to the Asset Management Plan Addendum.

Response:

Enbridge Gas is not seeking approval of its Asset Management Plan (AMP) Addendum. Enbridge Gas has filed the AMP Addendum in support of its request for ICM funding as per the OEB ICM policy.[1]

[1] EB-2014-0219 Report of the OEB – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014; EB-2020-0181 (2021 Rates Application – ICM), Procedural Order No. 3, February 5, 2021, page 3.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. B/T2/S1/pp. 4-6

Question:

Please recast Tables 1 and 2 (Capital Expenditures by Category - 2017-2026 – EGD and Union Rate Zones) and include budget amounts for 2017-2020.

Response:

The capital budget for 2017/18 is not readily available based on the asset category as presented in Table 1 and 2. Also, EGI believes that the information requested does not assist the OEB in determining whether the 2022 ICM projects meet the ICM eligible criteria for rate recovery. Please see the restated tables below including the budgets submitted for **2019** (EB-2018-0305, Exhibit B1, Tab 2, Schedule 1, Tables 1 and 2), **2020** (EB-2019-0194, Exhibit B, Tab 2, Schedule 1, Tables 1 and 2) **and 2021** (EB-2020-0181, Exhibit B, Tab 2, Schedule 1, Tables 1 and 2):

Table 1
Capital Expenditures[1] by category (2017-2026)
EGD Rate Zone ($ millions)

Line No.	Category	2017 Actual	2018 Actual	2019 Budget	2020 Budget	2021 Budget
		(a)	(b)	(c)	(d)	(e)
1	General Plant	48.1	47.3	52.4	46.8	102.4
2	System Access[10]	109.3	108.9	111.3	131.4	167.6
3	System Renewal	102.2	92.3	152.3	168.8	259.8
4	System Service	20.2	22.9	23.5	13.4	50.5
5	Total Overhead[11]	148.1	140.2	142.1	156.8	-
6	**Total - EGD Rate Zone**	**427.8**	**411.6**	**481.7**	**517.2**	**580.3**

Line No.	Category	2022 Budget	2023 Budget	2024 Budget	2025 Budget	2026 Budget
		(f)	(g)	(h)	(i)	(j)
1	General Plant	81.0	141.7	92.1	99.0	125.5
2	System Access[2]	151.9	169.5	201.0	168.1	173.6
3	System Renewal	465.3	460.5	313.6	288.3	342.0
4	System Service	36.1	42.0	68.5	107.4	45.4
5	Total Overhead[3]	-	-	-	-	-
6	**Total - EGD Rate Zone**	**734.3**	**813.7**	**675.2**	**662.8**	**686.6**

Table 2

[1] Capital expenditure shown for 2017-2018, In-Service for 2019-2026.
[2] System access capital does not include Community Expansion and Compressed Natural Gas.
[3] Overheads included with projects costs for 2021-2026.

Capital Expenditures[4] by category (2017-2026)
Union Rate Zones ($ millions)

Line No.	Category	2017 Actual	2018 Actual	2019 Budget	2020 Budget	2021 Budget
		(a)	(b)	(c)	(d)	(e)
1	General Plant	42.8	48.0	55.2	52.0	55.6
2	System Access[13]	96.2	83.5	107.9	86.9	150.7
3	System Renewal	94.1	99.4	97.5	206.9	327.6
4	System Service	405.8	201.2	184.6	106.1	93.1
5	Total Overhead[14]	78.6	81.0	82.5	76.4	-
6	**Total - Union Rate Zones**	**717.5**	**513.1**	**527.5**	**528.3**	**627.0**

Line No.	Category	2022 Budget	2023 Budget	2024 Budget	2025 Budget	2026 Budget
		(f)	(g)	(h)	(i)	(j)
1	General Plant	70.1	84.0	49.8	56.9	56.1
2	System Access[5]	120.6	213.2	126.5	123.0	128.3
3	System Renewal	200.6	169.9	303.9	451.2	361.6
4	System Service	151.8	245.9	155.5	372.8	252.4
5	Total Overhead[6]	-	-	-	-	-
6	**Total - Union Rate Zones**	**543.1**	**713.0**	**635.7**	**1,003.8**	**798.3**

[4] Capital expenditure shown for 2017-2018, In-Service for 2019-2026.
[13] System access capital does not include Community Expansion and Compressed Natural Gas.
[6] Overheads included with projects costs for 2021-2026.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. B/T2/S1/p. 24

Question:

Please explain how EGI selected the eligible ICM capital projects included in this Application. Please indicate if any projects were deemed ineligible and why?

Response:

If, in developing a capital budget, EGI is unable to meet the needs of the system within the materiality threshold, attempts are first made to defer or pace spend (Please see response at Exhibit I.STAFF.1 a) and I.SEC.5)). If after that, the budget still exceeds the materiality threshold for the rate zone, ICM treatment is considered for projects that meet the requirements outlined in the MAADs decision and the OEB ICM policy. These requirements are described in the pre-filed evidence at Exhibit B, Tab 2, Schedule 1, Section 2 beginning on page 16. As described in the evidence and its appendices, it is Enbridge Gas's view that these projects meet these requirements.

In each rate zone there are hundreds of projects that make up the full capital budget (see interrogatory response at Exhibit I.EP.3 d) and Exhibit I.EP.4 d)).

Projects that have significant impact on the operation of the business and that also meet the OEB ICM eligibility criteria (materiality and discrete project criteria) are selected for ICM treatment. EGI tries to accommodate all projects including projects that are ICM eligible below the ICM materiality threshold.

In the EGD rate zone, EGI was able to accommodate all projects except the two proposed ICM projects below the ICM threshold. Although some of the projects meet the project specific materiality threshold of $10 million and have significant impact on the operation of the distribution system, EGI was able to accommodate them below the materiality threshold, and were therefore deemed not eligible for ICM treatment. Similarly, in the Union rate zones, certain projects that have significant impact on the operation of the transmission and distribution business were deemed not eligible for ICM treatment as they did not meet the project specific materiality of $10 million. As shown in the pre-filed evidence at Exhibit B, Tab 2, Schedule 1, Table 10, the maximum eligible incremental capital in the Union rate zone is $87.6 million. EGI is requesting ICM funding for only $64.6 million, which is $23 million less than the maximum eligible incremental capital.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. B/T2/S1/p. 28

Question:

Please indicate when EGI identified the need to replace approximately 650 m of the existing NPS 42 Dawn to Cuthbert pipeline. Please identify any factors that might put the September 2022 in-service date at risk. Why does EGI require a 2022 in-service date?

Response:

The decision to proceed with replacing approximately 650 m of the existing NPS 42 Dawn to Cuthbert was made in October 2020.

There are no high impact risks currently identified on the project that would jeopardize the September in service date. The on-going global supply chain delays are continuously monitored by the project team and have the potential to delay the project.

An in-service date of 2022 is required to minimize risk associated with the unmonitored hazard of SCC.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. B/T2/S1/p. 28

Question:

Please indicate when EGI identified the need to rebuild the Byron Transmission Station located in Byron Ontario. Please identify any factors that might put the August 31, 2022 in-service date at risk. Why does EGI require a 2022 in-service date?

Response:

Please see interrogatory response at Exhibit I.ED.12 a).

Based on the current project progress and schedule, Enbridge Gas is on track to commission the upgraded Byron Transmission Station in 2022. Factors that could impact the expected in-service date of August 31, 2022 would include certain factors beyond EGI's control. Some potential risk factors include impacts resulting from severe weather, material lead time delays, permitting delays, and potential COVID-19 impacts. The risks to a delayed in-service date are low because the project schedule includes sufficient buffer to meet the 2022 heating season that typically begins in October.

As stated in the business case for the Byron project[1], a complete rebuild of the Byron Transmission Station was required in 2021 but delayed to 2022 to address:

a) Integrity concerns discovered as part of the Company's indirect heater assessment. The assessment recommended that both heaters on Byron Transmission Station be replaced in 2021.
b) Noise concerns raised by complainants in Q4 2018 and confirmed by the Company's Acoustical Measurement reports in Q4 2018 and Q1 2019 that Byron Transmission Station exceeded the Ministry of Environment, Conservation, and Parks noise limit. Enbridge Gas is obligated to address these concerns as soon as reasonably feasible under Environmental Compliance Approval #4459-BJGQQY.
c) Maintenance and operations concern regarding equipment spacing and integrity concerns associated with Station inlet valves; and
d) Inability of the existing Station to support the long term demands of the London market beyond 2022.

[1] Exhibit B, Tab 2, Schedule 2, Appendix B, Page 5 to 8.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. B/T2/S1/p. 29

Question:

Please indicate when EGI identified the need to replace the existing NPS 4 Kirkland Lake Lateral. Please identify any factors that might put the November 2022 in-service date at risk. Why does EGI require a 2022 in-service date?

Response:

The need to replace the lateral was identified in April 2021. Factors that could put the November 2022 in-service date at risk would include severe weather, material lead time delays, permitting delays and potential COVID-19 impacts to the workforce. EGI requires a November 2022 in-service date to remove the pressure restriction which has been placed on the pipeline prior to the 2022/23 Operating Season.

A new contract customer has an in-service date of November 1st, 2022. The NPS 4 and NPS 8 lines must be able to operate together at a common pressure to meet all peak day demand scenarios. The lines currently cannot be operated together, due to the pressure restriction on the NPS 4.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Consumers Council of Canada (CCC)

Interrogatory

Reference:

Ex. B/T2/S1/p. 1 and p. 30

Question:

EGI is requesting ICM funding that results in a total revenue requirement for 2022 of $10.8 million. EGI received approval of ICM funding in 2019, 2020 and 2021. For each of those years please set out the following:

a) The amount of ICM funding approved for each project;
b) The associated revenue requirement impact of each project;
c) The actual capital expenditures;
d) The projected in-service date for each project; and
e) The actual in-service date for each project.

Response:

Note that the total revenue requirement in the question above of $10.8M does not represent the 2022 revenue requirement but rather the total revenue requirement of the projects until the end of the deferred rebasing period. The response below also reflects the total revenue requirements by project. Also, the actual capital expenditure provided below are actuals up to December 31, 2020. Financial results have not been finalized for 2021 at this time and are not available.

In 2019 Rates (EB-2018-0305), EGI requested approval for 4 ICM projects including Kingsville Reinforcement, Stratford Reinforcement, Don River Replacement and Sudbury Replacement. Approval was received for Kingsville and Stratford projects:

Kingsville Reinforcement
Approved ICM Funding = $118.183M
Total Revenue Requirement = $36.908M[1]
Actual Capital Expenditures = $91.2M
Projected ISD = November 2019
Actual ISD = October 24, 2019

[1] EB-2018-0305, September 30, 2019, Exhibit M1, Tab 1, Appendix B, p. 1, line 16, columns (a) – (e).

Stratford Reinforcement
Approved ICM Funding = $1.800M
Total Revenue Requirement = $0.550M[2]
Actual Capital Expenditures = $25.1M
Projected ISD = November 2019
Actual ISD = September 14, 2019

In 2020 Rates (EB-2019-0194), EGI requested approval for 2 ICM projects including Don River Replacement and Windsor Line Replacement. Approval was received for both projects:

Don River Replacement
Approved ICM Funding = $30.047M
Total Revenue Requirement = $8.191M[3]
Actual Capital Expenditures = $30.2M
Projected ISD = May 2020
Actual ISD = April 21, 2020

Windsor Line Replacement

Approved ICM Funding = $82.900M
Total Revenue Requirement = $22.230M[4]
Actual Capital Expenditures = $41.6M
Projected ISD = November 2020
Actual ISD = September 10, 2021

In 2021 Rates (EB-2020-0181), EGI requested approval for 3 ICM projects including St. Laurent NPS 12 Replacement, London Line Replacement and Sarnia Industrial Line Reinforcement. Approval was received for the London Line project:

London Line Replacement

Approved ICM Funding = $124.039M
Total Revenue Requirement = $19.358M[5]
Actual Capital Expenditures = $7.6M
Projected ISD = December 2021
Actual ISD = December 10, 2021

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[2] EB-2018-0305, September 30, 2019, Exhibit M1, Tab 1, Appendix B, p. 2, line 16, columns (a) – (e).
[3] EB-2019-0194, May 25, 2020, Exhibit B, Tab 2, Schedule 1, Appendix E, p. 1, line 16, columns (a) – (d).
[4] EB-2019-0194, May 25, 2020, Exhibit B, Tab 2, Schedule 1, Appendix E, p. 2, line 16, columns (a) – (d).
[5] EB-2020-0181, May 18, 2021, Exhibit B, Tab 2, Schedule 1, Appendix E, p. 1, line 16, columns (a) – (c).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters (CME)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, page 26 of 35

At page 26, EGI stated that the projects it seeks ICM funding for includes phase 3 of the St. Laurent Ottawa North Replacement.

In a letter dated February 10, 2021 for EB-2020-0181, EGI withdrew its request for phase 3 funding of the St. Laurent Ottawa North Replacement and stated that it would seek funding for both phase 3 and phase 4 of the project in the 2022 ICM application.

Question:

a) Please describe what has changed with the St. Laurent Ottawa North Replacement project which has caused EGI not to request phase 4 funding in this proceeding.

b) CME's understanding from EGI's February 10, 2021 letter was that EGI withdrew its request for funding for only phase 3 of the project to address the Board's concern regarding considering phase 3 from phase 4 funding. Please provide EGI's reasoning for only requesting phase 3 funding in this application.

Response

a- b)

Since filing its original Application for phases 3 and 4 of the St. Laurent Ottawa North Replacement Project (filed March 2, 2021), Enbridge Gas has refined and adjusted the Project construction schedule to accommodate the delay that resulted from the MTO's objections to the Phase 4 Preferred Route ("PR") and the OEB's subsequent decision to place the original Application into abeyance[1]. Accordingly, the Updated Application (filed September 10, 2021) reflected the new phase 4 PR as well as a reclassification of pipeline segments between phases 3 and 4. Phase 3 segments have an in-service date of December 2022 and phase 4 segments have an in-service date of December 2023.[2] Therefore, Enbridge Gas has proposed to recover the phase 3 costs as part of its incremental capital funding request for 2022 and will propose to recover phase 4 costs as part of its incremental capital funding request for 2023.[3]

[1] The OEB filed a letter on May 5, 2021, indicating the original Application would be placed in abeyance until receipt of further notification from Enbridge Gas on the status of issues raised by the MTO.
[2] EB-2020-0293, Exhibit D, Tab 1, Schedule 1, p. 9.
[3] See response to OEB Staff interrogatories at EB-2020-0293, December 13, 2021, Exhibit I.STAFF.9.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers & Exporters (CME)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, page 2 of 14.

At page 2 and onwards, EGI provides the business case summaries for ICM projects by ratezone. In its business cases for the St. Laurent Ottawa North Replacement and the NPS 20 Replacement Cherry to Bathurst describe potential repair options that were considered.

Question:

a) With respect to the repair alternatives for these two projects, did EGI quantify the costs of repair, including the associated advantages of spreading capital expenditures over multiple years, and the associated disadvantages of integrity digs and other concerns?

b) If the answer to a) is yes, please provide EGI's estimated cost for the repair option for these two projects.

c) How does EGI weigh quantifiable aspects of repair versus replace decisions (total cost and timing of costs) against more difficult to quantify attributes of a solution, such as disruption to traffic or constructing pipeline to modern standards?

Response

a - c)

The St Laurent Ottawa North Replacement (Phase 3) and the NPS 20 Replacement Cherry to Bathurst projects in the EGD rate zone are subject to Leave to Construct applications. The St Laurent Ottawa North Replacement project (Phase 3) is currently a live proceeding where the need and prudence for the project is being addressed. In its letter dated December 10, 2021, the OEB indicated that given the St. Laurent Ottawa North Replacement Project (Phase 3) is currently subject to a leave to construct application where the issues of need and prudence are being addressed, these issues are not in scope in this proceeding.

The NPS 20 Replacement Cherry to Bathurst was subject to a leave to construct application, where the need and prudence of the project was addressed. This project was approved by the OEB on December 17, 2020.

EGI provided an estimate of the costs of repair alternatives in each project’s LTC application.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, Page 31

Question:

a) Please provide an expanded version of table 12 showing all years until the revenue requirement is $0. Please also add rows showing (i) Enbridge's overall revenue requirement for each year and (ii) the revenue requirement from the ICM request as a percent of the total. If the values in future years are uncertain, please make and state assumptions and caveats as needed.

b) Please propose program design details regarding issues such as: (i) the method and timing of determining program results for the purposes of determining shareholder incentives, (ii) the method of attributing measured gas savings to those arising from the program and those arising from external factors, and (iii) the appropriate duration of customer engagement and results measurement.

c) If Enbridge were to adopt Enerlife's recommendation beginning in 2023, please discuss a reasonable program ramp-up by way of budget envelopes for each year from 2023 to 2027.

Response

a) Please see Attachment 1. For simplicity, Enbridge Gas has provided individual project revenue requirements until the year 2050. There will still be some continuing revenue requirement after that date. All assumptions remain unchanged from the current OEB approved. Enbridge Gas's overall revenue requirement for each year is unavailable.

b - c)

These questions are not relevant to the relief being sought in this application. There are no programs proposed in this application.

Line No.	Particulars ($000's)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
	EGD Rate Zone														
1	St. Laurent Ottawa North Replacement Phase 3	(4,594)	7,440	7,385	7,325	7,260	7,190	7,115	7,036	6,953	6,866	6,775	6,681	6,584	6,483
2	NPS 20 Replacement Cherry toBathurst	(4,953)	11,102	11,012	10,914	10,808	10,695	10,575	10,449	10,316	10,178	10,035	9,886	9,733	9,576
	Union South Rate Zone														
3	Dawn to Cuthert Replacement and Retrofits	(1,034)	2,024	2,043	2,056	2,062	2,064	2,061	2,053	2,043	2,028	2,012	1,992	1,970	1,947
4	Byron Transmission Station	(1,896)	1,473	1,616	1,721	1,796	1,847	1,880	1,897	1,901	1,896	1,883	1,864	1,840	1,811
	Union North Rate Zone														
5	Kirkland Lake Lateral Replacement	(936)	2,199	2,169	2,137	2,104	2,069	2,034	1,997	1,960	1,921	1,882	1,842	1,801	1,759
6	Total Incremental Revenue Requirement	(13,412)	24,238	24,225	24,153	24,030	23,865	23,664	23,432	23,172	22,889	22,586	22,265	21,927	21,576

Line No.	Particulars ($000's)	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
	EGD Rate Zone															
1	St. Laurent Ottawa North Replacement Phase 3	6,380	6,274	6,166	6,055	5,942	5,827	5,710	5,592	5,471	5,349	5,226	5,100	4,974	4,846	4,718
2	NPS 20 Replacement Cherry toBathurst	9,414	9,248	9,079	8,907	8,731	8,552	8,370	8,185	7,998	7,809	7,617	7,423	7,228	7,030	6,831
	Union South Rate Zone															
3	Dawn to Cuthert Replacement and Retrofits	1,921	1,894	1,866	1,836	1,805	1,773	1,740	1,706	1,672	1,636	1,601	1,564	1,527	1,490	1,452
4	Byron Transmission Station	1,780	1,746	1,710	1,672	1,633	1,593	1,552	1,510	1,468	1,425	1,382	1,339	1,296	1,252	1,208
	Union North Rate Zone															
5	Kirkland Lake Lateral Replacement	1,717	1,674	1,630	1,586	1,542	1,496	1,451	1,405	1,358	1,311	1,264	1,216	1,169	1,120	1,072
6	Total Incremental Revenue Requirement	21,212	20,836	20,451	20,056	19,652	19,241	18,823	18,398	17,967	17,531	17,090	16,644	16,194	15,739	15,281

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Appendix A, Page 469

Question:

a) Please provide the complete tables used to calculate the NPV assessment of alternatives for the Dawn-Cuthbert project (including DCF tables or equivalent).

b) Please complete the following table:

	2022	…	Final year	Total
Option A - Repair				
ILI inspection costs				
MFL inspection costs				
Integrity digs				
Pipeline replacement cost				
Other (please describe)				
Total				
Option B - Replace				
ILI inspection costs				
MFL inspection costs				
Integrity digs				
Pipeline replacement cost				
Other (please describe)				
Total				

c) Do the NPV values include abandonment costs? If not, please (i) provide revised NPV values including abandonment costs, (ii) provide updated DCF tables including abandonment costs, and (iii) provide an updated version of the table in (b) including the abandonment costs.

d) Please reproduce table 1 on page 471 with an additional column reconciling these figures with the amounts included in the $20.13 million NPV figure on the previous page.

e) For each cost in table 1 on page 471 that is not included in the NPV calculations, please explain why that decision was made.

f) Please recalculate the NPV figures for option A and B with a time horizon that ends in 2050. Please provide all underlying calculations.

g) Please provide a

Response

a) Please see Attachments 1 and 2.

b) Please see Attachment 3.

c) Yes, abandonment costs have been included.

d) Please see table below:

Dawn-Cuthbert Project Costs in $	Table 1	NPV Analysis	Variance	
Internal Labour	180,000			
Contract Labour	10,350,000			
Third Party Services Materials	3,300,000			
Materials	3,600,000			
Lands	10,000			
Contingency	2,180,000			
Project Costs	**19,620,000**	**19,619,000**	**(1,000)**	i
IDC	150,000	133,000	(17,000)	ii
Indirect Overheads	4,390,000	-	(4,390,000)	iii
Total Project Costs	**24,160,000**	**19,752,000**	**(4,408,000)**	
Abandonment Costs	-	1,530,000	1,530,000	iv
Period 22 & 32 Integrity Digs	-	907,000	907,000	v
Total	**24,160,000**	**22,189,000**	**(1,971,000)**	vi

Notes:

i. Difference due to rounding.
ii. Minor difference due to timing of estimates.
iii. Indirect overheads are not included in the NPV analysis.
iv. Abandonment costs are not included in Table 1: Estimated Project Costs but are included in the NPV analysis.
v. Capital costs related to integrity digs in periods 22 and 32 are not included in Table 1: Estimated Project Costs but are included in the NPV analysis.
vi. Total capital costs of $22,189,000 included in the NPV analysis as seen in Attachment 2.

e) Enbridge Gas has not included indirect overhead costs in the NPV analysis as per OEB established Discounted Cash Flow methodology.

f) The NPV of the options with a time horizon ending in 2050 is $(19.92) million for Option A and $(19.78) million for Option B. Please see Attachments 4 and 5.

g) EGI is unable to respond to this incomplete question.

DCF Analysis

Dawn-Cuthbert Project
Option A - Inspect/Maintain, Replace 2031
InService Date: Nov-01-2022

	Project Year ($000's)	Project Total	0	1	2	3	4	5	6	7	8	9	10
1	**Operating Cash Flow**												
	Revenue	-	-	-	-	-	-	-	-	-	-	-	-
	Expenses:												
	O & M Expense	(2,312)	-	(800)	-	-	-	-	(866)	-	-	-	-
	Municipal Tax	(12,395)	-	(98)	(110)	(112)	(113)	(115)	(117)	(132)	(134)	(136)	(288)
	Income Tax	3,933	-	273	30	30	30	31	260	35	35	36	76
	Net Operating Cash Flow	(10,774)	-	(626)	(80)	(82)	(83)	(85)	(722)	(97)	(98)	(100)	(212)
2	**Capital**												
	Incremental Capital	(26,047)	(768)	(9,064)	(1,176)	-	-	-	-	(1,214)	-	-	(13,326)
	Change in Working Capital	-	-	(40)	40	-	-	-	(44)	44	-	-	-
	Total Capital	(26,047)	(768)	(9,105)	(1,136)	-	-	-	(44)	(1,171)	-	-	(13,326)
3	**CCA Tax Shield**												
	CCA Tax Shield	6,513	-	309	218	188	173	159	147	148	149	137	486
	Net Present Value												
	PV of Operating Cash Flow	(3,780)	-	(584)	(71)	(70)	(68)	(65)	(534)	(68)	(66)	(64)	(130)
	PV of Capital	(19,843)	(768)	(8,690)	(1,034)	-	-	-	(33)	(845)	-	-	(8,360)
	PV of CCA Tax Shield	3,415	-	288	194	160	141	123	108	104	100	88	298
	Total NPV by Year	(20,208)	(768)	(8,986)	(911)	90	73	58	(458)	(809)	34	24	(8,192)

Project NPV **(20,208)**

DCF Analysis

Dawn-Cuthbert Project
Option A - Inspect/Maintain, Replace 2031
InService Date: Nov-01-2022

Project Year ($000's)	Project Total	11	12	13	14	15	16	17	18	19	20
Operating Cash Flow											
Revenue	-	-	-	-	-	-	-	-	-	-	-
Expenses:											
O & M Expense	(2,312)	-	-	-	-	-	-	-	-	-	-
Municipal Tax	(12,395)	(292)	(297)	(301)	(305)	(310)	(315)	(319)	(324)	(329)	(334)
Income Tax	3,933	77	79	80	81	82	83	85	86	87	89
Net Operating Cash Flow	(10,774)	(215)	(218)	(221)	(225)	(228)	(231)	(235)	(238)	(242)	(245)
Capital											
Incremental Capital	(26,047)	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	-	-	-	-	-	-	-	-	-	-	-
Total Capital	(26,047)	-	-	-	-	-	-	-	-	-	-
CCA Tax Shield											
CCA Tax Shield	6,513	588	323	297	273	251	231	213	196	180	166
Net Present Value											
PV of Operating Cash Flow	(3,780)	(126)	(122)	(118)	(114)	(111)	(107)	(104)	(101)	(97)	(94)
PV of Capital	(19,843)	-	-	-	-	-	-	-	-	-	-
PV of CCA Tax Shield	3,415	344	180	158	139	122	107	94	83	73	64
Total NPV by Year	(20,208)	218	58	40	25	11	(0)	(10)	(18)	(25)	(31)

Project NPV	**(20,208)**

DCF Analysis

Dawn-Cuthbert Project
Option A - Inspect/Maintain, Replace 2031
InService Date: Nov-01-2022

Project Year ($000's)	Project Total	21	22	23	24	25	26	27	28	29	30
Operating Cash Flow											
Revenue	-	-	-	-	-	-	-	-	-	-	-
Expenses:											
O & M Expense	(2,312)	(291)	-	-	-	-	-	-	-	-	-
Municipal Tax	(12,395)	(339)	(344)	(349)	(355)	(360)	(365)	(371)	(376)	(382)	(388)
Income Tax	3,933	167	91	93	94	95	97	98	100	101	103
Net Operating Cash Flow	(10,774)	(463)	(253)	(257)	(261)	(264)	(268)	(272)	(277)	(281)	(285)
Capital											
Incremental Capital	(26,047)	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	-	(15)	15	-	-	-	-	-	-	-	-
Total Capital	(26,047)	(15)	15	-	-	-	-	-	-	-	-
CCA Tax Shield											
CCA Tax Shield	6,513	152	140	129	119	109	100	92	85	78	72
Net Present Value											
PV of Operating Cash Flow	(3,780)	(170)	(89)	(86)	(83)	(81)	(78)	(76)	(73)	(71)	(69)
PV of Capital	(19,843)	(6)	5	-	-	-	-	-	-	-	-
PV of CCA Tax Shield	3,415	56	49	43	38	33	29	26	23	20	17
Total NPV by Year	(20,208)	(120)	(34)	(43)	(45)	(47)	(49)	(50)	(51)	(51)	(51)

Project NPV	**(20,208)**

DCF Analysis

Dawn-Cuthbert Project
Option A - Inspect/Maintain, Replace 2031
InService Date: Nov-01-2022

Project Year ($000's)	Project Total	31	32	33	34	35	36	37	38	39	40
Operating Cash Flow											
Revenue	-	-	-	-	-	-	-	-	-	-	-
Expenses:											
O & M Expense	(2,312)	(355)	-	-	-	-	-	-	-	-	-
Municipal Tax	(12,395)	(393)	(407)	(413)	(419)	(426)	(432)	(439)	(445)	(452)	(459)
Income Tax	3,933	198	108	110	111	113	115	116	118	120	122
Net Operating Cash Flow	(10,774)	(550)	(299)	(304)	(308)	(313)	(318)	(322)	(327)	(332)	(337)
Capital											
Incremental Capital	(26,047)	-	(498)	-	-	-	-	-	-	-	-
Change in Working Capital	-	(18)	18	-	-	-	-	-	-	-	-
Total Capital	(26,047)	(18)	(480)	-	-	-	-	-	-	-	-
CCA Tax Shield											
CCA Tax Shield	6,513	66	66	66	61	56	52	47	44	40	107
Net Present Value											
PV of Operating Cash Flow	(3,780)	(127)	(66)	(64)	(62)	(60)	(58)	(56)	(54)	(53)	(21)
PV of Capital	(19,843)	(4)	(108)	-	-	-	-	-	-	-	-
PV of CCA Tax Shield	3,415	15	15	14	12	11	9	8	7	6	16
Total NPV by Year	(20,208)	(116)	(159)	(50)	(50)	(49)	(49)	(48)	(47)	(46)	(5)

Project NPV	**(20,208)**

DCF Analysis

Dawn-Cuthbert Project
Option B - Replace
InService Date: Nov-01-2022

	Project Year ($000's)	Project Total	0	1	2	3	4	5	6	7	8	9	10
1	**Operating Cash Flow**												
	Revenue	-	-	-	-	-	-	-	-	-	-	-	-
	Expenses:												
	O & M Expense	(886)	-	-	-	-	-	-	-	-	-	-	-
	Municipal Tax	(11,571)	-	(208)	(213)	(216)	(219)	(223)	(226)	(229)	(233)	(236)	(240)
	Income Tax	3,336	-	90	57	57	58	59	60	61	62	63	64
	Net Operating Cash Flow	(9,120)	-	(118)	(156)	(159)	(161)	(164)	(166)	(169)	(171)	(174)	(176)
2	**Capital**												
	Incremental Capital	(22,189)	(1,440)	(19,334)	(508)	-	-	-	-	-	-	-	-
	Change in Working Capital	-	-	-	-	-	-	-	-	-	-	-	-
	Total Capital	(22,189)	(1,440)	(19,334)	(508)	-	-	-	-	-	-	-	-
3	**CCA Tax Shield**												
	CCA Tax Shield	5,623	-	1,013	373	337	310	286	263	242	222	205	188
	Net Present Value												
	PV of Operating Cash Flow	(3,163)	-	(110)	(138)	(135)	(131)	(127)	(123)	(119)	(115)	(111)	(108)
	PV of Capital	(20,616)	(1,440)	(18,454)	(463)	-	-	-	-	-	-	-	-
	PV of CCA Tax Shield	3,653	-	945	332	287	252	221	194	170	150	131	115
	Total NPV by Year	(20,127)	(1,440)	(17,619)	(269)	152	121	94	71	52	35	20	7

Project NPV **(20,127)**

DCF Analysis

Dawn-Cuthbert Project
Option B - Replace
InService Date: Nov-01-2022

Project Year ($000's)	Project Total	11	12	13	14	15	16	17	18	19	20
Operating Cash Flow											
Revenue	-	-	-	-	-	-	-	-	-	-	-
Expenses:											
O & M Expense	(886)	(239)	-	-	-	-	-	-	-	-	-
Municipal Tax	(11,571)	(243)	(247)	(251)	(254)	(258)	(262)	(266)	(270)	(274)	(278)
Income Tax	3,336	128	65	66	67	68	69	71	72	73	74
Net Operating Cash Flow	(9,120)	(355)	(182)	(184)	(187)	(190)	(193)	(196)	(198)	(201)	(204)
Capital											
Incremental Capital	(22,189)	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	-	(12)	12	-	-	-	-	-	-	-	-
Total Capital	(22,189)	(12)	12	-	-	-	-	-	-	-	-
CCA Tax Shield											
CCA Tax Shield	5,623	173	159	147	135	124	114	105	97	89	82
Net Present Value											
PV of Operating Cash Flow	(3,163)	(207)	(101)	(98)	(95)	(92)	(89)	(86)	(84)	(81)	(79)
PV of Capital	(20,616)	(7)	7	-	-	-	-	-	-	-	-
PV of CCA Tax Shield	3,653	101	89	78	69	60	53	46	41	36	31
Total NPV by Year	(20,127)	(113)	(5)	(20)	(27)	(32)	(36)	(40)	(43)	(45)	(47)

Project NPV	**(20,127)**

DCF Analysis

Dawn-Cuthbert Project
Option B - Replace
InService Date: Nov-01-2022

Project Year ($000's)	Project Total	21	22	23	24	25	26	27	28	29	30
Operating Cash Flow											
Revenue	-	-	-	-	-	-	-	-	-	-	-
Expenses:											
O & M Expense	(886)	(291)	-	-	-	-	-	-	-	-	-
Municipal Tax	(11,571)	(282)	(292)	(297)	(301)	(305)	(310)	(315)	(319)	(324)	(329)
Income Tax	3,336	152	77	79	80	81	82	83	85	86	87
Net Operating Cash Flow	(9,120)	(422)	(215)	(218)	(221)	(225)	(228)	(231)	(235)	(238)	(242)
Capital											
Incremental Capital	(22,189)	-	(409)	-	-	-	-	-	-	-	-
Change in Working Capital	-	(15)	15	-	-	-	-	-	-	-	-
Total Capital	(22,189)	(15)	(394)	-	-	-	-	-	-	-	-
CCA Tax Shield											
CCA Tax Shield	5,623	75	74	72	66	61	56	52	47	44	40
Net Present Value											
PV of Operating Cash Flow	(3,163)	(155)	(75)	(73)	(71)	(68)	(66)	(64)	(62)	(60)	(58)
PV of Capital	(20,616)	(6)	(141)	-	-	-	-	-	-	-	-
PV of CCA Tax Shield	3,653	28	26	24	21	19	16	14	13	11	10
Total NPV by Year	(20,127)	(133)	(191)	(49)	(49)	(50)	(50)	(50)	(50)	(49)	(49)

Project NPV	**(20,127)**

DCF Analysis
Dawn-Cuthbert Project
Option B - Replace
InService Date: Nov-01-2022

Project Year ($000's)	Project Total	31	32	33	34	35	36	37	38	39	40
Operating Cash Flow											
Revenue	-	-	-	-	-	-	-	-	-	-	-
Expenses:											
O & M Expense	(886)	(355)	-	-	-	-	-	-	-	-	-
Municipal Tax	(11,571)	(334)	(347)	(352)	(357)	(363)	(368)	(374)	(379)	(385)	(391)
Income Tax	3,336	183	92	93	95	96	98	99	100	102	104
Net Operating Cash Flow	(9,120)	(507)	(255)	(259)	(263)	(267)	(271)	(275)	(279)	(283)	(287)
Capital											
Incremental Capital	(22,189)	-	(498)	-	-	-	-	-	-	-	-
Change in Working Capital	-	(18)	18	-	-	-	-	-	-	-	-
Total Capital	(22,189)	(18)	(480)	-	-	-	-	-	-	-	-
CCA Tax Shield											
CCA Tax Shield	5,623	37	39	41	38	35	32	30	27	25	67
Net Present Value											
PV of Operating Cash Flow	(3,163)	(117)	(56)	(54)	(53)	(51)	(49)	(48)	(46)	(45)	(25)
PV of Capital	(20,616)	(4)	(108)	-	-	-	-	-	-	-	-
PV of CCA Tax Shield	3,653	9	9	9	8	7	6	5	5	4	10
Total NPV by Year	(20,127)	(112)	(155)	(46)	(45)	(44)	(43)	(43)	(42)	(41)	(15)

Project NPV **(20,127)**

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Option A - Repair											
ILI inspection costs		800,000					865,946				
MFL inspection costs											
Integrity digs			1,100,000					1,214,489			
Pipeline replacement cost	767,882	9,064,324	75,952								13,326,350
Other (Municipal and Income Taxes)		(482,762)	(138,284)	(106,272)	(89,968)	(74,852)	(290,302)	(51,059)	(50,654)	(37,270)	(274,226)
Total	767,882	9,381,562	1,037,668	(106,272)	(89,968)	(74,852)	575,644	1,163,430	(50,654)	(37,270)	13,052,124
Option B - Replace											
ILI inspection costs											
MFL inspection costs											
Integrity digs											
Pipeline replacement cost	1,439,897	19,334,268	507,904								
Other (Municipal and Income Taxes)		(895,033)	(217,121)	(178,709)	(149,329)	(122,073)	(96,769)	(73,255)	(51,386)	(31,026)	(12,052)
Total	1,439,897	18,439,235	290,783	(178,709)	(149,329)	(122,073)	(96,769)	(73,255)	(51,386)	(31,026)	(12,052)

	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Option A - Repair										
ILI inspection costs										
MFL inspection costs										
Integrity digs										
Pipeline replacement cost										
Other (Municipal and Income Taxes)	(373,451)	(104,688)	(75,610)	(48,547)	(23,334)	182	22,142	42,674	61,898	79,924
Total	(373,451)	(104,688)	(75,610)	(48,547)	(23,334)	182	22,142	42,674	61,898	79,924
Option B - Replace										
ILI inspection costs										
MFL inspection costs	239,019									
Integrity digs										
Pipeline replacement cost										
Other (Municipal and Income Taxes)	(57,688)	22,191	37,662	52,153	65,748	78,522	90,544	101,880	112,587	122,720
Total	181,331	22,191	37,662	52,153	65,748	78,522	90,544	101,880	112,587	122,720

	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
Option A - Repair										
ILI inspection costs										
MFL inspection costs	291,362									
Integrity digs										
Pipeline replacement cost										
Other (Municipal and Income Taxes)	19,642	112,777	127,782	141,947	155,345	168,042	180,100	191,577	202,523	212,988
Total	311,004	112,777	127,782	141,947	155,345	168,042	180,100	191,577	202,523	212,988
Option B - Replace										
ILI inspection costs										
MFL inspection costs	291,362									
Integrity digs		408,636								
Pipeline replacement cost										
Other (Municipal and Income Taxes)	55,119	141,176	145,949	154,978	163,595	171,838	179,742	187,338	194,656	201,723
Total	346,481	549,812	145,949	154,978	163,595	171,838	179,742	187,338	194,656	201,723

	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	Total
Option A - Repair											
ILI inspection costs											1,665,946
MFL inspection costs	355,169										646,531
Integrity digs		498,124									2,812,613
Pipeline replacement cost											23,234,508
Other (Municipal and Income Taxes)	128,896	233,089	237,591	247,438	256,931	266,103	274,988	283,614	292,010	300,200	2,019,124
Total	484,065	731,213	237,591	247,438	256,931	266,103	274,988	283,614	292,010	300,200	30,378,722
Option B - Replace											
ILI inspection costs											-
MFL inspection costs	355,169										885,550
Integrity digs		498,124									906,760
Pipeline replacement cost											21,282,069
Other (Municipal and Income Taxes)	114,444	215,645	217,331	224,525	231,512	238,315	244,953	251,446	257,811	264,063	2,655,725
Total	469,613	713,769	217,331	224,525	231,512	238,315	244,953	251,446	257,811	264,063	25,730,104

DCF Analysis

Dawn-Cuthbert Project
Option A - Horizon = 2050
InService Date: Nov-01-2022

	Project Year ($000's)	Project Total	0	1	2	3	4	5	6	7	8	9	10
1	**Operating Cash Flow**												
	Revenue	-	-	-	-	-	-	-	-	-	-	-	-
	Expenses:												
	O & M Expense	(1,957)	-	(800)	-	-	-	-	(866)	-	-	-	-
	Municipal Tax	(7,722)	-	(98)	(110)	(112)	(113)	(115)	(117)	(132)	(134)	(136)	(288)
	Income Tax	2,600	-	273	30	30	30	31	260	35	35	36	76
	Net Operating Cash Flow	(7,079)	-	(626)	(80)	(82)	(83)	(85)	(722)	(97)	(98)	(100)	(212)
2	**Capital**												
	Incremental Capital	(25,549)	(768)	(9,064)	(1,176)	-	-	-	-	(1,214)	-	-	(13,326)
	Change in Working Capital	-	-	(40)	40	-	-	-	(44)	44	-	-	-
	Total Capital	(25,549)	(768)	(9,105)	(1,136)	-	-	-	(44)	(1,171)	-	-	(13,326)
3	**CCA Tax Shield**												
	CCA Tax Shield	5,985	-	309	218	188	173	159	147	148	149	137	486
	Net Present Value												
	PV of Operating Cash Flow	(3,514)	-	(584)	(71)	(70)	(68)	(65)	(534)	(68)	(66)	(64)	(130)
	PV of Capital	(19,731)	(768)	(8,690)	(1,034)	-	-	-	(33)	(845)	-	-	(8,360)
	PV of CCA Tax Shield	3,322	-	288	194	160	141	123	108	104	100	88	298
	Total NPV by Year	(19,924)	(768)	(8,986)	(911)	90	73	58	(458)	(809)	34	24	(8,192)

Project NPV **(19,924)**

DCF Analysis
Dawn-Cuthbert Project
Option A - Horizon = 2050
InService Date: Nov-01-2022

Project Year ($000's)	Project Total	11	12	13	14	15	16	17	18	19	20
Operating Cash Flow											
Revenue	-	-	-	-	-	-	-	-	-	-	-
Expenses:											
O & M Expense	(1,957)	-	-	-	-	-	-	-	-	-	-
Municipal Tax	(7,722)	(292)	(297)	(301)	(305)	(310)	(315)	(319)	(324)	(329)	(334)
Income Tax	2,600	77	79	80	81	82	83	85	86	87	89
Net Operating Cash Flow	(7,079)	(215)	(218)	(221)	(225)	(228)	(231)	(235)	(238)	(242)	(245)
Capital											
Incremental Capital	(25,549)	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	-	-	-	-	-	-	-	-	-	-	-
Total Capital	(25,549)	-	-	-	-	-	-	-	-	-	-
CCA Tax Shield											
CCA Tax Shield	5,985	588	323	297	273	251	231	213	196	180	166
Net Present Value											
PV of Operating Cash Flow	(3,514)	(126)	(122)	(118)	(114)	(111)	(107)	(104)	(101)	(97)	(94)
PV of Capital	(19,731)	-	-	-	-	-	-	-	-	-	-
PV of CCA Tax Shield	3,322	344	180	158	139	122	107	94	83	73	64
Total NPV by Year	(19,924)	218	58	40	25	11	(0)	(10)	(18)	(25)	(31)

Project NPV	**(19,924)**

DCF Analysis

Dawn-Cuthbert Project
Option A - Horizon = 2050
InService Date: Nov-01-2022

Project Year ($000's)	Project Total	21	22	23	24	25	26	27	28	29
Operating Cash Flow										
Revenue	-	-	-	-	-	-	-	-	-	-
Expenses:										
O & M Expense	(1,957)	(291)	-	-	-	-	-	-	-	-
Municipal Tax	(7,722)	(339)	(344)	(349)	(355)	(360)	(365)	(371)	(376)	(382)
Income Tax	2,600	167	91	93	94	95	97	98	100	101
Net Operating Cash Flow	(7,079)	(463)	(253)	(257)	(261)	(264)	(268)	(272)	(277)	(281)
Capital										
Incremental Capital	(25,549)	-	-	-	-	-	-	-	-	-
Change in Working Capital	-	(15)	15	-	-	-	-	-	-	-
Total Capital	(25,549)	(15)	15	-	-	-	-	-	-	-
CCA Tax Shield										
CCA Tax Shield	5,985	152	140	129	119	109	100	92	85	227
Net Present Value										
PV of Operating Cash Flow	(3,514)	(170)	(89)	(86)	(83)	(81)	(78)	(76)	(73)	34
PV of Capital	(19,731)	(6)	5	-	-	-	-	-	-	-
PV of CCA Tax Shield	3,322	56	49	43	38	33	29	26	23	57
Total NPV by Year	(19,924)	(120)	(34)	(43)	(45)	(47)	(49)	(50)	(51)	91

Project NPV	**(19,924)**

DCF Analysis

Dawn-Cuthbert Project
Option B - Horizon = 2050
InService Date: Nov-01-2022

	Project Year ($000's)	Project Total	0	1	2	3	4	5	6	7	8	9	10
1	**Operating Cash Flow**												
	Revenue	-	-	-	-	-	-	-	-	-	-	-	-
	Expenses:												
	O & M Expense	(530)	-	-	-	-	-	-	-	-	-	-	-
	Municipal Tax	(7,593)	-	(208)	(213)	(216)	(219)	(223)	(226)	(229)	(233)	(236)	(240)
	Income Tax	2,188	-	90	57	57	58	59	60	61	62	63	64
	Net Operating Cash Flow	(5,935)	-	(118)	(156)	(159)	(161)	(164)	(166)	(169)	(171)	(174)	(176)
2	**Capital**												
	Incremental Capital	(21,691)	(1,440)	(19,334)	(508)	-	-	-	-	-	-	-	-
	Change in Working Capital	-	-	-	-	-	-	-	-	-	-	-	-
	Total Capital	(21,691)	(1,440)	(19,334)	(508)	-	-	-	-	-	-	-	-
3	**CCA Tax Shield**												
	CCA Tax Shield	5,294	-	1,013	373	337	310	286	263	242	222	205	188
	Net Present Value												
	PV of Operating Cash Flow	(2,867)	-	(110)	(138)	(135)	(131)	(127)	(123)	(119)	(115)	(111)	(108)
	PV of Capital	(20,504)	(1,440)	(18,454)	(463)	-	-	-	-	-	-	-	-
	PV of CCA Tax Shield	3,594	-	945	332	287	252	221	194	170	150	131	115
	Total NPV by Year	(19,776)	(1,440)	(17,619)	(269)	152	121	94	71	52	35	20	7

Project NPV	**(19,776)**

DCF Analysis
Dawn-Cuthbert Project
Option B - Horizon = 2050
InService Date: Nov-01-2022

Project Year ($000's)	Project Total	11	12	13	14	15	16	17	18	19	20
Operating Cash Flow											
Revenue	-	-	-	-	-	-	-	-	-	-	-
Expenses:											
O & M Expense	(530)	(239)	-	-	-	-	-	-	-	-	-
Municipal Tax	(7,593)	(243)	(247)	(251)	(254)	(258)	(262)	(266)	(270)	(274)	(278)
Income Tax	2,188	128	65	66	67	68	69	71	72	73	74
Net Operating Cash Flow	(5,935)	(355)	(182)	(184)	(187)	(190)	(193)	(196)	(198)	(201)	(204)
Capital											
Incremental Capital	(21,691)	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	-	(12)	12	-	-	-	-	-	-	-	-
Total Capital	(21,691)	(12)	12	-	-	-	-	-	-	-	-
CCA Tax Shield											
CCA Tax Shield	5,294	173	159	147	135	124	114	105	97	89	82
Net Present Value											
PV of Operating Cash Flow	(2,867)	(207)	(101)	(98)	(95)	(92)	(89)	(86)	(84)	(81)	(79)
PV of Capital	(20,504)	(7)	7	-	-	-	-	-	-	-	-
PV of CCA Tax Shield	3,594	101	89	78	69	60	53	46	41	36	31
Total NPV by Year	(19,776)	(113)	(5)	(20)	(27)	(32)	(36)	(40)	(43)	(45)	(47)

Project NPV **(19,776)**

DCF Analysis
Dawn-Cuthbert Project
Option B - Horizon = 2050
InService Date: Nov-01-2022

Project Year ($000's)	Project Total	21	22	23	24	25	26	27	28	29
Operating Cash Flow										
Revenue	-	-	-	-	-	-	-	-	-	-
Expenses:										
O & M Expense	(530)	(291)	-	-	-	-	-	-	-	-
Municipal Tax	(7,593)	(282)	(292)	(297)	(301)	(305)	(310)	(315)	(319)	(324)
Income Tax	2,188	152	77	79	80	81	82	83	85	86
Net Operating Cash Flow	(5,935)	(422)	(215)	(218)	(221)	(225)	(228)	(231)	(235)	(238)
Capital										
Incremental Capital	(21,691)	-	(409)	-	-	-	-	-	-	-
Change in Working Capital	-	(15)	15	-	-	-	-	-	-	-
Total Capital	(21,691)	(15)	(394)	-	-	-	-	-	-	-
CCA Tax Shield										
CCA Tax Shield	5,294	75	74	72	66	61	56	52	47	127
Net Present Value										
PV of Operating Cash Flow	(2,867)	(155)	(75)	(73)	(71)	(68)	(66)	(64)	(62)	(2)
PV of Capital	(20,504)	(6)	(141)	-	-	-	-	-	-	-
PV of CCA Tax Shield	3,594	28	26	24	21	19	16	14	13	32
Total NPV by Year	(19,776)	(133)	(191)	(49)	(49)	(50)	(50)	(50)	(50)	30

Project NPV **(19,776)**

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Appendix A, Page 469

Question:

a) If the OEB were to direct Enbridge to select Option A, when would Enbridge conduct its first EMAT ILI inspection

b) If the OEB were to direct Enbridge to select Option A, would the repair costs incurred by Enbridge be added to the revenue requirement at rebasing or would they need to be covered by existing rates? Please explain.

c) Please explain in detail why this project cannot wait for rebasing.

d) Please provide a table showing the date of each inspection of the station and a bullet point summary of the findings. Please file the reports containing the conclusions of these inspection.

Response

a) EGI is not seeking OEB approval of which option to pursue to address pipeline integrity concerns for the NPS 42 Dawn to Cuthbert pipeline in this application. However, if EMAT ILI was selected as the preferred option, the first EMAT ILI inspection would be completed the year following the completion of modifications required to perform the in-line inspection, in accordance with typical retrofit project execution time frames. It is anticipated that this would be 2023.

b) As indicated in part a), EGI is not seeking OEB approval to construct the pipeline. If option A was selected, the repair costs would be included as part of the total costs in the revenue requirement at rebasing.

c) As detailed in Exhibit B, Tab 2, Schedule 2, Appendix A, pages 10 and 11, the consequence associated with a failure of the NPS 42 Dawn-Cuthbert would create significant disruption to EGI's in-franchise and ex-franchise customers. The inability to reliably monitor the NPS 42 Dawn-Cuthbert pipeline for SCC (stress corrosion cracking) creates an intolerable risk for EGI. Therefore, the risk needs to be managed prior to rebasing.

d) EGI does not believe that this question has any relevance to this proceeding. The condition of stations connected to the NPS 42 Dawn-Cuthbert pipeline do not contribute to the need for the project.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Appendix A, Page 469

Question:

a) Approximately when will replacement costs for the proposed pipelines be fully depreciated? Please make and state all assumptions and caveats as necessary.

b) How much of the cost of the pipeline replacement will likely remain undepreciated by (i) 2040 and (ii) 2050? Please make and state all assumptions and caveats as necessary.

c) Please confirm the percentage of Ontario's annual greenhouse gas emissions that are attributable to natural gas combustion.

d) Please estimate the probability (%) that electric heat pumps will be a significantly less expensive method to heat most buildings compared to natural gas (e.g. due to carbon pricing, improved equipment, etc.) in: (i) 2030, (ii) 2040, and (iii) 2050. Please provide a specific percentage with any caveats as necessary.

e) Please estimate the probability that portion of gas pipeline will be required by 2050. Please provide a specific percentage with any caveats as necessary.

f) Is Enbridge willing to bear any of the risk that the proposed infrastructure will be underutilized or stranded by 2050? If no, why not? If yes, what portion?

Response

a) The current OEB approved depreciation rate for transmission pipelines in the Union rate zone is 1.98%. The replacement costs for the proposed pipelines should therefore be fully depreciated in 51 years assuming no changes to depreciation rates.

b) (i) Approximately 64% of the cost of the pipeline replacement will remain undepreciated by 2040 assuming no changes to the current OEB approved depreciation rate of 1.98%.

2040 – 2022 = 18 years
18 years x 1.98% = 36% depreciated
100% - 36% = 64% undepreciated

(ii) Approximately 45% of the cost of the pipeline replacement will remain undepreciated by 2050 assuming no changes to the current OEB approved depreciation rate of 1.98%

2050 – 2022 = 28 years
28 years x 1.98% = 55% depreciated
100% - 55% = 45% undepreciated

c - d)

These questions are out of scope to the relief being sought in this proceeding and do not assist the OEB in determining whether the ICM project meet the ICM criteria for rate recovery.

e) Enbridge Gas believes that the pipeline will remain used and useful over its life.

f) These issues exceed the scope of this proceeding. However, in an effort to be as responsive as possible the Company provides a limited response to ED's question below. No, as the supplier of last resort, the Company is not proposing to bear any incremental risk associated with fulfilling its obligation to serve the firm contractual needs of ratepayers on a design day, while also ensuring the safety and/or reliability of its employees, facilities, and the public.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Appendix A, Page 469

Question:

a) Is the repair option (option A) sufficient to meet the standards set out in CSA Z662? If not, please explain in detail and provide the section numbers and excerpts of all relevant portions of CSA Z662.

b) Please attach excerpts from all asset management plans addressing this pipeline.

c) When did Enbridge first decide that the pipelines at issue in this application had to be replaced? How have the safety and reliability issues been addressed operationally since that time?

Response

a) Confirmed the repair option (Option A) is sufficient to meet these standards.

b) In the 2021-5 Asset Management Plan (EB-2020-0181, Exhibit C, Tab 2, Schedule 1) the need for facilities to support inline inspection of the parallel lines running from the Dawn facilities to Cuthbert Road was identified. The investment summary is included as Attachment 1 to this response which provides the investment of $24.6M and an in-service date of 2022.

The following excerpt appears within the body of that Asset Management Plan.

Section 5.5.8.2 p. 207*: The section of NPS 26, NPS 34 and NPS 42 pipelines leaving Dawn toward the Cuthbert station (one kilometre away) cannot be inspected using in-line inspection (ILI). The current technique for inspecting these sections is external corrosion direct assessment (ECDA) which provides important information when no other option is available. However, to thoroughly inspect these pipelines, ILI is internally accepted as the required level of diligence for direct assessment of >30% SMYS pipe.*

Section 5.5.8.3, p. 208*: Any gas release of a >30% SMYS pipeline can result in significant risk to public safety and may require a substantial emergency response and temporary shutdown. The Dawn-Cuthbert pipeline segments are highly critical assets which carry a significant portion of the capacity on the Dawn Parkway System. The absence of inline inspection data creates challenges in appropriately managing the risk of these highly critical pipeline segments.*

Section 5.5.8.4, p. 208*: Three sections of pipe (NPS 26, NPS 34 and NPS 42) each 800 metres in length, located between the Dawn facility and the Cuthbert metering station, cannot be inspected using ILI tools. This project will involve installing ILI launchers and receivers within the Dawn facility and performing existing line retrofits to remove restrictive fitting or pipe configurations, which will allow for the pipeline segments to be in-line inspected with a targeted in-service date of late summer 2022.*

As the project was developed, the decision was made to replace the NPS 42 pipeline and retrofit the NPS 34 and NPS 26 pipelines with launchers and receivers.

The Asset Management Plan addendum filed as part of this proceeding (Exhibit B, Tab 2, Schedule 3, pages. 14, 17, 18) identifies a 2022 forecast of $22.0M (including overheads) for the replacement of the NPS 42 pipeline alone. With the scope change for the NPS 42 to include full replacement, the investments on the NPS 42, NPS 34, and NPS 26 were separated within the Asset Management Plan.

c) Analysis on the alternatives began towards the end of 2019, leading to a recommendation to pursue the project (in consideration of the alternatives) in December 2020. Please see Attachment 2 to this response. Further engineering review and analysis led to the direct capital cost of $19.6M which is reflected in the Business Case for this project (Exhibit B,Tab 2, Schedule 2, Appendix A).

SCC opportunistically discovered to date falls into CEPA Category I. Per *CEPA Recommended Practices for Managing Near-neutral pH Stress Corrosion Cracking, 3rd edition*, no mitigative actions are recommended, however condition monitoring is required. NPV analysis determined that pipeline replacement is economically favorable compared to condition monitoring.

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Investment Summary Report

Investment Code	Report Start Year	Number of Years
48257	2021	5

Investment Name

INTE: Dawn - Cuthbert - ECDA to ILI Retrofit NPS 42, 34, 26

Investment Description

Issue/Concern:
General concern: The Integrity Management Program is a mandated regulatory requirement which has been designed to comply with all applicable codes and standards. The program consists of the regular assessment and maintenance of the integrity of EGI's pipeline systems to ensure their continued safety and reliability. Most of the expenditure included in this category is for pipelines that operate above 30 per cent SMYS. It includes installation costs for permanent in-line inspection (ILI) tool launcher and receiver facilities, retrofits to existing lines to remove restrictive fittings or pipe configurations so they can be inspected with ILI tools, repair and replacement of pipeline segments with integrity issues that are identified through the inspections.

Project-specific concern: The NPS 42, NPS 34, NPS 26 pipelines between Dawn Compressor station and Cuthbert Road receiver site has been inspected using external corrosion direct assessment (ECDA). Although it meets the intent of the TIMP, there are specific features that ECDA could not detect comparing to the inline inspection. ILI of these transmission lines are required to ensure continued safety and reliability of EGI's assets.

Assets: Transmission Pipeline (NPS 42, NPS 34, NPS 26 pipelines between Dawn Compressor station and Cuthbert Road receiver site)

Related Programs: Transmission Integrity Management Program (TIMP)

Recommended Alternative Description

Scope of Work: This project involves the replacement and conversion of transmission pipelines, so that they can be inline inspected between Trafalgar Valve Nest (TVN) at Dawn and the Cuthbert Measurement site.

Solution Impact: This project will enable the transmission pipelines between Dawn and Cuthbert to be in-line inspected to assess their condition.

Resources: Projects group to provide project management support from design and planning phase to project execution

Project Timing and Execution Risks: The projected in-service date for this project is in 2022.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Transmission Pipe & Underground Storage- Integrity
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_53 - Union South Storage
	Asset Program (EGI)	TPS - Integrity
	Asset Class (EGI)	Transmission Pipe & Underground Storage
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	Required as per CSA Z662. (Sections 3.2, 10.3) and stipulated through EGD standards as listed in Integrity Manual Section 4.2.6.1.10 In-Line Inspection Re-Inspection Interval.
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
Option 1	Recommended	$ (21,559,122)	0.00	$ 24,600,000	1/1/202 1

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 1,000,000	$ 23,600,000	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended

Value Function Measure	Value	Value in Percentage
Total Investment Cost (CA)	(21,559)	100%
Total	**(21,559)**	**100%**

Dawn to Cuthbert Pipelines – Integrity Program

Risk Decision & Recommended Solution

December 3, 2020

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Meeting Agenda

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Agenda Item	**Time Allotted** Minutes	**Purpose** Inform, Input, Decide	**Decision Roles** RAPIDs, as applicable	**Speaker**	**Pre-read** Y/N
Safety Moment	5	Inform		Ryan	N
Meeting Objectives	5	Inform		Erik	Y
Overview of the Issue	5	Inform		Ryan	Y
Review Key Decision and RAPID, Risk Treatment Recommendation	15	Decide	A – Wes D - Shawn	Ryan	Y

Meeting Objectives

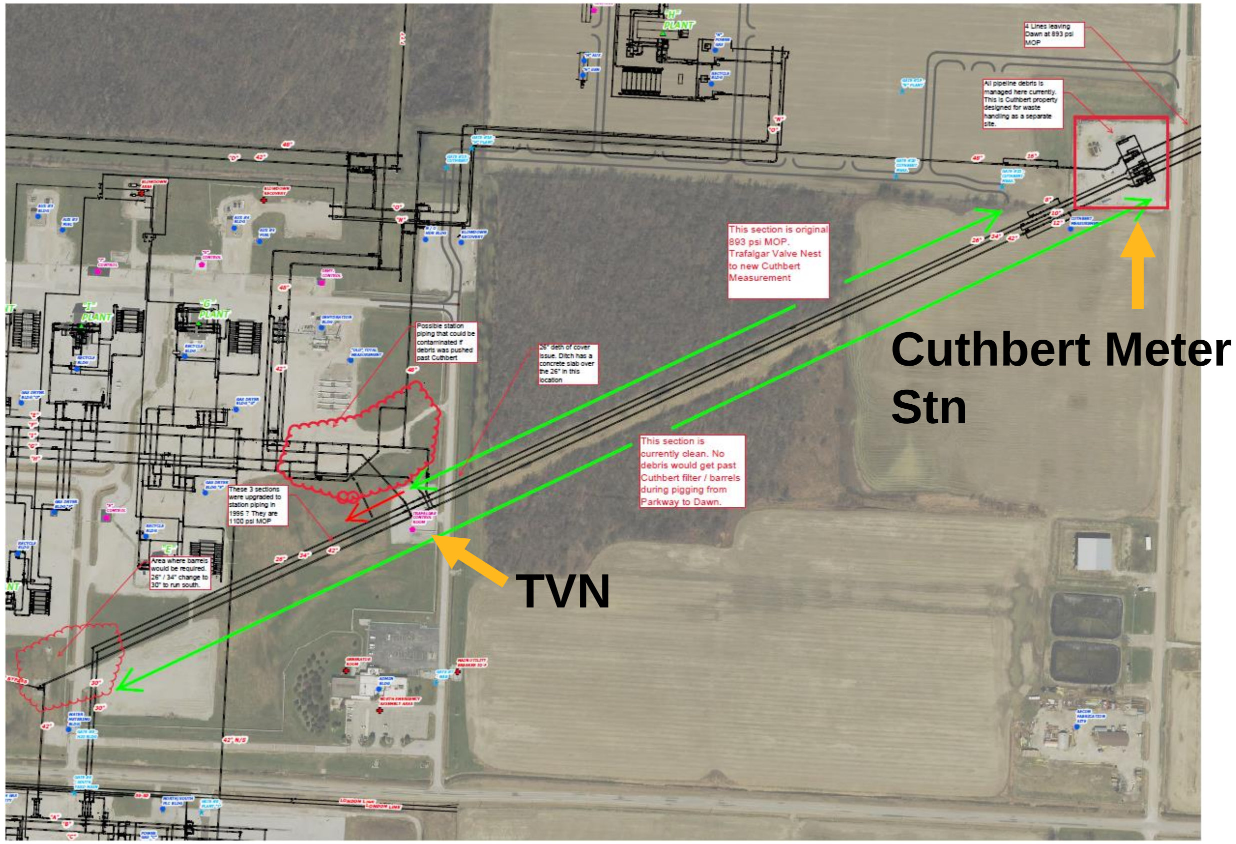
- Discuss the Risk Decision & RAPID
- Review the alternatives & the recommended option for risk treatment

Overview

Dawn to Cuthbert Pipelines: NPS 42, NPS 26, & NPS 34

- The three pipelines between Trafalgar Valve Nest (TVN) and the Cuthbert Meter Station were traditionally inspected using ECDA.
- The rest of the Dawn-Parkway Transmission System are inspected using ILI. Generally the ILI tools travel westerly and exit at Cuthbert.
- Stress Corrosion Cracking (SCC) issues identified on the NPS 42 pipelines, specifically the segments installed in the 1970s where Polyken wrapping tape coating was applied.
- ECDA could not detect SCC features.

Pipeline	Age	Grade	Wall thickness (in)	Stress level @893 PSI
NPS 26 Dawn to Cuthbert	1957	X52	0.31	72% SMYS
NPS 34 Dawn to Cuthbert	1964	X52	0.41	71% SMYS
NSP 42 Dawn to Cuthbert	1975	X65/X60	0.50/0.44	58%/71% SMYS



Key Decision & RAPID

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Risk Treatment: From ECDA to ILI

- With the known issues of SCC on the NPS 42 and the technical limitation of ECDA, Integrity Management proposes to improve the inspection method from ECDA to ILI.
- The options for each pipeline are: Retrofits vs. Replacement
- Alternatives are created based on the different combination of retrofit & replacement between the three pipelines.

Key Decisions	Recommend	Perform	Input	Agree	Decide
Risk Treatment	E. Naczynski	R. Tao	Angela Scott / Erin Wishart / Stephen Jehlicka / Nick Molnar Peter Fisher / Paul Medd Karen Waters / Amitoz Randhawa / Rachel D'Eon Bob Wellington / Justin Lockhart	W. Armstrong	S. Khoshaien

Dawn-Cuthbert Pipelines – Alternatives

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Different combinations of retrofit & replacement

Alternatives	Pros / Cons	Upfront Capital*	NPV** 40 year / 20 year	
Recommended Option **Option 1 – Replace NPS 42, Retrofit NPS 26, NPS 34**	✓ Eliminate any potential SCC features between Dawn TVN and Cuthbert ✓ Lowest total cost option when considering both long term capital & O&M expenses × Potential anomalies on the 1950s/60s pipelines	17,597,190	**(21,022,493)**	**(16,838,983)**
Option 2 – Replace NPS 26 & NPS 34, Retrofit NPS 42***	✓ Eliminate any potential anomalies on the 1950s/60s pipelines × SCC features could develop between inspections × Highest total cost option	22,328,243	(34,376,899)	(28,379,767)
Option 3 – Replace NPS 26, NPS 34, NPS 42	✓ Eliminate any potential integrity features of all three pipeline × Highest upfront capital cost option	29,449,485	(29,569,101)	(24,832,545)
Option 4 – Retrofit NPS 26, NPS 34, NPS 42***	✓ Lowest upfront capital cost × Potential anomalies on all three pipelines	10,475,948	(25,825,251)	(20,381,052)

* - Class 5 cost estimates for options comparison purposes only
**- NPV analysis includes cost of inspection (O&M) & integrity digs (Capital)
***- NPS 42 replacement projected to take place in 2031 for Option 2 & 4

Other Considerations

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Financial & Regulatory treatment

- Separate projects for each of the pipelines
- 'Base' Core capital portfolio – Growth capital
- The proposed replacement & retrofit projects do not require an LTC
  - ➢ Size-for-size replacement within the existing corridor
- All three projects to be managed & executed by Major Projects
- Current proposed timeline:
  - ➢ 2021 Design & Planning
  - ➢ 2022 Construction & Inline Inspection
  - ➢ 2023 Restoration & Integrity Digs

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Questions?

Thank You

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Appendix A, Page 469

Question:

a) Please confirm that the abandonment costs will be paid out of a pool of funds that Enbridge has collected in the past. Please explain the answer in detail.

b) Please detail the abandonment costs and how they will be funded.

c) If the repair option is chosen, how will that impact the funds that have been reserved for pipeline abandonment?

Response

a - b)

Enbridge Gas confirms that the abandonment costs of the existing Dawn-Cuthbert pipeline will be charged/debited to accumulated depreciation, thereby reducing the provision or outstanding liability for future abandonment costs (or costs of retirement or net salvage amount) recognized by the Company. For financial reporting purposes, Enbridge Gas reclasses its outstanding liability/provision for net salvage/abandonment/costs of retirement from accumulated depreciation to a regulatory liability. While Enbridge Gas recovers a provision for abandonment costs as part of the depreciation expense recovered in rates over the life of its assets, it does not set aside or segregate those funds collected. The abandonment will be funded through the Company's operating cash flows or credit facilities.

The estimated abandonment costs for the Project are $1,530,000. For clarity, abandonment costs of the existing pipeline are not included as part of the project's in-service capital cost sought for ICM rate recovery. A provision for the abandonment of the old pipeline was recovered in rates as part of the depreciation expense recognized over its life. Similarly, a provision for the abandonment of the new pipeline will be recovered in rates as part of depreciation expense recognized over its life.

c) If the Repair Option is chosen, the liability for future abandonment costs will continue to grow with the continued depreciation of the asset (which includes a net salvage component/provision).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Appendix A, Page 469

Question:

a) Please assess the probability that the pipeline will still need to be replaced in 2031 even with inspections and integrity digs. Please provide an estimated probability. Please fully justify your answer.

b) Please assess the probability that the pipeline will not need to be replaced until 2040 with inspections and integrity digs. Please provide an estimated probability. Please fully justify your answer.

Response

a - b)

Given that the currently available methods of detecting SCC on the NPS 42 Dawn-Cuthbert pipeline are not considered reliable, it is not possible to make a justifiable probabilistic determination.

ENBRIDGE GAS INC.

Answer to Interrogatory from Environmental Defence

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Appendix A, Page 469

Question:

a) Would Enbridge's planned Dawn to Corunna impact the need for this project or the impacts of an integrity issue in this area?

Response

a) No, Enbridge Gas's planned Dawn to Corunna will not impact the need for this project, nor will it impact an integrity issue in this area.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Page 10

Preamble:

Enbridge describes the need for the Byron Station as follows:

> Multiple Integrity concerns were identified through an indirect heater assessment conducted by Enbridge Gas. Concerns include noise complaints, integrity of Station inlet valves and inability of the existing Station to support the long term demand of the London market beyond 2022.

Question:

a) Please provide a full breakdown of the cost of the work that would be required solely to fix the integrity of Station inlet valves and the heating system.

b) Please describe the capacity of the station before and after the proposed work.

c) Please explain in detail why leave to construct is not required even though this project is intended in part to support the long term demand of the London market beyond 2022.

d) Please explain in detail why this project cannot wait for rebasing.

e) Please provide a table showing the date of each inspection of the station and a bullet point summary of the findings. Please file the reports containing the conclusions of these inspection.

Response

a) The cost estimate for the heaters and station inlet valves alone is not available. As stated in the business case for the Byron project[1], the need for Byron Station rebuild project includes the need to address heater integrity concerns, noise concerns, maintenance and operation concerns (including equipment spacing and integrity of

[1] EB-2021-0148, Exhibit B, Tab 2, Schedule 2, Appendix B, Page 5 to 8, dated October 15, 2021

station inlet valves), and inability of the existing Station to support the long term demands of the London market beyond 2022. Addressing the station inlet valves and heating system alone does not address the need of the project to resolve noise concern and security of supply concerns beyond 2022.

The cost estimates of the Byron project were done (i) for the heaters and meters combined and (ii) for the heaters, meters, and regulators combined. The cost estimates for these options are provided in the response at Exhibit I.FRPO.15, Attachment 1, pages 8 to 9.

b) See Exhibit B, Tab 2, Schedule 2, Appendix B, page 7, paragraph 15.

c) As described in Exhibit B, Tab 2, Schedule 2, Appendix B, the Project is designed to replace/rebuild the existing Byron Transmission Station to address integrity and noise concerns and to serve increasing demand in the London area. As this project does not include the construction of any "hydrocarbon line" as defined within the *Ontario Energy Board Act, 1998* ("OEB Act"), no order of the OEB granting leave to construct is required.

d) Rebasing at the earliest would take place in 2024. Please see the response at Exhibit I.CCC.5 addressing reasons why the project needs to be completed in 2022 and Exhibit I.ED.12 d) that addresses why project construction commenced in 2021.

e)

Inspections	Date	Summary of Findings	Reports
2018 Indirect Heater Assessment	Fall 2018	See 2019 Byron Trans South Heater Repairs.pdf	See Exhibit I.APPrO.5 (a) Attachment 1
2018 Acoustical Measurements of the Byron Transmission Station	November 22 2018	• During the site visit, sound level measurements were conducted at four neighbouring points of reception, generally in conformance with MECP procedural guideline NPC-103 • At 1 of the 4 receptors, the location immediately south of the station, the measured sound level exceeded the applicable criterion by 12 dBA, which was qualitatively attributed to sound from both the boilers and the above-grade natural gas piping and/or metering/regulation equipment. • An inspection was planned in February 2019 to capture "worst case" noise emissions during colder weather conditions.	See Exhibit B, Tab 2, Schedule 2, Appendix B, page 9 of 32

2019 Acoustical Measurements of the Byron Transmission Station	February 14, 2019	• HGC revisited Byron TS to conduct detailed acoustical measurements of various noise emitting components • The results of those measurements were used to create a 3-D acoustical model of the site and surrounding area, accuracy of the model was confirmed based on sound level measurements conducted around the station fence line, and in the vicinity of the nearest home • Those measurements indicate that the sound levels of the station exceed the limit of the Ministry of the Environment, Conservation and Parks ("MECP") by up to 20 dBA at the upper storey windows of the neighbouring home • Noise mitigation (acoustic lagging, acoustical covers, and a noise barrier) was suggested to reduce the noise level at the station, but only implementing those noise control measures would still result in a theoretical 5dBA excess	See Attachment 1
2021 Noise Impact Study	4 March 2021	• With the preliminary station rebuild design having been developed in early 2021, a Noise Impact Study was undertaken to determine if the sound levels of the proposed upgraded station would meet MECP limits. • The study formally summarized the results from Acoustic Measurements taken on February 14, 2019, where the current sound levels of the station exceed the applicable MECP limit by up to 20dBA at a neighbouring home, attributed to sound from boilers, above-ground piping and metering/regulation equipment • The results of the acoustical analysis detailed in the Noise Impact Study indicate that the sound levels of the upgraded boilers and regulation equipment will be reduced considerably, relative to the existing equipment, to well below the applicable MECP limit at the neighbouring home • Similarly, the sound level of the emergency generator will be within the applicable MECP limit provided that testing is limited to daytime/evening hours • Acoustical measurements will be conducted to confirm the sound level of the upgraded station meets MECP limit	See Exhibit B, Tab 2, Schedule 2, Appendix B, page 13 of 32

From:	Corey Kinart
To:	Luna Ghose
Cc:	Swetha Kulandaivelan
Subject:	[External] Byron TS Noise Control Feasibility
Date:	Wednesday, February 27, 2019 1:01:10 PM
Attachments:	Byron TS Noise Source Figure.pdf

Hi Luna,

As discussed this morning, we revisited the Byron TS on February 14, 2019 to conduct detailed acoustical measurements of the various noise emitting components. The results of those measurements were used to develop a 3-dimensional acoustical model of the site and surrounding area, the accuracy of which was verified based on sound level measurements conducted around the station fence line, and in the vicinity of the nearest home that is approximately 20 metres south of the station. Those measurements indicate that the sound levels of the station exceed the limit of the Ministry of the Environment, Conservation and Parks ("MECP") by up to 20 dBA at the upper storey windows of the neighbouring home.

During the site visit, sound emissions were measured from each of the two heaters (combustion chambers and exhaust stacks, separately), each of three regulation runs (1A1, 2A1 and 3A1), and the 200# outlet run at the south end of the station. (Note that no gas was flowing through 1A2/1A3, 2A2 or 3A2 during our measurements; also, although no gas was flowing through the western half of the 200# outlet run, about as much noise was emitted from that portion of piping as from the eastern half, where gas was flowing). The location of each of these noise sources is shown in the attached Figure 1. Inputting the results of these source measurements to the acoustical model, the relative contribution of each was predicted at the neighbouring home, toward developing conceptual recommendations for noise control. The analysis indicates that, to appreciably reduce the total sound level at the neighbouring home, noise control would be required for all piping and regulation equipment identified above, as well as for the combustion chambers of both heaters. The following outlines a preliminary noise control strategy, for consideration:

- Acoustical lagging applied to all above-grade portions of piping associated with each of regulation runs 1A1, 2A1 and 3A1 and all of the 200# outlet run, consisting of 8 inches of 6 lb/ft3 porous insulation and a 2 lb/ft2 outer layer of mass loaded vinyl;
- Removable acoustical covers applied to the regulation equipment within each of regulation runs 1A1, 2A1 and 3A1;
- A noise barrier on the southwest side of the heaters as depicted in Figure 1, which could be constructed from any of a variety of materials such as wood, metal, brick, pre-cast concrete or other concrete/wood composite systems provided that it is free of gaps or cracks along and below its extent and has a solid construction with a surface density of no less than 20 kg/m^2;
- It may also be prudent to apply acoustical lagging/covers to the 1A2/1A3, 2A2 and 3A2 piping and regulation equipment, to mitigate sound emissions under conditions where gas is flowing through these runs;

Despite the benefit of these noise control measures, station sound levels are predicted to remain ***5 dBA above*** the MECP limits; mitigating this residual sound level excess would require further noise control for the combustion chambers of the heaters, which could take the form of barriers in closer proximity, or acoustical enclosures. However, as discussed this morning, given that such measures may be of questionable technical feasibility, we have not considered them in any further detail, nor have we pursued budgetary costing for the above noted noise control measures. Based on our past experience with similar projects, an order-of-magnitude cost estimate for the above noted noise control measures would be $100,000.

If you would like to explore further the feasibility of developing a noise control strategy that achieves full compliance with MECP limits, and/or to obtain budgetary costing from one or more noise control hardware suppliers, please let me know.

Trusting this information is helpful, if you have any questions or require any additional information, please don't hesitate to give me a call.

Cheers,

Corey Kinart, MBA, PEng
Senior Associate

HGC Engineering **NOISE | VIBRATION | ACOUSTICS**
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Figure 1: Union Gas Byron Transmission Station Showing Locations of Noise Sources and Potential Noise Barrier

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Appendix B, Page 3

Question:

a) Please list all CSA standards and other binding legal standards that apply to this project and describe how they apply.

b) Would Enbridge be in breach of any CSA or other binding legal standards were it not to proceed with this project? If yes, please provide a table with an excerpt of the standard in question, how continued operation would be in breach of that standard, and the cost to address only that specific issue in isolation.

Response

a) The station will be designed and built to the applicable codes and standards defined under CSA Z662-19 as adopted by TSSA Code Adoption Document FS-253-20 and any other applicable federal and provincial guidelines.

b) Enbridge Gas is not in breach of any CSA or other binding legal standards other than the noise concerns.

Project Need	Applicable Standards	Applicable Excerpts	Descriptions of Applicability
Noise Concerns	Ontario Ministry of the Environment, Conservation and Parks Publication NPC-300, Environmental Noise Guideline, Stationary and Transportation Sources - Approval and Planning, August, 2013 City of London By-Law PW-12-19004	Refer to EB-2021-0148, Exhibit B, Tab 2, Schedule 2, Appendix B, page 9 of 32 - 2018 Acoustical Measurements of the Byron Transmission Station and to Refer to EB-2021-0148, Exhibit B, Tab 2, Schedule 2, Appendix B, page 13 of 32 - the 2021 Noise Impact Study	Based on the 2018 Acoustical Measurements of the Byron Transmission Station and the 2021 Noise Impact Study, Byron Transmission Station exceeded the Ministry of the Environment, Conservation and Parks noise level.

Per the 2018 Acoustical Measurements of the Byron Transmission Station, the primary noise producing equipment at the site include two heaters, and above-grade natural gas piping and metering/regulation equipment. Replacement of identified noise producing equipment is part of the current project scope.

As recommended in Byron Transmission presentation on July 9, 2018 (filed in the response at Exhibit I.FRPO.15, Attachment 1) a full station rebuild would be required to address the noise concern of the station.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Appendix B, Page 77

Question:

a) Please estimate the cost of (i) Replacement of heater systems and meters only; and (ii) Replacement of the heater systems, meters and regulators only.

b) Please provide an NPV comparison (i) a full rebuild, (ii) replacement of heater systems and meters only, and (iii) replacement of the heater systems, meters and regulators only.

c) Please explain why "the construction duration was too long to accommodate the Station shut down without impacting security of supply" for the partial replacement but not the full replacement.

d) Could the partial replacement construction take place in phases to avoid impacting security of supply?

e) How long of a window is available for construction to take place without impacting security of supply?

f) How long of a window is available for construction to take place without requiring temporary by-pass stations?

g) How long is option B expected to take?

Response

Enbridge Gas respectively submits that the reference provided by Environmental Defence in this Interrogatory should correctly be:

Exhibit B, Tab 2, Schedule 2, Appendix B, page 27

a) i) The cost estimate for the ‘Replacement of heater systems and meters only’ option can be found at Interrogatory response at Exhibit I.FRPO.15 Attachment 1, page 8.
ii) The cost estimate for the ‘Replacement of the heater systems, meters and regulators only’ option can be found at Interrogatory response at Exhibit I.FRPO.15 Attachment 1, page 9.

b) NPV comparison on the various alternative was not completed. See the response at Exhibit I.FRPO.15 Attachment 1 for the recommendation that the complete station rebuild is the only option that address all project needs. The other alternatives did not provide solutions to the noise concerns and overall station capacity issues beyond 2022.

c) To maintain security of supply downstream of the Byron Transmission station, the station needs to maintain a consistent supply to the 3450 kPa outlet.

In the partial replacement alternative, a temporary bypass station including temporary metering, heating, filtration, and telemetry would need to be installed to maintain supply to the 3450 kPa outlet. Additionally, due to the amount of flow required, the temporary bypass station can only sustain load during the summer months. The construction timeframe during the summer months is insufficient to accomplish all activities required to remove, install, and commission the equipment to be replaced.

In the full station rebuild option, the new proposed station will be built around the existing station that will always remain active negating the requirement to build. a temporary bypass station. Only after the new station is commissioned, would the existing station be decommissioned. The existing station will be able to maintain supply until winter 2022.

d) No. The meter cannot be isolated without the shutting down the station. Replacing the heater could be done in isolation however this does not address the other concerns.

e) There are no concerns with security of supply through to winter 2022 by constructing the new station around the existing station because Enbridge Gas will continue operating on the existing station until it is decommissioned.

f) A temporary bypass station is not required by constructing the new station around the existing station.

g) Refer to Exhibit B, Tab 2, Schedule 2, Appendix B, page 25 for the project schedule.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Appendix B, Page 30

Question:

a) On approximately what date did Enbridge first notify the OEB of the Byron project?

b) On approximately what date did Enbridge first decide that it would be seeking ICM funding for this project?

c) Why did Enbridge begin construction in May 2021?

d) Could Enbridge have delayed construction until after this application had been heard? If not, why not?

Response

a) The Byron project (Byron Transmission Station Rebuild Project) was included in Union Gas' Asset Management Plan 2019-2028 which was filed as part of EGI's 2019 Rates application[1]. In this application, EGI noted both capacity and integrity concerns at the Byron Transmission Station with a planned replacement of 2022 at a cost of approximately $15.5M.

b) As Enbridge Gas reviewed the capital budget requirements for the Union rate zone, it became clear that the capital needs exceeded the materiality threshold. Having identified capital spend that could be reduced or deferred, larger discrete projects were identified to be considered for ICM treatment. This occurred over the summer of 2021. Also, please see the response at Exhibit I.STAFF.1 a).

c) As stated in the business case for the Byron project[2], work began to secure land as early as 2019 with the goal of addressing growing concerns regarding the integrity of the heating system, noise and the maintenance and operability of the station.

[1] EB-2018-0305, Exhibit C1, Tab 3, Schedule 1, filed on December 14, 2018
[2] Appendix B, Exhibit B, Tab 1, Schedule 1, paragraph 16-18.

In EGI's Asset Management Plan Addendum - 2020[3], filed in the 2020 Rates application, Enbridge Gas noted its intention to bring forward the investment at the Byron Transmission Station to 2021. Construction work was started in 2021 with this goal in mind. By May 2021, Enbridge Gas had received partial permits and site preparation work began. Site Plan Approval was received in July 2021 and Building Permits were received in August 2021. Construction work proceeded as quickly as possible after that but with the permit delays the station will not go into service until 2022.

d) As Enbridge Gas was not (and is not) seeking OEB approval to proceed with this project (see Exhibit I.ED.9 c)), it was not necessary to wait for this process before moving ahead with the required work. Enbridge Gas leverages its Asset Management Planning process to create and manage a multi-year plan so that work can be prioritized and executed through its various phases from planning to execution. With respect to the Byron Transmission Station, the documentation above shows that work began in 2019, land was purchased in 2020, engineering design and permitting were undertaken through 2021, and construction is being completed through 2021-2022. Significant delays in addressing the concerns at this station would be introduced if EGI held off on these steps until after this application has been heard.

[3] EB-2019-0194, Exhibit C, Tab 1, Schedule 1, filed on October 25, 2019

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Appendix B, Page 27

Preamble:

This alternative considered replacing components of the existing Station but was dismissed as the construction duration was too long to accommodate the Station shut down without impacting security of supply. In addition, this alternative would not mitigate all of the noise and maintenance and operational concerns with the existing Station. Variants of this alternative were also considered, including: (i) Replacement of heater systems and meters; and (ii) Replacement of the heater systems, meters and regulators. These variants were dismissed as viable alternatives…

Question:

a) On approximately what date did Enbridge begin and end the assessment described above?

b) Please provide the internal Enbridge documentation detailing the replacement option and the decision not to pursue it.

Response

a) The assessment started in January of 2018 and was concluded in July of 2018.

b) The internal documentation is filed in the response at Exhibit I.FRPO.15, Attachment 1.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Appendix C, Page 145

Question:

a) Please provide the complete tables used to calculate the NPV assessment of alternatives for the Kirkland project (including DCF tables or equivalent).

b) Please complete the following table:

	2022	…	Final year	Total
Option C - Repair				
Inspection costs				
Integrity digs				
Pipeline replacement cost				
Other (please describe)				
Total				
Option B - Replace				
Inspection costs				
Integrity digs				
Pipeline replacement cost				
Other (please describe)				
Total				

c) Do the NPV values include abandonment costs? If not, please (i) provide revised NPV values including abandonment costs, (ii) provide updated DCF tables including abandonment costs, and (iii) provide an updated version of the table in (b) including the abandonment costs. This is requested only for Options C and B.

d) Please reproduce table 1 on page 147 with an additional column reconciling these figures with the amounts included in the $15.5 million NPV figure on the previous page.

e) For each cost in table 1 on page 147 that is not included in the NPV calculations, please explain why that decision was made.

f) Please recalculate the NPV figures for option B and C with a time horizon that ends in 2050. Please provide all underlying calculations

g) Please recalculate the NPV figures for option B and C with a time horizon that ends in 2040. Please provide all underlying calculations.

Response

a) Please see Attachments 1 to 3 for the DCF tables of the NPV assessment.

b) Please see Attachment 4.

c) The NPV analysis was based on the project cost estimate. No abandonment costs were included within the total project costs provided, due to a class 5 level of estimating. The abandonment costs were not known for this project at the time of the class 5 estimate. The project cost includes an amount for contingency for unknown costs. As the project progresses, costs that become known are drawn down from the contingency amount and are allocated to their respective cost categories. The actual cost including abandonment/dismantlement cost will be filed as part of the Post-Financial Construction Report for the project. Also, for clarity, abandonment costs are not included as part of the project cost for ICM rate recovery.

d) Please see the reproduced table 1 reconciling with the amounts included in the $15.5 million NPV figure.

Kirkland Project Cost in $	Table 1	NPV Analysis	Variance
Material Costs	$1,982,400		
Labour Costs	$7,728,000		
External Permitting, Land	$168,000		
Outside Services	$3,074,400		
Direct Overheads	$487,200		
Contingency Costs	$3,360,000		
Project Cost	**$16,800,000**	**$16,800,000**	**-**
Indirect Overheads	$3,750,059	-	($3,750,059)
IDC	$116,281	$116,281	-
Total Project Costs	**$20,666,340**	**$16,916,281**	**$(3,750,059)**
Integrity Digs	-	$1,008,651	$1,008,651
Total	**$20,666,340**	**$17,924,932**	**$(2,741,408)**

e) The indirect overhead was excluded for the NPV assessment. Consistent with the discounted cash flow methodology as described through E.B.O. 188, the financial assessment of both the repair and replacement options used direct capital costs. Therefore, indirect overheads for all options were accordingly excluded. The integrity digs are expected to happen once every 10 years.

f) Please see the NPV figures for Option B and C with a time horizon that ends in 2050:

$Millions	**Replacement Scenario**	**Repair Scenario**
	Option B	**Option C**
Net Present Value	**(15.0)**	**(22.9)**

g) Please see the NPV figures for Option B and C with a time horizon that ends in 2040:

$Millions	**Replacement Scenario**	**Repair Scenario**
	Option B	**Option C**
Net Present Value	**(14.6)**	**(18.6)**

DCF Analysis - 40 Year Horizon

Kirkland Lake Option A - Replacement
InService Date: Oct 3 - 2022

Project Year ($000's)	Project Total	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Operating Cash Flow												
Revenue	-	-	-	-	-	-	-	-	-	-	-	-
Expenses:												
O & M Expense	(2,690)	-	-	-	-	-	-	-	-	-	-	(488)
Municipal Tax	(2,934)	-	(16)	(62)	(62)	(63)	(63)	(64)	(65)	(65)	(66)	(67)
Income Tax	1,490	-	4	16	16	17	17	17	17	17	17	147
Net Operating Cash Flow	(4,134)	-	(12)	(45)	(46)	(46)	(47)	(47)	(48)	(48)	(49)	(407)
Capital												
Incremental Capital	(21,005)	(602)	(19,395)	-	-	-	-	-	-	-	-	(183)
Change in Working Capital	-	-	-	-	-	-	-	-	-	-	-	-
Total Capital	(21,005)	(602)	(19,395)	-	-	-	-	-	-	-	-	(183)
CCA Tax Shield												
		-	159	308	290	272	256	241	226	213	200	189
Net Present Value												
PV of Operating Cash Flow	(1,530)	-	(11)	(42)	(40)	(39)	(37)	(36)	(35)	(33)	(32)	(259)
PV of Capital	(19,652)	(598)	(18,729)	-	-	-	-	-	-	-	-	(116)
PV of CCA Tax Shield	2,968	-	154	284	255	229	205	184	165	148	133	120
Total NPV by Year	(18,214)	(598)	(18,587)	243	215	190	168	148	131	115	101	(255)

Project NPV	**(18,214)**

DCF Analysis - 40 Year Horizon

Kirkland Lake Option A - Replacement
InService Date: Oct 3 - 2022

Project Year ($000's)	Project Total	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Operating Cash Flow												
Revenue	-	-	-	-	-	-	-	-	-	-	-	-
Expenses:												
O & M Expense	(2,690)	-	-	-	-	-	-	-	-	-	(594)	-
Municipal Tax	(2,934)	(67)	(68)	(69)	(69)	(70)	(71)	(71)	(72)	(73)	(74)	(74)
Income Tax	1,490	18	18	18	18	19	19	19	19	19	177	20
Net Operating Cash Flow	(4,134)	(49)	(50)	(50)	(51)	(51)	(52)	(53)	(53)	(54)	(491)	(55)
Capital												
Incremental Capital	(21,005)	-	-	-	-	-	-	-	-	-	(223)	-
Change in Working Capital	-	-	-	-	-	-	-	-	-	-	-	-
Total Capital	(21,005)	-	-	-	-	-	-	-	-	-	(223)	-
CCA Tax Shield												
		180	169	159	149	140	132	124	116	109	105	100
Net Present Value												
PV of Operating Cash Flow	(1,530)	(30)	(29)	(28)	(27)	(26)	(25)	(24)	(23)	(22)	(196)	(21)
PV of Capital	(19,652)	-	-	-	-	-	-	-	-	-	(89)	-
PV of CCA Tax Shield	2,968	109	98	88	79	71	63	57	51	46	42	38
Total NPV by Year	(18,214)	79	69	60	52	45	38	33	28	23	(243)	17

Project NPV **(18,214)**

DCF Analysis - 40 Year Horizon

Kirkland Lake Option A - Replacement
InService Date: Oct 3 - 2022

Project Year ($000's)	Project Total	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
Operating Cash Flow												
Revenue	-	-	-	-	-	-	-	-	-	-	-	-
Expenses:												
O & M Expense	(2,690)	-	-	-	-	-	-	-	-	(725)	-	-
Municipal Tax	(2,934)	(75)	(76)	(77)	(77)	(78)	(79)	(80)	(81)	(81)	(82)	(83)
Income Tax	1,490	20	20	20	21	21	21	21	21	214	22	22
Net Operating Cash Flow	(4,134)	(55)	(56)	(56)	(57)	(57)	(58)	(59)	(59)	(592)	(60)	(61)
Capital												
Incremental Capital	(21,005)	-	-	-	-	-	-	-	-	(272)	-	-
Change in Working Capital	-	-	-	-	-	-	-	-	-	-	-	-
Total Capital	(21,005)	-	-	-	-	-	-	-	-	(272)	-	-
CCA Tax Shield												
		94	88	83	78	73	69	65	61	60	58	55
Net Present Value												
PV of Operating Cash Flow	(1,530)	(20)	(19)	(19)	(18)	(17)	(17)	(16)	(16)	(148)	(14)	(14)
PV of Capital	(19,652)	-	-	-	-	-	-	-	-	(68)	-	-
PV of CCA Tax Shield	2,968	34	31	28	25	22	20	18	16	15	14	12
Total NPV by Year	(18,214)	14	11	9	7	5	3	2	0	(201)	(1)	(1)
Project NPV	**(18,214)**											

DCF Analysis - 40 Year Horizon

Kirkland Lake Option A - Replacement
InService Date: Oct 3 - 2022

Project Year ($000's)	Project Total	2054	2055	2056	2057	2058	2059	2060	2061
Operating Cash Flow									
Revenue	-	-	-	-	-	-	-	-	-
Expenses:									
O & M Expense	(2,690)	-	-	-	-	-	-	-	(883)
Municipal Tax	(2,934)	(84)	(85)	(85)	(86)	(87)	(88)	(89)	(90)
Income Tax	1,490	22	22	23	23	23	23	24	258
Net Operating Cash Flow	(4,134)	(62)	(62)	(63)	(63)	(64)	(65)	(65)	(715)
Capital									
Incremental Capital	(21,005)	-	-	-	-	-	-	-	(331)
Change in Working Capital	-	-	-	-	-	-	-	-	-
Total Capital	(21,005)	-	-	-	-	-	-	-	(331)
CCA Tax Shield									
		51	48	45	43	40	38	35	374
Net Present Value									
PV of Operating Cash Flow	(1,530)	(13)	(13)	(12)	(12)	(12)	(11)	(11)	(112)
PV of Capital	(19,652)	-	-	-	-	-	-	-	(52)
PV of CCA Tax Shield	2,968	11	10	9	8	7	6	6	59
Total NPV by Year	(18,214)	(2)	(3)	(3)	(4)	(4)	(5)	(5)	(106)

Project NPV **(18,214)**

DCF Analysis - 40 Year Horizon

Kirkland Lake Option B - Replacement
InService Date: Oct 3 - 2022

Project Year ($000's)	Project Total	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Operating Cash Flow											
Revenue	-	-	-	-	-	-	-	-	-	-	-
Expenses:											
O & M Expense	(2,690)	-	-	-	-	-	-	-	-	-	-
Municipal Tax	(2,187)	-	(12)	(46)	(46)	(47)	(47)	(48)	(48)	(49)	(49)
Income Tax	1,292	-	3	12	12	12	13	13	13	13	13
Net Operating Cash Flow	(3,584)	-	(9)	(34)	(34)	(34)	(35)	(35)	(35)	(36)	(36)
Capital											
Incremental Capital	(17,925)	(602)	(16,314)	-	-	-	-	-	-	-	-
Change in Working Capital	-	-	-	-	-	-	-	-	-	-	-
Total Capital	(17,925)	(602)	(16,314)	-	-	-	-	-	-	-	-
CCA Tax Shield											
	4,512	-	134	261	245	231	217	204	191	180	169
Net Present Value											
PV of Operating Cash Flow	(1,303)	-	(9)	(31)	(30)	(29)	(28)	(27)	(26)	(25)	(24)
PV of Capital	(16,678)	(598)	(15,754)	-	-	-	-	-	-	-	-
PV of CCA Tax Shield	2,519	-	130	240	216	194	174	156	140	125	113
Total NPV by Year	(15,462)	(598)	(15,633)	209	186	165	146	129	114	100	89

Project NPV	**(15,462)**

DCF Analysis - 40 Year Horizon

Kirkland Lake Option B - Replacement
InService Date: Oct 3 - 2022

Project Year ($000's)	Project Total	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Operating Cash Flow													
Revenue	-	-	-	-	-	-	-	-	-	-	-	-	-
Expenses:													
O & M Expense	(2,690)	(488)	-	-	-	-	-	-	-	-	-	(594)	-
Municipal Tax	(2,187)	(50)	(50)	(51)	(51)	(52)	(52)	(53)	(53)	(54)	(54)	(55)	(55)
Income Tax	1,292	142	13	13	14	14	14	14	14	14	14	172	15
Net Operating Cash Flow	(3,584)	(395)	(37)	(37)	(38)	(38)	(38)	(39)	(39)	(40)	(40)	(477)	(41)
Capital													
Incremental Capital	(17,925)	(183)	-	-	-	-	-	-	-	-	-	(223)	-
Change in Working Capital	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Capital	(17,925)	(183)	-	-	-	-	-	-	-	-	-	(223)	-
CCA Tax Shield													
	4,512	160	152	143	135	126	119	112	105	99	93	89	85
Net Present Value													
PV of Operating Cash Flow	(1,303)	(251)	(22)	(22)	(21)	(20)	(19)	(19)	(18)	(17)	(17)	(190)	(15)
PV of Capital	(16,678)	(116)	-	-	-	-	-	-	-	-	-	(89)	-
PV of CCA Tax Shield	2,519	102	92	83	74	67	60	54	48	43	39	35	33
Total NPV by Year	(15,462)	(265)	70	61	54	47	41	35	30	26	22	(244)	17

Project NPV **(15,462)**

DCF Analysis - 40 Year Horizon

Kirkland Lake Option B - Replacement
InService Date: Oct 3 - 2022

Project Year ($000's)	Project Total	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054
Operating Cash Flow													
Revenue	-	-	-	-	-	-	-	-	-	-	-	-	-
Expenses:													
O & M Expense	(2,690)	-	-	-	-	-	-	-	-	(725)	-	-	-
Municipal Tax	(2,187)	(56)	(57)	(57)	(58)	(58)	(59)	(59)	(60)	(61)	(61)	(62)	(62)
Income Tax	1,292	15	15	15	15	15	16	16	16	208	16	16	17
Net Operating Cash Flow	(3,584)	(41)	(42)	(42)	(42)	(43)	(43)	(44)	(44)	(577)	(45)	(45)	(46)
Capital													
Incremental Capital	(17,925)	-	-	-	-	-	-	-	-	(272)	-	-	-
Change in Working Capital	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Capital	(17,925)	-	-	-	-	-	-	-	-	(272)	-	-	-
CCA Tax Shield													
	4,512	80	76	71	67	63	59	55	52	51	50	47	44
Net Present Value													
PV of Operating Cash Flow	(1,303)	(15)	(14)	(14)	(13)	(13)	(12)	(12)	(12)	(144)	(11)	(10)	(10)
PV of Capital	(16,678)	-	-	-	-	-	-	-	-	(68)	-	-	-
PV of CCA Tax Shield	2,519	29	26	23	21	19	17	15	14	13	12	11	10
Total NPV by Year	(15,462)	14	12	10	8	6	5	3	2	(200)	1	0	(0)

Project NPV **(15,462)**

DCF Analysis - 40 Year Horizon

Kirkland Lake Option B - Replacement
InService Date: Oct 3 - 2022

Project Year ($000's)	Project Total	2055	2056	2057	2058	2059	2060	2061
Operating Cash Flow								
Revenue	-	-	-	-	-	-	-	-
Expenses:								
O & M Expense	(2,690)	-	-	-	-	-	-	(883)
Municipal Tax	(2,187)	(63)	(64)	(64)	(65)	(66)	(66)	(67)
Income Tax	1,292	17	17	17	17	17	18	252
Net Operating Cash Flow	(3,584)	(46)	(47)	(47)	(48)	(48)	(49)	(698)
Capital								
Incremental Capital	(17,925)	-	-	-	-	-	-	(331)
Change in Working Capital	-	-	-	-	-	-	-	-
Total Capital	(17,925)	-	-	-	-	-	-	(331)
CCA Tax Shield								
	4,512	42	39	37	35	33	31	330
Net Present Value								
PV of Operating Cash Flow	(1,303)	(10)	(9)	(9)	(9)	(8)	(8)	(110)
PV of Capital	(16,678)	-	-	-	-	-	-	(52)
PV of CCA Tax Shield	2,519	9	8	7	6	6	5	52
Total NPV by Year	(15,462)	(1)	(2)	(2)	(2)	(3)	(3)	(110)
Project NPV	**(15,462)**							

DCF Analysis - 40 Year Horizon

Kirkland Lake Option C - Repair

Project Year ($000's)	Project Total	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Operating Cash Flow												
Revenue	-	-	-	-	-	-	-	-	-	-	-	-
Expenses:												
O & M Expense	(47,878)	(1,950)	(2,040)	(2,081)	(2,122)	(798)	(731)	(746)	(761)	(776)	(881)	(807)
Municipal Tax	(603)	(3)	(12)	(12)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)
Income Tax	12,847	518	544	555	566	215	197	201	205	209	237	218
Net Operating Cash Flow	(35,633)	(1,435)	(1,508)	(1,538)	(1,569)	(596)	(547)	(558)	(569)	(580)	(657)	(603)
Capital												
Incremental Capital	(25,210)	(1,024)	(1,071)	(1,092)	(1,114)	(376)	(384)	(392)	(399)	(407)	(416)	(424)
Change in Working Capital	-	-	-	-	-	-	-	-	-	-	-	-
Total Capital	(25,210)	(1,024)	(1,071)	(1,092)	(1,114)	(376)	(384)	(392)	(399)	(407)	(416)	(424)
CCA Tax Shield												
	-	33	53	72	79	80	82	84	81	83	85	87
Net Present Value												
PV of Operating Cash Flow	(16,638)	(1,427)	(1,457)	(1,418)	(1,381)	(500)	(438)	(427)	(415)	(404)	(437)	(383)
PV of Capital	(11,778)	(1,018)	(1,034)	(1,007)	(980)	(316)	(308)	(300)	(292)	(284)	(277)	(269)
PV of CCA Tax Shield	2,037	32	51	67	69	67	66	64	59	58	57	56
Total NPV by Year	(26,380)	(2,413)	(2,440)	(2,358)	(2,292)	(749)	(680)	(662)	(648)	(630)	(657)	(597)

Project NPV **(26,380)**

DCF Analysis - 40 Year Horizon

Kirkland Lake Option C - Repair

Project Year ($000's)	Project Total	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Operating Cash Flow												
Revenue	-	-	-	-	-	-	-	-	-	-	-	-
Expenses:												
O & M Expense	(47,878)	(824)	(840)	(857)	(973)	(892)	(909)	(928)	(946)	(1,074)	(984)	(1,004)
Municipal Tax	(603)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(15)	(15)	(15)	(15)
Income Tax	12,847	222	226	231	262	240	245	250	255	289	265	270
Net Operating Cash Flow	(35,633)	(615)	(628)	(640)	(725)	(666)	(679)	(692)	(706)	(800)	(734)	(749)
Capital												
Incremental Capital	(25,210)	(432)	(441)	(450)	(459)	(468)	(477)	(487)	(497)	(507)	(517)	(1,095)
Change in Working Capital	-	-	-	-	-	-	-	-	-	-	-	-
Total Capital	(25,210)	(432)	(441)	(450)	(459)	(468)	(477)	(487)	(497)	(507)	(517)	(1,095)
CCA Tax Shield												
	-	90	92	94	96	98	100	102	105	107	109	118
Net Present Value												
PV of Operating Cash Flow	(16,638)	(373)	(363)	(353)	(382)	(335)	(326)	(317)	(309)	(334)	(293)	(285)
PV of Capital	(11,778)	(262)	(255)	(248)	(242)	(235)	(229)	(223)	(217)	(212)	(206)	(417)
PV of CCA Tax Shield	2,037	54	53	52	51	49	48	47	46	45	44	45
Total NPV by Year	(26,380)	(581)	(565)	(550)	(574)	(521)	(507)	(494)	(480)	(501)	(455)	(657)
Project NPV	**(26,380)**											

DCF Analysis - 40 Year Horizon

Kirkland Lake Option C - Repair

Project Year ($000's)	Project Total	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
Operating Cash Flow												
Revenue	-	-	-	-	-	-	-	-	-	-	-	-
Expenses:												
O & M Expense	(47,878)	(1,024)	(1,045)	(1,186)	(1,087)	(1,108)	(1,131)	(1,153)	(1,310)	(1,200)	(1,224)	(1,248)
Municipal Tax	(603)	(15)	(15)	(15)	(16)	(16)	(16)	(16)	(16)	(16)	(17)	(17)
Income Tax	12,847	275	281	318	292	298	304	310	351	322	329	335
Net Operating Cash Flow	(35,633)	(764)	(779)	(883)	(810)	(826)	(843)	(859)	(974)	(894)	(912)	(930)
Capital												
Incremental Capital	(25,210)	(538)	(548)	(559)	(571)	(582)	(594)	(605)	(618)	(630)	(643)	(655)
Change in Working Capital	-	-	-	-	-	-	-	-	-	-	-	-
Total Capital	(25,210)	(538)	(548)	(559)	(571)	(582)	(594)	(605)	(618)	(630)	(643)	(655)
CCA Tax Shield												
	-	125	127	129	130	132	134	136	138	140	142	145
Net Present Value												
PV of Operating Cash Flow	(16,638)	(277)	(270)	(292)	(256)	(249)	(242)	(236)	(255)	(224)	(218)	(212)
PV of Capital	(11,778)	(195)	(190)	(185)	(180)	(175)	(171)	(166)	(162)	(158)	(153)	(149)
PV of CCA Tax Shield	2,037	46	44	43	41	40	39	37	36	35	34	33
Total NPV by Year	(26,380)	(427)	(416)	(435)	(395)	(385)	(375)	(365)	(381)	(346)	(337)	(328)
Project NPV	**(26,380)**											

DCF Analysis - 40 Year Horizon

Kirkland Lake Option C - Repair

Project Year ($000's)	Project Total	2054	2055	2056	2057	2058	2059	2060	2061
Operating Cash Flow									
Revenue	-	-	-	-	-	-	-	-	-
Expenses:									
O & M Expense	(47,878)	(1,273)	(1,446)	(1,325)	(1,351)	(1,378)	(1,406)	(1,596)	(1,463)
Municipal Tax	(603)	(17)	(17)	(17)	(17)	(18)	(18)	(18)	(18)
Income Tax	12,847	342	388	356	363	370	377	428	392
Net Operating Cash Flow	(35,633)	(948)	(1,075)	(986)	(1,006)	(1,026)	(1,046)	(1,186)	(1,088)
Capital									
Incremental Capital	(25,210)	(668)	(682)	(695)	(709)	(724)	(738)	(753)	(768)
Change in Working Capital	-	-	-	-	-	-	-	-	-
Total Capital	(25,210)	(668)	(682)	(695)	(709)	(724)	(738)	(753)	(768)
CCA Tax Shield									
	-	147	150	152	155	158	161	164	1,432
Net Present Value									
PV of Operating Cash Flow	(16,638)	(206)	(223)	(196)	(190)	(185)	(180)	(195)	(171)
PV of Capital	(11,778)	(145)	(142)	(138)	(134)	(131)	(127)	(124)	(121)
PV of CCA Tax Shield	2,037	32	31	30	29	29	28	27	225
Total NPV by Year	(26,380)	(320)	(334)	(303)	(295)	(287)	(280)	(292)	(67)
Project NPV	**(26,380)**								

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Option C - Repair											
Inspection costs	-	-	-	-	81,182	-	-	-	-	89,632	-
Integrity digs	2,973,750	3,111,000	3,173,220	3,236,684	1,093,430	1,115,298	1,137,604	1,160,356	1,183,563	1,207,235	1,231,379
Pipeline replacement cost											
Other (please describe)											
Total	2,973,750	3,111,000	3,173,220	3,236,684	1,174,612	1,115,298	1,137,604	1,160,356	1,183,563	1,296,867	1,231,379
Option B - Replace											
Inspection costs	-	-	-	-	-	-	-	-	-	-	487,598
Integrity digs	-	-	-	-	-	-	-	-	-	-	182,849
Pipeline replacement cost	601,845	16,314,436	-	-	-	-	-	-	-	-	
Other (please describe)											
Total	601,845	16,314,436	-	-	-	-	-	-	-	-	670,447

	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Option C - Repair												
Inspection costs	-	-	-	98,961	-	-	-	-	109,261	-	-	-
Integrity digs	1,256,007	1,281,127	1,306,750	1,332,885	1,359,542	1,386,733	1,414,468	1,442,757	1,471,612	1,501,045	2,099,440	1,561,687
Pipeline replacement cost												
Other (please describe)												
Total	1,256,007	1,281,127	1,306,750	1,431,846	1,359,542	1,386,733	1,414,468	1,442,757	1,580,873	1,501,045	2,099,440	1,561,687
Option B - Replace												
Inspection costs	-	-	-	-	-	-	-	-	-	594,379	-	-
Integrity digs	-	-	-	-	-	-	-	-	-	222,892	-	-
Pipeline replacement cost	-	-	-	-	-	-	-	-	-	-	-	-
Other (please describe)	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-	817,271	-	-

	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
Option C - Repair												
Inspection costs	-	120,633	-	-	-	-	133,188	-	-	-	-	147,051
Integrity digs	1,592,921	1,624,779	1,657,275	1,690,420	1,724,228	1,758,713	1,793,887	1,829,765	1,866,360	1,903,688	1,941,761	1,980,597
Pipeline replacement cost												
Other (please describe)												
Total	1,592,921	1,745,412	1,657,275	1,690,420	1,724,228	1,758,713	1,927,076	1,829,765	1,866,360	1,903,688	1,941,761	2,127,647
Option B - Replace												
Inspection costs	-	-	-	-	-	-	-	724,545	-	-	-	-
Integrity digs	-	-	-	-	-	-	-	271,704	-	-	-	-
Pipeline replacement cost	-	-	-	-	-	-	-	-	-	-	-	-
Other (please describe)	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	996,249	-	-	-	-

	2056	2057	2058	2059	2060	Final Year	Total
Option C - Repair							
Inspection costs	-	-	-	-	162,356	-	942,264
Integrity digs	2,020,208	2,060,613	2,101,825	2,143,861	2,186,739	2,230,473	72,145,686
Pipeline replacement cost							
Other (please describe)							
Total	2,020,208	2,060,613	2,101,825	2,143,861	2,349,094	2,230,473	73,087,950
Option B - Replace							
Inspection costs	-	-	-	-	-	883,216	2,689,737
Integrity digs	-	-	-	-	-	331,206	1,008,651
Pipeline replacement cost	-	-	-	-	-	-	16,916,281
Other (please describe)	-	-	-	-	-	-	-
Total	-	-	-	-	-	1,214,422	20,614,670

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Appendix C, Page 145

Question:

a) If the OEB were to direct Enbridge to select Option C, when would Enbridge conduct its first inspection?

b) If the OEB were to direct Enbridge to select Option C, would the repair costs incurred by Enbridge be added to the revenue requirement at rebasing or would they need to be covered by existing rates? Please explain.

c) Please explain in detail why this project cannot wait for rebasing.

d) Please provide a table showing the date of each inspection of the station and a bullet point summary of the findings. Please file the reports containing the conclusions of these inspection.

Response

a) EGI is not seeking OEB approval of which option to pursue to address pipeline integrity concerns for the NPS 4 Kirkland Lake pipeline in this application. As per Exhibit B, Tab 2, Schedule 2, Appendix C, page 6 of 147, paragraph 5, the Existing Line was first inspected in 2007. If the OEB were to direct EGI to select Option C, it is expected that the first integrity dig would occur in 2022, however, an exact date cannot be determined at this time

b) As indicated in part a), EGI is not seeking OEB approval to construct the pipeline. If option A was selected, the repair costs would be included as part of the total costs in the revenue requirement at rebasing.

c) As detailed in Exhibit B, Tab 2, Schedule 2, Appendix C, Pages 4 to 13, this project is driven by integrity concerns around the existing NPS 4 Lateral which include age, depth of cover issues, coating faults, areas of washout and erosion. The consequence associated with a failure of the existing line would create significant disruption to EGI's customers and create an intolerable risk for EGI. Therefore, the risk needs to be managed prior to rebasing.

d) EGI does not believe that this question has any relevance to this proceeding. The condition of stations connected to the NPS 4 Kirkland Lake pipeline do not contribute to the need for the proposed pipeline replacement project.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Appendix C, Page 145

Question:

a) Approximately when will replacement costs for the proposed pipeline be fully depreciated? Please make and state all assumptions and caveats as necessary.

b) How much of the cost of the pipeline replacement will likely remain undepreciated by (i) 2040 and (ii) 2050? Please make and state all assumptions and caveats as necessary.

c) Please confirm the percentage of Ontario's annual greenhouse gas emissions that are attributable to natural gas combustion.

d) Please estimate the probability that this portion of pipeline will be required by 2050. Please provide a specific percentage with any caveats as necessary.

e) Is Enbridge willing to bear any of the risk that the proposed infrastructure will be underutilized or stranded by 2050? If no, why not? If yes, what portion?

Response

a) The current OEB approved depreciation rate for Union North rate zone metallic distribution mains is 3.02%. The replacement costs for the proposed pipeline should therefore be fully depreciated in 34 years assuming no changes to depreciation rates.

b) (i) Approximately 46% of the cost of the pipeline replacement will remain undepreciated by 2040 assuming no changes to the current OEB approved depreciation rate of 3.02%.

2040 – 2022 = 18 years
18 years x 3.02% = 54% depreciated
100% - 54% = 46% undepreciated

(ii) Approximately 15% of the cost of the pipeline replacement will remain undepreciated by 2050 assuming no changes to the current OEB approved depreciation rate of 3.02%.

2050 – 2022 = 28 years
28 years x 3.02% = 85% depreciated
100% - 85% = 15% undepreciated

c) Please see response at Exhibit I.ED.4 c).

d) Enbridge Gas believes that the pipeline will remain used and useful over its life.

e) These issues exceed the scope of this proceeding. However, in an effort to be as responsive as possible the Company provides a limited response to ED’s question below. No, as the supplier of last resort, the Company is not proposing to bear any incremental risk associated with fulfilling its obligation to serve the firm contractual needs of ratepayers on a design day, while also ensuring the safety and/or reliability of its employees, facilities, and the public.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Appendix C, Page 145

Question:

a) Is the repair option (option C) sufficient to meet the standards set out in CSA Z662? If not, please explain in detail and provide the section numbers and excerpts of all relevant portions of CSA Z662.

b) Please attach excerpts from all asset management plans addressing this pipeline.

c) When did Enbridge first decide that the pipelines at issue in this application had to be replaced? How have the safety and reliability issues been addressed operationally since that time?

Response

a) Yes the repair option (Option C) is sufficient to meet these standards. As indicated at Exhibit B, Tab 2, Schedule 2, Appendix C, pages 140 & 146, this option is more costly.

b) This project was first identified in the 2021-2025 Asset Management Plan (EB-2020-0181 Exhibit C, Tab 2, Schedule 1). The project details (Investment Summary Report) were included in the Appendix to that Asset Management Plan and are included as Attachment 1 to this response. This project is also identified in the addendum to that Asset Management Plan filed at Exhibit B, Tab 2, Schedule 3, in which a small cost reduction is noted to the estimate.

c) The decision to replace the pipeline was made in April 2021. The pipeline pressure has been temporarily restricted to 5860 kPag until it can be replaced.

ENBRIDGE Investment Summary Report	Investment Code: 102128	Report Start Year: 2021	Number of Years: 5
	Investment Name: Kirkland Lake Lateral Replacement		

Investment Description

Issue/Concern:
The Kirkland Lake Lateral is 12 km of NPS 4 steel pipe of late 1950s vintage (1957/1958) operating at an MOP of 6895KPa / 1000psig (>30%SMYS) and is considered a transmission main under the Transmission Integrity Management Program (TIMP):
- Main runs through mostly bedrock with blasted main bed and rocky backfill.
- Depth of Cover (DoC) and backfill washout is a big concern- 2019 ECDA included a DoC survey and found over 1.3km of pipe with less than 0.6m of cover.
- One inoperable valve at Swastika.
- The main has 1 river crossing.
- Approximately 4 km of the 12 km of pipe was replaced for class location mitigation work.
- Lateral supplies Kirkland Lake and some mining customers and is looped with another NPS 8 main (Kirkland Lake Loop)
- Utilization for these two mains is nearing full capacity, especially when the addition of three new mines takes place:
  - When demand increases (i.e. addition of these three mines) this would eliminate the ability to use the NPS 8 system as a back feed / bypass to allow repairs on the NPS 4 mains, should additional leaks occur.
  - Repairs on the NPS 4 would then require local isolation via bypass, dramatically increasing leak repair costs and repair times.
- Since this is a transmission line operating >30%SMYS, any leaks must be repaired via cut-out replacements (no sleeves).
- This main was inspected by ECDA in 2007. The report gave an estimated 12-year life from that point in time and found 11 immediate dig locations.

- A leak was found in September 2019 (1st leak in at least 12 years) and was repaired via cut-out / replacement using the NPS 8 loop to isolate the NPS 4 as capacity demands allowed for this process. Repair cost was approximately $375K.
- ECDA inspection was performed in late fall of 2019:
  - 13 immediate digs in 12 locations were identified and require mitigation within 18 months (June 2021).
  - These digs are O&M expenses, if cut-out repair is required, this would be Capital (replacement of >1m of pipe)
  - An additional 40 indications were classified as "scheduled for investigation" and require investigation digs within 48 months (2023).
  - TIMP estimates a cost of approximately $100K per dig.
  - TIMP estimates that in total, approximately $6M in digs and repairs is required to mitigate these 53 indications.
- TIMP has imposed a pressure reduction to the main of 850 psig as a temporary mitigation.

Justification:
The NPV analysis for replace versus repair shows a strong recommendation towards replacing the main as the least costly option.

Assets: Kirkland Lake Lateral

Related Programs: TIMP Inspection Program

Recommended Alternative Description

Scope of Work: Due to the condition of the existing NPS 4 Kirkland Lake Lateral, a cost estimate has been requested for the replacement of the line. This is a result of the latest ECDA report on the pipeline. Portions of the line have recently been replaced in 2018 and 2019 as part of the Class Location program. The remaining sections are proposed for replacement (8.5 km total of NPS 4). This option is a size for size replacement.

Solution Impact:
Replacement with new pipe will remove the over 300 corrosion indications being found by ECDA and reduce the likelihood for corrosion leaks as well as damage, as the new main will be set to the correct depth of cover.

Resources:
2022 OTC - resources TBD

Project Timing & Execution Risk: A 2022 in-service date considering this option will most likely require OEB approval through a Leave To Construct (LTC) application.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - DP - Main Replacement - Vintage Steel Mains Replacement Program
Investment Stage	Short Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_45 - Timmins
	Asset Program (EGI)	DP - Main Replacement
	Asset Class (EGI)	Distribution Pipe
2. Compliance	Compliance Investment	Yes
	Compliance Justification & Code	2019 ECDA identified 13 Immediate Dig / Repair features that need to be mitigated no later than 2021, with an additional 40 features requiring scheduled mitigation by 2023. There are a further 300 indications being monitored. TIMP is suggesting that replacement versus repair be a preferred option. If the pipe is replaced then TIMP will remain in compliance. Otherwise repairs will be required for the 13 immediate and 40 scheduled digs through O&M.
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
102128	2021	5

Investment Name

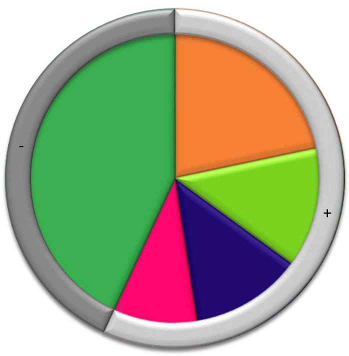
Kirkland Lake Lateral Replacement

Alternative Spend Profile - Recommended

Name	Status	NPV	B/C Ratio	Net Base Capex O (CA)	Alternative Start Date
NPS 4 Size for Size Replacement	Recommended	$ 4,614,115	1.32	$ 16,800,000	1/1/2021

Account Type	2021	2022	2023	2024	2025
Base CAPEX O	$ 600,000	$ 16,200,000	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -

Alternative Value - Recommended



Value Function Measure	Value	Value in Percentage
Cost Avoidance OPEX (CA)	7,263	22%
Budget Savings OPEX (CA)	4,490	13%
Cost Avoidance CAPEX (CA)	4,180	12%
Budget Savings CAPEX (CA)	3,126	9%
Financial Risk	0	0%
Employee And Contractor Safety Risk	0	0%
Environmental Risk And Remediation	0	0%
Public Safety Risk	0	0%
Reputational Risk	0	0%
Revenue Impact (CA)	0	0%
Operational Risk	0	0%
Total Investment Cost (CA)	(14,444)	43%
Total	**4,614**	**100%**

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Appendix C, Page 145

Question:

a) Please confirm that the abandonment costs will be paid out of a pool of funds that Enbridge has collected in the past. Please explain the answer in detail.

b) Please detail the abandonment costs and how they will be funded.

c) If the repair option is chosen, how will that impact the funds that have been reserved for pipeline abandonment?

Response

a - b)

Enbridge Gas confirms that the abandonment costs of the existing Kirkland Lake pipeline will be charged/debited to accumulated depreciation, thereby reducing the provision or outstanding liability for future abandonment costs (or costs of retirement or net salvage amount) recognized by the Company. For financial reporting purposes, Enbridge Gas reclasses its outstanding liability/provision for net salvage/abandonment/costs of retirement from accumulated depreciation to a regulatory liability. While Enbridge Gas recovers a provision for abandonment costs as part of the depreciation expense recovered in rates over the life of its assets, it does not set aside or segregate those funds collected. The abandonment will be funded through the Company's operating cash flows or credit facilities. Also, see the response at Exhibit I.ED.6 a) & b).

Please see the response at Exhibit I.ED.14 c) for the abandonment cost estimate.

c) If the Repair Option is chosen, the liability for future abandonment costs will continue to grow with the continued depreciation of the asset (which includes a net salvage component/provision).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Appendix C, Page 145

Question:

a) Please assess the probability that the pipeline will still need to be replaced in 2031 even with inspections and integrity digs. Please provide an estimated probability. Please fully justify your answer.

b) Please assess the probability that the pipeline will not need to be replaced until 2040 with inspections and integrity digs. Please provide an estimated probability. Please fully justify your answer.

Response

a - b)

The decision to replace the Existing Line as opposed to maintain and repair was based on economic viability and is not an absolute event. The cost of the replacement project is significantly less expensive than the cost to repair and maintain. It is not possible to make a justifiable probabilistic determination of replacement as posed in the questions.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 1

Question:

a) Please reproduce figure 1 on page 3 with an overall trendline including both LUG and LEGD.

b) What is the financial cost of UFG in 2020?

c) How many tonnes CO2e are released per m3 of gas leaked to the atmosphere?

d) Please reproduce figure 2 on page 4 with a column showing the tonnes CO2e of the UFG each year.

e) If UFG were to be subject to the carbon price in the future as of 2030, what would the annual cost be based on the current trajectory of UFG and the carbon price in 2030?

f) Does the UFG report estimate behind-the-meter UFG?

g) Does Enbridge have an estimate of behind-the-meter UFG? If yes, please provide it.

Response

a - g)

As per OEB's letter dated December 10, 2021 (EB-2021-0148), issues related to UFG are out of scope in this proceeding.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence

Interrogatory

Reference:

Exhibit C, Tab 2, Schedule 1

Question:

a) If a performance metric were set for UFG for Enbridge, what does Enbridge believe that metric should be and what would a reasonable starting target be?

b) Aside from a formal OEB-mandated performance metric, is Enbridge willing to adopt a targeted UFG value or consider doing so at rebasing?

Response

Please see response at Exhibit I.ED.21.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe (EP)

Interrogatory

Reference:

Exhibit A, Tab 2, Schedule 1, Pages 2 and 3, paragraph 3

Question(s):

a) Please confirm that this application is the third application for ICM funding since the MAADs decision (EB-2019-0194, EB-2020-0181, and EB-2021-0148).

b) Please file a table listing the projects approved for ICM funding in EB-2019-0194 and EB-2020-0181 together with the one proposed in this application, EB-2021-0148, showing the capital cost of each project and the rate rider for a typical residential customer in respective rate zones.

Response:

a) Not confirmed. This is Enbridge Gas's fourth application for ICM funding since the MAADs decision.

Application	Docket #
2019 Rates	EB-2018-0305
2020 Rates	EB-2019-0194
2021 Rates	EB-2020-0181
2022 Rates	EB-2021-0148

b) Consistent with the response at part a), Enbridge Gas has provided all approved and proposed ICM unit rates for a typical residential customer in Table 1.

Table 1
2019, 2020 & 2021 Approved and 2022 Proposed Residential ICM Unit Rates by Rate Zone

Line No.	Particulars (cents/m3)	Capital Cost ($000's)	Residential ICM Unit Rate EGD Rate 1	Union South Rate M1	Union North Rate 01
		(a)	(b)	(c)	(d)
	Approved EB-2018-0305				
1	Kingsville Reinforcement	118,183	-	0.1154	-
2	Stratford Reinforcement	1,800	-	0.0017	-
	Approved EB-2019-0194				
3	Don River Replacement	30,047	0.0235		
4	Windsor Line Replacement	82,900	-	0.1158	-
	Approved EB-2020-0181				
5	London Lines Replacement	124,039	-	0.0933	-
	Proposed EB-2021-0148				
6	St. Laurent Ottawa North Replacement Ph 3	86,037	0.0133	-	-
7	NPS 20 Replacement Cherry to Bathurst	126,730	0.0316	-	-
8	Dawn to Cuthbert Replacement and Retrofits	23,508	*Note 1*	0.0013	0.0021
9	Byron Transmission Station	20,381	-	(0.0025)	-
10	Kirkland Lake Lateral Replacement	20,666	-	-	0.0225
11	Total		0.0684	0.3250	0.0246

Note:
(1) The increase in Union South Rate M12 demand charges from the Dawn to Cuthbert Replacements and Retrofits project has a total bill impact of less than $0.05 on a typical Rate 1 residential customer in the EGD rate zone.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe (EP)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, page 3, paragraph 11

Preamble:

Enbridge has filed an addendum to its Asset Management Plan. Energy Probe is concerned that the Addendum raises into question the significance of the Asset Management Plan that was filed by Enbridge in the EB-2020-0181 proceeding for approval of its Phase 2 rate increase for 2021.

Question(s):

a) Is Enbridge seeking OEB approval of the addendum to its Asset Management Plan? If the answer is yes, please explain what Enbridge would do if the OEB does not approve the addendum. If the answer is no, please explain why not.

b) Please discuss Enbridge's understanding of the significance of OEB approval of the Asset Management Plan which was filed by Enbridge in the EB-2020-0181 proceeding if it can be amended in a subsequent year?

Response:

a) Enbridge is not seeking OEB approval of the addendum to its Asset Management Plan. Enbridge has provided the Addendum as support for the 2022 ICM funding requests. Enbridge notes that in the 2021 Rates Decision, the OEB found the USP and AMP provided sufficient information for the OEB to assess the 2021 ICM funding requests[1].

b) As noted above the OEB did not "approve" the Asset Management Plan, but instead used the Asset Management Plan to understand the 2021 ICM funding request. The needs of the assets evolve constantly and, although significant attention goes into creating the Asset Management Plan, it is a snapshot in time. The purpose of the Addendum filed in this this proceeding is to provide an update to the Asset Management Plan with a focus on the application year (2022). As with the Asset Management Plan, the Addendum is filed to support the 2022 ICM funding requests.

[1] EB-2020-0181, Decision and Order, May 6, 2021, p. 6.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe (EP)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, page 5, Table 1

Question(s):

a) Considering that total EGD Rate Zone 2022 Capital Budget is $734.3 million please explain how and why Enbridge decided to apply for ICM funding for the two specific projects and not some other projects that it is funding with its own capital within the $521.5 EGD rate zone threshold?

b) Do any of the projects proposed for ICM funding generate incremental revenue? If the answer is yes, what is the amount of revenue?

c) Were the projects proposed for ICM funding the projects of highest priority in the entire $734.3 EGD million EGD Rate Zone budget?

d) Please file a complete list of projects that make up the $734.3 million EGD Rate Zone budget in the order of priority

Response:

a) Please see the response at Exhibit I.CCC.3.

b) Please see the response at Exhibit I.STAFF.1 b).

c) The projects proposed for ICM funding in the EGD rate zone address integrity issues and operational reliability risk in densely populated urban settings, and take time to plan and execute. These projects have a significant impact on the operation of the distribution system and without a planned replacement, there are risks for an increasing number of leaks with impacts to public safety and customer outages. Additionally, the disruption to the public in general in these urban centres will be greater with unplanned emergency work leading to traffic disruption.

d) Please find attached a full list of the projects that make up the $734.3M in the EGD Rate Zone. These projects have been grouped by the planning categories that are used within Asset Management.

LEG/ LUG	Planning Group	Investment Name		2022 Budget
EGD			**$**	**734,278,632**
EGD	**Compliance**	PM:Well Casing-Replace	$	399,750
EGD	**Compliance**	LM:Leaking Valves-Replace	$	377,610
EGD	**Compliance**	SM:SCADA-Annual Upgrade	$	67,650
EGD	**Compliance**	2022 Farm tap Program	$	126,881
EGD	**Compliance**	2022 Assets Downstream of Bulk Meters	$	250,194
EGD	**Compliance**	Beaverton District Station	$	24,600
EGD	**Compliance**	GM South Station	$	24,600
EGD	**Compliance**	Peterborough District Station	$	24,600
EGD	**Compliance**	Portland Energy Center - Electrical	$	24,600
EGD	**Compliance**	Station B - Electrical	$	24,600
EGD	**Compliance**	Dixie and Derry District	$	86,100
EGD	**Compliance**	MM:ESD Bottles-Upgrade	$	147,600
EGD	**Compliance**	SCOR:132 OPP-Upgrades	$	146,916
EGD	**Compliance**	Anode Blanket - Area 50	$	72,431
EGD	**Compliance**	GTAA	$	61,500
EGD	**Compliance**	International Bridge /Cornwall Control Station - Electrical	$	61,500
EGD	**Compliance**	JBL	$	61,500
EGD	**Compliance**	SCOR:62211-PSV-008-Decrease Set Pressure	$	37,131
EGD	**Compliance**	SCOR:62204-PSV-008-Decrease Set Pressure	$	129,957
EGD	**Compliance**	Bridge Crossing Painting Program	$	184,500
EGD	**Compliance**	Torbram and Derry	$	24,600
EGD	**Compliance**	SCOR:62211-PSV-013-Increase Capacity	$	55,696
EGD	**Compliance**	Cavan Feeder Station	$	123,000
EGD	**Compliance**	SCOR:62204-PSV-013-Increase Capacity	$	170,801
EGD	**Compliance**	SCOR:62206-PSV-013-Decrease Set Pressure	$	84,885
EGD	**Compliance**	Anode Blanket - Area 30	$	118,525
EGD	**Compliance**	Kemptville Gate Station - Electrical	$	24,600
EGD	**Compliance**	SCOR:62205-PSV-013-Decrease Set Pressure	$	170,801
EGD	**Compliance**	SCOR:62209-PSV-008-Increase Set Pressure	$	170,801
EGD	**Compliance**	SCOR:62210-PSV-008-Increase Set Pressure	$	170,801
EGD	**Compliance**	SCOR:131-PSV-50x-Inlet Size Increase	$	267,341
EGD	**Compliance**	Elizabethtown/Bethel - Electrical	$	24,600
EGD	**Compliance**	Anode Blanket - Area 40	$	177,787
EGD	**Compliance**	2022 Commercial / Industrial LPDMS Program	$	440,031
EGD	**Compliance**	HALEY GATE	$	44,003
EGD	**Compliance**	NPS 16 Wilkesport Gathering Retrofit	$	553,500
EGD	**Compliance**	Anode Blanket - Area 60	$	285,338
EGD	**Compliance**	SCOR:541 MOP/OPP-Upgrade	$	68,506
EGD	**Compliance**	SCOR:62206-PSV-008-Increase Set Pressure	$	300,138
EGD	**Compliance**	SCOR:62209-PSV-013-Increase Capacity	$	519,829
EGD	**Compliance**	SCOR:62210-PSV-013-Increase Capacity	$	519,829
EGD	**Compliance**	SCOR:62205-PSV-008-Increase Set Pressure	$	337,147
EGD	**Compliance**	Rectifier Ground Bed Replacement Program	$	123,000
EGD	**Compliance**	SCOR:62211-PSV-010-Decrease Set Pressure	$	309,239
EGD	**Compliance**	2022 Dig Program S&T	$	738,000
EGD	**Compliance**	Anode Blanket - Area 20	$	362,159
EGD	**Compliance**	SCOR:62204 Discharge Header OPP-Reinstall	$	449,838
EGD	**Compliance**	Integrity Management Solutions Enhancements Program 2022	$	861,000
EGD	**Compliance**	Anode Blanket - Area 80	$	449,955
EGD	**Compliance**	2022 CIS Releases	$	984,000
EGD	**Compliance**	PCOV:TCV7 A1 Obs Well-Drill	$	1,464,008
EGD	**Compliance**	Integrity Management (FIMP) (2021 - 2023)	$	615,000
EGD	**Compliance**	NPS 16 Wilkesport Transmission Retrofit	$	1,353,000
EGD	**Compliance**	Service Relay Blanket - Area 50	$	510,658
EGD	**Compliance**	Excess Soils 2021	$	861,000
EGD	**Compliance**	MARTIN GROVE FEEDER	$	1,787,961
EGD	**Compliance**	Anode Blanket - Area 10	$	937,224
EGD	**Compliance**	Ottawa Gate Station - Integrity Retrofit > 30% SMYS	$	1,472,310
EGD	**Compliance**	MXGI Area 50	$	809,879
EGD	**Compliance**	Service Relay Blanket - Area 30	$	1,187,679
EGD	**Compliance**	CREDITVIEW AND 403 / MCCONELL DISTRICT	$	1,612,063
EGD	**Compliance**	Service Relay Blanket - Area 40	$	1,177,565
EGD	**Compliance**	CROWLAND STORAGE TRANSFER	$	615,000
EGD	**Compliance**	Service Relay Blanket - Area 80	$	1,554,325
EGD	**Compliance**	MXGI Area 80	$	1,311,233
EGD	**Compliance**	Rectifier Program - All Areas	$	664,200
EGD	**Compliance**	LEG: AMI Pilot Project	$	3,075,000
EGD	**Compliance**	Campbell St Station, Collingwood	$	2,462,791
EGD	**Compliance**	FIMP Station Assessment Program	$	1,426,800
EGD	**Compliance**	MXGI Area 40	$	1,851,152
EGD	**Compliance**	Service Relay Blanket - Area 20	$	2,763,122
EGD	**Compliance**	MXGI Area 60	$	2,603,183

EGD	**Compliance**	2022 Integrity Dig Program	$	8,118,000
EGD	**Compliance**	MXGI Area 30	$	2,815,294
EGD	**Compliance**	Brampton Gate Station Rebuild	$	6,196,158
EGD	**Compliance**	Service Relay Blanket - Area 60	$	3,604,943
EGD	**Compliance**	MXGI Area 20	$	3,818,002
EGD	**Compliance**	PARKWAY GATE	$	12,488,063
EGD	**Compliance**	ST JOHN SIDEROAD FEEDER STATION	$	12,848,842
EGD	**Compliance**	Niagara ILI Retrofits - Network 8980 & 8983 - NPS 8 & NPS 12	$	13,537,380
EGD	**Compliance**	Service Relay Blanket - Area 10	$	6,499,427
EGD	**Compliance**	MXGI Area 10	$	6,074,094
EGD	**Compliance**	Meter Purchases- New Customer Additions	$	6,997,274
EGD	**Compliance**	Meter Purchases- MXGI's, MXG's, MXOT's	$	20,079,103
EGD	**Must-Do**	2022 Furniture & Ergonomics Blanket	$	264,450
EGD	**Must-Do**	Relocation Program - Transit	$	(9,963,000)
EGD	**Must-Do**	Relocation Program - Engineering Construction	$	(11,145,570)
EGD	**Must-Do**	CIS Migration from SAP HEC to Enbridge Cloud @ Azure	$	615,000
EGD	**Must-Do**	Oracle Database Upgrade 2021 (LEGD)	$	153,750
EGD	**Must-Do**	Relocation Program - Area 10	$	(1,353,000)
EGD	**Must-Do**	Microsoft SQL Server Upgrade 2022 (LEGD)	$	73,800
EGD	**Must-Do**	L'Original Reinforcement	$	92,772
EGD	**Must-Do**	2022 Sales stations rebuilds	$	1,230,000
EGD	**Must-Do**	Carling & Lebreton LP Replacement	$	107,140
EGD	**Must-Do**	NPS 20 Don River Waterfront Relocation (Temporary Solution)	$	824,794
EGD	**Must-Do**	Area 20 - Apartment Traditional - New Construction	$	565
EGD	**Must-Do**	Area 10 - Apartment Traditional - New Construction	$	2,556
EGD	**Must-Do**	LM:MS UPS-Replace	$	16,913
EGD	**Must-Do**	SCOR:352 Gas Detectrs-Replace	$	16,236
EGD	**Must-Do**	SCOR:622xx Unit Vlv-Heat Trace	$	16,236
EGD	**Must-Do**	SCOR:810 Touch Screens-Rplace	$	24,354
EGD	**Must-Do**	Cabling 2022-2026	$	127,920
EGD	**Must-Do**	Area 60 - Apartment Traditional - New Construction	$	36,323
EGD	**Must-Do**	A60: 34 Waverley, Ottawa, Header Replacement	$	44,895
EGD	**Must-Do**	SM:Obsolete Elec-Replace	$	67,650
EGD	**Must-Do**	SM:Obsolete Instr-Replace	$	67,650
EGD	**Must-Do**	SCOR:HMI PCs-Replace	$	79,950
EGD	**Must-Do**	PM:Roads&Laneways-Improve	$	81,180
EGD	**Must-Do**	SCOR:65004 AUX Pump-Replace	$	82,410
EGD	**Must-Do**	Marielle Crt Replacement	$	86,100
EGD	**Must-Do**	LM:Well Loops-Adjust	$	87,385
EGD	**Must-Do**	2022 HEADER PROGRAM AREA 60	$	100,491
EGD	**Must-Do**	Operations Technology Enhancements & Upgrades LEG - 2022	$	110,700
EGD	**Must-Do**	2022 - SAP Product and System Refreshes	$	116,850
EGD	**Must-Do**	SCOR:Obsolete Mech-Replace	$	116,850
EGD	**Must-Do**	32915A - ROLLING HILLS & GAMBLE DISTRCT	$	123,000
EGD	**Must-Do**	Engineering & STO Win10 lifecycle 2022	$	123,000
EGD	**Must-Do**	Area 10 - Industrial - New Construction	$	38,335
EGD	**Must-Do**	2022 HEADER PROGRAM - GTA EAST	$	227,304
EGD	**Must-Do**	SCOR:Unit Pre-Heat-Convrt	$	338,250
EGD	**Must-Do**	2022 Blanket for Building Systems	$	2,371,440
EGD	**Must-Do**	2022 HEADER PROGRAM - GTA WEST	$	321,645
EGD	**Must-Do**	Area 40 - Apartment Ensuite - New Construction	$	78,078
EGD	**Must-Do**	Rockland XHP Reinforcement	$	79,950
EGD	**Must-Do**	2022 HEADER PROGRAM - AREA 10	$	487,080
EGD	**Must-Do**	IT - 00 - Desktop Sustainment EGD 2022	$	492,000
EGD	**Must-Do**	EG - Customer Data Analytics Solutions (2022)	$	615,000
EGD	**Must-Do**	2022 Telemetry	$	1,722,000
EGD	**Must-Do**	Area 30 - Industrial - New Construction	$	182,573
EGD	**Must-Do**	Area 20 - Apartment Ensuite - New Construction	$	1,015,776
EGD	**Must-Do**	SCOR:Meter Area-Upgrade (Phase 2)	$	26,448,509
EGD	**Must-Do**	2022 - 486 Tools & Equipment	$	1,131,605
EGD	**Must-Do**	Direct Capital Overheads	$	307,500
EGD	**Must-Do**	Pressure Elevation for Network 5301	$	19,219
EGD	**Must-Do**	Station Emergency Replacement Blanket - All Areas	$	246,000
EGD	**Must-Do**	Area 20 - Industrial - New Construction	$	368,169
EGD	**Must-Do**	Relocation Program - Area 60	$	639,880
EGD	**Must-Do**	Relocation Program - Area 80	$	1,476,000
EGD	**Must-Do**	Relocation Program - Area 30	$	1,730,508
EGD	**Must-Do**	2022 - 485 Heavy Work Equipment	$	3,952,703
EGD	**Must-Do**	mCHP TOC	$	4,920,000
EGD	**Must-Do**	McCowan Ave HP Reinforcement	$	2,375,567
EGD	**Must-Do**	AJAX Reinforcement	$	198,338
EGD	**Must-Do**	Area 20 - Commercial - Replacement	$	693,251
EGD	**Must-Do**	Area 30 - Apartment Ensuite - New Construction	$	155,795
EGD	**Must-Do**	Area 80 - Residential - Replacement	$	952,208
EGD	**Must-Do**	Area 80 - Industrial - New Construction	$	1,082,794

EGD	**Must-Do**	2022 - 484 Light and Medium duty vehicles	$	6,133,297
EGD	**Must-Do**	2021 - 486 Tools & Equipment ProStopp TDW	$	6,150,000
EGD	**Must-Do**	Area 80 - Commercial - Replacement	$	1,032,904
EGD	**Must-Do**	Area 50 - Commercial - New Construction	$	680,929
EGD	**Must-Do**	Relocation Program - Area 50	$	3,444,000
EGD	**Must-Do**	Relocation Program - Area 40	$	3,945,858
EGD	**Must-Do**	Area 20 - Residential - Replacement	$	2,343,707
EGD	**Must-Do**	Area 80 - Commercial - New Construction	$	2,718,696
EGD	**Must-Do**	Relocation Program - Area 20	$	4,305,000
EGD	**Must-Do**	Area 40 - Commercial - New Construction	$	3,341,114
EGD	**Must-Do**	Area 10 - Apartment Ensuite - New Construction	$	2,588,089
EGD	**Must-Do**	Area 20 - Commercial - New Construction	$	4,549,597
EGD	**Must-Do**	Area 60 - Industrial - New Construction	$	3,109,700
EGD	**Must-Do**	Area 50 - Residential - Replacement	$	3,413,765
EGD	**Must-Do**	Area 10 - Residential - New Construction	$	12,245,945
EGD	**Must-Do**	Area 30 - Commercial - New Construction	$	3,332,817
EGD	**Must-Do**	Area 30 - Residential - Replacement	$	3,029,975
EGD	**Must-Do**	EA Fixed O/H - Mtce	$	5,963,489
EGD	**Must-Do**	Area 60 - Commercial - New Construction	$	1,684,517
EGD	**Must-Do**	EA Fixed O/H - Growth	$	10,912,609
EGD	**Must-Do**	Area 40 - Residential - Replacement	$	6,029,937
EGD	**Must-Do**	Area 40 - Residential - New Construction	$	6,815,703
EGD	**Must-Do**	Area 80 - Residential - New Construction	$	7,842,038
EGD	**Must-Do**	Area 20 - Residential - New Construction	$	5,849,229
EGD	**Must-Do**	Area 10 - Commercial - New Construction	$	7,701,368
EGD	**Must-Do**	Area 50 - Residential - New Construction	$	5,949,287
EGD	**Must-Do**	Area 10 - Residential - Replacement	$	7,481,215
EGD	**Must-Do**	Area 60 - Residential - Replacement	$	12,357,890
EGD	**Must-Do**	Area 30 - Residential - New Construction	$	8,064,588
EGD	**Must-Do**	Area 60 - Residential - New Construction	$	21,156,809
EGD	**Value Driven**	30: VSM - Major Mackenzie, Bayview to Maple, Replacement	$	374,049
EGD	**Value Driven**	30: VSM - Major Mackenzie, Sussex To Cedar, Replacement	$	1,013,684
EGD	**Value Driven**	IT - 00 - Desktop Replacement EGD 2022	$	2,091,000
EGD	**Value Driven**	Oracle Middleware Upgrade 2021	$	92,250
EGD	**Value Driven**	PM:Wells-Acidize	$	627,300
EGD	**Value Driven**	93 Rameau Dr, Toronto 2" LP Header Replacement	$	153,241
EGD	**Value Driven**	87 Rameau Dr, Toronto 4" LP Header Replacement	$	241,637
EGD	**Value Driven**	75 Rameau Dr, Toronto 4" & 2" LP Header Replacement	$	432,359
EGD	**Value Driven**	A10: Redstone & Raintree Path, Etobicoke, Noded Header Replacement	$	371,219
EGD	**Value Driven**	Young St LP Replacement	$	1,223,830
EGD	**Value Driven**	1801 Lawrence Ave E, Scarborough	$	242,987
EGD	**Value Driven**	2061 Bridletowne Cir & 91 L'Amoreaux Steel Header Replacements	$	1,283,701
EGD	**Value Driven**	PMKC:TKC68H New HWell	$	2,945,850
EGD	**Value Driven**	High Risk Excavation Locate Prioritization Project	$	615,000
EGD	**Value Driven**	Campbellford Replacement Phase 3 Front St	$	628,932
EGD	**Value Driven**	VPC-Link and stairwells	$	922,500
EGD	**Value Driven**	IT - 00 - Mobile Devices EGD 2022	$	246,000
EGD	**Value Driven**	SM:100MOD Hdr Valves-Replace	$	1,537,500
EGD	**Value Driven**	SCOR:60011 Oil Filtr-Replace	$	467,093
EGD	**Value Driven**	SCOR:61008 Top End-O/H incl. Cam Upgrade	$	467,400
EGD	**Value Driven**	Damage Reduction - Pipeline patrol technology	$	1,230,000
EGD	**Value Driven**	SCOR:60004 Oil Filtr-Replace	$	467,093
EGD	**Value Driven**	Technical Training Technology 2022	$	615,000
EGD	**Value Driven**	LMKC:TKC68H New HWell	$	636,525
EGD	**Value Driven**	EQMT Enhancements and Lifecycle Work 2022	$	369,000
EGD	**Value Driven**	Asset Integrity Field Mobility Solution 2022	$	615,000
EGD	**Value Driven**	IT - 00 - Plotter Replacement EGD 2022	$	369,000
EGD	**Value Driven**	Gas Storage Business Solutions 2022	$	369,000
EGD	**Value Driven**	2022 LEG Rate Zone Targeted GHG & Energy Reductions	$	430,500
EGD	**Value Driven**	IT Meeting Room AV Sustainment 2022	$	184,500
EGD	**Value Driven**	SCOR:60004 iBalance-Upgrade	$	375,150
EGD	**Value Driven**	MCGLASHAN & MCGLASHAN DISTRICT	$	6,150
EGD	**Value Driven**	SCOR:65004 Forced Lube-Replace	$	184,500
EGD	**Value Driven**	GIS Integration Placeholder	$	2,460,000
EGD	**Value Driven**	SCOR:65011 Forced Lube-Replace	$	184,500
EGD	**Value Driven**	TOWNLINE & RUSHOLME DISTRICT	$	6,150
EGD	**Value Driven**	ALGONQUIN FOREST & CONCESSION 2 DISTRICT	$	108,086
EGD	**Value Driven**	Asset Management And Analytics 2022	$	615,000
EGD	**Value Driven**	Morrison THP Replacement	$	301,350
EGD	**Value Driven**	YORKGATE & FINCH DISTRICT	$	6,150
EGD	**Value Driven**	SHEPPARD & KENNEDY DISTRICT	$	6,150
EGD	**Value Driven**	(O)-ELLESMERE / BUDEA	$	6,150
EGD	**Value Driven**	Janet St Port Colborne	$	418,190
EGD	**Value Driven**	Replacement Blanket - Area 80	$	12,377
EGD	**Value Driven**	BRAMALEA & ADVANCE BLVD. DISTRICT	$	6,150

EGD	**Value Driven**	COUNTY RD #55 HWY #9 DISTRICT (NEW TECUSETH)	$	6,150
EGD	**Value Driven**	14131A- BAYVIEW & POST ROAD DISTRICT	$	167,895
EGD	**Value Driven**	C.N.E. & LAKESHORE DISTRICT STATION REBUILD 15817A	$	167,895
EGD	**Value Driven**	BAYVIEW & SHEPPARD DISTRICT	$	6,150
EGD	**Value Driven**	AVENUE RD & MACPHERSON DISTRICT STATION REBUILD 15125A	$	175,214
EGD	**Value Driven**	20243A - HWY # 50 & CADETTA DISTRICT (BOLTON)	$	215,250
EGD	**Value Driven**	ST. PAUL & SANDFIELD DISTRICT (ALEXANDRIA)	$	2,460
EGD	**Value Driven**	6B621A - BANTREE & EDINBURGH DISTRICT	$	236,775
EGD	**Value Driven**	6B792A - INNES & ORLEANS DISTRICT	$	236,775
EGD	**Value Driven**	6B796A - WOODROFFE & EARL MULLIGAN DISTRICT	$	236,775
EGD	**Value Driven**	76171A - THIRTY RD N OF SPRINGCREEK DISTRICT	$	234,881
EGD	**Value Driven**	81033A - Bowen Rd & Sider Rd	$	234,881
EGD	**Value Driven**	85163A- MILLER & HAUN DISTRICT	$	234,881
EGD	**Value Driven**	SCOR - Instrument air from Starter Air	$	239,850
EGD	**Value Driven**	62403A - ROGER STEVENS & JAMES CRAIG DISTRICT (NORTH GOWER)	$	236,775
EGD	**Value Driven**	6C077A - CASSELMAN SOUTH & BRISSON DISTRICT	$	236,775
EGD	**Value Driven**	AFE/OWP Enhancements 2022	$	246,000
EGD	**Value Driven**	EnTRAC Changes & Enhancements 2022	$	246,000
EGD	**Value Driven**	FINCH & ALAMOSA DISTRICT	$	196,876
EGD	**Value Driven**	EAGLESON & EMERALD MEADOWS DISTRICT	$	298,275
EGD	**Value Driven**	2746401 - BIRCHMOUNT & ST. CLAIR DISTRICT	$	307,500
EGD	**Value Driven**	2968155 - BAYFILED & DUNLOP LP	$	307,500
EGD	**Value Driven**	30890A - HEMLOCK & 10TH LINE DISTRICT (STOUFFVILLE)	$	307,500
EGD	**Value Driven**	31428A - RAM FOREST & WESLEY CORNERS	$	307,500
EGD	**Value Driven**	32311A - WILLIAM & PRESTON LAKE DISTRICT	$	307,500
EGD	**Value Driven**	32717A - WESTON RD & KING RD DISTRICT	$	307,500
EGD	**Value Driven**	32924A - HWY # 7 & ROYBRIDGE GATE DISTRICT	$	307,500
EGD	**Value Driven**	50519A - POTTAGEVILLE DISTRICT(SCHOMBERG GATE)	$	307,500
EGD	**Value Driven**	51051A - EDGAR & HWY # 26 DISTRICT (COLLINGWOOD)	$	307,500
EGD	**Value Driven**	Payment Enhancements 2022	$	307,500
EGD	**Value Driven**	21 Potsdam Rd Header Replacement	$	310,506
EGD	**Value Driven**	Replacement Blanket - Area 30	$	107,871
EGD	**Value Driven**	SCOR:62204 Vessel Closure-Rplace	$	340,416
EGD	**Value Driven**	SCOR:62211 Vessel Closure-Rplace	$	340,416
EGD	**Value Driven**	Replacement Blanket - Area 40	$	109,739
EGD	**Value Driven**	KIPLING & NORTH QUEEN DISTRICT	$	6,150
EGD	**Value Driven**	Enbridge Yard CNG Station B	$	363,465
EGD	**Value Driven**	SPADINA & MACPHERSON DISTRICT	$	6,150
EGD	**Value Driven**	Replacement Blanket - Area 50	$	93,152
EGD	**Value Driven**	NPS12 880 Wellington City Centre Complex - Ottawa	$	564,969
EGD	**Value Driven**	Regional Rd 65 West Lincoln	$	426,810
EGD	**Value Driven**	Truck modem replacement	$	2,460,000
EGD	**Value Driven**	CIS Data Archiving	$	430,500
EGD	**Value Driven**	RPA's for Customer Care 2022	$	430,500
EGD	**Value Driven**	A10: 65-75 Goodview Rd (South), North York, Noded Header Replacement	$	446,100
EGD	**Value Driven**	A10: Cibola and Chippewa Toronto Islands, Replacement	$	455,698
EGD	**Value Driven**	BAYVIEW & BYNG DISTRICT	$	6,150
EGD	**Value Driven**	ESRI GIS Release 2022	$	615,000
EGD	**Value Driven**	SCOR:64105 JWC-Replace	$	61,500
EGD	**Value Driven**	Parliament & Winchester Station Replacement	$	1,553,308
EGD	**Value Driven**	14365A - BIRMINGHAM & KIPLING DISTRICT	$	492,000
EGD	**Value Driven**	EG - Asset & Work Data Analytics Solution (2022)	$	492,000
EGD	**Value Driven**	LAKEVIEW CRES BARRIE SHALLOW GAS MAIN	$	492,000
EGD	**Value Driven**	Technical Records Releases 2022	$	615,000
EGD	**Value Driven**	Ridge Rd North Fort Erie	$	535,050
EGD	**Value Driven**	HARVIE 7 MORRISON DISTRICT	$	6,150
EGD	**Value Driven**	MILTON & OXFORD DISTRICT	$	427,733
EGD	**Value Driven**	SCOR:541 Drainage System-Upgrade	$	16,236
EGD	**Value Driven**	Lundys Lane Reg. Road 20 Niagara Falls	$	595,320
EGD	**Value Driven**	Concord St Isolated Steel Replace with Main St PE, Ottawa	$	591,292
EGD	**Value Driven**	Back Office QA BDEX Enhancements 2022	$	615,000
EGD	**Value Driven**	Engineering Application Lifecycle Program 2022	$	615,000
EGD	**Value Driven**	TIS Technology and Innovation Lab	$	615,000
EGD	**Value Driven**	NGV Rental VRA's - (Until 2025)	$	152,752
EGD	**Value Driven**	Replacement - Vintage PE Lined Mains - Peterborough	$	55,350
EGD	**Value Driven**	SSOM:UT Meters-Replace	$	639,600
EGD	**Value Driven**	VSM - West Beaver Creek	$	922,500
EGD	**Value Driven**	Copper Service Replacement - Area 40	$	267,392
EGD	**Value Driven**	McCarthy and First St, Orangeville	$	973,844
EGD	**Value Driven**	Chatbot Enhancements 2022	$	731,850
EGD	**Value Driven**	A10: 46-68 Goodview Rd (North), North York, Noded Header Replacement	$	762,107
EGD	**Value Driven**	SCOR:60009 iBalance-Upgrade	$	1,444,635
EGD	**Value Driven**	SSOM:K-801 Isolation Valves - Replace	$	180,810
EGD	**Value Driven**	SSOM:K-802 Isolation Valves - Replace	$	686,374
EGD	**Value Driven**	A50 Base Borden 6 inch replacement	$	246,000

EGD	**Value Driven**	EG - SAP Business Warehouse Solution (2022)	$	922,500
EGD	**Value Driven**	INDIAN & WRIGHT DISTRICT STATION REBUILD	$	1,001,988
EGD	**Value Driven**	VSM - Cooper St and Somerset St - LP	$	1,367,529
EGD	**Value Driven**	Copper Service Replacement - Area 20	$	689,649
EGD	**Value Driven**	WAMS Stabilization & Releases (2022 - LEGD & LUG)	$	1,107,000
EGD	**Value Driven**	Replacement Blanket - Area 20	$	417,745
EGD	**Value Driven**	MyAccount Enhancements 2022	$	1,230,000
EGD	**Value Driven**	1" ST - Archill Crescent	$	1,129,380
EGD	**Value Driven**	NPS 12 SC HP Bayview Ave (Area 10) Loss of Cover - Truman Rd to Wimpole Rd	$	1,293,997
EGD	**Value Driven**	JONESVILLE FEEDER	$	1,328,400
EGD	**Value Driven**	A20: Klaiman, Mississauga-Replacement	$	1,459,316
EGD	**Value Driven**	VSM - Firestone Road - 2" ST	$	1,460,367
EGD	**Value Driven**	VPC-B	$	1,537,500
EGD	**Value Driven**	Greenbriar Ave Frost Mitigation	$	1,396,050
EGD	**Value Driven**	WINSTON CHURCHILL AND STEELES FEEDER	$	1,316,100
EGD	**Value Driven**	Granada Drive STC	$	1,882,350
EGD	**Value Driven**	Green Button	$	3,075,000
EGD	**Value Driven**	Brockville Operations Centre	$	6,150,000
EGD	**Value Driven**	AMP Fitting Replacement - Area 50	$	388,332
EGD	**Value Driven**	eGIS Upgrade (2021 - 2022)	$	307,500
EGD	**Value Driven**	Meter Reading Handheld Replacement	$	1,845,000
EGD	**Value Driven**	Copper Service Replacement - Area 80	$	808,862
EGD	**Value Driven**	NGT Existing customer Maintenance Capital - (Until 2026)	$	364,283
EGD	**Value Driven**	Content Management Enhancements 2022	$	2,460,000
EGD	**Value Driven**	NPS 6 Rugby Gate to Penetanguishine NW5301	$	2,460,000
EGD	**Value Driven**	Replacement Blanket - Area 60	$	973,431
EGD	**Value Driven**	VSM - Yonge and Davis Dr West - Phase2	$	49,200
EGD	**Value Driven**	Mobile Meter Reading 2.0	$	246,000
EGD	**Value Driven**	NGT Maintenance Capital for company/fleet NG refueling stations (2021 to 2028)	$	567,981
EGD	**Value Driven**	BEAMSVILLE GATE	$	2,646,837
EGD	**Value Driven**	AMP Fitting Replacement - Area 40	$	784,752
EGD	**Value Driven**	VSM - Yonge and Davis Dr West - Phase1	$	3,482,674
EGD	**Value Driven**	PIPE-INRE-19 BRADFORD ST	$	1,624,719
EGD	**Value Driven**	ESRI GIS Utility Network 2022	$	922,500
EGD	**Value Driven**	Replacement Blanket - Area 10	$	1,633,465
EGD	**Value Driven**	Dale Gate Station Rebuild	$	3,088,407
EGD	**Value Driven**	AMP Fitting Replacement - Area 80	$	1,156,979
EGD	**Value Driven**	Copper Service Replacement - Area 10	$	1,285,392
EGD	**Value Driven**	A20:Homark Dr., Mississauga-Replacment.	$	4,296,255
EGD	**Value Driven**	KEELE AND STEELES/CNR FEEDER	$	1,316,214
EGD	**Value Driven**	AMP Fitting Replacement - Area 60	$	1,889,212
EGD	**Value Driven**	A50: Big Bay Point VPM Aldyl A	$	2,460,000
EGD	**Value Driven**	Albion Gate Station Control Valve Upgrade	$	4,292,208
EGD	**Value Driven**	AMP Fitting Replacement - Area 30	$	1,370,254
EGD	**Value Driven**	Black Creek Rd and River Trail, Fort Erie - VPM Aldyl-A MP lined in steel	$	5,350,475
EGD	**Value Driven**	A60: Sparks St, Ottawa, Replacement	$	1,230
EGD	**Value Driven**	Oshawa LP Replacement Phase 2 King St	$	3,034,420
EGD	**Value Driven**	Vintage Steel: NPS 12 SC HP on Parliament St, Carlton St to Front St	$	6,953,442
EGD	**Value Driven**	AMP Fitting Replacement - Area 20	$	2,418,440
EGD	**Value Driven**	NPS 12 Martin Grove Rd - Clements Rd to Lavington	$	3,832,817
EGD	**Value Driven**	VPC Annex/Metershop Area Renovations	$	1,168,500
EGD	**Value Driven**	AMP Fitting Replacement - Area 10	$	3,406,318
EGD	**Value Driven**	St. Laurent Phase 3 - Coventry/Cummings/St Laurent	$	10,778,528
EGD	**Value Driven**	St. Laurent Phase 4 - Lower Section	$	778,000
EGD	**Value Driven**	St. Laurent Phase 3 - (Montreal to Rockcliffe)	$	11,288,673
EGD	**Value Driven**	VPM - Erin Township	$	2,703,294
EGD	**Value Driven**	A10: Wilson Avenue, Toronto, VSM Replacement	$	338,250
EGD	**Value Driven**	St. Laurent Phase 4 - East/West (NPS12 Steel)	$	369,000
EGD	**Value Driven**	SCOR:600XX Compressor Replacement	$	5,259,859
EGD	**Value Driven**	SMOC/Coventry Facility Consolidation	$	4,305,000
EGD	**Value Driven**	Station B New Building	$	9,840,000
EGD	**Value Driven**	St. Laurent Phase 3 - North/South (NPS12/16 Steel)	$	63,969,359
EGD	**Value Driven**	NPS 20 Lake Shore Replacement (Cherry to Bathurst)	$	126,729,864
EGD	**Efficiencies and workplan reductions**	Efficiencies and workplan reductions	$	(12,648,895)
Grand Total			**$**	**734,278,632**

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe (EP)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, page 6, Table 2

Question(s):

a) Considering that total Union Rate Zones 2022 Capital Budget is $543.1 million please explain how and why Enbridge decided to apply for ICM funding for the three specific projects and not some other projects that it is funding with its own capital within the $455.5 Union Rate Zones threshold?

b) Do any of the projects proposed for ICM funding generate incremental revenue? If the answer is yes, what is the amount of revenue?

c) Were the projects proposed for ICM funding the projects of highest priority in the entire $543.1 million Union Rate Zones budget?

d) Please file a complete list of projects that make up the $543.1 million Union Rate Zones budget in the order of priority.

Response:

a) Please see the response at Exhibit I.CCC.3.

b) Please see the response at Exhibit I.STAFF.1 b).

c) Byron Transmission Station
As indicated in the business case at Exhibit B, Tab 2, Schedule 2, Appendix B, the Byron Transmission Station is driven by a number of integrity issues and growth. The Business Case lists the compliance drivers amongst others. Specifically, noise[1] and heating system[2] are identified as compliance issues. The Project was initially categorized as growth driven (Must Do) but the integrity issues (Compliance) were of greater concern the project could have been moved up to the Compliance category which is the highest priority grouping.

[1] Exhibit B, Tab 2, Schedule 2, Appendix B, page 6
[2] Exhibit B, Tab 2, Schedule 2, Appendix B, pages 5-6

Dawn-Cuthbert NPS 42 Replacement
The Dawn-Cuthbert project falls under the Compliance category which is the highest priority grouping. The Business Case at Exhibit B, Tab 2, Schedule 2, Appendix A describes in detail the integrity inspections that have been completed on this pipeline[3] and the reasons that the level of uncertainty that are inherent in the available inspection techniques are not consistent with Enbridge Gas's Transmission Integrity Management Program which has been established in compliance with CSA Z662.

This is a large pipeline operating at high pressure and, from a network perspective, it plays a significant role in feeding gas to southern Ontario. As such, there are risks related to health & safety and operational reliability should Enbridge Gas experience a failure on this pipeline. The available condition information, and the uncertainty that comes from the available inspection methods are not acceptable to Enbridge Gas. As such, Enbridge Gas has decided to replace the pipeline in compliance with its TIMP and its responsibilities under the CSA Z662[4].

Kirkland Lake Lateral Replacement
Once the integrity issues were identified on the Kirkland Lake Lateral, a Net Present Value (NPV) analysis was used to support a decision to replace the pipeline. The pressure restriction that was imposed as a result of integrity concerns reduced operational flexibility in the area and, as such, the pipeline replacement has been prioritized to 2022. The project is listed in the Value Driven list of projects.

The Business Case at Exhibit B, Tab 2, Schedule 2, Appendix C describes the inspection history and findings for this pipeline[5]. With the large number of known and anticipated integrity repairs, Enbridge Gas completed a NPV analysis to determine whether it would be more cost-effective to replace the pipeline or to continue to repair it.

With a planned replacement in 2022 (the work could not be planned and executed sooner) the decision was taken to place a pressure restriction on the pipeline, restricting the maximum pressure and recognizing the deteriorating condition of the pipeline.

Although this allowed the work to be deferred so that planning could be completed, it needed to be completed as quickly as possible to restore operational flexibility to the Kirkland Lake system.

d) Please find attached a full list of the projects that make up the $543.1M in the Union Gas Rate Zone. These projects have been grouped by the planning categories that are used within Asset Management.

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[3] Exhibit B, Tab 2, Schedule 2, Appendix A, pages 2-8
[4] Exhibit B, Tab 2, Schedule 2, Appendix A, pages 4, para. 7
[5] Exhibit B, Tab 2, Schedule 2, Appendix C, page 6

LEG/LUG	Planning Group	Investment Name		2022 Budget
UG			**$**	**543,121,100**
UG	**Compliance**	Leaking Valves-Replacement Program	$	1,195,560
UG	**Compliance**	2022 Odourant Upgrades - ED Units	$	36,900
UG	**Compliance**	FCS Upgrade 2022	$	61,500
UG	**Compliance**	CHAT: Dist-Repl-Compy-Services	$	24,141
UG	**Compliance**	HAMI: Corrosion Rectifier Groundbed Program	$	92,250
UG	**Compliance**	WATE: Corrosion Rectifier Groundbed Program	$	92,250
UG	**Compliance**	2022 - LAB FACILITIES UPGRADE	$	98,400
UG	**Compliance**	SUDB: Dist-Repl-Contr-Services	$	57,669
UG	**Compliance**	2022 Industrial Billing Communications Upgrade	$	123,000
UG	**Compliance**	Web Enhancements 2022	$	123,000
UG	**Compliance**	SARN: Dist-Repl-Contr-Services	$	47,207
UG	**Compliance**	BRAN: Dist-Repl-Contr-Services	$	54,120
UG	**Compliance**	NBAY: Dist-Repl-Comp-Services	$	(25,012)
UG	**Compliance**	TIMM: Dist-Repl-Compy-Services	$	54,371
UG	**Compliance**	Enniskillen/156 Tie-Over Retrofit	$	178,350
UG	**Compliance**	SARN: Dist-Repl-Compy-Services	$	32,409
UG	**Compliance**	King - District Casing Upgrade	$	100,860
UG	**Compliance**	TIMM: Anodes	$	94,026
UG	**Compliance**	WIND: Corrosion Rectifier Groundbed Program	$	75,276
UG	**Compliance**	PureConnect program 2022 (LUG)	$	215,250
UG	**Compliance**	NBAY: Dist-Repl-Contr-Services	$	110,620
UG	**Compliance**	BRAN: Meter & Regulator Inst Repl-Company	$	83,601
UG	**Compliance**	STO STORAGE WELL UPGRADES 2022	$	264,450
UG	**Compliance**	Waubuno Pool Class Location Replacement	$	268,503
UG	**Compliance**	CHAT: Dist-Repl-Contr-Services	$	112,883
UG	**Compliance**	HALT: Meter & Regulator Inst Repl-Company	$	144,604
UG	**Compliance**	Sombra Retrofit	$	15,252
UG	**Compliance**	Oil City Retrofit	$	15,498
UG	**Compliance**	THUN: Anodes	$	132,862
UG	**Compliance**	LOND: Corrosion Rectifier Groundbed Program	$	125,460
UG	**Compliance**	HAMI: Meter & Regulator Inst Repl-Company	$	178,495
UG	**Compliance**	King: Corrosion Rectifier Groundbed Program	$	381,300
UG	**Compliance**	Bridge Crossing Painting Program	$	461,250
UG	**Compliance**	SUDB: Dist-Repl-Comp-Services	$	23,229
UG	**Compliance**	KING: 22-21-025 Dist-Replacement Company Services	$	102,536
UG	**Compliance**	HALT: Anodes	$	525,210
UG	**Compliance**	WATE: Meter & Regulator Inst Repl-Company	$	201,090
UG	**Compliance**	Well Pad Improvements - Lock Blocks	$	141,253
UG	**Compliance**	Lobo B Yard Suction Valve Replacement (OBV 1305)	$	553,500
UG	**Compliance**	High Performance Coating Program	$	568,260
UG	**Compliance**	Rectifier Ground Bed Replacement Program	$	113,652
UG	**Compliance**	KING: 22-21-043 Dist-Repl-Contractor Services	$	259,053
UG	**Compliance**	LOND: Dist-Repl-Compy-Services	$	151,355
UG	**Compliance**	Wellhead Upgrade Project	$	279,259
UG	**Compliance**	Sudbury Section 1 Michaud Road	$	615,000
UG	**Compliance**	TIMM: Meter & Regulator Inst Repl-Company	$	455,448
UG	**Compliance**	KING: Anodes	$	266,646
UG	**Compliance**	LOND: Dist-Repl-Contr-Services	$	273,933
UG	**Compliance**	Thunder Bay Loop Retrofit	$	24,600
UG	**Compliance**	WIND: Dist-Repl-Compy-Services	$	236,129
UG	**Compliance**	Trafalgar NPS 34 - Unnamed Road Class Location Replacement	$	676,500
UG	**Compliance**	Espanola Retrofit	$	24,600
UG	**Compliance**	Sudbury Loop & Sudbury Sec 2b Retrofit	$	24,600
UG	**Compliance**	Brantford North Retrofit	$	30,750
UG	**Compliance**	NPS 16 Kitchener-Waterloo West Retrofit	$	861,000
UG	**Compliance**	SUDB: Anodes	$	406,269
UG	**Compliance**	NBAY: Anodes	$	330,463
UG	**Compliance**	Northern Region: Corrosion Rectifier Groundbed Program	$	934,800
UG	**Compliance**	Integrity Capital Tools Program	$	123,000
UG	**Compliance**	CHAT: Meter & Regulator Inst Repl-Company	$	541,664
UG	**Compliance**	Sudbury Lateral - East of Jocko Point	$	1,107,000
UG	**Compliance**	Sudbury Lateral NPS 10	$	1,107,000
UG	**Compliance**	STO Convert High Bleed devices to Low/no bleed	$	861,000
UG	**Compliance**	Panhandle NPS 20 - N Talbot Road Class Location Replacement	$	1,230,000
UG	**Compliance**	Owen Sound Section 4 Retrofit	$	1,230,000
UG	**Compliance**	Trafalgar NPS 34 Hamilton-Milton Class Location Replacement (Oldenburg Road)	$	1,230,000
UG	**Compliance**	Marten River Retrofit	$	61,500
UG	**Compliance**	HAMI: Dist-Repl-Contr-Services	$	370,230
UG	**Compliance**	THUN: Dist-Repl-Compy-Services	$	389,630
UG	**Compliance**	Guelph Retrofit	$	1,353,000
UG	**Compliance**	Panhandle NPS 16 - Bradley Line Class Location Replacement	$	92,250
UG	**Compliance**	WATE: Dist-Repl-Contr-Services	$	541,200

UG	**Compliance**	Panhandle NPS 16 - South of S Service Rd Class Location Replacement	$	1,476,000
UG	**Compliance**	LOND: Anodes	$	332,069
UG	**Compliance**	Redrock Retrofit	$	24,600
UG	**Compliance**	NPS 12 Nanticoke Retrofit	$	1,599,000
UG	**Compliance**	NBAY: Meter & Regulator Inst Repl-Company	$	1,203,551
UG	**Compliance**	TBAY: Meter & Regulator Inst Repl-Company	$	1,200,025
UG	**Compliance**	Panhandle NPS 20 AC Mitigation	$	1,463,700
UG	**Compliance**	WIND: Anodes	$	562,255
UG	**Compliance**	Dominon East NPS 8 - Unity Road	$	123,000
UG	**Compliance**	Brantford North - McLean School Road	$	1,845,000
UG	**Compliance**	Owen Sound Section 1 Retrofit	$	30,750
UG	**Compliance**	Imperial Oil Cogen Retrofit	$	30,750
UG	**Compliance**	2022 Integrity Dig Program S&T	$	1,937,250
UG	**Compliance**	2022 Fire Suppression and Auto Transfer Generator	$	2,019,660
UG	**Compliance**	INTE: Guelph Reinforcement Retrofit	$	1,968,000
UG	**Compliance**	Trafalgar NPS 34 Hamilton-Milton Class Location Replacement (Centre Road)	$	1,845,000
UG	**Compliance**	WIND: Dist-Repl-Contr-Services	$	660,268
UG	**Compliance**	HALT: Dist-Repl-Contr-Services	$	653,130
UG	**Compliance**	INTE: Dawn - Cuthbert - ECDA to ILI Retrofit NPS 26	$	2,079,636
UG	**Compliance**	WATE: Anodes	$	1,057,800
UG	**Compliance**	2022 Well Lateral Integrity Program	$	2,460,000
UG	**Compliance**	NPS 24 Trafalgar Bypass Retrofit	$	184,500
UG	**Compliance**	SUDB: Meter & Regulator Inst Repl-Company	$	1,722,697
UG	**Compliance**	London North	$	2,583,000
UG	**Compliance**	Payne Kimball Retrofit	$	2,583,000
UG	**Compliance**	INTE: Dawn - Cuthbert - ECDA to ILI Retrofit NPS 34	$	2,450,452
UG	**Compliance**	Sudbury Section 1 Sturgeon River North Side	$	492,000
UG	**Compliance**	Sudbury Section 1 - Yellek	$	2,952,000
UG	**Compliance**	BRAN: Meter & Regulator Inst Repl-Contractor	$	2,049,308
UG	**Compliance**	Millhaven Retrofit	$	2,462,645
UG	**Compliance**	WIND: Meter & Regulator Inst Repl-Company	$	1,910,094
UG	**Compliance**	Trafalgar NPS 48 - Saxton Road Class Location Replacement	$	3,382,500
UG	**Compliance**	KING: Meter & Regulator Inst Repl-Company	$	2,472,577
UG	**Compliance**	INTE: Destec Retrofit	$	3,090,833
UG	**Compliance**	HAMI: Anodes	$	3,924,223
UG	**Compliance**	INTE: Picton Retrofit	$	4,305,972
UG	**Compliance**	HALT: Meter & Regulator Inst Repl-Contractor	$	3,075,091
UG	**Compliance**	WIND: Meter & Regulator Inst Repl-Contractor	$	3,585,232
UG	**Compliance**	Coniston Lateral Replacement	$	1,107,000
UG	**Compliance**	HAMI: Meter & Regulator Inst Repl-Contractor	$	3,757,441
UG	**Compliance**	LOND: Meter & Regulator Inst Repl-Company	$	3,147,606
UG	**Compliance**	2022 Depth of Cover Mitigation Program	$	6,519,000
UG	**Compliance**	WATE: Meter & Regulator Inst Repl-Contractor	$	4,878,120
UG	**Compliance**	LOND: Meter & Regulator Inst Repl-Contractor	$	5,525,587
UG	**Compliance**	2022 Integrity Dig Program	$	11,070,000
UG	**Compliance**	FIMP Station Assessment Program	$	4,268,100
UG	**Compliance**	SMC-Meter & Regulator Additions North	$	1,082,438
UG	**Compliance**	INTE: Dawn - Cuthbert - NPS 42 replacement	$	23,508,153
UG	**Compliance**	SMC-Meter & Regulator Additions South	$	3,386,502
UG	**Compliance**	SMC_Meter & Regulator Replacements - North	$	4,506,729
UG	**Compliance**	SMC_Meter & Regulator Replacements - South	$	15,038,686
UG	**Must-Do**	2022 Furniture & Ergonomics Blanket	$	319,800
UG	**Must-Do**	HAMI: Dunnville Line Reinforcement	$	492,000
UG	**Must-Do**	Telepresence and Network Upgrades 2022	$	123,000
UG	**Must-Do**	UG Mobility Sustainment 2022	$	123,000
UG	**Must-Do**	Underground Storage & Reservoir Engineering Business Solutions 2022	$	369,000
UG	**Must-Do**	Microsoft SQL Server Upgrade 2022 (LUG)	$	98,400
UG	**Must-Do**	Dawn Aux 3 Siemens MCC replacement	$	113,652
UG	**Must-Do**	CHAT: Erie Shores Dr, Chatham-Kent, Replacement	$	83,486
UG	**Must-Do**	CHAT: Glenmar Ave, Chatham-Kent, Replacement	$	83,486
UG	**Must-Do**	WIND: Stanley Ave, Kingsville, Replacement	$	111,315
UG	**Must-Do**	TRANSIT: Dist-Repl-Mains Transit Relocation	$	(492,000)
UG	**Must-Do**	HAMI: Third St, Walpole, BU Replacement	$	24,908
UG	**Must-Do**	HAMI: Haddon Ave N, Hamilton, BU Replacement	$	39,852
UG	**Must-Do**	HAMI-South Coast - Walpole	$	83,180
UG	**Must-Do**	BRAN - Wellington St. E. (Dover to Oxford) Repl. BU - Otterville	$	28,452
UG	**Must-Do**	BRAN - James St. and George St. Repl. BU - Langton	$	78,967
UG	**Must-Do**	BRAN - Norfolk St. (Dover to Dead End) Repl. BU - Otterville	$	80,874
UG	**Must-Do**	BRAN - Grey St. and George St. Repl. BU - Langton	$	104,176
UG	**Must-Do**	Parkway A MCR PLC Upgrade	$	67,650
UG	**Must-Do**	HAMI: Peebles St, Caledonia, BU Replacement	$	74,723
UG	**Must-Do**	HAMI: Conc 10, Walpole, BU Replacement	$	94,649
UG	**Must-Do**	HAMI: Kohler Rd, Rainham, BU Replacement	$	104,058
UG	**Must-Do**	HAMI: Holmesdale Ave, Hamilton, BU Replacement	$	109,593
UG	**Must-Do**	BRAN - Windham St. Repl. BU - Simcoe	$	58,981

UG	**Must-Do**	BRAN - King Lane (Cedar to Tyrell) Repl. BU - Simcoe	$	88,275
UG	**Must-Do**	BRAN - Buck's Park Repl. BU - Port Dover	$	91,704
UG	**Must-Do**	SARN - Christina St at Highbury Pk Leakage - Sarnia BU	$	111,386
UG	**Must-Do**	Vehicle Assignment Per Policy	$	2,420,640
UG	**Must-Do**	THUN: Land Rights-Replacements	$	3,690
UG	**Must-Do**	TIMM: Land Rights-Replacements	$	3,690
UG	**Must-Do**	NBAY: Upgrade Maplewood PRS (43801127)	$	11,819
UG	**Must-Do**	NBAY: Land Rights-Replacements	$	6,150
UG	**Must-Do**	NBAY: Misc Materials-Company	$	6,150
UG	**Must-Do**	SUDB: Land Rights-Replacements	$	6,150
UG	**Must-Do**	SUDB: Misc Materials-Company	$	6,150
UG	**Must-Do**	King - Giant Tiger Tee Retirement (Napanee)	$	14,760
UG	**Must-Do**	LOND: Bonduelle 1st Stage	$	17,220
UG	**Must-Do**	2022 Cabling	$	127,920
UG	**Must-Do**	Halt: Kingsway Dr. Burlington BU Replacement	$	25,184
UG	**Must-Do**	HAMI: Harrison Rd, Seneca, BU Replacement	$	24,908
UG	**Must-Do**	KING: 22-22-711 Apple Rd PRS (28705115) Rebuild	$	25,315
UG	**Must-Do**	Lobo/Bright Compressor Station Lighting	$	24,600
UG	**Must-Do**	HAMI: Hall Rd W, Glanbrook, BU Replacement	$	29,889
UG	**Must-Do**	North London install 600m 4" PE.	$	30,192
UG	**Must-Do**	BRAN: 11V-101 Port Dover South Distribution Station, Port Dover, Station Rebuild	$	27,060
UG	**Must-Do**	HAMI - HSR	$	36,900
UG	**Must-Do**	HAMI: Land Rights-Replacements	$	18,450
UG	**Must-Do**	BRAN: 12S-403 Echo Energy Producer Station, Middleton Twp, Station Rebuild	$	40,590
UG	**Must-Do**	NE: Southview & Martindale, Sudbury, Valve Nest Repl	$	40,590
UG	**Must-Do**	HAMI: Balsam Ave N, Hamilton, BU Replacement	$	42,620
UG	**Must-Do**	HAMI: Napier St N, Dundas, BU Replacement	$	47,324
UG	**Must-Do**	HAMI: Sandy Bay Rd, Dunnville, BU Replacement	$	47,324
UG	**Must-Do**	HAMI: West Hamilton, Hamilton, BU Replacement	$	47,324
UG	**Must-Do**	2022 Odourant Upgrades -Disposal/Decommission	$	49,200
UG	**Must-Do**	BRAN - Lakeshore Rd. @ Big Creek Bridge Crossing Port Rowan	$	61,500
UG	**Must-Do**	HALT: Land Rights-Replacements	$	30,750
UG	**Must-Do**	Dow A: Fire & Gas Detection Panel - Replace	$	52,619
UG	**Must-Do**	STO GAS DETECTION REPLACEMENT	$	54,555
UG	**Must-Do**	HAMI: Canborough ,BU Replacement	$	56,457
UG	**Must-Do**	Atmospheric Storage Tank Level Instrumentation 2022	$	60,885
UG	**Must-Do**	BRAN - Old Mill Rd. & William St. Bridge Crossing Delhi	$	61,500
UG	**Must-Do**	Dawn Aux 3 PLC Upgrade	$	61,992
UG	**Must-Do**	HALT-New Oakville Hospital	$	61,500
UG	**Must-Do**	HAMI - US Steel Atmospheric Tank Replacement - Hamilton	$	61,500
UG	**Must-Do**	HALT: Maple Leaf Pork Station Replacement, Corrosion	$	86,100
UG	**Must-Do**	HAMI: Norfolk St S, Hamilton, BU Replacement	$	74,723
UG	**Must-Do**	Measurement RTU Pilot Project	$	73,800
UG	**Must-Do**	Parkway/Hagar Compressor Building Lighting	$	73,800
UG	**Must-Do**	TBAY 33-22-608 Lakeshore DR NPS2 Plastic Main Install-Kenora	$	75,791
UG	**Must-Do**	Halt: Sixth Line, Oakville, BU Replacement	$	75,276
UG	**Must-Do**	Parkway Safety & Security Upgrades	$	77,210
UG	**Must-Do**	TBAY: 33-22-708 Ackland's / Dryden GM Main & Customer Station	$	78,875
UG	**Must-Do**	HAMI - South Coast - Walpole	$	83,180
UG	**Must-Do**	NW IRR Program	$	26,184
UG	**Must-Do**	KING: Indirect Materials-Replacements	$	18,879
UG	**Must-Do**	Bickford West PLC Upgrade	$	86,100
UG	**Must-Do**	Halt: Avon Cres, Oakville, BU Replacement	$	87,176
UG	**Must-Do**	Halt: Rebecca St, Oakville, BU Replacement	$	89,667
UG	**Must-Do**	King - Rooftop Piping 945 Gardiners Road - Cataraqui Town Centre	$	92,250
UG	**Must-Do**	Autosol Upgrade 2022	$	93,480
UG	**Must-Do**	BRAN: 14S-401R Holbrook South Distribution Station, Norwich, Station Rebuild	$	8,118
UG	**Must-Do**	Operations Technology Enhancements - LUG - 2022	$	98,400
UG	**Must-Do**	2022 Turbine Meter Automatic Oilers Upgrade	$	98,154
UG	**Must-Do**	Parkway Main Control Building - Fire Ga	$	73,800
UG	**Must-Do**	TBAY: 33-22-609 James St NPS4 ST Valve + Tee Replacement	$	100,065
UG	**Must-Do**	BRAN: 12T-503 ON Energy Producer Station, Delhi, Station Rebuild	$	67,650
UG	**Must-Do**	Obsolete Electrical-Replace	$	101,475
UG	**Must-Do**	Obsolete Instrumentation-Replace	$	101,475
UG	**Must-Do**	HAMI: George St, Dunnville, BU Replacement	$	103,505
UG	**Must-Do**	CHAT - 07G-321R Montgomery & Wood LP - rebuild	$	106,383
UG	**Must-Do**	WIND - 06B-601R Meadowbrook #1 LP - rebuild	$	106,383
UG	**Must-Do**	HALT: Dist-Repl-Contr-Mains Leakage	$	113,160
UG	**Must-Do**	HAMI: King St W, Hamilton, BU Replacement	$	112,914
UG	**Must-Do**	HAMI: Jackson St W, Hamilton, BU Replacement	$	119,556
UG	**Must-Do**	Engineering & STO Win10 lifecycle 2022	$	123,000
UG	**Must-Do**	BizTalk Lifecycle	$	61,500
UG	**Must-Do**	Dawn Safety & Security Upgrades	$	129,724
UG	**Must-Do**	LOND: Install 750m of NPS 4 on Oxford Street, Woodstock	$	135,300
UG	**Must-Do**	STO - UPS Battery replacements	$	147,600

UG	**Must-Do**	Dawn Compressor Building Lighting	$	154,980
UG	**Must-Do**	WIND: Upgrade Tupperville Trans Station (09G-501)	$	184,746
UG	**Must-Do**	2022 North Building Systems Blanket	$	1,662,960
UG	**Must-Do**	2022 ECES Business Continuity	$	246,000
UG	**Must-Do**	WATE: Plan(T)-Dist-Stn Measuring/Corrosion Stn	$	123,000
UG	**Must-Do**	Payton Mills: Coynes Rd Reinforcement	$	262,486
UG	**Must-Do**	King: 22-22-504 Tweed Reinforcement - McClellan and Pomeroy	$	270,600
UG	**Must-Do**	3rd Party Pre-Work - New Business	$	34,648
UG	**Must-Do**	2022 South Building Systems Blanket	$	2,431,710
UG	**Must-Do**	3rd Party Pre-Work	$	33,303
UG	**Must-Do**	WATE - Mount Forest System Reinforcement	$	306,860
UG	**Must-Do**	3rd Party Pre-Work	$	38,498
UG	**Must-Do**	King: 22-22-505 Tweed Reinforcement - Crookston Road	$	321,030
UG	**Must-Do**	3rd Party Pre-Work	$	42,348
UG	**Must-Do**	LOND: Upgrade Beachville Gate Station (14R-101)	$	344,400
UG	**Must-Do**	2022 Odourant Upgrades -Sweep Tanks	$	369,000
UG	**Must-Do**	3rd Party Pre-Work - New Business	$	46,198
UG	**Must-Do**	HALT: Main Street, Georgetown, Reinforcement (370m NPS12)	$	467,400
UG	**Must-Do**	TCPL Dawn PLC Upgrade	$	67,650
UG	**Must-Do**	CHAT: Company Program - New Business - Scattered Mains - Contractor	$	226,567
UG	**Must-Do**	WATE - Breslau System Reinforcement	$	567,714
UG	**Must-Do**	SARN: Company Program - New Business - Scattered Mains - Contractor	$	292,805
UG	**Must-Do**	3rd Party Pre-Work - New Business	$	98,111
UG	**Must-Do**	Ultrasonic Meter Transducer Upgrade	$	261,375
UG	**Must-Do**	TIMM: Company Program - Customer Connections	$	377,840
UG	**Must-Do**	WATE - Winterbourne System Reinforcement	$	773,055
UG	**Must-Do**	THUN: Dist-Repl-Compy-Mains Municipal	$	250,309
UG	**Must-Do**	20L-501R Bayfield Gate Station Rebuild	$	843,069
UG	**Must-Do**	TBAY: Company Program - New Business - Scattered Mains - Company	$	359,230
UG	**Must-Do**	BRAN - St. George System Reinforcement, Brant	$	890,520
UG	**Must-Do**	WATE: 22S-401 Drayton Distribution Station, Drayton, Station Rebuild	$	894,333
UG	**Must-Do**	TIMM: 45-21-500 Hwy 655 HP Reinforcement (NPS 6 near LaForest TBS)	$	891,750
UG	**Must-Do**	2022 - Tech Training - Tools Replacement	$	976,372
UG	**Must-Do**	3rd Party Pre-Work - New Business	$	288,737
UG	**Must-Do**	2022 - Tech Training-Tools Addition	$	1,016,226
UG	**Must-Do**	Direct Capital Overheads	$	307,500
UG	**Must-Do**	BRAN - Brantford System Reinforcement (New Station), Proj# 06-22-705	$	1,125,450
UG	**Must-Do**	WATE - Guelph System Reinforcement	$	1,136,471
UG	**Must-Do**	KING: 22-21-702 Odessa TBS (28405001) Rebuild	$	1,203,541
UG	**Must-Do**	2022 Odourant Upgrades - MOIS Upgrades	$	1,230,000
UG	**Must-Do**	3rd Party Pre-Work	$	38,498
UG	**Must-Do**	3rd Party Pre-Work - New Business	$	384,983
UG	**Must-Do**	Halt: Khalsa Gate Oakville reinforcement	$	492,000
UG	**Must-Do**	3rd Party Pre-Work	$	153,993
UG	**Must-Do**	CHAT: Company Program - Customer Connections	$	846,957
UG	**Must-Do**	TIMM: 45-21-302 Macassa Mine New NG Service to Shaft #4	$	1,476,000
UG	**Must-Do**	TBAY 33-23-502 Victor St and Riverdale Road NPS6 Reinforcement	$	1,588,269
UG	**Must-Do**	King: 22-YY-022 Mains Municipal	$	732,966
UG	**Must-Do**	3rd Party Pre-Work	$	92,398
UG	**Must-Do**	SARN: Company Program - Customer Connections	$	846,930
UG	**Must-Do**	3rd Party Pre-Work	$	76,997
UG	**Must-Do**	BRAN: Dist-Repl-Contr-Mains Municipal	$	1,196,790
UG	**Must-Do**	Halt Oakville Dunoak to Trafalgar reinforcement	$	2,224,503
UG	**Must-Do**	NBAY: Company Program - New Business - Scattered Mains - Contractor	$	1,177,197
UG	**Must-Do**	Halt Vision Georgetown reinforcement	$	2,267,937
UG	**Must-Do**	3rd Party Pre-Work - New Business	$	481,229
UG	**Must-Do**	HAMI: Georgetown TBS Station (21X-401R) Capacity - Reinforcement	$	2,460,000
UG	**Must-Do**	WIND: Company Program - New Business - Scattered Mains - Contractor	$	1,106,178
UG	**Must-Do**	3rd Party Pre-Work - New Business	$	365,734
UG	**Must-Do**	BRAN: Company Program - New Business - Scattered Mains - Contractor	$	1,258,290
UG	**Must-Do**	NE: Dist-Repl-Contr-Mains Municipal	$	1,010,069
UG	**Must-Do**	2022 RTU Upgrade Program	$	3,075,000
UG	**Must-Do**	TBAY: Company Program - Customer Connections	$	1,598,383
UG	**Must-Do**	Fixed Overhead - STIP	$	2,291,500
UG	**Must-Do**	2022 - OS - Heavy Work Equipment	$	3,849,826
UG	**Must-Do**	WATE: 18T-101 Kitchener Gate , Kitchener, Station Rebuild	$	1,984,092
UG	**Must-Do**	LOND: Upgrade Ingersoll Trans (14R-102) Reinforcement	$	9,065,100
UG	**Must-Do**	ECS: Greenstone Mine, Geraldton (12km of NPS 6)	$	4,681,006
UG	**Must-Do**	King - Chesterville, Crysler, Finch Reinforcement	$	350,550
UG	**Must-Do**	WATE: Company Program - New Business - Scattered Mains - Contractor	$	2,934,780
UG	**Must-Do**	BRAN: Company Program - Customer Connections	$	3,153,720
UG	**Must-Do**	KING: 22-21-001 Company Program - New Business - Scattered Mains - Contractor	$	2,678,711
UG	**Must-Do**	HAMI: Dist-Repl-Contr-Mains Municipal	$	2,134,050
UG	**Must-Do**	2022 - OS - Transportation-Replacements	$	6,236,174
UG	**Must-Do**	HALT: Company Program - New Business - Scattered Mains - Contractor	$	3,739,200

UG	**Must-Do**	LOND: Company Program - New Business - Scattered Mains - Contractor	$	2,960,590
UG	**Must-Do**	SUDB: Company Program - Customer Connections	$	2,945,343
UG	**Must-Do**	HALT: Company Program - Customer Connections	$	4,001,190
UG	**Must-Do**	HAMI: Company Program - New Business - Scattered Mains - Contractor	$	3,737,970
UG	**Must-Do**	HALT: Dist-Repl-Contr-Mains Municipal	$	4,022,100
UG	**Must-Do**	HAMI: Company Program - Customer Connections	$	4,295,160
UG	**Must-Do**	NBAY: Company Program - Customer Connections	$	4,801,220
UG	**Must-Do**	WIND: Company Program - Customer Connections	$	4,947,697
UG	**Must-Do**	LOND: Dist-Repl-Contr-Mains Municipal	$	5,006,982
UG	**Must-Do**	WATE: Dist-Repl-Contr-Mains Municipal	$	6,753,930
UG	**Must-Do**	WIND: Dist-Repl-Contr-Mains Municipal	$	7,419,723
UG	**Must-Do**	WIND: Generic Greenhouse Windsor	$	7,995,000
UG	**Must-Do**	KING: Company Program - Customer Connections	$	6,744,897
UG	**Must-Do**	LOND: Upgrade Byron Transmission Stn (13N-501) Reinforcement	$	20,380,828
UG	**Must-Do**	WATE: Company Program - Customer Connections	$	8,702,250
UG	**Must-Do**	LOND: Company Program - Customer Connections	$	10,826,941
UG	**Must-Do**	Sarnia Expansion (NPS 20 Dow to Bluewater)	$	555,159
UG	**Value Driven**	HAMI: Argyle St N, Caledonia, BU Replacement	$	536,065
UG	**Value Driven**	Bright A2 Gas Generator - Mid life Overhaul	$	3,455,168
UG	**Value Driven**	Union Rate Zones Micro Operations Sites Program	$	2,460,000
UG	**Value Driven**	Well Optimization Program 2022	$	307,500
UG	**Value Driven**	Kirkland Lake Lateral Replacement	$	20,666,339
UG	**Value Driven**	Waubuno Compression Lifecycle	$	144,131
UG	**Value Driven**	UG – TIS Hardware Sustainment Fund - 2022	$	2,706,000
UG	**Value Driven**	Dawn: 5985 CV & Piping - Improvements	$	418,200
UG	**Value Driven**	Oracle Database Upgrade 2021 (LUG)	$	184,500
UG	**Value Driven**	WIND: Tecumseh Rd E - Ph1, Windsor, Replacement	$	2,226,300
UG	**Value Driven**	Bright A1 - Siemens Valve Controllers	$	129,150
UG	**Value Driven**	Bright A2 - Siemens Valve Controllers	$	129,150
UG	**Value Driven**	KING: 22-22-704 College and Sidney DRS (27801009) Rebuild	$	694,950
UG	**Value Driven**	Siemens Valve Controllers Replacement	$	1,193,100
UG	**Value Driven**	Lisgar PLC Upgrade	$	135,300
UG	**Value Driven**	Dawn D - Fire & Gas Detection Panel	$	89,975
UG	**Value Driven**	SiteCore Upgrades 2022	$	147,600
UG	**Value Driven**	Parkway Measurement PLC Upgrade	$	233,700
UG	**Value Driven**	Dawn E - Fire & Gas Detection Panel	$	116,850
UG	**Value Driven**	Dawn G - Fire & Gas Detection Panel	$	127,859
UG	**Value Driven**	13O-113R Bathurse & Talbot	$	14,760
UG	**Value Driven**	WIND: Renaud St, Tecumseh, Replacement	$	150,275
UG	**Value Driven**	Dawn D Siemens MCC replacement	$	393,047
UG	**Value Driven**	Dawn G Siemens MCC replacement	$	14,207
UG	**Value Driven**	WIND: 12014 - 12072 Tecumseh Rd E, Tecumseh, Replacement	$	244,893
UG	**Value Driven**	HAMI: Maple St, Dunnville, BU Replacement	$	124,538
UG	**Value Driven**	Dawn E Siemens MCC replacement	$	381,300
UG	**Value Driven**	HAMI: Brant St, Dunnville, BU Replacement	$	134,501
UG	**Value Driven**	HAMI: Binkley Station Rebuild, Vault	$	553,500
UG	**Value Driven**	HAMI: Hwy 5 & Brock Station Rebuild, Vault	$	553,500
UG	**Value Driven**	HAMI: Kenora & Bancroft Station Rebuild, Vault	$	553,500
UG	**Value Driven**	Parkway West Perimeter Security Path	$	276,750
UG	**Value Driven**	Kirkwall Backup Generator	$	215,250
UG	**Value Driven**	Bright B PLC Upgrade	$	627,300
UG	**Value Driven**	CHAT - 07G-201 Baldoon Transmission - Station Rebuild	$	1,560,066
UG	**Value Driven**	BRAN: 16V-402R Dunsdon St Distribution Station, Brantford, Station Rebuild	$	426,195
UG	**Value Driven**	HAMI: Cheapside Rd, Walpole, BU Replacement	$	224,168
UG	**Value Driven**	WATE: 18U-601 Avenue Rd Distribution Station, Cambridge, Station Rebuild	$	358,545
UG	**Value Driven**	Dawn: Air System Upgrade	$	609,588
UG	**Value Driven**	WATE: 21T-301 Salem Gate Station, Salem, Station Rebuild	$	108,240
UG	**Value Driven**	BRAN - Head N. (Windham to Maple) Repl. BU - Simcoe	$	136,085
UG	**Value Driven**	BRAN: 15V-111R Stanley St Distribution Station, Brantford, Station Rebuild	$	121,770
UG	**Value Driven**	HAMI - HWY 6 - Walpole	$	291,130
UG	**Value Driven**	HAMI: Niagara St, Dunnville, BU Replacement	$	322,137
UG	**Value Driven**	HAMI: East Caledonia, BU Replacement	$	154,427
UG	**Value Driven**	BRAN - Queen St. (Grey to Priddle) Repl. BU - Langton	$	204,863
UG	**Value Driven**	HAMI: Cayuga, BU Replacement	$	169,648
UG	**Value Driven**	Halt: Holly Ave, Milton, BU Replacement	$	172,692
UG	**Value Driven**	Lobo B PLC Upgrade	$	92,250
UG	**Value Driven**	WIND: County Rd 34 MIP, Cottam, Replacement	$	640,061
UG	**Value Driven**	HAMI: Locke St E, Dunnville, BU Replacement	$	254,057
UG	**Value Driven**	HAMI: Sims Lock Rd, Seneca, BU Replacement	$	258,761
UG	**Value Driven**	HAMI: Glassco Ave N, Hamilton, BU Replacement	$	269,001
UG	**Value Driven**	HAMI: Nairn St, Caledonia, BU Replacement	$	300,274
UG	**Value Driven**	LOND - Nixon Ave. BU - London	$	445,543
UG	**Value Driven**	Dawn Aux 4-1 Gen Top End O/H	$	185,976
UG	**Value Driven**	Payne Measurement Upgrade	$	195,570
UG	**Value Driven**	Halt_Delrex blvd Shallow main georgetown	$	146,241

UG	**Value Driven**	Dawn NAB Generator-Replace	$	1,008,600
UG	**Value Driven**	Hagar Backup Generator Control Panel Upgrade	$	225,380
UG	**Value Driven**	BODS Upgrade 2021	$	92,250
UG	**Value Driven**	16P-501R Medina Gate & MOP Upgrade	$	781,264
UG	**Value Driven**	Parkway East Building Improvements	$	135,300
UG	**Value Driven**	SARN - Rosedale Ave Leakage - Sarnia BU	$	451,112
UG	**Value Driven**	THUN: Indirect Materials-Replacements	$	52,447
UG	**Value Driven**	HAMI: Fennell & Upper Ottawa Station, LP	$	147,600
UG	**Value Driven**	THUN: Red Rock Inc. (Former Mill) SMS Retirement	$	149,996
UG	**Value Driven**	4749 Control Valve Power Gas Cabinet	$	151,290
UG	**Value Driven**	TIMM: Indirect Materials-Replacements	$	87,945
UG	**Value Driven**	WATE: 22T-501R Alma Distribution Station, Alma, Station Rebuild	$	155,595
UG	**Value Driven**	87 DHS Operator Bickford V1	$	166,050
UG	**Value Driven**	11O-202R St George and Curtis	$	171,714
UG	**Value Driven**	13O-225R Trafalgar & Egerton Low Pressure Rebuild	$	171,714
UG	**Value Driven**	14O-507R Rabb and Linwood LP	$	171,714
UG	**Value Driven**	Dawn G Surge Controller	$	213,098
UG	**Value Driven**	HAMI: Gardiner Ave E, Dunnville, BU Replacement	$	454,424
UG	**Value Driven**	HALT: Plan(T)-Dist-Stn Measuring/Corrosion Stn	$	184,500
UG	**Value Driven**	King - under rated valves Napanee TBS 28101001	$	184,500
UG	**Value Driven**	KING: 22-22-703 Belleville Sidney St TBS (27801001) Valve Upgrades	$	184,500
UG	**Value Driven**	Lobo B Unit Control Building Upgrade	$	184,500
UG	**Value Driven**	Unionline Releases 2022	$	184,500
UG	**Value Driven**	King - Sectionalization (Corrosion & Valves)	$	200,646
UG	**Value Driven**	STO Obsolete Mechanical - Replace	$	202,950
UG	**Value Driven**	Windsor/Chatham IRR Program	$	65,707
UG	**Value Driven**	TCO Obsolete Mechanical - Replace	$	215,250
UG	**Value Driven**	NE IRR Program	$	102,780
UG	**Value Driven**	Hagar Winter Equipment Covered Storage	$	246,000
UG	**Value Driven**	HAMI: Plan(T)-Dist-Stn Measuring/Corrosion Stn	$	246,000
UG	**Value Driven**	HAMI-Mohawk Aerial Crossing	$	270,600
UG	**Value Driven**	Bright C GGLO scheduling valve and Controller replacement	$	273,060
UG	**Value Driven**	Parkway C GGLO scheduling valve & controller replacement	$	273,060
UG	**Value Driven**	Hexagon Releases 2022	$	276,750
UG	**Value Driven**	King - Property Line PLPRS Replacement (Various Locations)	$	63,038
UG	**Value Driven**	HALT: Roylen Rd & Ripley Crt Station, LP	$	295,200
UG	**Value Driven**	KING: 22-YY-023 Dist Company Mains Leakage	$	207,850
UG	**Value Driven**	NE: 43401007 - Lively DRS, Rebuild	$	474,373
UG	**Value Driven**	NE: Bonney St, SSM, Valve Repl.	$	308,750
UG	**Value Driven**	ESG Enhancements	$	307,500
UG	**Value Driven**	KING: PSLL Maintenance	$	148,867
UG	**Value Driven**	NBAY: Plan(T)-Dist-Stn Measuring/Corrosion Stn	$	268,817
UG	**Value Driven**	NE: 43202072 - Vale Clarabelle Mill, Heater	$	338,988
UG	**Value Driven**	BRAN: 12S-202 Fernlea Farm Distribution Station, Delhi, Station Rebuild	$	121,770
UG	**Value Driven**	WATE: 19S-603 Waterloo-Laurel Creek Station, Waterloo, Station Rebuild	$	121,770
UG	**Value Driven**	WATE: 20S-301 Elmira Gate Station, Elmira, Station Rebuild	$	121,770
UG	**Value Driven**	HALT: Dalebrook Drive Dist Station, LP	$	344,400
UG	**Value Driven**	WIND: Mersea Rd 2 - Ph 2, Leamington, Replacement	$	1,669,725
UG	**Value Driven**	LOND - Waterloo St. BU - London	$	779,701
UG	**Value Driven**	WATE: 19U-601 Guelph Highway 24 Gate Station, Guelph, Station Rebuild	$	470,844
UG	**Value Driven**	BRAN: 13T-402 Hawtrey Distribution Station, Norwich Twp, Station Rebuild	$	223,781
UG	**Value Driven**	WATE: 27R-401 Durham Gate Station, Durham, Station Rebuild	$	358,545
UG	**Value Driven**	THUN: PSLL Maintenance	$	173,389
UG	**Value Driven**	Energy Services Digital Transformation Program 2022	$	369,000
UG	**Value Driven**	NE: Whittaker St., Sudbury, Replacement	$	385,294
UG	**Value Driven**	HAMI: Dist-Repl-Contr-Mains Leakage	$	396,060
UG	**Value Driven**	NBAY: PSLL Maintenance	$	194,488
UG	**Value Driven**	Gas Chromatograph Replacement	$	243,540
UG	**Value Driven**	HAMI: Sutor Rd, Rainham, BU Replacement	$	234,131
UG	**Value Driven**	TIMM: Val Rita TBS, Rebuild	$	538,324
UG	**Value Driven**	HAMI: Glancaster Hwy 6 & 20 Rd Station Rebuild, Frost Heave	$	553,500
UG	**Value Driven**	NE: 43501002 - Coniston DRS, Rebuild	$	600,850
UG	**Value Driven**	WATE - Concession St. Bridge Crossing Cambridge	$	492,000
UG	**Value Driven**	LOND: Dist-Repl-Contr-Mains Leakage	$	300,741
UG	**Value Driven**	KING: 22-20-007 Plan(T)-Dist-Stn Measuring/Corrosion Stn	$	246,000
UG	**Value Driven**	Eastern (LUG) IRR Program	$	85,162
UG	**Value Driven**	TBAY: 33-22-601 Atikokan Lateral Leak Dwnst of Sapawe Mill	$	522,750
UG	**Value Driven**	TBAY: 33-22-600 Atikokan Lateral - TP8 -Leak	$	522,750
UG	**Value Driven**	TBAY & TIMM: Plan(T)-Dist-Stn Measuring/Corrosion Stn	$	258,193
UG	**Value Driven**	WIND: Plan(T)-Dist-Stn Measuring/Corrosion Stn	$	420,057
UG	**Value Driven**	BRAN - Otterville Rd. (James to Middleton) Repl. BU - Otterville	$	895,784
UG	**Value Driven**	LOND: Plan(T)-Dist-Stn Measuring/Corrosion Stn	$	276,750
UG	**Value Driven**	Call/Voice Analytics 2022	$	615,000
UG	**Value Driven**	ConTrax Program 2022	$	615,000
UG	**Value Driven**	HALT: Action TBS Heater Installation, Frost	$	615,000

UG	**Value Driven**	Operating Technologies Lifecycle 2022	$	492,000
UG	**Value Driven**	Outbound Communication Enhancements 2022	$	615,000
UG	**Value Driven**	Dawn Dehy Plant- Process Tank Replacement	$	721,149
UG	**Value Driven**	KING: 22-21-701 Cobourg East TBS (27301068) Lineheater	$	742,841
UG	**Value Driven**	NE: Dist-Repl-Contr-Mains Leakage	$	333,132
UG	**Value Driven**	WIND: PSLL Maintenance	$	329,823
UG	**Value Driven**	THUN: Dist-Repl-Compy-Mains Leakage	$	689,104
UG	**Value Driven**	NW PFM Compliance Program	$	125,829
UG	**Value Driven**	WATE: 23Q-301 Harrison Gate Station, Harrison, Station Rebuild	$	869,979
UG	**Value Driven**	BRAN: Dist-Repl-Contr-Mains Leakage	$	875,760
UG	**Value Driven**	Hamilton/Halton IRR Program	$	175,216
UG	**Value Driven**	TBAY: 33-21-600 Centennial Park Exposed NPS 8	$	677,194
UG	**Value Driven**	WIND: Dist-Repl-Contr-Mains Leakage	$	612,233
UG	**Value Driven**	LOND - Jacqueline BU - London	$	1,336,629
UG	**Value Driven**	Hamilton Facility Decommissioning	$	861,000
UG	**Value Driven**	WATE: 19R-501R Wellesley Distribution Station, Wellesley Twp, Station Rebuild	$	933,570
UG	**Value Driven**	50 Keil Old Power House Decommissioning	$	861,000
UG	**Value Driven**	18M-301 Hensall Gate	$	1,013,724
UG	**Value Driven**	WIND - 03D-306R Mersea Gosfield - Station rebuild with heater & filter	$	1,050,429
UG	**Value Driven**	BRAN - Albert St. Repl. BU - Langton	$	1,325,510
UG	**Value Driven**	LOND - Lyman & Whethered BU - London	$	1,336,629
UG	**Value Driven**	Dryden Operations Centre	$	5,854,800
UG	**Value Driven**	NE: 43201017 - Warren TBS, Rebuild	$	851,277
UG	**Value Driven**	Ontario - Northern, Southwest, Southeast: New Wireless Pressure Recorder	$	549,810
UG	**Value Driven**	WATE: 19V-105R Stone & Gordon Vault Station, Guelph, Station Rebuild	$	1,030,986
UG	**Value Driven**	WATE: PSLL Maintenance	$	581,175
UG	**Value Driven**	SARN - London Rd Leakage - Sarnia BU	$	1,225,244
UG	**Value Driven**	SCADA Enhancements 2022	$	1,230,000
UG	**Value Driven**	SARN -Woodland Ave LP Leakage - Sarnia BU	$	1,449,685
UG	**Value Driven**	Eastern PFM Compliance Program	$	198,891
UG	**Value Driven**	NE PFM Compliance Program	$	342,986
UG	**Value Driven**	Meter handheld replacement (LUG)	$	922,500
UG	**Value Driven**	HAMI: PSLL Maintenance	$	738,000
UG	**Value Driven**	LOND: PSLL Maintenance	$	776,815
UG	**Value Driven**	LOND - PH 1 Stevenson & Brydges BU - London	$	1,893,558
UG	**Value Driven**	WIND - 05C-501 Essex Transmission	$	1,292,811
UG	**Value Driven**	TIMM: 45-22-702 Kirkland Lake (Northland) Power SMS Rebuild	$	1,682,848
UG	**Value Driven**	Network Sustainment 2022	$	1,845,000
UG	**Value Driven**	50 Keil Renovations - Phase 3	$	5,781,000
UG	**Value Driven**	50 Keil Old 2nd Floor Renovations	$	1,660,500
UG	**Value Driven**	TIMM: 45-22-700 Goldcorp Dome Mine SMS, Rebuild	$	2,122,600
UG	**Value Driven**	Dawn ECO MCR - COVID Impacts	$	492,000
UG	**Value Driven**	HAMI: NPS 10 Dominon Line Power Line Rd, Ancaster	$	624,064
UG	**Value Driven**	Windsor/Chatham PFM Compliance Program	$	906,510
UG	**Value Driven**	Hamilton/Halton PFM Compliance Program	$	698,148
UG	**Value Driven**	CNG Stations - Project #3	$	3,075,000
UG	**Value Driven**	London/Sarnia PFM Compliance Program	$	1,026,927
UG	**Value Driven**	WIND-03D-310R - Mersea Rd 3 Distribution	$	178,181
UG	**Value Driven**	Strategic Land Purchases - 2022	$	3,690,000
UG	**Value Driven**	Waterloo/Brantford PFM Compliance Program	$	1,077,665
UG	**Value Driven**	Waterloo/Brantford IRR Program	$	937,993
UG	**Value Driven**	London/Sarnia IRR Program	$	1,066,959
UG	**Value Driven**	555 Riverview Regional Operations Centre	$	7,257,000
UG	**Value Driven**	WIND-03D-301 Leamington North Gate Station	$	4,580,545
UG	**Value Driven**	Windsor Line Replacement	$	1,005,525
UG	**Value Driven**	HALT-Hall Rd Station Georgetown	$	6,497,016
UG	**Value Driven**	CS-Belleville PropertyPurch&En*C/O 2019*	$	8,364,000
UG	**Value Driven**	Moulton Replacement BU	$	123,000
UG	**Value Driven**	Distribution Operations Station Painting	$	2,460,000
UG	**Value Driven**	Windsor Line Replacement - West Portion	$	1,709,085
UG	**Value Driven**	LOND-London Lines Replacement	$	7,151,050
UG	**Efficiencies and workplan reductions**	Efficiencies and workplan reductions	$	(14,070,412)
Grand Total			**$**	**543,121,100**

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe (EP)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, Page 20, Table 8

Question(s):

a) Please confirm that 2018 Revenues are 2018 Actual Revenues at 2018 OEB Approved Rates including 2018 ICM riders. Please explain your answer.

b) Please confirm that 2020 Revenues are 2020 Actual Revenues at 2020 OEB Approved Rates that include 2018, 2019 and 2020 OEB Approved ICM riders. Please explain your answer

Response:

a) Confirmed. The 2018 OEB-approved distribution revenues for the EGD rate zone are the 2018 approved base year revenues calculated at 2018 approved rates. The Company did not have ICM in 2018 therefore approved 2018 distribution revenue does not include ICM.

b) Not confirmed. The 2020 distribution revenues for both the EGD and Union rate zones are calculated at the 2018 and 2013 base year approved rates. 2020 distribution revenue does not include approved ICM unit rates since the revenue is prepared using 2018 and 2013 base year rates. Enbridge Gas's ICM unit rates are approved to fund the revenue requirement of specific capital projects in previous years. Accordingly, ICM is excluded from revenue used to calculate the growth factor in determination of the current year threshold value.

The growth factors have been calculated using the same methodology as in the 2019, 2020 and 2021 ICM applications.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe (EP)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, page 23, Table 10 and Exhibit B, Tab 2, Schedule 3, page 13

Question(s):

Please confirm that the ICM eligible capital based on the 2021 AMP would be $110.7 million ($632.2 million less $521.5 million). Please explain your answer.

Response:

Not confirmed. The ICM eligible capital for 2022 is determined by calculating the in-service expenditures based on the 2022 Asset Management Addendum for each rate zone. Note that the AMP documents are presented based on annual capital expenditures and not the in-service capital view. The 2022 in-service capital expenditure budget for the EGD rate zone is $734.3M (Exhibit B, Tab 2, Schedule 1, Table 1, page 5). The ICM eligible capital is $212.8M (Exhibit B, Tab 2, Schedule 1, Table 10, page 23).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe (EP)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Appendix A, page 3

Preamble:

“It operates above 30% of the specified minimum yield strength (“SMYS”).”

Question(s):

a) What is the CSA Z662 Class Location of this 1.1 km of NPS 42 pipeline?

b) What is the percent SMYS at its maximum and normal operating pressures?

Response:

a) This pipeline contains Class 1 and Class 2 areas.

b) The NPS 42 Dawn-Cuthbert pipeline has a maximum hoop stress of 71% SMYS. The Maximum Operating Pressure (MOP) is as indicated in Exhibit B, Tab 2, Schedule 2, Appendix A, page 3, paragraph 4. This pipeline typically operates between 4500 kPa and 6160 kPa. Periods of pipeline maintenance can result in pressures lower than this range.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe (EP)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2, Appendix A, page 471: Appendix B, page 31 and Appendix C, page 147.

Question(s):

a) Please confirm that the three project cost estimates referenced above use three different contingency percentages, namely 11.4%, 12% and 25%.

b) Please explain why a different contingency percentage was used for each project estimate.

c) Please confirm that the ICM funding requests include contingency amounts.

d) Please list Enbridge projects previously approved for ICM funding and the amount of contingency approved by the OEB and actually used up in each project.

Response:

a) [Dawn-Cuthbert]: The contingency shown in pre-filed evidence is incorrect, and should be $2.04M, which is 11.4% of the direct charges. EGI is not proposing to update the cost estimate as the difference is immaterial and any difference between the actual and budgeted costs will be captured in the ICM deferral account.

   [Byron]: Confirmed that the contingency amount for Byron Transmission Station project is 12%.

   [Kirkland Lake]: Confirmed that the contingency amount for the Kirkland Lake project is 25%.

b) Contingency is determined by the project maturity, level of detail, and risk profile on a per project basis. Smaller projects rely on a cost estimate standard as a baseline to determine contingency while larger projects will use a PDRI process which is similar to a monte carlo analysis to determine contingency.

c) Confirmed, the ICM funding requests include contingency amounts.

d) Please refer to the table below:

ICM Docket #	Project	Approved Contingency	Actual Contingency used up
EB-2018-0305	Kingsville Reinforcement	$13,598,000	$0
EB-2018-0305	Stratford Reinforcement	$3,623,000	$0
EB-2019-0194	Windsor Line Replacement	$11,963,000	*n/a
EB-2019-0194	Don River Replacement	$3,687,764	$2,076,382
EB-2020-0181	London Lines Replacement	$13,331,000	*n/a

*The Windsor Line and London Lines project are not complete, actual contingency amounts used up cannot be determined at this time.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe (EP)

Interrogatory

Reference:

Exhibit B, Tab 2, Sch. 2, Page 2

Question(s):

Please provide the starting and ending point, the operating pressure, and the cost of the following St. Laurent Ottawa North replacements:

a) 9 km of NPS 12 XHP ST
b) 2.4 km of NPS 16 XHP ST

Response:

a - b)

As per the OEB's letter dated December 10, 2021, the St. Laurent Ottawa North Replacement Project (Phase 3) is currently subject to a leave to construct application where the issues of need and prudence are being addressed. Accordingly, these questions are out of scope in this proceeding. The information requested in this interrogatory can be found in Enbridge Gas's Updated Application[1] and responses to interrogatories[2] in the St. Laurent Replacement Project proceeding (EB-2020-0293).

[1] See Exhibit B, Tab 1, Schedule 1, Attachments 9-11, for maps of the St. Laurent system detailing the location of the proposed NPS 12 XHP ST and NPS 16 XHP ST pipelines

[2] See Exhibit I.FRPO.16, for maximum operating pressure of all existing XHP ST pipelines; and Exhibit I.ED.9, for a detailed breakdown of estimated Project costs for each segment of pipeline proposed, organized according to the Project phase and pipeline composition, plastic (polyethylene) vs. steel.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe (EP)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 3, page 9

Preamble:

The evidence indicates that ICM-eligible St. Laurent Phase 3 increased by $48.6 million due to refinement in project scope and costing, and that ICM-eligible NPS 20 Lake Shore Replacement (Cherry to Bathurst) increased by $42.9 million.

Question(s):

a) Please file the current itemized budget for each project.

b) Is Enbridge currently charging an ICM rider for either project? If the answer is yes, how much was collected from ratepayers by each rider in 2021?

Response:

a) The costs for each project are being/have been reviewed in the LTC applications for each project.

   The St. Laurent Ottawa North Replacement budget is unchanged from the LTC filed in EB-2020-0293, updated September 10, 2021:

Table 9: Estimated Project Costs

Item No.	Description	IP PE Costs	XHP ST Costs	Total Costs
1.0	Material Costs	$358,484	$1,268,313	$1,626,797
2.0	Labour Costs	$20,369,317	$48,953,572	$69,422,889
3.0	External Permitting & Land	$6,303	787,387	$793,690
4.0	Outside Services	$2,849,096	$4,523,814	$7,372,910
5.0	Direct Overheads	$531,062	$751,515	$1,282,577
6.0	Contingency Costs	$3,318,390	$16,405,401	$19,723,791
7.0	**Project Cost**	**$27,432,652**	**$72,690,002**	**$100,122,654**
8.0	Indirect Overheads	$6,203,171	$16,340,923	$22,544,094
9.0	Interest During Construction	$230,655	$782,119	$1,012,774
10.0	**Total Project Costs****	**$33,866,478**	**$89,813,044**	**$123,679,522**

*XHP ST costs are a Class 5 cost estimate
**Abandonment costs are not included in the cost estimates. Abandonment costs for IP PE are estimated to be $2,817,235 and XHP ST abandonment costs are estimated to be $7,518,548

As indicated at Exhibit B, Tab 2, Schedule 2, the NPS 20 Replacement Cherry to Bathurst budget is updated (reduced by $3 million) from the LTC filed in EB-2020-0136. See table below.

Estimated Project Costs NPS 20 LakeShore Replacement (Cherry to Bathurst)

Item No.	Description	Total Costs	
1	Material Costs	$	3,486,320.00
2	Labour Costs	$	70,030,922.00
3	External Permitting & Land	$	1,055,700.00
4	Outside Services	$	5,199,780.00
5	Direct Overheads	$	950,975.00
6	Contingency Costs	$	24,739,704.00
7	**Project Cost**	**$**	**105,463,401.00**
8	Indirect Overheads	$	23,013,270.00
9	Interest During Construction	$	1,485,613.00
10	**Total Project Costs**	**$**	**129,962,284.00**

b) No, there is no ICM unit rate in Enbridge Gas's approved rates for either the St. Laurent Ottawa North Replacement (Phase 3) or the NPS 20 Replacement Cherry to Bathurst project. Enbridge Gas has applied for ICM unit rates for both projects as part of the current application.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit A, Tab 2, Sch. 1, pg. 5

Preamble:

In the above referenced page, EGI provides the rate impact for each rate zone. The CCA applied obscures the rate impact. We would like to understand the rate impact without the benefit of the CCA which diminishes quickly.

Question(s):

For each of the Rate zones, what would the forecasted rate impacts be for the applied for projects in the first year after CCA reductions have ended for the respective projects.

Response:

CCA is calculated based on a declining balance method. As a result, the revenue requirement for each year for the life of a project includes some level of CCA benefit.

Incremental CCA measures were implemented in 2019 that, in addition to other benefits, provides for a 50% increase in the CCA benefit in respect of property acquired after November 20, 2018 that becomes available for use before 2024. The CCA benefit and impact on a project's revenue requirement is most significant in the in-service year of a project.

In order to be responsive to the request, Enbridge Gas has provided 2023 ICM unit rates calculated based on the 2023 revenue requirement and 2022 forecast at Attachment 1. Note, the 2023 revenue requirement includes the 2023 CCA benefit but the impact is more consistent with the CCA benefit experienced each year thereafter.

EGD RATE ZONE
Derivation of 2023 Incremental Capital Module ("ICM") Rates by Rate Class using 2023 Revenue Requirement

Line No.	Particulars	2023 ICM Revenue Requirement (1) (000's)	2022 Forecast Volumes	Billing Units	2023 ICM Rate at 2023 Revenue Requirement (cents / m³)
		(a)	(b)	(c)	(d) = (a / b * 100)
	Bundled Services				
1	Rate 1	9,363	5,104,272	10^3m^3	0.1834
2	Rate 6	7,621	4,724,179	10^3m^3	0.1613
3	Rate 9	-	-	10^3m^3	-
4	Rate 100	23	4,051	$10^3m^3/d$	0.5702
5	Rate 110	653	74,003	$10^3m^3/d$	0.8824
6	Rate 115	183	13,773	$10^3m^3/d$	1.3252
7	Rate 135	1	55,553	10^3m^3	0.0009
8	Rate 145	6	6,541	$10^3m^3/d$	0.0965
9	Rate 170	15	27,557	$10^3m^3/d$	0.0526
10	Rate 200	80	14,324	$10^3m^3/d$	0.5565
	Unbundled Services				
11	Rate 125	598	111,124	$10^3m^3/d$	0.5381
12	Rate 300	0.7	47	$10^3m^3/d$	1.4216
13	Total EGD Rate Zone	18,542			

Notes:
(1) Exhibit B, Tab 2, Schedule 1, Appendix E, pp. 1 - 2, column (b).

UNION RATE ZONES
Derivation of 2023 Incremental Capital Module ("ICM") Rates by Rate Class using 2023 Revenue Requirement

Line No.	Particulars	2023 ICM Revenue Requirement (1) ($000s)	2022 Forecast Usage	Billing Units	2023 ICM Rate at 2023 Revenue Requirement (cents / m³)
		(a)	(b)	(c)	(d) = (a / b * 100)
	Union North				
	Rate 01 General Service				
1	Monthly Delivery Charge	892	1,025,730	10^3m^3	0.0869
	Rate 10 General Service				
2	Monthly Delivery Charge	297	367,857	10^3m^3	0.0807
	Rate 20 Medium Volume Firm Service				
3	Delivery Demand Charge	594	83,824	$10^3m^3/d$	0.7090
	Rate 25 Large Volume Interruptible Service				
4	Monthly Delivery Charge	68	95,235	10^3m^3	0.0718
	Rate 100 Large Volume Firm Service				
5	Delivery Demand Charge	470	45,469	$10^3m^3/d$	1.0332
6	Total Union North In-Franchise	2,321			

Notes:
(1) Exhibit B, Tab 2, Schedule 1, Appendix E, pp. 3 - 5, column (b).

UNION RATE ZONES
Derivation of 2023 Incremental Capital Module ("ICM") Rates by Rate Class using 2023 Revenue Requirement

Line No.	Particulars	2023 ICM Revenue Requirement (1) ($000s)	2022 Forecast Usage	Billing Units	2023 ICM Rate at 2023 Revenue Requirement (cents / m³)
		(a)	(b)	(c)	(d) = (a / b * 100)
	Union South				
	Rate M1 Small Volume General Service				
1	Monthly Delivery Commodity Charge	723	3,134,770	10³m³	0.0231
	Rate M2 Large Volume General Service				
2	Monthly Delivery Commodity Charge	269	1,290,856	10³m³	0.0208
	Rate M4 Firm Commercial/Industrial Contract Rate				
	Firm Contracts				
3	Monthly Demand Charge	88	46,823	10³m³/d	0.1872
	Interruptible Contracts				
	Monthly Delivery Commodity Charge	-	2,275	10³m³	-
	Rate M5A Interruptible Commercial/Industrial Contract Rate				
	Firm Contracts				
4	Monthly Demand Charge	1	444	10³m³/d	0.1621
	Interruptible Contracts				
	Delivery Commodity Charge (Avg Price)	-	59,781	10³m³	-
	Rate M7 Special Large Volume Contract Rate				
	Firm Contracts				
5	Monthly Demand Charge	103	59,760	10³m³/d	0.1724
	Interruptible / Seasonal Contracts				
	Monthly Delivery Commodity Charge	-	93,732	10³m³	-
	Rate M9 Large Wholesale Service				
6	Monthly Demand Charge	12	6,040	10³m³/d	0.2049
	Rate M10 Small Wholesale Service				
7	Monthly Delivery Commodity Charge	0	360	10³m³	0.0319
	Rate T1 Contract Carriage Service				
	Firm Contracts				
8	Monthly Demand Charge	43	26,075	10³m³/d	0.1639
	Interruptible Contracts				
	Interruptible Transportation Commodity Charge	-	34,865	10³m³	-
	Rate T2 Contract Carriage Service				
	Firm Contracts				
9	Monthly Demand Charge	518	296,408	10³m³/d	0.1749
	Interruptible Contracts				
	Interruptible Transportation Commodity Charge	-	178,978	10³m³	-
	Rate T3 Contract Carriage Service				
10	Monthly Demand Charge	62	28,200	10³m³/d	0.2197
11	Total Union South In-franchise	1,819			
12	Total Union In-franchise	4,140			

Notes:
(1) Exhibit B, Tab 2, Schedule 1, Appendix E, pp. 3 - 5, column (b).

UNION RATE ZONES

Derivation of 2023 Incremental Capital Module ("ICM") Rates by Rate Class using 2023 Revenue Requirement

Line No.	Particulars	2023 ICM Revenue Requirement (1) ($000s)	2022 Forecast Usage	Billing Units	2023 ICM Rate at 2023 Revenue Requirement (cents / m³)
		(a)	(b)	(c)	(d) = (a / b * 100)
	Ex-franchise				
	Rate M12/C1 Transportation Service				
1	Dawn to Parkway Demand Charge	1,275	57,238,670	GJ/d	0.022
2	Dawn to Kirkwall Demand Charge	26	1,409,148	GJ/d	0.019
3	Kirkwall to Parkway Demand Charge	20	5,053,860	GJ/d	0.004
4	M12-X Demand Charge	120	4,238,868	GJ/d	0.028
5	Parkway to Kirkwall/Dawn Demand Charge	41	6,707,088	GJ/d	0.006
6	Kirkwall to Dawn Demand Charge	72	5,544,072	GJ/d	0.013
	Rate M17 Transportation Service				
7	Dawn to Delivery Area Demand Charge	2	106,356	GJ/d	0.017
8	Total Ex-franchise	1,557			
9	Total Union Rate Zones	5,696			

Notes:
(1) Exhibit B, Tab 2, Schedule 1, Appendix E, pp. 3 - 5, column (b).

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit A, Tab 2, Sch. 1, pg. 8, footnote 15

Question(s):

Please outline the factors that feed into the conversion from as spent to in service.

a) Please demonstrate by providing the calculation for System Renewal in line 3 of Table 3.

Response:

a) The conversion of EGI budgets from an annual capital expenditure to an in-service view is achieved by reviewing the Asset Management Plan investments on an individual basis. All projects greater than $2M are reviewed to determine the forecasted in-service date. In this example, if the in-service date falls within the 2022 calendar year, any prior year project actuals and the related overheads are added to the 2022 total expenditures. Note the AMP capital expenditure for the System Renewal category is $404.3M for 2022 compared to an in-service capital expenditure of $465.3M (as shown in EB-2021-0148, Exhibit B, Tab 2, Schedule 1, Table 3, Line 3). An example of a project that had an in-service adjustment for 2022 is the NPS 20 Replacement Cherry to Bathurst Project. The forecasted spend prior to 2022 for this project is $28.1M.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit A, Tab 2, Sch. 1, pg. 10

Preamble:

We would like to understand more about the increases summarized in the EGD Rate Zone table.

Question(s):

Please breakdown the increases of $40M and $15M into the major components and the justification associated with those components

Response:

The variances in Distribution Pipe, Main Replacement are due to the following drivers:

1- Increase of $40M in relation to changes to the phasing of segments for the St. Laurent Ottawa North Replacement Phase 3 project as filed in the revised LTC (EB-2020-0293). There are no changes to the project scope.

2- Variances in the replacement program are due to changes in scope, timing and costing for several projects. The most significant project drivers are:

  - A20: Homark Dr. Mississauga Replacement $4.3M
  - NPS 12 Martin Grove Rd – Clements Rd to Lavington $3.8M
  - VSM – Yonge and Davis Dr West – Phase 1 $3.5M
  - Oshawa LP Replacement Phase 2 King St $3.0M
  - A50: Big Bay Point VPM Aldyl A $2.5M
  - Accumulation of many smaller variances ($2.1M)

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 2, Sch. 1, Appendix A, pg. 2, Table B, line 7

Preamble:

We would like to understand more about the significant increase in the Union Gas rate zone for General Plant Improvements.

Question(s):

Please provide a description and breakdown of costs that drove the substantial increase in line 7 starting in 2021 and continuing through the forecast period.

a) Please provide the three largest projects and their cost estimates

Response:

The increase in costs is due to the construction of new field offices in the Union Gas rate zone and renovations to the Keil Dr. location in Chatham. A summary of projects driving the increase from 2021 to 2022 is provided below. The forecast years (2023-2026) are not subject to this application but are identified in the 2021 AMP (EB-2020-0181, Exhibit C, Tab 2, Schedule 1).

a) Keil Dr Renovations (2021-22) - $13.2M
   Belleville Regional Operations Centre (2022) - $10.6M
   50 Keil Combined Heat and Power (2021) $8.1M
   555 Riverview Regional Operations Centre (2022) $7.3M

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 2, Sch. 1, Appendix A, pg. 4, Table E, line 4

Preamble:

We would like to understand more about the significant increase in the EGD rate zone for Gate & Feeder Stations.

Question(s):

Please provide a description and breakdown of costs that drove the substantial increase in line 4 starting in 2020 and continuing through the forecast period.

a) Please provide the three largest projects and their cost estimates

Response:

The increase in costs is due to refinements of timing and costs in the Stations portfolio. In-service capital expenditures were reduced in 2021 with some projects being deferred and moved to 2022. A summary of projects driving the increase from 2020 to 2022 is listed below. The forecast years (2023-2026) are not subject to this application but are identified in the 2021 AMP (EB-2020-0181, Exhibit C, Tab 2, Schedule 1).

a) Parkway Gate (2022) - $12.5M
St John Sideroad Feeder Station (2022) - $12.8M
Brampton Gate Station Rebuild (2022) - $6.2M
Albion Gate Station Control Valve Upgrade (2022) - $4.3M

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 2, Sch. 1, Appendix A, pg. 5, Table F, line 14

Preamble:

We would like to understand more about the significant increase in the Union Gas rate zone for Station Rebuilds - Gate & Feeder.

Question(s):

Please provide a description and breakdown of costs that drove the substantial increase in line 14 starting in 2021 and continuing through the forecast period.

a) Please provide the three largest projects and their cost estimates

Response:

The increase in costs is due to refinements of timing and costs in the Stations portfolio. A summary of projects driving the increase from 2021 to 2022 is below. The forecast years are not subject to this application but are identified in the 2021 AMP (EB-2020-0181, Exhibit C, Tab 2, Schedule 1) and will be further reviewed through the development of the 2023-2032 AMP.

a) HALT-Hall Rd Station Georgetown (2022) - $6.5M
WIND-03D-301 Leamington North Gate Station $4.6M
CNG Projects (2022) - $3.1M
TIMM Goldcorp Dome Mine SMS Rebuild (2022) - $2.1M
TIMM Kirkland Lake (Northland) Power SMS Rebuild (2022) - $1.7M

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 2, Sch. 1, Appendix A, pg. 6, Table G and pg. 7, Table H and
EB-2020-0181 Exhibit B, Tab 2, Sch. 1, Appendix A, pg. 6, Table G

Preamble:

We would like to understand more about the significant increase for both rate zones for Integrity Initiatives.

Question(s):

Please provide a description and breakdown of costs that drove the substantial increases starting in 2021 and continuing through the forecast period.

a) Please detail why these initiatives are categorized under System Service vs. System Renewal

b) For each rate zone, please provide the three largest projects and their cost estimates

c) Please explain the factors or drivers that resulted in a significant increase in Integrity Initiatives for the EGD rate zone starting in 2022 compared to

Response:

The Capital Expenditure tables from 2016 to 2020 do not have overheads layered into the projects. From 2021 to 2026 the overheads associated with the individual investments were layered into the table.

In keeping with Enbridge Gas's Transmission Integrity Management Program, Enbridge Gas has been completing retrofits to install launchers and receivers at stations – this will lead to an increase in the number of inline inspections that can be completed and an increase in the number of integrity digs and repairs that may be required.

EGI has enhanced the Facilities Integrity Management Program (FIMP), which provides the framework to identify threats, monitor facility conditions and manage integrity data to ensure that the pipeline facilities system is suitable for continued safe and reliable service and to comply with applicable regulations.

a) The legacy Companies (Enbridge Gas Distribution and Union Gas) categorized integrity spend under System Service and System Renewal. As part of the realignment for the reporting for the two legacy Companies, both rate zones (EGD and Union Gas) shifted to categorize it as System Service in the 2020 Rates Application (EB-2020-0181, Exhibit C, Tab 1, Schedule 1, Table 2, pages. 43 -44). The Integrity Management Program performs inspections on assets to inform condition and support asset-related decisions. The outcome of the inspections could produce new investments that could fall under System Service or System Renewal depending on the targeted asset.

b) The three largest projects in the integrity initiatives cost category in 2022 for each rate zone are defined below. Note that these are provided as they were specified at the time of this rate application submission and that the 2021 inline inspection program has now yielded specific integrity digs.

<u>EGD Rate Zone</u>

Project Name	2022 In-Service Capital
Niagara ILI Retrofits – Network 8980 & 8983 – NPS 8 & NPS 12	$13.5M
2022 Integrity Dig Program	$8.1M
Ottawa Gate Station Integrity Retrofits>30% SMYS	$1.5M

Union Gas Rate Zone

Project Name	2022 In-Service Capital
INTE: Dawn-Cuthbert – NPS 42 replacement	$23.5M
2022 Integrity Dig Program	$11.1M
INTE: Picton Retrofit	$4.3M

c) The question is incomplete but the drivers of the increased spend are noted in response to (a) above.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 2, Sch. 1, Appendix A, pg. 7, Table H, line 14

Preamble:

We would like to understand more about the significant increase in the Union Gas rate zone for Transmission Reinforcement.

Question(s):

Please provide a description and breakdown of costs that drove the substantial increase in line 14 starting in 2020 and continuing through the forecast period.

a) Please provide the three largest projects and their cost estimates

Response:

Transmission reinforcement projects are driven by forecasted demand and expected customer growth. A summary of projects driving the increase from 2020 to 2022 is below. The forecast years are not subject to this application but are identified in the 2021 AMP (EB-2020-0181, Exhibit C, Tab 2, Schedule 1) and will be refined as part of the development of the 2023-32 AMP. In addition to those listed below there are many smaller reinforcement projects.

a) LOND: Byron Transmission Station (2022) - $20.4M
LOND: Upgrade Ingersoll Trans (14R-102) Reinforcement (2022) - $9.1M
ECS: Greenstone Mine, Geraldton (12km of NPS 6) - $4.7M
HAMI: Georgetown TBS Station (21X-401R) Capacity – Reinforcement - $2.5M
HALT Vision Georgetown Reinforcement - $2.3M
HALT Oakville Dunoak to Trafalgar Reinforcement - $2.2M

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 2, Sch. 2, pg. 11-12

Preamble:

We would like to understand the mitigation of risk associated with the decision to expand/re-build the Byron Transmission station.

Question(s):

Will the rebuild of the station expose EGI to noise complaints of new facility or will there be a post construction noise assessment to compare to baseline?

Response:

A Noise Impact Study was completed on March 4, 2021 to evaluate the potential noise impact of the proposed upgrades to Byron Transmission Station. Please see Exhibit B, Tab 2, Schedule 2, Appendix B, pages 13 to 21.

Conservative analysis completed as part of this study confirms the feasibility of sufficient noise control measure for the proposed upgrades to the station.

Detailed acoustical measurements are recommended to be conducted after the upgraded station is commissioned to confirm the as-built sound emission of the station and determine if any further tailored noise control measure is required.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 2, Sch. 2, Appendix A, pg. 3-16

Preamble:

EGI evidence states: "*The existing Dawn to Cuthbert pipeline consists of approximately 1.1 km of NPS 42 ST pipeline running in an easement paralleling two adjacent NPS 26/30 and NPS 34/30 ST pipelines*."

And

"*Furthermore, integrity inspections that are required as part of the Enbridge Gas Integrity Management Plan on any of the adjacent Dawn Parkway System pipelines requires the manipulation of gas flow in order to push or pull ILI tools through pipelines. Isolation of the NPS 42 Dawn to Cuthbert pipeline and adjacent NPS 26 and NPS 34 during a failure prevents these activities from taking place until the failure event is rectified.*"

We would like to understand the priority placed on the NPS 42 pipeline from a condition assessment perspective.

Question(s):

Please provide the year of installation of the two parallel pipes in the easement in the area of the proposed replacement.

a) Please provide the operating hoop stress of those parallel pipes.
b) Please describe their condition in comparison to the section that is proposed to be replaced.
c) Is the picture in Figure 3 of pipe in the section that is proposed to be replaced?
    I. If the picture shows typical corrosion, why is EGI not proposing a longer replacement?
d) Why must the NPS 26 and 34 be isolated in the event of a failure on the NPS 42?
    I. Can the NPS 42 be shut-in separate from the other two pipelines?
    II. Please explain and provide a diagram showing the valving and dimensions to describe the reasoning.

Response:

For clarity, the two parallel lines referenced in the questions are not in scope in this application. As indicated in the pre-filed evidence, EGI is seeking ICM funding for the replacement of approximately 650 m of the existing NPS 42 Dawn to Cuthbert pipeline located between located between the Cuthbert Road Measurement Station and the Trafalgar Valve Nest.

a) EGI does not believe that this question has any relevance to this proceeding. However, in order to be responsive to the interrogatory, the Company is providing the response below:
   I. NPS 26 Dawn-Cuthbert: 1957 (72% SMYS)
   II. NSP 34 Dawn-Cuthbert: 1964 (71% SMYS)

b) EGI does not believe that this question has any relevance to this proceeding. However, to be responsive to the interrogatory, the section of parallel pipes, although in better condition as they do not have no identified Stress Corrosion Cracking, will be retrofit for inline inspection as part of a parallel project to the NPS 42 replacement providing for future monitoring of their condition.

c) No. As per the caption, Figure 3 shows typical corrosion for the NPS 42 Dawn-Kirkwall pipeline. While some segments of the NPS 42 Dawn-Kirkwall pipeline were installed at the same time and using the same materials as the NPS 42 Dawn-Cuthbert pipeline, the NPS 42 Dawn-Kirkwall pipeline is routinely inspected via ILI. Metal loss features, including corrosion, can be reliably assessed through ILI. EGI excavates targeted features of significant metal loss for repair or replacement.

d) See the responses below:
   I. During normal operations, the NPS 42 can be isolated from the NPS 26 and NPS 34 pipelines.
   II. Due to the proximity of the parallel NPS 26 and 34 pipelines to the NPS 42, the NPS 26 and 34 would be isolated to ensure a failure on the NPS 42 does not adversely impact the paralleling pipelines. The parallel lines could be potentially damaged by the energy released if the NPS 42 ruptured and would need to be evaluated prior to being placed back into service.
   The spacing between the pipelines at this location is 7.3 m. between the NPS 34 and the NPS 42, and 12.8 m. between the NPS 26 and NPS 42. At this location, the alignment of the pipelines from northernmost to southernmost is NPS 26, NPS 34, and NPS 42. The pipelines can be isolated independently at Trafalgar Valve Nest and Cuthbert Measurement. Refer to Exhibit B, Tab 2, Schedule 2, Appendix A, page 14 of 471.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 2, Sch. 2, Appendix A, pg. 3-16

Preamble:

EGI evidence states: "*The existing Dawn to Cuthbert pipeline consists of approximately 1.1 km of NPS 42 ST pipeline running in an easement paralleling two adjacent NPS 26/30 and NPS 34/30 ST pipelines*."

And

"*Furthermore, integrity inspections that are required as part of the Enbridge Gas Integrity Management Plan on any of the adjacent Dawn Parkway System pipelines requires the manipulation of gas flow in order to push or pull ILI tools through pipelines. Isolation of the NPS 42 Dawn to Cuthbert pipeline and adjacent NPS 26 and NPS 34 during a failure prevents these activities from taking place until the failure event is rectified.*"

We would like to understand the priority placed on the NPS 42 pipeline from a condition assessment perspective.

Question(s):

Does the second excerpt translate to: EGI does not do integrity inspections during a contemporaneous failure event?

a) If so, is that not common sense and not any different from any other parallel piping systems?

b) If not, please explain the relevance of the excerpt.

Response:

a) The referenced excerpt describes the impact that a potential failure of the NPS 42 Dawn-Cuthbert pipeline would have on EGI's ability to execute other work within EGI's Transmission Integrity Management Program (TIMP).

b) As described by Exhibit B, Tab 2, Schedule 2, Appendix A, page 11, paragraph 21, TIMP activities on other EGI pipelines connected to the Dawn-Parkway system could also be impacted by a failure of the NPS 42 Dawn-Cuthbert pipeline.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 2, Sch. 2, Appendix A, pg. 16, 125, 163, 232, 439 and 449

Preamble:

We provide the following excerpts from the series of technical reports provided in Appendix A and have underlined concluding statements from these reports.

Pg. 16 August 27, 2001 - **Excavation Summary:** *This corrosion was documented as corrosion area number six and determined to be within the acceptable axial length for the measured maximum depth of 1.7mm.*

Pg. 125 October 25. 2005 – ***Summary:*** *Thirteen areas of corrosion were noted having wall loss of less than 10% the actual wall thickness and six areas were found having wall loss of up to 12%. Most of the corrosion was located next to the long seam. Five areas of mechanical damage were recorded with MD-02 and MD-03 having linear indications within the gouging. The linear indications could not be sized for depth due to their location in the gouge and their lengths.*

Remediation action required the removal of five areas of mechanical damage and the linear indications found within the gouges of MD-02 and MD-03 by following the approved grinding procedure specifications. A rubber backed 120 grit buffing disc was used to remove the linear indications and mechanical damage, ensuring minimal grind lengths and a smooth transition to the adjacent surface. Magnetic particle testing was performed to ensure the removal of all defects. All defects were removed below 10% NWT.

Pg. 163 Sept. 3, 2019 - ***Mechanical Damage Summary:*** *All damage features were successfully removed as per the Enbridge Gas Engineering remediation report for this site. No further repairs were required, site to be recoated.*

Pg. 232 Sept. 20, 2019 - ***Metal-Loss Assessment Summary:*** *There was a total of 12 metal loss features noted in the NDE assessment area. All metal loss areas were existing grinds and did not exceed 3%NWT. All metal loss areas are to be recoated, no further repairs are required as per the Enbridge Gas Remediation Report for this site. Site to be recoated and backfilled.*

Mechanical Damage Summary: *There was a total of 55 damage features noted in the NDE assessment area consisting of 11 gouge/scrape features and 44 scabs or scab-like features. These features were all located in the base metal and were not associated with any other feature. No cracking was associated with any of these features. All damage features were successfully removed within the grind limits outlined in the Enbridge Gas Remediation Report for this site. All grind repairs were found acceptable by Enbridge Gas Engineering, site to be coated and backfilled.*

Additional Comments: *All grind repairs were found acceptable by Enbridge Gas Engineering, no further repairs were required.*

The above reports chronicle a series of inspections that occurred over almost 20 years. We would like to understand how these series of reports have resulted in a conclusion of replacing the NPS 42 pipe in 2022

Question(s):

Please confirm that each inspection resulted in some amount of pipe treatment and concluded that no further repairs were required.

Response:

Enbridge Gas confirms that all pipe features identified in the preamble were assessed and repaired, as required. However, the time-dependent threat of SCC is the primary integrity driver of the project, specifically because of the inability to reliably detect the areas with the most severe SCC, as referenced in Exhibit B, Tab 2, Schedule 2, Appendix A, pages 5 to 10 of 471.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 2, Sch. 2, Appendix A, pg. 16, 125, 163, 232, 439 and 449

Preamble:

Pg. 439 March 14, 2021 Executive Summary: Note that the previous ECDA surveys completed in 2005 showed that while the coating on the 26” and 34” lines appeared to be in fair to poor condition with little to no corrosion on the surface of the pipe, the 42” pipe showed areas of Polyken disbondment with minor to moderate pitting corrosion with up to 16% wall loss (Trapped water under coating had a pH of 7). It was also predicted that further pitting would not exceed another 10 mils (for a total of 80mils). until year 2025.

Pg. 449 March 14, 2021 Conclusions and Recommendations: It is important to note that the previous ECDA conducted in 2005 recorded 16% wall loss under disbonded Polyken (trapped water pH of 7) for the 42” Line. Therefore, the prior history of corrosion for the 42” Line is set to Moderate. Finally, it is recommended to set the reassessment interval to ten (10) years. Note, this interval may be modified with respect to results obtained in Steps 3 and 4 of the ECDA process.

Question(s):

Please provide a specific reference and page number in the evidence that provides the determination of 16% wall loss.

a) Please confirm that the prediction in 2005 was for 20 more years of service life.

b) After the 2019 repairs, using the same prediction methodology and proper maintenance, how many more years of service life would be predicted.

Response:

Reference to 16% wall loss is contained within Exhibit B, Tab 2, Schedule 2, Appendix A, pages 382 and 411.

a) The statement made in Exhibit B, Tab 2, Schedule 2, Appendix A, page 382 referring to year 2025 does not pertain to SCC. This statement is limited in scope to external corrosion pits and their suitability for continued service at a theoretical growth rate. No statements or prediction was made regarding any other active pipeline hazards, including SCC.

b) Exhibit B, Tab 2, Schedule 2, Appendix A, pages 439 and 449 contain no statements or predictions regarding SCC.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 2, Sch. 2, Appendix A, pg. 16, 125, 163, 232, 439 and 449

Pg. 469 NET PRESENT VALUE ASSESSMENT OF ALTERNATIVES

Question(s):

Please file the entire report that contains the cost analysis of Options A and B.

a) If not included in the report, please provide the timing assumed for EMAT LI in the subject analysis.

Response:

Please see the response at Exhibit I.ED.5 which includes the Decision Record as an attachment.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 2, Sch. 2, Appendix B

Preamble:

EGI evidence states: *As early as 2018, the Company (Union Gas Limited at the time) identified a number of integrity, safety, reliability, maintenance and operational concerns that supported a rebuild of the Station…*

…inability to inability *of the existing Station to support the long term demands of the London market beyond 2022.*

Question(s):

Please file the 2018 report identifying the concerns.

a) Please provide the demand required from each station feed and its relative capacity in:

    i) 2018
    ii) 2022
    iii) 2027

Response:

a) See Attachment 1 for the 2018 report highlighting the concerns at the station. Confidential information identifying customer names has been redacted from the publicly filed version of Attachment.

The demand required from each station feed and the relative capacity is shown in the table below. The station is at capacity in 2022 and this does not include additional future large customers outside of regular forecasted growth.

Year	Min Inlet to Station (kPa)	Heater Flow (sm³/h)	Heater Capacity (sm³/h)	% Cap	Orifice Meter Flow (sm³/h)	Orifice Meter Capacity (sm³/h)	% Cap	1A Demand (sm³/h)	1A Reg Capacity (sm³/h)	% Cap	2A Demand (sm³/h)	2A Reg Capacity (sm³/h)	% Cap	3A Demand (sm³/h)	3A Reg Capacity (sm³/h)	% Cap
2018	4,550	170,000	170,000	100%	170,000	196,300	87%	170,000	187,700	91%	60,700	63,800	95%	7,725	9,950	78%
2022	4,114	184,300	170,000	108%	184,300	179,400	103%	184,300	187,700	98%	62,600	63,800	98%	7,850	9,950	79%
2027	4,007	185,500	170,000	109%	185,500	176,430	105%	185,500	187,700	99%	63,000	63,800	99%	8,575	9,950	86%

Byron Transmission
Positioning for Growth

July 9th, 2018

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An Enbridge Company

Executive Summary

Performed:

- Detailed analysis of historical operational parameters against station capacity and forecasted growth.
- Detailed assessment for station equipment operations needs and maintenance demands and considering reliability of the station, EHS and ergonomics.
- Positioning station towards forecasted growth and required rebuild to meet capacity demand by 2022 and beyond.

Challenges:

- Station equipment capacity
- Securing funds for required rebuilds / refurbishment
- System growth and securing sales contracts with economic uncertainties

Ask: Endorsement of recommended approaches to position Byron for growth:

- Capital Budget: $ 15.6 MM → Capacity till 2044

  Full rebuild of Byron Transmission on summer 2022

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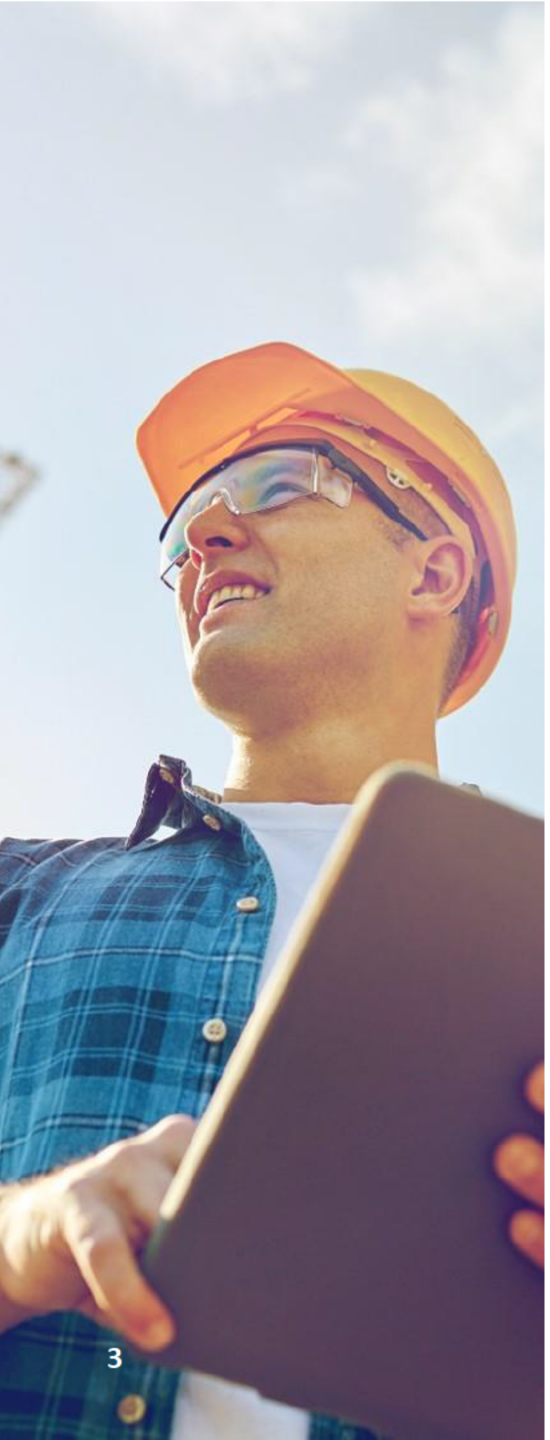

Agenda

- Gas Flow Overview
- Capacity Analysis
- Process Flow Overview
- Byron Assessment & Rebuilding Options
- Recommendations

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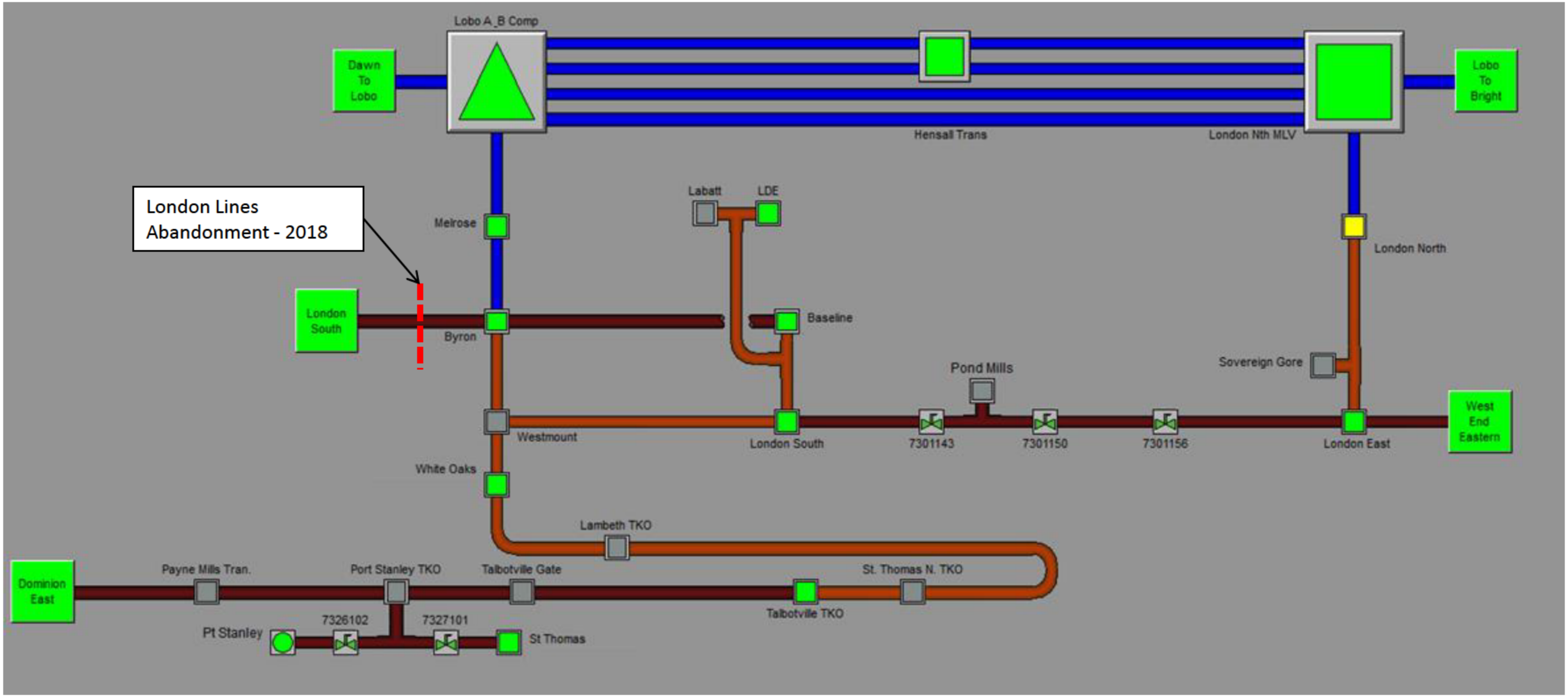
London City Gas Flow Overview



Capacity Analysis

Drivers

FBP Growth

Industrial Growth

Station Capacity

Equipment Condition

Abandonment of London Lines

Inputs

[redacted]

1,300 m3/hr (currently in service)

Indicated increase to 2,400 m3/hr in 2020 (Final increase to 3,400 m3/hr within 5 years)

[redacted]

600 m3/hr (2018 in service)

Indicated increase to 1,000 m3/hr in 2020

[redacted]

8,600 m3/hr (2019 in service)

[redacted]

5,000 m3/hr (2019 in service – feasibility level)

System Parameters:

Min inlet = 4171 kPa

Max Outlet = 3240 kPa

Capacity = 186,000 m3/hr

Growth

Station Capacity adequate till 2022

Beyond 2022:

Increase flow throughput

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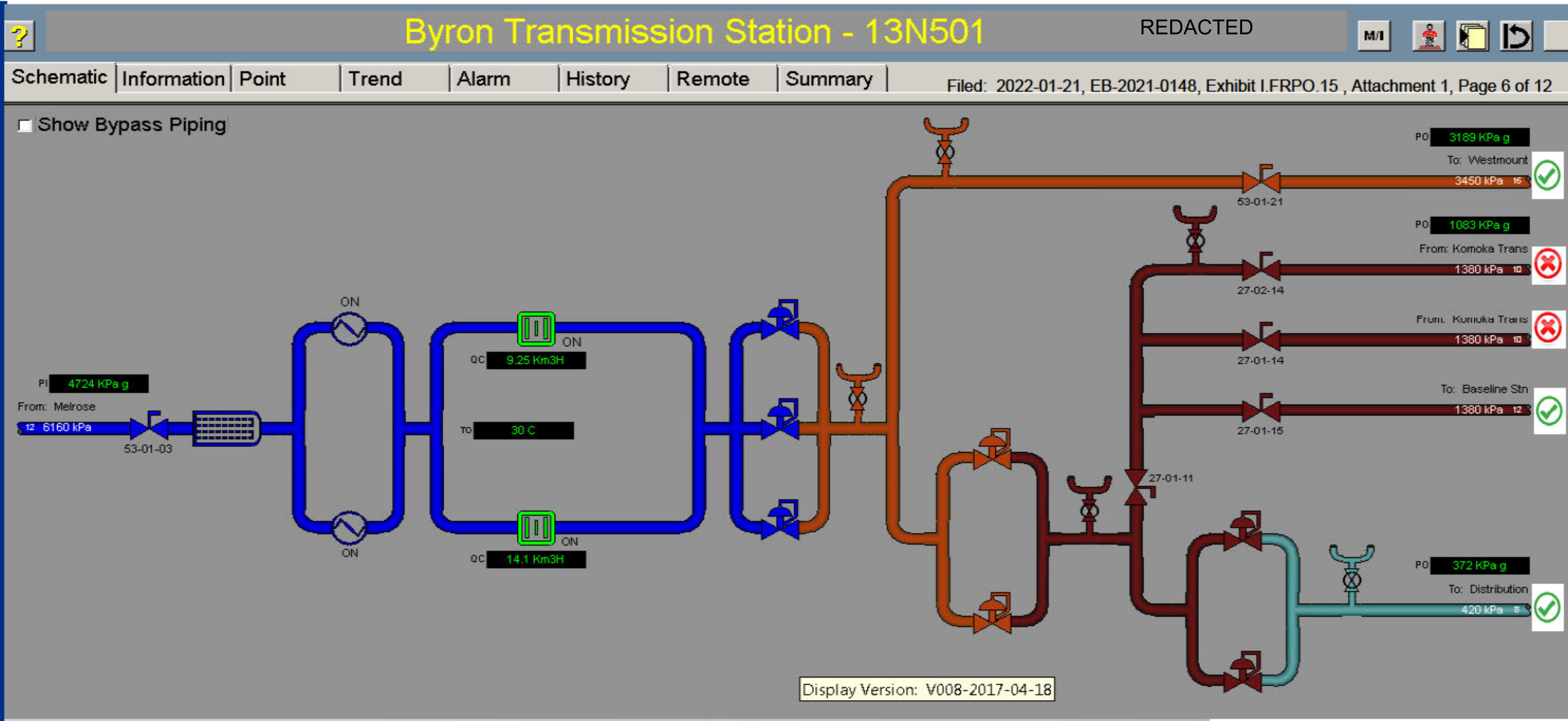
Byron Transmission



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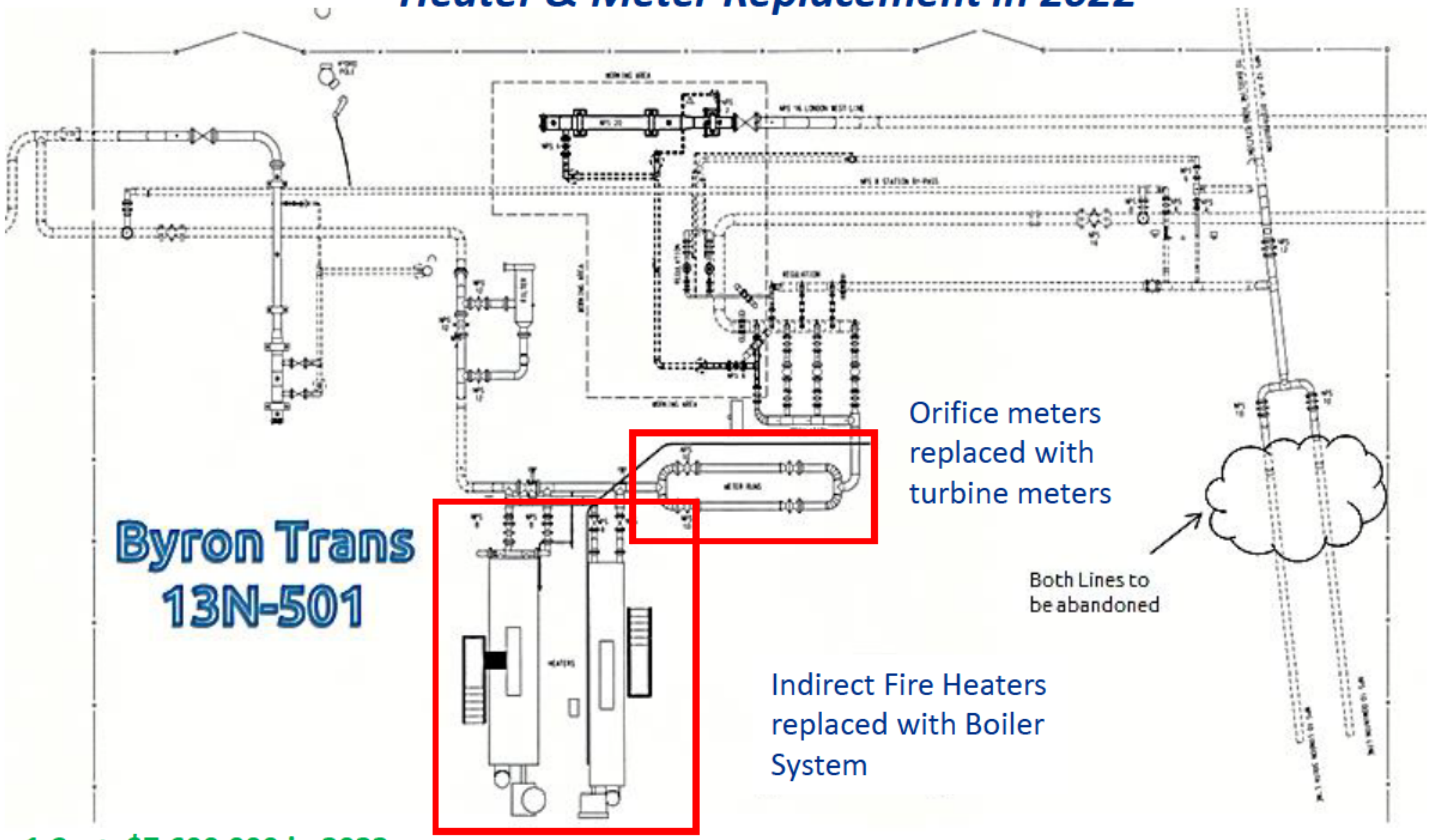
Station Equipment Assessment

Equipment	Condition/Capacity (Using Temporary Parameters)	Existing Mitigation
Filter/Separator	Filter replaced in 2017	Adequate Capacity
In-Direct Line Heaters	50% Efficient BS&B+NATCO Boilers (7MMBTU Total) Freeze off at 420 kPa outlet past 170,000 m3/hr Freeze off at 1380 kPa outlet past 180,000 m3/hr	Heat trace 100% redundant runs SCADA monitoring
Orifice Meters	Max 7” Bore Size at max capacity of 186,000 m3/hr Beyond 186,000 m3/hr results in poor accuracy Pressure drop from bore affecting inlet to the regulators	Sufficient to 186,000 m3/hr Beyond, replace with turbine meters
1st Stage Regulators (3450 kPa outlet)	6” EZR’s with 100% TRIM, Capacity adequate to 2028; Subject to rebuild of meter/heaters in 2022; Noise/erosion concerns (At source, 100 dB(A) at peak flow)	None ; Potential noise wall
2nd Stage Regulators (1380 kPa outlet)	3” EZH’s with 100% TRIM, Capacity adequate to 2028 Subject to rebuild of meter/heaters in 2022; Noise/erosion concerns (At source, 110 dB(A) at peak flow)	None - Potential noise wall
3rd Stage Regulators (420 kPa outlet)	2” EZR 100% TRIM + 3” Rockwell 441 Regulator Capacity adequate to 2028 Subject to rebuild of meter/heaters in 2022	None
Piping	Majority of pipe installed in1968; Velocity at outlet of 2nd stage regulators = 71 m/s in 2022; Observed vibration	None
Station Layout	Issues with emergency escape routes Insufficient maintenance accessibility	None

Proposed Rebuild:
Option 1

Heater & Meter Replacement in 2022



Phase 1 Cost: $7,600,000 in 2022

Phase 2 Cost :$13,400,000 in 2028

Adequate capacity to 2028 (194,000 m3/hr)

- **Outstanding Risk**
  - **Station bypass with regulation & purchase of additional land**
  - **Beyond 2028, station limited by existing regulators at 1st/2nd stage**
  - **Pipe integrity, emissions, egress, noise & velocity**

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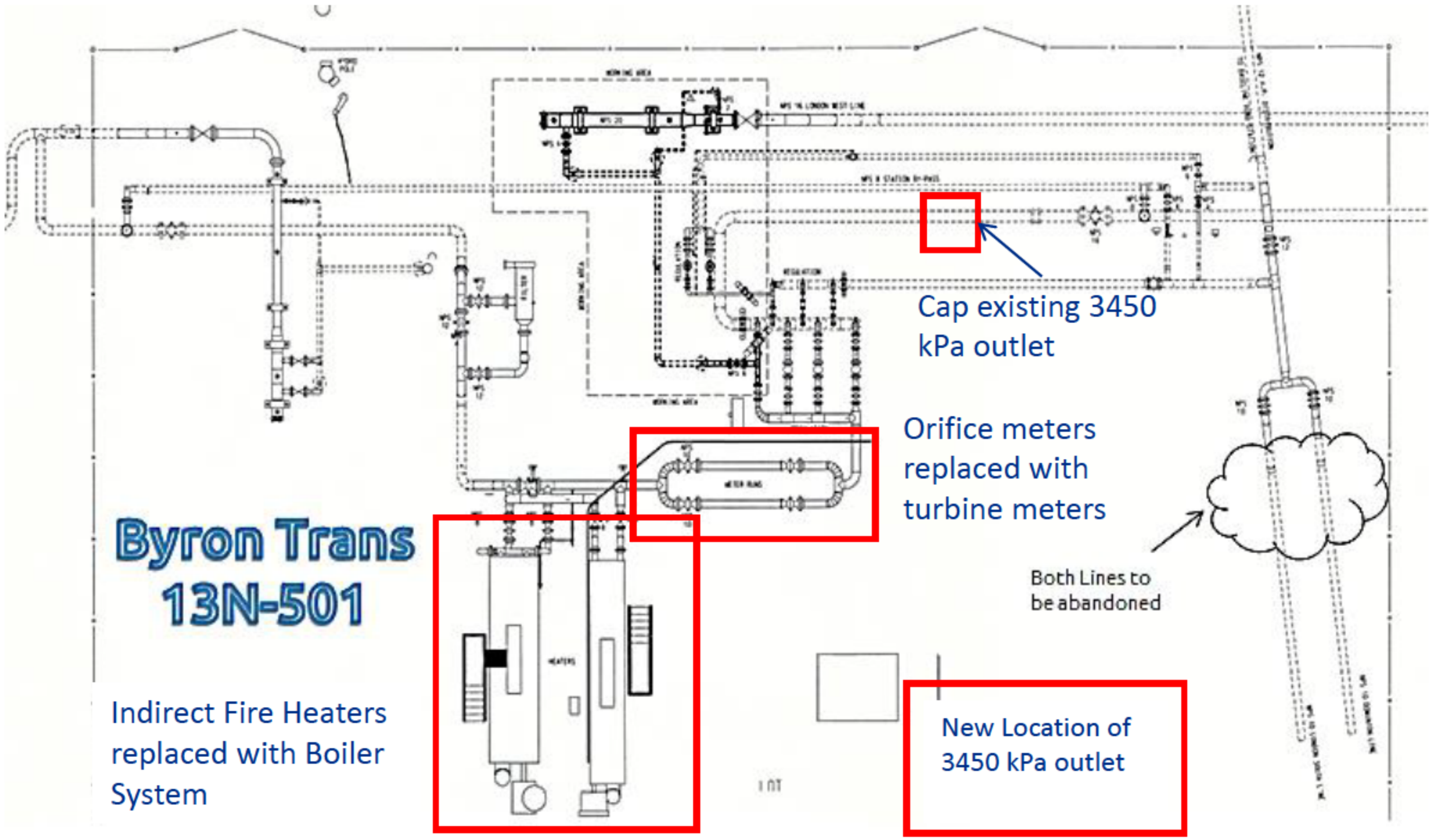
Heater & Meter Replacement + Moving 3450 kPa Outlet in 2022

Proposed Rebuild: Option 2



Phase 1 Cost: $12,000,000 in 2022

Phase 2 Cost :$5,800,000 in 2028

Provides adequate capacity to 2044 (225,000 m3/hr) for 3450 kPa outlet

- **Outstanding risks**
  - **Station capacity remains limited to 2028 (194,000 m3/hr) by 1380 kPa pressure cut**
  - **Station bypass with regulation & purchase of additional land**
  - **Pipe integrity, emissions, egress, noise & velocity**

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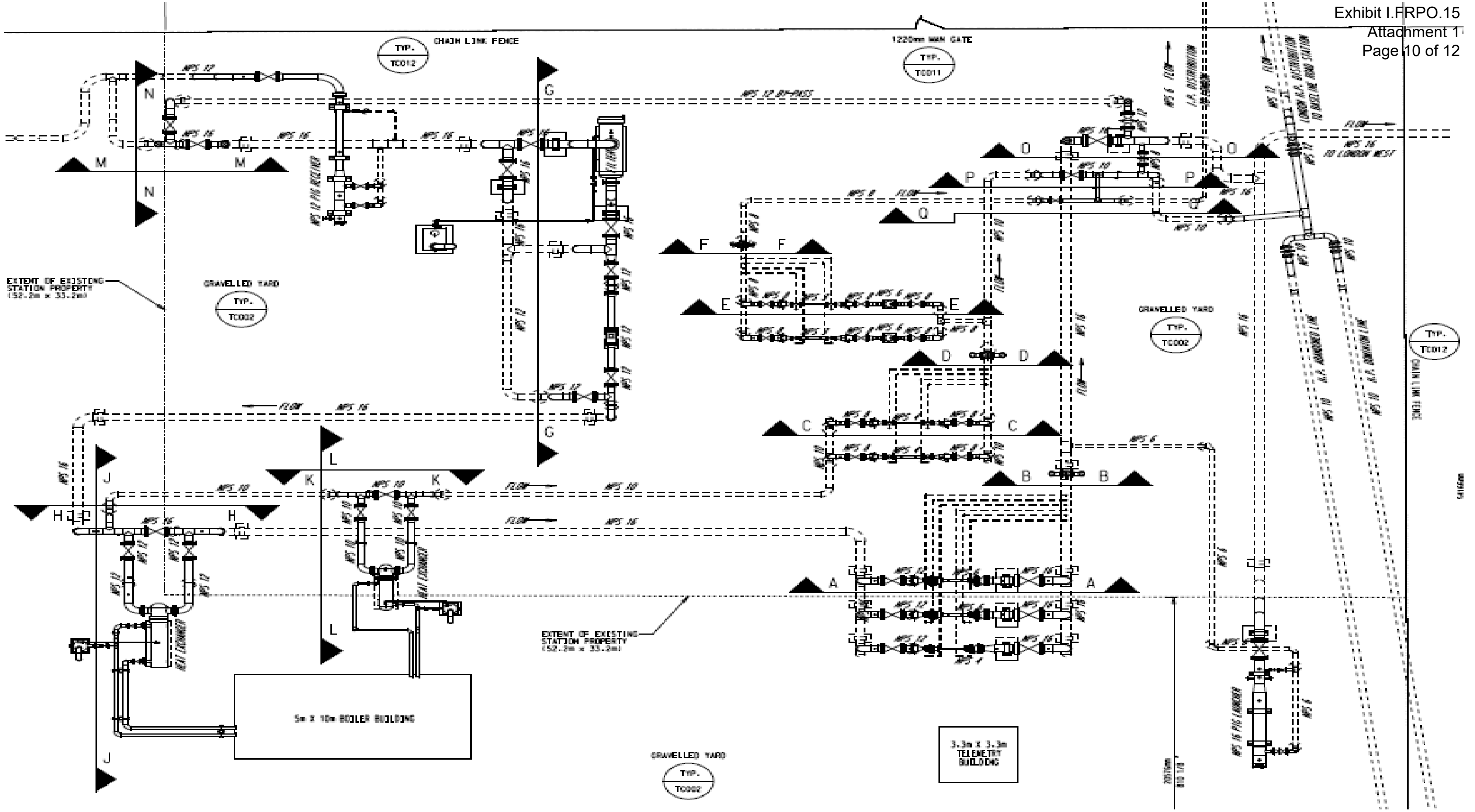
Proposed Rebuild: Option 3

Full Rebuild in 2022



- Cost: $15,600,000 in 2022
- Use existing station during construction of Byron Trans rebuild
- Requires purchase of additional land
- Provides adequate capacity to 2044

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Recommendation

Approach	Opportunities	Challenges
Byron Transmission: Option #3 **Rebuild in Summer 2022**	• Positioning for growth till 2044 • Potential for additional growth with relatively minor station changes (i.e. replacing filter or replacing regulator) • Enhanced station safety, reliability, & maintainability • Eliminate noise concerns in rapidly growing neighbourhood • Reduction in glycol volume • Enhanced layout and station ergonomics	• **Securing $15.6 MM** • Capacity to 2044 is based on regular rate growth • assumes reinforcement upstream and downstream is completed as needed

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Q& A
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ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 2, Sch. 2, Appendix B

Preamble:

Table 1 provides the Estimated Project Costs. We would like to understand better the process of securing third party contractors and the impact on resulting costs relative to estimates.

Question(s):

Please confirm that the construction work was awarded through RFP.

a) If not, why not?

b) If so, how many pre-qualified contractors bid on this work?

c) Please provide the range of contractor labour costs bid and the comparison with the Class 1 and Class 5 contractor labour estimates.

d) From recent replacement projects (e.g., Windsor Line, London Lines) what is the range of bids relative to the applied for estimates for labour?
    i) Please provide the specific range for each.
    ii) Please provide the estimated actual labour that is known or projected at this time.
        (1) Please clarify changes to scope (e.g., Windsor Line running line revisions).

Response:

a - c)

The construction work was awarded under the Facilities Agreement between Enbridge Gas and Aecon Utilities. This agreement was negotiated to provide construction services for a broad portfolio of utility work and projects. There was no project-specific RFP for this work.

d) The examples cited as well as most of our utility project work is administered under the Facilities Agreement, therefore bid information does not exist.

   i.) Also see response in part (a).

   ii.) The project cost estimate and a description of scope changes and other factors that cause the change in project cost estimate are provided at Exhibit B, Tab 2, Schedule 2, Appendix B, pages 31-32.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 2, Sch. 2, Appendix C

Preamble:

EGI evidence states: *The current system includes two lines, the Existing Line that is in scope for replacement, and a second NPS 8 Kirkland Lake Loop pipeline that runs in parallel to the Existing Line for the majority of the distance from the TransCanada Pipelines ("TCPL") supply station…*

… The Existing Line and parallel NPS 8 pipeline were determined to be primarily medium risk on the Enbridge Operational Risk Matrix…

Considering forecast customer demand and peak loading, a loss of containment leak and repair on the Existing Line may result in customer outages, as the NPS 8 Kirkland Lake Loop may not have sufficient capacity to support the Municipality of Kirkland Lake (Residential and Commercial customers), the Kirkland Lake Generating Station and Macassa Mines…

… The Project is a like for like replacement. The rationale for the decision is to provide replacement capacity for the current Kirkland Lake Lateral pipeline while also providing reliability of supply for emergency and operational scenarios in summer and shoulder month conditions.

We would like to understand better the risk assessment and alternatives considered

Question(s):

Is the NPS 8 also a risk?

a) If so, why is EGI only replacing one pipeline?
   i) Is the NPS 8 currently in the EGI Asset Management plan for scheduled replacement?
      (1) If so, why not replace both with one pipeline?

b) If not, could EGI increase the pressure in the NPS 8 pipe to maintain flow without needing the NPS 4 pipe?
   i) What is the highest HDD that would allow the NPS 8 to serve firm load?
      (1) Please provide the inlet and outlet pressures of:

(a) The pipes currently in a peak day scenario
(b) The NPS 8 under the highest HDD scenario.
   (i) In the single NPS 8 HDD scenario, could the station(s) be modified to allow a lower inlet to maintain firm customers in a peak day scenario

c) In the last excerpt from EGI evidence stating that the reason to replace the NPS 4 pipe is to have a second feed for emergency or planned operational scenarios (i.e., not peak winter day design).

d) Please explain the answers above fully.

Response:

a) NPS 8 Kirkland Lake Loop was installed in 1990 using modern materials and construction practices. It is part of an inline inspection program, with the last ILI having been completed in 2019. Digs were completed in 2020 and 2021 to address localized issues reported from the ILI and maintain the pipeline in a fit for service condition, but the overall pipeline is in good condition. Therefore, it is not scheduled for replacement as part of the Asset Management Plan.

b) Design Day modelling is restricted to the minimum supply pressure provided by TransCanada Energy (TCE). An agreement with TCE is in place to provide 4,275 kPa supply pressure. This agreement can be cancelled with two years of notification to EGI. The pressure would revert to 4,000 kPa when the agreement is cancelled. The modelled pressure in the NPS 8 cannot be raised beyond the TCE supply pressure.

   i) The NPS 8 can serve firm load up to the modelled Design Day of 55.7 HDD.

   EGI also reviews the distribution system's capability to meet all interruptible contract load at 80% of the model's Design Day temperature (44.56 HDD). At a supply pressure of 4,275 kPa from TCE, the pressure into the inlet of the contract power plant customers is approaching its minimum. At a supply pressure of 4,000 kPa from TCE, minimum inlets are not met into the contract power plant customers and the Chaput Hughes TBS. With this reduced supply pressure, the minimum inlets at the contract power plant customers cannot be met at a 0 HDD (i.e., summer conditions).

   It is recommended the NPS 4 is replaced size for size to meet all peak day scenarios.

i.(1) (a)

Table 1: Kirkland Lake System Pressures for FRPO 17 b i. (1) a)

Kirkland Lake System Stations	Pressure (kPa)
42501001 STN - Kenogami CMS	4,275 [1]
42501011 STN - Tembec PRS	4,259
42501002 STN - Swastika TBS	4,034
42501020 STN - Shaft #3 TBS	3,942
42501005 STN - Chaput Hughes TBS	3,739
12500031 STN - Shaft #4 TBS	3,738
42501013 STN - Power Generation (Baseload)	3,853
42501015 STN - Power Generation (Peaker)	3,853
42501004 STN - Kirkland Lake TBS	3,833

1 – Outlet supply pressure from TCE. Remaining pressures are station inlet pressures

i.(1)(b)

See Table 1: System Pressures for FRPO 17 b i. (1) (a). As per response to 17 b i), the NPS 8 serve firm load up Design Day conditions.

i (1)(b)(i)

Station minimum inlets have been reviewed and modified as part of the Project. It is infeasible to lower the contract Power Plant customer's minimum inlet further, due to their delivery pressure requirements.

c- d)

The NPS 4 and NPS 8 line have tie-overs that allow them to feed each station across their length. If an integrity issue is found on a section of the NPS 4 or NPS 8, these tie-over points can assist with isolating the issue by avoiding or mitigating customer service interruptions. Dependent on daily temperature and contract demand, having both pipelines operating together adds additional flexibility for integrity inspections and other operational scenarios.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 2, Sch. 2, Appendix C, Exhibit C, Tab 2, Sch 1 EGI AMP 2021-25 Appendix Inv Codes 102128 & 49607
And EB-2020-0192 Exhibit I.FRPO.6 and FRPO.7

Preamble:

We are interested in understanding the output reports by using two replacement projects in the AMP (Kirkland Lake Lateral and London Lines) and factors associated with prioritization.

Question(s):

For the Kirkland Lake Lateral, please provide a description of each of the Value Function Measures and provide its numerical determination.

a) How is Value in Percentage utilized?

   i. Please describe how the absolute value of cost, avoided costs and total investment costs are summed to provide a denominator for the purposes of a percentage.
   ii. What is the utility of the percentage and how is that metric used?

Response:

For descriptions of value measures, see Table 4.1-4: EGI's Value Measures in EGI AMP 2021-2025 filed in EB-2020-0181, Exhibit C, Tab 2, Schedule 1.

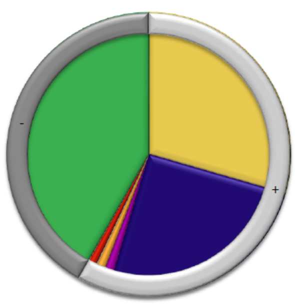
For Kirkland Lake, the primary values are savings in OPEX and CAPEX as described in the NPV analysis (see Exhibit B, Tab 2, Schedule 2, Appendix C, pages 145 to146). This analysis is an update to that presented in the 2021-2025 Asset Management Plan for investment 102128. Other value measures were not calculated since the NPV analysis clearly demonstrated the advantage of the replacement over a repair.

As is noted in the AMP Addendum (Exhibit B, Tab 2, Schedule 3, page 7) Enbridge Gas has more formally separated the Risk Management process from the Asset Investment Planning and Management process. In the case of a project like Kirkland Lake, this meant that there was a process whereby a decision was taken first to treat the risk –

either through temporary measures such as pressure restrictions or through longer term measures such as ongoing repair or replacement (in this case a combination of both).

Having established temporary measures, analysis was completed to determine which long-term measure should be implemented – in this case either an ongoing commitment to repair leaks as they are discovered or a decision to replace the pipeline. A net present value calculation was done to determine the most cost-effective way to permanently address the risk and the capital investment was brought into the Asset Management Plan.

i. Value in Percentage – Calculation of Denominator
The following example will illustrate how the absolute value of cost, avoided costs and total investment costs are summed to provide a denominator for the purposes of a percentage.



Value Function Measure	Value	Value in Percentage
Gas Storage Reliability (CA)	8,708	29%
Cost Avoidance CAPEX (CA)	7,450	25%
Financial Risk	364	1%
Environmental Risk And Remediation	339	1%
Public Safety Risk	317	1%
Avoided GHG Emissions (CA)	22	0%
Budget Savings OPEX (CA)	12	0%
Cost Avoidance OPEX (CA)	0	0%
Budget Savings CAPEX (CA)	0	0%
Revenue Impact (CA)	0	0%
Total Investment Cost (CA)	(12,342)	42%
Total	**4,870**	**100%**

The table below shows how this data is used to calculate the Denominator for the Value in Percentage as well as the Value in Percentage.

The values in Column 1 are the same as those shown in the Copperleaf extract above. These values are established through workshops and analysis in keeping with Enbridge's Value Framework as described in the Asset Management Plan 2021-5, Section 4.1.4 (EB-2020-0181 Exhibit C, Tab 2, Schedule 1). The values in Column 2 are the absolute value of the values in Column 1 – in most cases they are the same but in the case of the cost of the project the absolute value of that number is taken (shown highlighted). The sum of the absolute values (at the bottom of Column 2) is the denominator for the calculation of the Value in Percentage. Column 3 below shows how that is calculated – dividing each value by the denominator calculated at the bottom of Column 2.

Column 1 Calculation of Value	Column 2 Calculation of the Denominator for Value in Percentage	Column 3 Calculation of Value in Percentage
8707	8707	29%
7450	7450	25%
364	364	1%
339	339	1%
317	317	1%
22	22	0%
12	12	0%
0	0	0%
0	0	0%
0	0	0%
-12342	12342	42%
4869	29553	100%

ii. Value in Percentage – Utility
Although the Value in Percentage is an output from Copperleaf, it is not used in Asset Investment Decision Making. When a value assessment is completed it is used to show the percentage of the value that comes from each category – for example, Environmental Risk Reduction or CAPEX Reductions. This allows a quick comparison between risk categories and cost for different projects and supports the visual representation.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 2, Sch. 2, Appendix C, Exhibit C, Tab 2, Sch 1 EGI AMP 2021-25 Appendix Inv Codes 102128 & 49607
And EB-2020-0192 Exhibit I.FRPO.6 and FRPO.7

Preamble:

We are interested in understanding the output reports by using two replacement projects in the AMP (Kirkland Lake Lateral and London Lines) and factors associated with prioritization.

Question(s):

For the London Lines, please provide a description of each of the Value Function Measures and provide its numerical determination.

a) Specifically given the relatively low Operational and Financial Risks and very high negative Total, how and why was this project prioritized to 2021.

Response:

Please see the response at Exhibit I.FRPO.18 for the description of the Value Function Measures.

a) As has been described in the Leave to Construct Application and the interrogatories responses related to the approval of the London Lines project, the pipeline replacement project was prioritized based on Enbridge Gas's Risk Management process.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit B, Tab 2, Sch. 3, pg. 8

Preamble:

Panhandle Regional Expansion Project (PREP) Strategy Development:… *As part of the project plan, EGI will complete a supply-side IRP assessment in addition to a binding reverse open season. In this way, EGI will minimize the facilities required to serve incremental demand while optimizing any unwanted existing capacity.*

We are interested in understanding better the process undertaken to use supply-side IRP to mitigate the need for funding of long-term assets.

Question(s):

Please file the Ojibway to Dawn Firm Exchange Service with Call Option – 2023 published September 16, 2021.

a) Please provide the number of respondents to the RFP.

b) Please provide the timeline associated with evaluation of Panhandle demand, proposal evaluation and Leave to Construct application, if still needed.

Response:

a - b)

Enbridge Gas is not seeking any relief for the project specified in this question in this proceeding.

ENBRIDGE GAS INC.

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

Interrogatory

Preamble:

Dawn to Corunna Strategy Assessment

To mitigate the risks at this facility 20km of NPS 36 pipeline will be installed from Dawn to Corunna Compressor Station. The investment includes the retirement of 7 compressor units. This project replaces the equivalent design day storage capacity of 1.4PJ/d provided by the 7 compressors and will re-utilize horsepower at Dawn to eplace the capacity. The in-service date is targeted for November 1, 2023.

We would like to understand more about the analysis that resulted in applying for an NPS 36 pipeline versus upgrading/replacing compressors and foundations.

Question(s):

Please file the study(ies) that drove the change to build the proposed pipeline instead of replacing the compressors and/or reinforcing the units with problem foundations.

Response:

Enbridge Gas is not seeking any relief for the project specified in this question in this proceeding.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit C, Tab 2, Sch. 1, pg. 18

Preamble:

Preamble: EGI evidence states: *"A notable change that occurred in December 2019 was that the LUG delivery areas moved from monthly meter reading to bi-monthly meter reading, to align with the LEGD practice. This change did not impact the methodology for estimating un-billed consumption but rather only increased the amount of billed volumes that were based on estimated consumption. It should be noted that the change from monthly to bi-monthly meter reading does not contribute to incremental UFG; however, it could contribute to increased volatility in the short-term.*

We understand that UFG matters are out of scope. However, one of the integration activities that EGI has undertaken in the rebasing period is harmonization of meter readings cycles and integration of the billing systems. We have come to understand that the "notable change" is causing substantial customer billing issues which can transfer costs to the customer as some meters, especially in LUG, are not being read for months. We, and we trust the Board, want to understand the scope of the current challenge and what EGI is doing to correct the issues.

Question(s):

For LUG in 2021, please provide the percentage of meters with no read for:

a) 4 months
b) 6 months
c) 9 months
d) 12 months

Response:

These questions are not relevant to the relief sought in this application. If FRPO wishes to pursue these items in the context of an OEB proceeding, then it may be that the question would be relevant within the annual disposition of deferral & variance account balances proceeding, which includes the performance scorecard.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit C, Tab 2, Sch. 1, pg. 18

Preamble:

Preamble: EGI evidence states: *"A notable change that occurred in December 2019 was that the LUG delivery areas moved from monthly meter reading to bi-monthly meter reading, to align with the LEGD practice. This change did not impact the methodology for estimating un-billed consumption but rather only increased the amount of billed volumes that were based on estimated consumption. It should be noted that the change from monthly to bi-monthly meter reading does not contribute to incremental UFG; however, it could contribute to increased volatility in the short-term.*

We understand that UFG matters are out of scope. However, one of the integration activities that EGI has undertaken in the rebasing period is harmonization of meter readings cycles and integration of the billing systems. We have come to understand that the "notable change" is causing substantial customer billing issues which can transfer costs to the customer as some meters, especially in LUG, are not being read for months. We, and we trust the Board, want to understand the scope of the current challenge and what EGI is doing to correct the issues.

Question(s):

For LUG in 2021, what percent of accounts received a zero consumption bill:

a) From January to June

b) From July to November

Response:

Please see response at Exhibit I.FRPO.22.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit C, Tab 2, Sch. 1, pg. 18

Preamble:

Preamble: EGI evidence states: *"A notable change that occurred in December 2019 was that the LUG delivery areas moved from monthly meter reading to bi-monthly meter reading, to align with the LEGD practice. This change did not impact the methodology for estimating un-billed consumption but rather only increased the amount of billed volumes that were based on estimated consumption. It should be noted that the change from monthly to bi-monthly meter reading does not contribute to incremental UFG; however, it could contribute to increased volatility in the short-term.*

We understand that UFG matters are out of scope. However, one of the integration activities that EGI has undertaken in the rebasing period is harmonization of meter readings cycles and integration of the billing systems. We have come to understand that the "notable change" is causing substantial customer billing issues which can transfer costs to the customer as some meters, especially in LUG, are not being read for months. We, and we trust the Board, want to understand the scope of the current challenge and what EGI is doing to correct the issues.

Question(s):

What criteria is used to determine if a customer is billed an estimate or billed for zero consumption for a month for which the meter is not read.

a) If the bill is estimated, does classification (actual vs. estimate) appear in the consumption data (e.g., the Invoice Rate Ready data) for direct purchase pools

b) If not, what would be the cost to add this field to the data provided?

Response:

Please see response at Exhibit I.FRPO.22.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit C, Tab 2, Sch. 1, pg. 18

Preamble:

Preamble: EGI evidence states: *"A notable change that occurred in December 2019 was that the LUG delivery areas moved from monthly meter reading to bi-monthly meter reading, to align with the LEGD practice. This change did not impact the methodology for estimating un-billed consumption but rather only increased the amount of billed volumes that were based on estimated consumption. It should be noted that the change from monthly to bi-monthly meter reading does not contribute to incremental UFG; however, it could contribute to increased volatility in the short-term.*

We understand that UFG matters are out of scope. However, one of the integration activities that EGI has undertaken in the rebasing period is harmonization of meter readings cycles and integration of the billing systems. We have come to understand that the "notable change" is causing substantial customer billing issues which can transfer costs to the customer as some meters, especially in LUG, are not being read for months. We, and we trust the Board, want to understand the scope of the current challenge and what EGI is doing to correct the issues.

Question(s):

If a direct purchase customer whose year-end contract balance is impacted by estimated or zero consumption readings, will EGI commit to reversing the charges to the customer caused by the estimated or zero consumption billings.

Response:

Please see response at Exhibit I.FRPO.22.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit C, Tab 2, Sch. 1, pg. 18

Preamble:

Preamble: EGI evidence states: *"A notable change that occurred in December 2019 was that the LUG delivery areas moved from monthly meter reading to bi-monthly meter reading, to align with the LEGD practice. This change did not impact the methodology for estimating un-billed consumption but rather only increased the amount of billed volumes that were based on estimated consumption. It should be noted that the change from monthly to bi-monthly meter reading does not contribute to incremental UFG; however, it could contribute to increased volatility in the short-term.*

We understand that UFG matters are out of scope. However, one of the integration activities that EGI has undertaken in the rebasing period is harmonization of meter readings cycles and integration of the billing systems. We have come to understand that the "notable change" is causing substantial customer billing issues which can transfer costs to the customer as some meters, especially in LUG, are not being read for months. We, and we trust the Board, want to understand the scope of the current challenge and what EGI is doing to correct the issues.

Question(s):

If a group of general service rate customers are aggregated into a direct purchase group, what avenues do these customers have to seek adjustments to their accounts?

a) Is there an Account Executive or similar type role.

Response:

Please see response at Exhibit I.FRPO.22.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit C, Tab 2, Sch. 1, pg. 18

Preamble:

Preamble: EGI evidence states: *"A notable change that occurred in December 2019 was that the LUG delivery areas moved from monthly meter reading to bi-monthly meter reading, to align with the LEGD practice. This change did not impact the methodology for estimating un-billed consumption but rather only increased the amount of billed volumes that were based on estimated consumption. It should be noted that the change from monthly to bi-monthly meter reading does not contribute to incremental UFG; however, it could contribute to increased volatility in the short-term.*

We understand that UFG matters are out of scope. However, one of the integration activities that EGI has undertaken in the rebasing period is harmonization of meter readings cycles and integration of the billing systems. We have come to understand that the "notable change" is causing substantial customer billing issues which can transfer costs to the customer as some meters, especially in LUG, are not being read for months. We, and we trust the Board, want to understand the scope of the current challenge and what EGI is doing to correct the issues.

Question(s):

What is the average wait time to get to a live account representative using the customer billing enquiry number 1-877-362-7434 and what is the abandonment rate:

a) From January to June of 2021?
b) From July to November of 2021?

Response:

Please see response at Exhibit I.FRPO.22.

ENBRIDGE GAS INC.

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

Interrogatory

Reference:

Exhibit C, Tab 2, Sch. 1, pg. 18

Preamble:

Preamble: EGI evidence states: *"A notable change that occurred in December 2019 was that the LUG delivery areas moved from monthly meter reading to bi-monthly meter reading, to align with the LEGD practice. This change did not impact the methodology for estimating un-billed consumption but rather only increased the amount of billed volumes that were based on estimated consumption. It should be noted that the change from monthly to bi-monthly meter reading does not contribute to incremental UFG; however, it could contribute to increased volatility in the short-term.*

We understand that UFG matters are out of scope. However, one of the integration activities that EGI has undertaken in the rebasing period is harmonization of meter readings cycles and integration of the billing systems. We have come to understand that the "notable change" is causing substantial customer billing issues which can transfer costs to the customer as some meters, especially in LUG, are not being read for months. We, and we trust the Board, want to understand the scope of the current challenge and what EGI is doing to correct the issues.

Question(s):

Please provide the amount invested in the meter read, billing and customer accounting for EGI:

a) Using 2020 actual costs
b) Using 2021 actual costs for 9 months and forecast costs for the final 3 months

Response:

Please see response at Exhibit I.FRPO.22.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association (LPMA)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, Table 8

Question:

Have the growth factors calculated in Table 8 been calculated using the same methodology as in previous ICM applications? If not, what has changed?

Response

Yes, the growth factors have been calculated using the same methodology as in previous ICM applications.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association (LPMA)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, Appendix F, page 2

Question:

Please confirm that the allocation of the projects shown for the Union rate zones is the same for the new assets as it was for the assets being replaced. If not confirmed, please explain the change and provide a table showing the difference between the proposed allocation and the previous allocation methodology.

Response

Confirmed.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association (LPMA)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, Attachment 1, Table C

Question:

In line 1 of Table C, should “2021 In-Service Capital Forecast” be “2022 In-Service Capital Forecast”?

Response

Line 1 of Table C should be “2022 In-Service Capital Forecast”. Enbridge Gas will file a correction to the evidence with the interrogatory responses.

ENBRIDGE GAS INC.

Answer to Interrogatory from
London Property Management Association (LPMA)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1, Table 10

Question:

In line 1 of Table 10, should "2021 In-Service Capital Forecast" be "2022 In-Service Capital Forecast"?

Response

Line 1 of Table 10 should be "2022 In-Service Capital Forecast". Enbridge Gas will file a correction to the evidence with the interrogatory responses.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe

Interrogatory

Reference:

Ex A, T2 Sch. 1

Question(s):

For the five proposed ICM projects, please provide a table with the following information for each project.

- Project name
- Description of 'Project' scope (i.e. facilities included)
- Project costs
- Costs incurred to-date for the project
- Proposed in-service date (or actual if already in-service)
- Status and case number of the Leave to Construct application or approvals (if applicable)
- Variance explanation if 'Project' scope in ICM proceeding is different than the scope outlined in the Leave to Construct (if applicable)
- Overhead amount
- Project Contingency percentage
- The amount of any Project costs approved by the OEB prior to this proceeding

Response

Please see table below for the information requested. Also, see pre-filed evidence at Exhibit B, Tab 2, Schedule 2.

Project Name	St. Laurent Ottawa North Replacement Phase 3	NPS 20 Replacement Cherry to Bathurst	Dawn to Cuthbert Replacement and Retrofits	Byron Transmission Station	Kirkland Lake Lateral Replacement
Project Scope	Replacing 16 km of steel gas main and 400 m of extra high pressure pipeline	Replacing a 4.5 km and 260 m section of the Kipling Oshawa Loop (KOL) pipeline	Replacing 650 m of pipeline and installation of ILI launcher and receiver	Complete replacement of the existing station	Replacing 8 km of the existing NPS 4 Kirkland Lake Lateral pipeline
Project Costs	$88.5M	$129.9M	$24.2M	$20.4M	$20.7M
Life-to-date Costs (Dec 31, 2021)*	n/a	n/a	n/a	n/a	n/a
Proposed ISD	December, 2022	October, 2022	September, 2022	August, 2022	November, 2022
LTC Status	EB-2020-0293 (in progress)	EB-2020-0136 (approved)	No LTC	No LTC	No LTC
Scope Variance	No change	No change	n/a	n/a	n/a
Overhead Amount	$15.8M	$23.0M	$4.4M	$3.6M	$3.8M
Contingency %	15% for IP PE costs and 30% for XHP ST costs	30%	11.4%	12%	25%
Previously Approved $	LTC decision pending	LTC OEB approved December 17th, 2020	n/a	n/a	n/a

*Financial results have not been finalized for 2021 at this time and are not available.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe

Interrogatory

Reference:

Ex A, T2 Sch. 1

Question(s):

a) Please confirm that ICM approval for one or more of the 2022 proposed ICM projects only provides Enbridge the ability to capitalize the project(s) and does not represent OEB approval of the project itself (i.e. a separate Leave to Construct is required to review and approve the project in more detail). If this is not correct, please explain.

b) In Enbridge's opinion is it preferred to receive ICM (or equivalent rate case) approval and then apply for Leave to Construct approval, or the other way around? Please explain the answer.

c) Please confirm that if Enbridge does not receive ICM approval for one or more of the proposed projects, Enbridge will not build the project(s). If not correct, please explain.

Response

a) The OEB approval to proceed with the ICM Projects[1] is obtained through the leave to construct (LTC) process. Among other things, the Purpose and Need of the proposed Projects are addressed as part of the LTC proceeding. Approval for ICM funding is obtained through the annual rate case. In this rate application (Phase 2), Enbridge Gas is seeking ICM funding during the 2022 and 2023 years for the Projects as per the OEB's ICM policy[2] and the MAADs decision[3]. As indicated in the pre-filed evidence at Exhibit B, Tab 2, Schedule 2, paragraph 3 and 4, the ICM projects in the EGD rate zone are subject to a leave to construct application where the need for the projects has been or will be addressed. The ICM projects in the Union rate zones do not require a LTC approval. To explain the need for these projects, Enbridge Gas has provided the business case for each of the projects.

[1] ICM projects that are subject to a LTC application.
[2] EB-2014-0219 Report of the OEB – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014
[3] EB-2017-0306/EB-2017-0307, Decision and Order, August 30, 2018, Pp.32-34.

Also, see the OEB's decision in EB-2019-0194 for the approval of 2020 ICM projects.[4]

b) Enbridge Gas does not believe that it is necessary to obtain LTC approval before filing for ICM treatment of a project. The Company's deferred rebasing rate-setting mechanism contemplates only one rates application each year (though it may include more than one phase). Therefore, Enbridge Gas must apply for all identified ICM-eligible projects at the same time (generally in advance of the Test Year), even if the related LTC Application has not yet been determined. Enbridge Gas will not (cannot) proceed with any ICM Projects that are subject to a LTC requirement without LTC approval for that Project. Enbridge Gas acknowledges that any ICM approval for the St Laurent Ottawa North Replacement (Phase 3) will be contingent on the OEB also granting LTC approval for that project if such approval has not been granted before the OEB issues its Decision in this proceeding.

c) Enbridge Gas will consider the OEB's 2022 Rates decision in its entirety in determining the impacts to its capital budget and how it will proceed with the ICM Projects.

[4] Decision and Order, May 14, 2020, p.8 and p.11.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe

Interrogatory

Reference:

Ex A, T2 Sch. 1

Question(s):

a) Please provide a copy OEB criteria requiring a project to need a Leave to Construct application.

b) Please provide an explanation of what Leave to Construct criteria trigger the requirement for St. Laurent Phase 3 to require a Leave to Construct application.

Response

a) The criteria requiring an application to the OEB for leave to construct facilities is set out in Section 90 of the *Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Sched. B*.

b) As the St. Laurent Replacement Project proposes to replace existing pipelines with pipelines of different size, for certain segments, and as Enbridge Gas requires additional authority to use lands (easement) an application for Leave to Construct was made to the OEB.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe

Interrogatory

Reference:

Ex A, T2 Sch. 1

Question(s):

a) Please explain the impacts if an ICM approval is given to a project and then the OEB rejects the project through the following Leave to Construct proceeding.

b) Please explain the impacts if an ICM approval is given to a project and then it is determined that an IRP alternative is more appropriate to meet consumer needs.

Response

a) Please see the response at Exhibit I.PP.2 b).

b) Enbridge Gas believes that this is a highly improbable outcome. As alternatives to proposed facilities (both pipeline and non-pipeline) are included within the scope established via the OEB's standard issues list for Leave to Construct ("LTC") applications,[1] the OEB will have considered such alternatives when reviewing and deciding upon the same.

   Where the Company has sought an order of the OEB granting ICM recovery for the costs associated with a project that requires LTC approval (where the OEB has not yet granted the same), the Company expects that any ICM recovery granted would be contingent on the OEB also granting LTC approval.

   Enbridge Gas expects that the OEB will grant ICM approval for projects that do not require an order of the OEB granting LTC on the basis of both: (i) the evidence advanced by the Company to support ICM recovery at that time; and (ii) the assessment of system constraints/needs and alternatives to resolve the same identified up to 10 years in advance through its Asset Management Plan.

[1] https://www.oeb.ca/sites/default/files/issues-list-LTC-natural-gas.pdf

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe

Interrogatory

Reference:

Ex. A, TX, Sch. X

Question(s):

For each proposed 2021 ICM project, please describe the impact if it were deferred to 2024 (rebasing).

Response

Each of the 2022 ICM projects are driven mainly by integrity concerns as identified in the project's business cases and leave to construct application, where applicable. In order to maintain a safe and reliable transmission and distribution system, it is important to continue to address these issues as they arise, recognizing that some projects will take more time in planning than others. Deferring these projects to 2024 (rebasing) would increase the risk related to health & safety as well as operational reliability, introducing the potential for significant disruption to EGI's customers. As such, the Asset Management Plan seeks to spread these investments out and avoid emergency disruptions through timely addressing of these concerns.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe

Interrogatory

Reference:

Ex. A, TX, Sch. X

Question(s):

a) Please confirm that the St. Laurent pipeline provides gas supply to customers outside Ontario.

b) Please confirm what total percentage and GJ (or equivalent m3 volume) flowing through the St. Laurent pipeline are consumed by:
   - Customers in Ottawa
   - Customers in Ontario
   - Customers outside Ontario

Response

a - b)

In its letter dated December 10, 2021, the OEB indicated that given the St. Laurent Ottawa North Replacement Project (Phase 3) is currently subject to a leave to construct application where the issues of need and prudence are being addressed, these issues are not in scope in this proceeding. Accordingly, these questions are out of scope in this proceeding.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe

Interrogatory

Reference:

Ex. B, T2, Sch. 1

"The capital expenditures of the projects for which Enbridge Gas is seeking ICM funding approval for the EGD rate zone and Union rate zones are prudent and represent the most cost effective option for ratepayers"

Question(s):

a) Please provide a copy of the prudence test that was used to assess the projects and the results of the assessment for each project.

Response

a) Enbridge Gas is not certain what "prudence test" PP is referring to. The Company has produced evidence, as part of separate applications for leave to construct facilities or as part of this current Application, in support of the need for facilities and (in the case of the latter) to recover the costs of the same. As part of its review of such applications and in accordance with its Mission, the OEB routinely determines whether or not projects are in the public interest and whether the costs of the same were prudently incurred. As indicated in the pre-filed evidence, the Company has filed business case summaries at Exhibit B, Tab 2, Schedule 2 which provide a description of each of the projects' need and prudence, with an overview of options considered.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe

Interrogatory

Reference:

Ex. B, T2, Sch. 1, Appendix A

General Plant Capital Expenditures1 by Category (2017-2026)

Question(s):

Please explain the primary reasons for the 58% increase in proposed capital spending from the most recent 2020 actual ($51.3 million) and the proposed 2022 ($81 million) budget.

Response

The variability of spend year over year in this category is reflective of the projects that are planned to go into service in each year. The projects below are representative of the projects that are leading to an increase in spend between 2020 actual and the proposed 2022 budget:

REWS – increased spend on facilities at Brockville Operation Centre ($6.1M) and SMOC/Coventry Facility consolidation ($4.4M).

Fleet – purchase of TD Williamson ProStopp tool ($6.2M).

TIS – increased spend on new projects including Green Button ($3.1M) and Content Management Enhancements ($2.5M) and Truck Modem Replacements ($2.5M).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe

Interrogatory

Reference:

Ex. B, T2, Sch. 2

Kirkland Lake Business Case

Question(s):

a) Please provide details on all IRP alternatives assessed for the proposed Kirkland Lake project.

b) Please provide a signed contract or other documentation providing firm commitments to support the statement that there is “expected growth with Macassa Mines as well as future demand in Kirkland Lake”.

c) Please provide all documentation and analysis that supports a “like for like” replacement instead of the ability to decrease the proposed pipeline.

Response

a) Enbridge Gas did not assess any IRP alternatives for the proposed project. Enbridge applied the Binary Screening Criteria as noted in EB-2021-0148, Exhibit B, Tab 2, Schedule 2, Appendix C, page 141 of 147

b) There is a contractual commitment signed with Kirkland Lake Gold Ltd. See Attachment 1 for a copy of a signed contract with the customer. Confidential information such as the customer contract parameters have been redacted from the publicly filed version of the attachment for reasons of commercial sensitivity.

c) The capacity of the Kirkland Lake distribution system is reduced by 6,200 m3/hr when an NPS 2 replacement is used in place of an NPS 4 size for size replacement pipe. This analysis uses a TransCanada (TCE) source pressure of 4,275 kPa under Design Day conditions (55.7 HDD).

The size for size replacement is recommended to support all peak day demand design scenarios. EGI reviews the distribution system's capability to meet all interruptible contract load at 80% of the model's Design Day temperature (44.56 HDD). When replaced with an NPS 2, at a supply pressure of 4,275 kPa from TCE, station inlet pressures are approaching their minimum at the contract power plant customers. If TCE reverts its minimum supply pressure to 4,000 kPa, the contract power plant customers and the Chaput Hughes TBS stations are below their minimum inlets. With this reduced supply pressure, the minimum inlets at the contract power plants customers cannot be met at a 0 HDD (i.e., summer conditions).

Contract ID	
Contract Name	KL GOLD MACASSA

This Northern GAS DISTRIBUTION CONTRACT ("**Contract**"), made as of the 1st day of April, 2021.

BETWEEN:

Enbridge Gas Inc.

hereinafter called "**the Company**"

- and -

Kirkland Lake Gold Ltd.

hereinafter called "**Customer**"

WHEREAS, the Company has built, or proposes to build, certain facilities to serve 1350 Government Road West, Kirkland Lake, ON (the "**Plant**");

AND WHEREAS, the facilities will be built by the Company in two phases, with the first phase anticipated to be completed by January 1, 2022 (the "**Shaft 3 Expansion Facilities")** and the second phase anticipated to be completed by November 1, 2022 (the "**Shaft 4 Expansion Facilities")** (the Shaft 3 Expansion Facilities and Shaft 4 Expansion Facilities, collectively, the "**Expansion Facilities**"**)**;

AND WHEREAS, Customer has requested from the Company and the Company has agreed to provide Customer with Services as specified in Schedule 1 (the "**Services**");

AND WHEREAS, in order for the Company to provide the Services to Customer, it has entered into a Delivery Pressure Agreement with TransCanada Pipelines Limited ("**TCPL**") dated March 12, 2020 (the "**TCPL Agreement**"), pursuant to which TCPL has agreed to use commercially reasonable efforts to deliver Gas to the Company at the Kirkland meter station at a minimum delivery pressure of 4275 kilopascals, subject to the terms and conditions of the TCPL Agreement;

AND WHEREAS, in order for the Company to provide Services to Customer without the delivery of Gas to the Company by TCPL at the Kirkland meter station at a minimum delivery pressure of 4275 kilopascals, the Company would be required to build facilities in addition to the Expansion Facilities (the "**Additional Facilities**") requiring contribution in aid of construction from Customer in excess of the amount set forth in this Contract;

AND WHEREAS, Customer desires that the Company not proceed with the Additional Facilities and instead obtain the required additional delivery pressure from TCPL under the TCPL Agreement, notwithstanding that the Company's ability to provide Services may be impacted by the acts or omissions of TCPL and that TCPL is entitled to terminate the TCPL Agreement by providing two (2) years' prior written notice to the Company;

AND WHEREAS, if Customer has elected direct purchase services, Customer will be responsible for supplying Gas to the Company;

AND WHEREAS, the Company will distribute Gas to Customer's Point(s) of Consumption under this Contract pursuant to the Rate Schedule identified in Schedule 1;

IN CONSIDERATION of the mutual covenants contained herein, and other good and valuable consideration, the receipt of and sufficiency of which is hereby acknowledged, the parties agree as follows:

1. INCORPORATIONS

The following are hereby incorporated in and form part of this Contract:

a) Contract Parameters as contained in Schedule 1 as amended from time to time; and
b) The latest posted version of the Northern Gas Distribution Service Terms and Conditions contained in Schedule 2 subject to Section 12.18 of the Company's general terms and conditions applicable to Union Rate Zones ("General Terms and Conditions"); and
c) The latest posted version of the General Terms and Conditions subject to Section 12.18 of the General Terms and Conditions; and
d) Rate Schedule(s) as identified in Schedule 1 as amended from time to time and as approved by the Ontario Energy Board.

2. CONDITIONS PRECEDENT

The obligations of the Company to provide Services hereunder are subject to the following conditions precedent that are for the sole benefit of the Company and which may be waived or extended, in whole or in part, in the manner provided in this Contract:

a) The Company shall have obtained, in form and substance satisfactory to the Company, and all conditions shall have been satisfied under all governmental, regulatory and other third party approvals, consents, orders and authorizations, that are required to:
   i. provide the Services;
   ii. construct the Shaft 3 Expansion Facilities; and
   iii. construct the Shaft 4 Expansion Facilities; and

b) The Company shall have obtained all internal approvals that are necessary or appropriate to:
   i. provide the Services;
   ii. construct the Shaft 3 Expansion Facilities; and
   iii. construct the Shaft 4 Expansion Facilities; and

c) The Company shall have completed and placed into Service the Shaft 3 Expansion Facilities; and
d) The Company shall have completed and placed into Service the Shaft 4 Expansion Facilities and

e) Financial assurances acceptable to the Company shall be supplied and maintained in accordance with the General Terms and Conditions; and

f) The Company shall have received a contribution in aid of construction to the Company of [redacted] (the "**Aid Amount**") from Customer pursuant to Customer's obligations herein; and

g) If Customer has elected bundled direct purchase services, Customer and the Company shall have executed and maintained in good standing a Northern Bundled T; and

h) If Customer has elected Transportation Service ("**T-Service**") and Customer had previously been provided a service by the Company that utilized the Company's contracted upstream transportation capacity, Customer and the Company shall have executed and maintained in good standing a Temporary Transportation Contract Assignment Agreement.

The Company and Customer shall each use commercially reasonable efforts to satisfy and fulfill the conditions precedent specified in Sections a), c), d), e), f), g) and h). The Company shall notify Customer forthwith in writing of the Company's satisfaction or waiver of each condition precedent. Subject to the following paragraph, if the Company concludes that it will not be able to satisfy a condition precedent, the Company may, upon written Notice to Customer, terminate this Contract and upon giving such Notice, this Contract shall be of no further force and effect and each of the parties shall be released from all further obligations hereunder, subject to Customer's obligations pursuant to Section 11 herein.

If the Company satisfies all conditions precedent applicable to the Shaft 3 Expansion Facilities and concludes that it will not be able to satisfy a condition precedent applicable to the Shaft 4 Expansion Facilities, (i) this Contract shall continue in full force and effect with respect to the Shaft 3 Expansion Facilities, Shaft 2 and Mill Contract Parameters only as set out in Schedule 1, and Schedule 1 will be amended accordingly, and (ii) Customer shall reimburse Company for all Project Costs (as defined below) and Cancellation Costs (as defined below) relating to the Shaft 4 Expansion Facilities. If the Company concludes that it will not be able to satisfy a condition precedent applicable to the Shaft 3 Expansion Facilities, it may continue with the development and construction of the Shaft 4 Expansion Facilities, and if it satisfies all conditions precedent applicable to the Shaft 4 Expansion Facilities, (i) this Contract shall continue in full force and effect with respect to the Shaft 4 Expansion Facilities, Shaft 2 and Mill Contract Parameters set out in Schedule 1, and Schedule 1 will be amended accordingly, and (ii) Customer shall reimburse Company for all Project Costs (as defined below) and Cancellation Costs (as defined below) relating to the Shaft 3 Expansion Facilities.

3. CONTRACT TERM

This Contract shall be effective from the date hereof. However, the Service, obligations, terms and conditions except the North T-Service Transportation from Dawn Base Service (if applicable), hereunder shall commence (i) with respect to the Shaft 3 Expansion Facilities, on the later of (such later date being the "**Day of First Delivery**") (a) January 1, 2022, and (b) the date that the last condition precedent applicable to the Shaft 3 Expansion Facilities as set out in Section 2 is satisfied or waived by the Company, and (ii) with respect to the Shaft 4 Expansion Facilities, on the later of (a) November 1, 2022, and (b) the date that the last condition precedent applicable to the Shaft 4 Expansion Facilities as set out in Section 2 is satisfied or waived by the Company. Subject to the provisions hereof, the Contract shall continue in full force and effect for a period of twenty (20) Contract Years (the "**Initial Term**") and continuing thereafter on a year to year basis unless written Notice to terminate is provided by either the Company or Customer. Such Notice must be delivered at least three

(3) months prior to the end of the then-current term.

"**Contract Year**" means a period of twelve (12) consecutive Months, beginning on January 1 of any Contract Year and ending on the subsequent December 31, except for the first contract year which shall begin on the Day of First Delivery and end on the subsequent December 31.

If Customer contracts for North T Service Transportation from Dawn Base Service, then notwithstanding the contract term of this Contract, Customer agrees the North T-Service Transportation from Dawn Base Service (if applicable) will be effective until the earlier of:

a) Customer ceases to take distribution service from the Company;
b) The underpinning TCPL transportation contract expires; or,
c) The Company is able to facilitate TCPL transporation service turnback at Customer's request consistent with the Company's turnback policy.

Renewal beyond the term of the underlying TCPL contract of the North T-Service Transportation from Dawn Base Service will be based on the renewal provisions of both the Company and TCPL's underpinning transportation capacity.

4. SERVICES PROVIDED

The Company agrees to provide Services as specified in Schedule 1 and Customer agrees to pay for such Services pursuant to these Contract terms and conditions as set out in this Contract, the referenced attachments, and the rate(s) referenced in Schedule 1.

If Customer has elected Bundled T Services, and if the Company does not receive Gas from Customer under the Northern Bundled T Contract, then the Company's obligations to provide Services under this Contract may, at the Company's option, be suspended or terminated by the Company. This suspension or termination will be effective as of the date specified in the Company's notice to Customer, notwithstanding the Notice provisions of the General Terms and Conditions.

If Customer (i) has elected Transportation Service, (ii) had previously been provided a service by the Company that utilized the Company's contracted upstream transportation capacity, and (iii) does not maintain in good standing a Temporary Transportation Contract Assignment Agreement during the term of this Contract, then the Company's obligations to provide Services under this Contract may, at the Company's option, be suspended or terminated by the Company. This suspension or termination will be effective as of the date specified in the Company's notice to Customer, notwithstanding the Notice provisions of the General Terms and Conditions.

5. FIRM DAILY CONTRACT DEMAND

The Firm Contract Demand ("**CD**") is as specified in Schedule 1.

5.01 CD INCREASES DURING CONTRACT YEAR

The first day in each Contract Year that the Customer overruns its CD ("**First Occurrence**") shall be recorded. "**Overrun**" shall have the meaning given that term as part of this Contract.

The second day in each Contract Year that the customer overruns its CD ("**Second Occurrence**"), shall result in an increase in the Customer's CD to the higher quantity used on the First Occurrence or the Second Occurrence effective as of the 1st day of the month of this Second Occurrence, at the Company's sole discretion. Customer charges will reflect the increased CD.

5.02 SUBSEQUENT CD INCREASES DURING CONTRACT YEAR
After the CD has been increased and anytime thereafter that it has been increased pursuant to Section 5.01, the next day that Customer overruns the increased CD within the Contract Year shall be deemed to be a new First Occurrence for the purposes of Section 5.01, and the next time thereafter that Customer overruns the CD within the Contract Term shall be deemed to be a new Second Occurrence for the purposes of Section 5.01, resulting in another increase in the CD as per the procedure set out in Section 5.01. For greater clarity, every time the CD is increased in a Contract Year, the occurrence number is set back to zero and thereafter if two more occurrences happen, the CD will be raised again, and so on for the remainder of the Contract Year. At the beginning of each Contract Year any outstanding First Occurrences will be set back to zero.

6. EXPANSION FACILITIES

The Company will use commercially reasonable efforts to construct the Expansion Facilities to serve the Plant. The target date for completion of the Shaft 3 Expansion Facilities is January 1, 2022 and the target date for completion of the Shaft 4 Expansion Facilities is November 1, 2022. The Company will provide written Notice to Customer when such facilities are complete and placed into service. The Company and Customer agree that the Company shall not be obligated to construct any portion of the Expansion Facilities between December 15 of any year and March 31 of the subsequent calendar year.

7. AID AMOUNT PAYMENT SCHEDULE

Customer will be required to pay to the Company the Aid Amount of [redacted] by [redacted]. Any applicable taxes will be applied to all amounts paid under this Section. Customer warrants and represents that no payment to be made by Customer under this Contract is subject to any withholding tax.

Notwithstanding any other provision to the contrary herein contained, if any amount is payable by a Party as a result of a breach, modification or termination of this Contract in circumstances in which section 182 of the Excise Tax Act (Canada) applies to the amount payable, then said amount shall be increased by an amount equal to the amount determined by multiplying any such payments by the applicable rate of GST.

8. LATE PAYMENT CHARGES

Any amounts due and payable by Customer to the Company arising under Sections 7, 10 and 11 of this Contract shall, if not paid by the due date thereof, be subject to late payment charges equal to 1.5% per month (for a nominal rate of 18% per annum compounded monthly) on any unpaid balance including previous arrears.

9. CREDIT REQUIREMENTS DURING INITIAL TERM

In addition to the terms of Section 5.04 of the General Terms and Conditions, the Company may, at any time during the Initial Term, request financial assurances to cover the potential financial exposure to the Company to the end of the Initial Term. Such financial assurances shall be determined by the Company in a commercially reasonable manner and may include, without limitation, expected return on capital invested. Failure to provide such financial assurances shall be treated in a manner provided for in Section 5.04 of the General Terms and Conditions.

10. DELIVERY PRESSURE AGREEMENT WITH TRANSCANADA PIPELINES LIMITED

Customer acknowledges that the Company's ability to provide services is dependent on TCPL delivering Gas to the Company at the Kirkland meter station at a minimum delivery pressure of 4275 kilopascals pursuant to the TCPL Agreement. Customer further acknowledges that the TCPL Agreement may be terminated by TCPL at any time by providing two (2) years' prior written notice to the Company. If the Company receives notice of termination of the TCPL Agreement from TCPL, the Company shall be entitled to terminate this Contract by providing no less than eighteen (18) months' prior written Notice to Customer. If the Contract is terminated by the Company in accordance with this Section 10 and the termination date occurs after the Day of First Delivery, Customer shall be liable to Company for the payment of all demand charges and commodity charges payable under this Contract for the remainder of its term which payments of demand charges and commodity charges for what would have been the remainder of the term shall become due and payable in full immediately upon termination of this Contract in accordance with this Section 10**.** Such payment of demand charges and commodity charges corresponding to the effective date of termination is estimated in Schedule 3 attached hereto. If the Contract is terminated by the Company in accordance with this Section 10 and the termination date occurs prior to the Day of First Delivery, Customer shall pay the Company the Project Costs and Cancellation Costs in accordance with Section 11. Upon such termination this Contract shall be of no further force and effect and each of the parties shall be released from all further obligations hereunder, subject to Customer's obligations pursuant to this Section 10 and Section 11, as applicable.

Notwithstanding any other provision of this Agreement, the Company shall not be liable to the Customer for any claims, demands, actions, causes of action, damages, losses, costs, liabilities and expense whatsoever which may be brought against Customer or which Customer may suffer or incur as a result of, in respect of, or arising out of any interruption, curtailment or cancellation of Services attributable to the acts or omissions of TCPL.

11. TERMINATION PRIOR TO COMPLETION OF EXPANSION FACILITIES

The Company shall have the right to terminate this Contract at any time prior to the Day of First Delivery, pursuant to Section 2 or Section 10, by giving written notice hereof, subject to the terms hereof.

If this Contract is terminated by the Company prior to the Day of First Delivery as outlined above, then:

(a) Upon such termination, this Contract shall be of no further force and effect and each of the parties shall be released from all further obligations hereunder, provided that any rights or remedies that a party may have for breaches of this Contract prior to such termination and any liability that a party may have incurred prior to such termination, and the parties' obligations under this Section 11, shall not thereby be released;

(b) Customer shall reimburse the Company for all Project Costs; and

(c) Customer shall reimburse the Company for all cancellation costs, fees or other amounts paid under contracts entered into by the Company to support the satisfaction of the conditions precedent set out in Section 2 ("**Cancellation Costs**").

The Company may invoice amounts under this Section from time to time, with the expectation that there will be an invoice rendered within 30 days of termination, and subsequent invoices as additional amounts payable hereunder are incurred from time to time. After delivery of such Notice of termination by the Company, the Company will use commercially reasonable efforts to cease incurring Project Costs and to mitigate Cancellation Costs upon such termination. In no event shall the Company invoice Customer for any Cancellation Costs or Project Costs not previously invoiced by the Company after 12 months from the termination date. Without limiting the foregoing, Customer shall have the right to audit at Customer's expense the costs claimed for reimbursement by the Company for a period of six (6) months after each invoice is issued.

"**Project Costs**" means any and all reasonable costs (including litigation costs, cancellation costs, carrying costs, and third party claims) expenses, losses, demands, damages, obligations, or other liabilities (whether of a capital or operating nature, and whether incurred or suffered before or after the date of this Contract) of the Company including amounts paid to affiliates in accordance with the Affiliate Relationship Code as established by the Ontario Energy Board) in connection with or in respect of development and construction of the Expansion Facilities (including without limitation the construction and placing into service of the Expansion Facilities, the obtaining of all governmental, regulatory, and other third party approvals, and the obtaining of rights of way) except for costs that have arisen from the gross negligence, fraud, or willful misconduct of the Company.

12. CONTRACT SUCCESSION

This Contract, unless terminated pursuant to Section 2 hereof, replaces all previous Gas Distribution Contracts between the parties, subject to settlement of any surviving obligations.

The undersigned execute this Contract as of the above date. If an Agent on behalf of Customer executes this Contract then, if requested by the Company, Agent or Customer shall at any time provide a copy of such authorization to the Company.

Kirkland Lake Gold Ltd.

DocuSigned by:
Milferd Burnett
9FFE20DA008F4AC...
Authorized Signatory

Milferd Burnett 4/7/2021

Please Print Name

DocuSigned by:
610B44CF3F66400...
Authorized Signatory

Duncan King 4/7/2021

Please Print Name

DocuSigned by:
11C00707A1B74EC...
Authorized Signatory

Tony Makuch 4/10/2021

Please Print Name

Enbridge Gas Inc.

Authorized Signatory

JOAN BYNG

Please Print Name

Schedule 3
Termination Schedule

Buyout Date (Year) - Assumes Termination Date is January 1	Total Estimated Termination Payment
2022	[redacted]
2023	[redacted]
2024	[redacted]
2025	[redacted]
2026	[redacted]
2027	[redacted]
2028	[redacted]
2029	[redacted]
2030	[redacted]
2031	[redacted]
2032	[redacted]
2033	[redacted]
2034	[redacted]
2035	[redacted]
2036	[redacted]
2037	[redacted]
2038	[redacted]
2039	[redacted]
2040	[redacted]
2041	[redacted]

Contract ID	
Contract Name	KL GOLD MACASSA

Schedule 1

Northern Gas Distribution Contract
General Contract Parameters

1. **DATES**

This Schedule 1 is effective on the Day of First Delivery.

2. **POINT OF RECEIPT FOR NORTH T-SERVICE**

Gas under this Contract will be received by the Company for Service at the following Point of Receipt: NDA - Northern Delivery Area.

3. **TYPE OF SERVICE**

Service under this Contract shall be a combination of Firm and/or Interruptible service in the quantity and for the Point(s) of Consumption, Point(s) of Receipt and Point(s) of Delivery specified in this Schedule 1.

a) Parameters below are effective on the Day of First Delivery with respect to the Shaft #3 Expansion Facilities

i) Distribution Parameters:

Service	**Daily Contract Demand** (m^3/Day)
Rate 20 – Medium Volume Firm Service – T Service	[redacted]
Rate 25 – Large Volume Interruptible Service –T Service	[redacted]
Rate 25 – Large Volume Interruptible Service – Sales Service – January 1 to April 30	[redacted]
Rate 25 – Large Volume Interruptible Service – Sales Service – May 1 to September 30	[redacted]
Rate 25 – Large Volume Interruptible Service – Sales Service – October 1 to December 31	[redacted]

ii) Customer Balancing Service

Daily Minimum (GJ)	**Daily Maximum (GJ)**	**Contract Sharing**	**Rank**
[redacted]	[redacted]	N/A	N/A

b) Parameters below will replace the parameters in paragraph a) above, effective on the later of a) November 1, 2022 and b) the date that the Company has put Shaft #4 Expansion Facilities into service

i) Distribution Parameters:

Service	**Daily Contract Demand** (m^3/Day)
Rate 20 – Medium Volume Firm Service – T Service	[redacted]
Rate 25 – Large Volume Interruptible Service –T Service	[redacted]
Rate 25 – Large Volume Interruptible Service – Sales Service – January 1 to April 30	[redacted]
Rate 25 – Large Volume Interruptible Service – Sales Service – May 1 to September 30	[redacted]
Rate 25 – Large Volume Interruptible Service – Sales Service – October 1 to December 31	[redacted]

ii) Customer Balancing Service

Daily Minimum (GJ)	**Daily Maximum (GJ)**	**Contract Sharing**	**Rank**
0	[redacted]	N/A	N/A

4. RATES FOR SERVICE

i. Charges will be as specified as in the applicable Rate Schedule(s).

ii. Rate 25 - Large Volume Interruptible - Transportation Service:

Delivery Charge [redacted] $\$/m^3$ Effective January 1, 2022

Rate 25 - Large Volume Interruptible - Sales Service:

Delivery Charge [redacted] $\$/m^3$ Effective January 1, 2022

iii. Rate 25 Gas Supply Charge is determined and amended from time to time by the Company to reflect market pricing. In circumstances where Rate 25 Gas sales service is interrupted by the Company, Gas supply may be available under the Rate 30 Rate Schedule.

iv. For customer balancing service (CBS), charges are posted on the Company’s website.

5. POINTS OF CONSUMPTION, HOURLY FLOW & DELIVERY PRESSURE

a) Parameters below are effective on the Day of First Delivery with respect to the Shaft #3 Expansion Facilities

The Company agrees to deliver Gas based on the following parameters:

Meter #	Location Description	Firm Hourly Quantity (FHQ)(m3)	Maximum Hourly Flow (m3)	Min Gauge Pressure (kPa)
TBD	Shaft #3	[redacted]	[redacted]	[redacted]
TBD	Shaft #2 & Mill	[redacted]	[redacted]	[redacted]

a) Parameters below will replace the parameters in paragraph a) above, effective on the later of a) November 1, 2022 and b) the date that the Company has put Shaft #4 Expansion Facilities into service

The Company agrees to deliver Gas based on the following parameters:

Meter #	Location Description	Firm Hourly Quantity (FHQ)(m3)	Maximum Hourly Flow (m3)	Min Gauge Pressure (kPa)
TBD	Shaft #3	[redacted]	[redacted]	[redacted]
TBD	Shaft #2 & Mill	[redacted]	[redacted]	[redacted]
TBD	Shaft #4	[redacted]	[redacted]	[redacted]

6. <u>MINIMUM ANNUAL VOLUME ("MAV")</u>

Contract Year 1

Firm MAV	[redacted]	m^3/year

Contract Year 2 and thereafter

Firm MAV	[redacted]	m^3/year

FIRST AMENDING AGREEMENT

This First Amending Agreement (this "Amendment"), made on April 21, 2021, is entered into by and between Enbridge Gas Inc. ("Enbridge") and Kirkland Lake Gold Ltd. ("Customer"). Each of Enbridge and Customer may be referred to herein as a "Party" and collectively as the "Parties."

RECITALS

A. Enbridge and Customer are parties to that certain Northern Gas Distribution Contract dated as of April 1, 2021, as amended (the "Agreement"); and

B. The Parties wish to amend the Agreement as herein set forth.

NOW, THEREFORE, in consideration of the premises and the mutual promises of each of the Parties herein contained, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

1. DEFINITIONS

1.1 **Definitions**. Capitalized terms used in this Amendment shall have the same meanings given to them in the Agreement unless otherwise indicated.

2. AMENDMENTS

2.1 **Amendment to Sections 5.01, and 5.02.** Effective as of April 1, 2021, Sections 5.01 and 5.02 of the Agreement are hereby deleted in their entirety and replaced with the words "Intentionally Deleted".

3. GENERAL PROVISIONS

3.1 **Binding Agreement**. The Agreement, as hereby amended, is ratified and confirmed and continues in full force and effect.

3.2 **Amendment**. This Amendment may not be modified or amended unless agreed to in writing by all of the Parties.

3.3 **Governing Law**. This Amendment shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein, without giving effect to the choice of law provisions thereof that would require the application of the laws of any other jurisdiction.

3.4 **Counterparts**. This Amendment may be signed in any number of counterparts, all of which taken together shall constitute one and the same instrument. Each Party may enter into this Amendment by signing any such counterparty and each counterpart may be signed and executed by the Parties and transmitted by PDF transmission and shall be as valid and effectual as if executed as an original.

[Signature Page Follows]

IN WITNESS WHEREOF, the duly authorized representatives of the Parties have caused this Amendment to be executed as of the date first written above.

ENBRIDGE GAS INC.

By: Joan B.

Name: JOAN BYNG

Title: Director, Large Volume Contracting + Policy

Kirkland Lake Gold Ltd.

DocuSigned by:

By: Milferd Burnett

9FFE20DA008F4AC...

Name: Milferd Burnett

Title: Director Supply Chain 4/26/2021

DocuSigned by:

By: Duncan King

FA4AEAAEB04248A...

Name: Duncan King

Title: Vice President, Canadian Operations 4/26/2021

By: ______________________________

Name:

Title:

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe

Interrogatory

Reference:

Ex. B, T2, Sch. 2

Question(s):

a) Please explain why the St. Laurent Phase 3 project was withdrawn from the request for ICM treatment in 2021.

b) Please explain why it is appropriate to reinstate the St. Laurent Phase 3 project for potential ICM consideration for 2022.

c) Is the St. Laurent Phase 3 a stand-alone project or is it combined with Phase 4 to form a single project?

d) If the St. Laurent Phase 3 project is a stand-alone project, please explain the project scope in the Leave to Construct [EB-2020-0293]

e) Please reconcile the estimated project costs for the St. Laurent Phase 3 project in this proceeding (i.e. amount for ICM treatment) against the proposed project costs in the Leave to Construct proceeding for the same project.

Response

a) Please see the response in the St. Laurent Replacement Project proceeding (EB-2020-0293, Exhibit I.PP.2, Filed: 2021-12-13).

b) Please see the response at Exhibit I.CME.1.

c) The St. Laurent project is a multi-phase project that is being completed over several years. Phases 1 and 2 of the Project have previously been constructed and placed into service.[1] As this application is for 2022 rate setting, only projects with an expected in-service date in 2022 are eligible for ICM funding as set out in the "Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, EB-2014-0219".

[1] The OEB also previously reviewed and granted leave to construct a portion of Phase 2 of the multi-phase project (EB-2019-0006).

As discussed in its Updated Application filed September 10, 2021[2], Phases 3 and 4 of the St. Laurent project are entirely distinct in that: (i) Phase 3 is planned to be placed into service in November 2022; (ii) Phase 4 is planned to be placed into service in November 2023; and (iii) neither phase is dependent upon any other phases being completed in order to be placed into service and to begin providing value to ratepayers.

d) In its decision in the St Laurent Project (Phase 1 and 2) leave to Construct application in EB-2019-0006[3], the OEB indicated that it "expects that approvals for the remaining multi-phases of the St. Laurent Project will be dealt with on a comprehensive basis, and that the OEB will not be seeing separate applications for leave to construct individual phases of the project in the future." As such, Enbridge Gas has filed a leave to construct application seeking OEB approval for the remaining phases of the St Laurent project in EB-2020-0293.

e) Please see table below.

Project Costs as per LTC application[1]

Project Costs by Phase: ($ Millions)	Phase 3			Phase 4	Total (Phase 3 & 4)
	2022 In-Service	2023 In-Service	Total		
Project Cost	69.99	1.97	71.96	28.16	100.12
Indirect Overheads	15.18	0.48	15.66	6.88	22.54
Interest During Construction	0.71	-	0.71	0.31	1.01
Total Project Costs	**85.87**	**2.45**	**88.33**	**35.35**	**123.68**

[1] EB-2020-0293, updated September 10, 2021

Project Costs for ICM funding as per 2022 Rate application

Project Costs by Phase: ($ Millions)	Phase 3			Phase 4	Total (Phase 3 & 4)
	2022 In-Service	2023 In-Service	Total		
Project Cost	69.99	N/A	N/A	N/A	N/A
Indirect Overheads	15.34	N/A	N/A	N/A	N/A
Interest During Construction	0.71	N/A	N/A	N/A	N/A
Total Project Costs	**86.04**	**N/A**	**N/A**	**N/A**	**N/A**

Difference (2022 In-Service Capital) (0.16)

[2] EB-2020-0293, Updated: 2021-09-10, Exhibit B, Tab 1, Schedule 1, pp 1-5
[3] EB-2019-0006, Decision and Order, September 26, 2019, p.8

The 2022 ICM funding request of $86.04 million for the St Laurent Phase 3 project was based on the original cost estimate in the LTC application (EB-2020-0293, filed on March 2, 2021). With the update in the project cost (as filed in the updated LTC application on September 10, 2021), the 2022 ICM amount is lower by $0.16 million due to lower overheads. EGI is proposing not to update the project cost as the difference is immaterial and any difference between the actual and budgeted costs will be captured in the ICM deferral account.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe

Interrogatory

Reference:

Ex. C, T1, Sch. 1

Question(s):

a) Please confirm when the updated AMP was completed.

b) What updates related to IRP have been included since the last version of the AMP?

c) Please identify how Enbridge's IRP alternative assessment commitments have been met in the updated AMP.

Response

a) EGI completed the 2022 Asset Management Plan Addendum (EB-2021-0148, Exhibit B, Tab 2, Schedule 3) on September 20, 2021 and filed on October 15, 2021. As noted in the Overview of that document, its purpose is to provide an update to the 2022 Budget and should be considered in conjunction with the 2021-5 Asset Management Plan filed at EB-2020-0181, Exhibit C, Tab 2, Schedule 1).

b) Key 2022 Asset Management Developments are described in section 4 of the AMP Addendum.

c) The 2022 AMP Addendum (EB-2021-0148, Exhibit B, Tab 2, Schedule 3, page 7) describes the following IRP update since the 2021-2025 AMP (EB-2020-0181, Exhibit C, Tab 2, Schedule 1):

> In July 2021, the Ontario Energy Board released its Decision and Order in the Enbridge Gas Inc. Integrated Resource Planning Proposal (EB-2020-0091). This provides direction for EGI with respect to the scope, timing, stakeholder engagement, and cost recovery of non-facility alternatives.
>
> Integrated Resource Planning represents a significant change to the facility planning that EGI has performed in the past and, as such, the Company is taking steps to

develop processes, resources and capabilities to integrate these new requirements into its existing asset management and other processes.

EGI is beginning to consider IRP Assessment on certain projects, consistent with the guidance provided by the OEB in its Decision (EB-2020-0091). As noted in the IRP Decision, the potential of IRP alternatives to meet asset needs will be considered in the 2023-2032 AMP.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

Exhibit B, general

Question(s):

Please provide a copy of all materials provided to the Applicant's Board of Directors regarding each of the proposed ICM projects, or regarding this ICM application.

Response:

There are no materials that were provided to the Board of Directors related to this ICM application.

The ICM projects in the EGD Rate Zone are/were subject to separate OEB review through Leave to Construct applications. Presumably questions about Board of Directors review of the projects was/is relevant in those proceedings, rather than this case. The St Laurent Ottawa North Replacement project (Phase 3) is currently a live proceeding where the need and prudence for the project is being addressed. In its letter dated December 10, 2021, the OEB indicated that given the St. Laurent Ottawa North Replacement Project (Phase 3) is currently subject to a leave to construct application where the issues of need and prudence are being addressed, these issues are not in scope in this proceeding. The NPS 20 Replacement Cherry to Bathurst was subject to a leave to construct application, where the need and prudence of the project was already addressed. This project was approved by the OEB on December 17, 2020.

However, to the extent the information can provide further clarity to the OEB, a response is provided below.

For materials related to St. Laurent Ottawa North Replacement Phase 3, please refer to interrogatory response in EB-2020-0293, Exhibit I.FRPO.15.

For materials related to the NPS 20 Replacement Cherry to Bathurst Project, please refer to interrogatory response in EB-2020-0136, Exhibit I.EP.2.

The ICM projects in the Union Gas Rate Zone are not subject to Leave to Construct Applications. However, with respect to the Dawn to Cuthbert Replacement and Retrofits Project, Byron Transmission Station Project and Kirkland Lake Lateral Replacement Project, there have been no specific materials provided to Enbridge Board of Directors.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

Exhibit B, general

Question(s):

Please provide a copy of any internal business cases for the proposed projects, if different from the business cases filed with the Application.

Response:

For the proposed ICM projects there are no other internal business cases that are substantively different from the business cases filed with the Application.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

Exhibit B, general

Question(s):

Please provide any information used by the Applicant in benchmarking of costs for projects similar to the ICM projects, or advise that no benchmarking was carried out.

Response:

No benchmarking has been carried out.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

Exhibit B-2-1, p.10-11, p.14-15

Question(s):

Please provide details with regard to the “REWS” project and the scope variation of it that contributed to the increase in General Plant spending in both rate zones.

Response:

To further explain the variance descriptions in Exhibit B, Tab 2, Schedule 1, pages 10 TO 11, the following are provided. Examples of the REWS projects that will be going into service in 2022 at EGD Rate Zone that were not part of the 2020 AMP Plan for 2022 are:

- SMOC/Coventry Facility Consolidation $4.3M
- Increase of $2.1M for the Brockville Operations Centre to $6.1M
- VPC Annex/Metershop Area Renovation $1.2M

Examples of the REWS projects that will be going into service in 2022 at Union Rate Zones that were not part of the 2020 AMP Plan for 2022 are:

- Belleville Property Purchase $8.4M
- Dryden Operations Centre $5.9M
- Other small adjustments to projects and scope ($1.4M)

The variation in in-service capital from one year to the next is driven by the specific Real Estate projects that are being completed. Some of the significant projects that were planned to be in-service in 2021 (when the 2021-2025 AMP was published) are noted below for the EGD Rate Zone:

- SMOC/Coventry Facility Consolidation $11.3M
- New Mechanical Services $11M
- VPC - 1 $7.6M

In the UG Rate Zone:

- 50 Keil Drive $11.5M
- Belleville New Building $7.1M
- Dryden Operations Centre $3.7M

In each rate zone some investments have been advanced to meet business needs, or to respond to market opportunities to acquire properties. Some have been delayed either to accommodate the advancement of others or as a result of planning and permitting delays.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

Exhibit B-2-1, p.18

Question(s):

Please confirm that, under the Board's policies, distributors on Price Cap IRM are expected to make best efforts to manage their capital spending within the ICM envelope, which in this case is $977 million for 2022. Please provide a detailed explanation of all efforts made by the Applicant to limit its capital spending in 2022 to the threshold limit, and provide an explanation for the reasons why those efforts were unsuccessful. Without limiting the generality of the foregoing, please provide copies of any policies, memoranda, presentations, directives, or other documents directing anyone in the company to limit capital spending to the threshold limit or, alternatively, setting a different capital spending limit for 2022.

Response:

Please see the response at Exhibit I.CCC.3 which includes the steps that Enbridge Gas takes to manage capital within the materiality threshold that is calculated annually. The process to set the capital budget is fully described in that response which is consistent with what has been presented in the Asset Management Plan. There are no other targets and the materials noted above do not exist.

Please see the response at Exhibit I.STAFF.1 for a list of specific projects that were deferred on the Union Gas Rate Zone. A similar list for the EGD Rate Zone is shown below.

Investment ID	Investment Name	Reason for deferral/reduction	Amount of in-service capital reduction
3610	Crowland Storage Transfer	Deferred to 2023	$2.0M
102570	MOP Verification Program	Specific projects had not been identified to fully use the program spend	$2.0M
503369	Lisgar Station	Scope reduced and deferred	$1.2M
	Efficiencies and workplan reductions	To be achieved through deferrals and efficiencies	$10.7M

Having gone through this exercise, and recognizing that the asset needs still exceeded the materiality threshold, Enbridge Gas reviewed each Asset Class Program to see if it could be further reduced through efficiencies, work deferrals or other means. Looking across all asset classes this led to a further reduction of $10.7M as noted above.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

Ex. B-2-1 Appendix E

Question(s):

Please review the table below, summarizing the year two impacts of the five proposed projects, and confirm its accuracy. (A live Excel version has been included.) Further, please confirm:

a) The Applicant is proposing to add a total of $276.3 million to rate base for the subject projects.

b) Before taking into account the tax shield from CCA, the annual cost to ratepayers in 2023 is expected to be $27.6 million.

c) If the assets were depreciated over twenty years, the annual cost before tax shield in 2023 would be $34.3 million.

ICM Summary - First Full Year 2023								
Project	***Additions to Rate Base***	***Depreciation***	***Cost of Debt***	***Cost of Equity***	***Tax Gross-up***	***Subtotal***	***Tax Shield***	***2023 Cost***
St. Laurent	$86,037	$1,998	$2,478	$2,790	$1,006	$8,272	-$832	$7,440
Cherry to Bathurst	$125,730	$3,072	$3,635	$4,094	$1,476	$12,277	-$1,174	$11,103
Dawn to Cuthbert	$23,508	$497	$926	$763	$275	$2,461	-$437	$2,024
Byron Transmission Stn.	$20,381	$522	$799	$660	$238	$2,219	-$746	$1,473
Kirkland Lake	$20,666	$624	$812	$670	$242	$2,348	-$149	$2,199
Totals	$276,322	$6,713	$8,650	$8,977	$3,237	$27,577	-$3,338	$24,239

Response:

Enbridge Gas has reviewed the provided table and has identified an inaccuracy. The additions to rate base figure for Cherry to Bathurst should be $126,730 as stated at Exhibit B, Tab 2, Schedule 1, Appendix E, page 2 of 5, Line 1. The resulting total additions to rate base should be $277,322.

a) Not confirmed. Total addition to rate base is $277.3 million.

b) The revenue requirement before taking into account the tax shield in 2023 is $27.6 million. Due to the averaging of 2022 and 2023 revenue requirements for cost recovery purposes, Enbridge Gas does not confirm that this is the annual cost to ratepayers in 2023. Also, see the response at Exhibit I.SEC.7.

c) Enbridge Gas is unable to confirm.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

Ex. B-2-1 Appendix G

Question(s):

Please provide calculations showing the unit rates by rate class for 2023.

Response:

The 2022 ICM unit rates presented at Exhibit B, Tab 2, Schedule 1, Appendix G were prepared based on a recovery period of January 1, 2022 to December 31, 2023. Accordingly, the unit rates for 2023 are the same as 2022.

The ICM unit rates were prepared assuming an implementation date in rates of January 1, 2022. Following the OEB's Decision in this proceeding, Enbridge Gas will file a draft rate order including updated ICM unit rates to reflect recovery of the total revenue requirement of the projects for the deferred rebasing period beginning with the implementation date if different than January 1, 2022.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

Ex. B-2-2 Appendix B, p.7

Question(s):

Please advise the extent to which the project is still needed in 2022 if the projected growth does not materialize. Please provide further data on load at this station.

Response:

As indicated in the pre-filed evidence at Exhibit B, Tab 2 Schedule 2, Appendix B, this project is also required to address heater integrity, noise complaints and compliance, maintenance/operational standards and valve integrity concerns. Please see the response at Exhibit I.FRPO.15 for further data on demands at the station.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

Interrogatory

Reference:

Ex. B-2-2 Appendix C, p.147

Question(s):

Please provide justification for the higher 25% contingency applied to all direct capital costs.

Response:

The estimate provided in pre-filed evidence for the Kirkland Lake lateral was at a class 5 level which has a lower level of scope definition and detail, hence the higher percentage of contingency applied. At time of filing the evidence for Dawn to Cuthbert in Exhibit B, Tab 2, Schedule 2, Appendix A, page 471 and Byron Transmission Station Rebuild estimate in Exhibit B, Tab 2, Schedule 2, Appendix B, page 31, the estimates were at an early class 3 level with defined scope and long lead material quoted.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 2

Question:

a) Do any of the following projects require any additional Board approval other than those being sought in this application?

- Dawn to Cuthbert Replacement and Retrofits Project
- Byron Transmission Station Project in the Union South rate zone
- Kirkland Lake Lateral Replacement Project in the Union North rate zone.

b) Please provide the Utility System Plan (or Asset Management Plan) date(s) in which these projects were first identified. Please provide the extract describing the project, estimated costs and projected start date that were provided in that Plan.

Response

a) No. In this application, Enbridge Gas is seeking OEB approval for ICM funding for these projects.

b) The Dawn to Cuthbert Replacement and Retrofits Project was first identified in the 2021-2025 Asset Management Plan (EB-2020-0181 Exhibit C, Tab 2, Schedule 1). The project details (Investment Summary Report) were included in the Appendix to that Asset Management Plan and are attached to the interrogatory response at Exhibit I.ED.5 b*)* in this application. The Investment Summary Report shows a cost of $24.6M and an in-service date of 2022.

   The Byron Transmission Station Project in the Union South rate zone was first identified in the 2019-2028 Union Gas Asset Management Plan (EB-2018-0305, Exhibit C1, Tab 3, Schedule 1). The project details were included in the Appendix to that Asset Management Plan and are filed as Attachment 1 to this response. Appendix D in Attachment 1 shows a cost of approximately $15.5M and an in-service date of 2022.

The Kirkland Lake Lateral Replacement Project in the Union North rate zone was first identified in the 2021-5 Asset Management Plan (EB-2020-0181 Exhibit C, Tab 2, Schedule 1). The project details (Investment Summary Report) were included in the Appendix to that Asset Management Plan and are attached to the response at Exhibit I.ED.17 b) in this application. The Investment Summary Report shows a cost of $16.8M and an in-service date of 2022.

Appendix D – Project Descriptions

1 Growth

1.1 Byron Transmission Station Rebuild Project (AMP ID 1518)

The Byron Transmission Station Rebuild Project is required as a result of the rapid growth on the south and west sides of the London System which are supplied gas from the Byron Transmission Station. Due to the growth interest in markets fed by Byron Transmission Station and the abandonment of the London Lines, the Byron Transmission Station is projected to reach capacity in 2022.*

NOTE: **Only regular rate growth is available until 2022, assuming all previously identified contract customers bring on their requested loads. If contracts fall through or are decreased, capacity is freed up on the system.*

1.1.1 Scope

The Byron Transmission Station Rebuild Project is a full rebuild currently scheduled to be completed in 2022.

- Purchase of land is in the plans for 2018 as additional land will be required.
- As part of the rebuild, the existing station will provide gas to the customers fed off of Byron Transmission Station, acting as temporary regulation.
- The regulations runs will be split so that the 6,160 kPa MOP feeds the 3,450 kPa MOP system and the 1,380 kPa MOP system will feed the 420 kPa MOP system.
- A new heating system (boiler system) will replace the existing inefficient and large volume glycol boilers. As a result of splitting the regulation runs, heating load requirements are reduced and efficiency of the system is increased.
- Monitor/operator regulation runs will replace the current design and position the station for future growth as existing regulators are at maximum capacity. This will also result in lower emissions (token relief versus existing full relief) and reduce noise (station situated in densely populated and growing neighbourhood).
- Existing orifice meters will be replaced by turbine meters to ensure accurate area measurement as well as measurement used for odourization purposes.
- The majority of station piping installed in 1968 will be removed and replaced with new pipe sized for future growth eliminating current velocity concerns.

All of the modifications to be completed as a result of this rebuild enhance station safety, reliability, and maintainability, positioning the area for growth out to 2044, assuming reinforcement is completed upstream and downstream as needed. There is potential for additional capacity with relatively minor station changes in 2044 and beyond.

1.1.2 Expenditures

Total capital expenditure for this project is $349 thousand in 2021 and $15.2 million in 2022.

1.1.3 Resources

These larger full station rebuild projects are traditionally planned and designed by the Major Projects department. Planning has a team of dedicated full-time employees that will continue to manage and execute major projects such as the Byron Transmission Rebuild. The construction work will be managed by Major Projects and a contractor will execute the work. Depending on the scope, the construction contractor resourcing will be managed through a combination of existing Environmental Assessment (EA) contractors and bid process to source out additional contractor resources where required (see Table 2.5.2.1 for estimated costs).

1.1.4 Leave to Construct

Not applicable.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1

Question:

Enbridge Gas filed a Leave to Construct application with the OEB for the NPS 20 Replacement Cherry to Bathurst on July 31st, 2020 under docket number EB-2020-0136. The OEB approved the Leave to Construct application on December 17, 2020. Conditions of the Board's order require the project to start within 8 months of the Order. In addition, the Board is required to be notified 10 days before construction begins.

a) Has EGI begun construction of this project? If yes, when did construction begin – if no when will it be started?

b) Why was an ICM application not made in conjunction or at the same time as the Leave-to-Construct Application?

Response

a) Yes, consistent with the correspondence filed with the OEB on July 9, 2021, the Company commenced construction on July 14, 2021. Enbridge Gas notes that the OEB's requirement on the start date of construction in the preamble is incorrectly stated as 8 months. As per the Condition of Approval in EB-2020-0136, the OEB requires the project to start within 18 months.

b) A leave to construct application addresses the Purpose, Need and Timing of a project. Approval for ICM funding is obtained through an annual rate case. Also, see response at Exhibit I.PP.2 a) and b).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 1

"*The ICM unit rates presented in Appendix G were prepared assuming an implementation date in rates of January 1, 2022. Following the OEB's Decision in this proceeding, Enbridge Gas will file a draft rate order including updated ICM unit rates to reflect recovery of the total revenue requirement of the projects for the deferred rebasing period beginning with the implementation date if different than January 1, 2022.*"

Leave to Construct Performance Standards https://www.oeb.ca/applications/how-file-application/performance-standards-processing-applications
There are two Leave to Construct performance standards. One performance standard is for more complex applications and one performance standard is for more straightforward applications. These performance standards will be in effect on April 1, 2021.

	Decision Writing Period (Elapsed Calendar Days)	Total Cycle Time (Elapsed Calendar Days)
Complex Electricity & Natural Gas	60	210
Short-form Electricity & Natural Gas	30	135

The Application was filed October 15, 2021 The Board's standard (above) shows a minimum of 210 to 135 calendar days for an application to be decided. Enbridge Gas is seeking approval of ICM unit rates beginning in 2022. The minimum cycle time implies that a decision of the Board would be no earlier than March 1, 2022.

Question:

a) Please recalculate the total revenue requirement of the projects for the deferred rebasing period beginning with the implementation date of March 1, 2022 for the 2022 and 2023 rate periods.

b) Based on the application filing date and the Board's standards for processing this type of application a Board decision is expected no earlier than March or April of 2022. Please clarify whether an ICM rate rider would collect for any costs incurred prior to the date of the Board's Order. If yes, and if EGI rates are not currently set on an interim basis, please explain why these amounts would not be considered retroactive ratemaking.

Response

a) The total ICM revenue requirement of $10.8 million is not impacted as a result of a change in the rates implementation date.

   The calculation of the average annual requirement used to derive the ICM unit rates increases from $5.4 million to $5.9 million as a result of the delay in the implementation date in rates from January 1, 2022 to March 1, 2022. The detail by ICM project is provided in Table 1.

Table 1
Total Average Annual Revenue Requirement
Implementation Date of March 1, 2022

Line No.	Particulars ($000's)	2022	2023	Total	Average Annual (1)
		(a)	(b)	(c)	(d)
	EGD Rate Zone				
1	St. Laurent Ottawa North Replacement Phase 3	(4,594)	7,440	2,846	1,552
2	NPS 20 Replacement Cherry to Bathurst	(4,953)	11,102	6,150	3,354
	Union South Rate Zone				
3	Dawn to Cuthbert Replacement and Retrofits	(1,034)	2,024	989	540
4	Byron Transmission Station	(1,896)	1,473	(422)	(230)
	Union North Rate Zone				
5	Kirkland Lake Lateral Replacement	(936)	2,199	1,264	689
6	Total Incremental Revenue Requirement	(13,412)	24,238	10,826	5,905

Note:

(1) Average annual revenue requirement calculated as the total revenue requirement from 2022 to 2023 recovered over the 22-month period from March 1, 2022 to December 31, 2023 expressed as an annual amount (12 months).

b) For clarity, the Company is not seeking leave to construct approval for projects that do not meet the leave to construct application thresholds as part of this application. The current application includes a business case and leave to construct like evidence for each of the projects that do not require leave to construct approval in order to support the need for the ICM funding request of the projects.

The OEB approved Enbridge Gas's 2022 Rates effective January 1, 2022 on an interim basis until the OEB renders a decision on the current application (Phase 2 of the 2022 Rates application).[1]

[1] EB-2021-0147, Decision on Settlement Proposal and Interim Rate Order, October 28, 2021, p. 4.

The timing of capital expenditures of the project may occur prior to the date of the OEB's decision in this application, however, the revenue requirement has been calculated based on a forecast of the project's in-service date. Each project has an in-service date forecast for 2022 consistent with the year in which the ICM unit rates are proposed. The matter of retroactive ratemaking is not an issue in this application since approved 2022 ICM unit rates will be included in the delivery/transportation rates paid by customers following the OEB's decision on the final rate order for 2022 in this application. Note that in any event, Enbridge Gas's 2022 rates are currently approved and implemented on an interim basis (see EB-2021-0147 Decision and Order, October 28, 2021, page 6).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Interrogatory

Reference:

EB-2019-0194, Exhibit C, Tab 1, Schedule 1 – EGI Asset Management Plan Addendum – 2020, October 25, 2019. /Exhibit B, Tab 2, Schedule 1, Appendix A

Table 1.1-1: Summary of 2020 Capital Spend - EGD Rate Zone, Union Rate Zone and total EGI (Includes Overheads)

2020 Budget	EGD Rate Zone	UG Rate Zone	Total EGI
General Plant	46.8	52.0	98.8
System Access	141.5	96.0	237.5
System Renewal	136.9	191.5	328.4
System Service	13.4	128.5	141.9
Total Overheads	146.5	78.4	225.0
TOTAL	485.2	546.4	1031.6

(costs expressed in millions of Canadian dollars)

Question:

a) Please explain the variances as between EGI's 2020 capital forecast filed in October 2019 Asset Management Plan and the actual 2020 spending.

Response

a) Below are tables by rate zone showing the comparison of the 2020 Addendum and the 2020 actuals on an annual capital expenditure basis. Note that in 2020, the Union Gas and EGD rate zone asset class mapping was revised to align with the new AMP mapping. The restated amounts by USP category are shown. The actuals shown in Exhibit B, Tab 2, Schedule 1, Appendix A represent in-service capital and are not comparable to the budget depicted in the Asset Plan Addendum.

2020 Capital Expenditure Variance (Actual vs Budget as per 2020 AMP)
EGD Rate Zone ($ millions)

Line No.	Category	2020 Budget as per 2020 AMP[1]	2020 Actual	Variance (b-a)
		(a)	(b)	(c)
1	General Plant	46.8	47.3	0.5
2	System Access	137.7	129.4	(8.4)
3	System Renewal	142.0	136.1	(5.9)
4	System Service	26.1	20.8	(5.3)
5	Overheads	132.5	127.6	(4.9)
6	**Total - Union Rate Zones**	**485.2**	**461.2**	**(24.0)**

Line No.		Variance	Explanations
1	General Plant	0.5	No significant variances across the REWS, TIS and Fleet asset programs
2	System Access	(8.4)	**DP –** lower relocations due to rebillable timing ($7M) **Growth –** decrease in number of attachments ($3M) and fewer NGV projects ($3M) and other $1M **Utilization** – higher meter purchases due to advancement of purchases in 2020 $4M
3	System Renewal	(5.9)	**DP** – lower service relays due to COVID impacts for customer facing work ($7M) and lower main replacements ($5M) **DS** – higher due to reprioritization of workplan $12M **Utilization** – decrease in regulator refit purchases and remediation work ($6M)
4	System Service	(5.3)	**Growth** – decrease in reinforcements ($2M) **DP** – decrease in integrity work ($2M) **DS** – decrease in integrity work ($2M)
5	Overheads	(4.9)	Reduced allocations from O&M ($5M)
6	**Total - EGD Rate Zone**	**(24.0)**	

[1] EB-2019-0194, Exhibit C, Tab 1, Schedule 1, Table 2, Filed: 2020-10-15.

2020 Capital Expenditure Variance (Actual vs Budget as per 2020 AMP)
Union Rate Zones ($ millions)

Line No.	Category	2020 Budget as per 2020 AMP[2]	2020 Actual	Variance (b-a)
		(a)	(b)	(c)
1	General Plant	52.0	46.4	(5.6)
2	System Access	92.9	84.1	(8.8)
3	System Renewal	218.6	146.0	(72.6)
4	System Service	108.9	110.7	1.8
5	Overheads	78.4	81.4	7.5
6	**Total - Union Rate Zones**	**546.4**	**468.6**	**(77.8)**

Line No.		Variance	Explanations
1	General Plant	(5.6)	**TIS** – Decrease of ($22M) due to reprioritization of TIS portfolio **REWS** – Increase of $5M **CS/TPS** – Strategic land purchases $11M
2	System Access	(8.8)	**DP** – Decrease in relocations/municipal work ($6M) **Growth** – Increase in costs related to customer attachments $4M offset by lower EA fixed overheads ($2M) **Utilization** – lower growth meter purchases ($4M)
3	System Renewal	(72.6)	**DP** – Main replacements lower due to Windsor Line project timeline extension to 2021 for West section ($48M) and change in prioritization of work ($20M) **Utilization** – Decrease of ($5M) due to advancement of meter purchases in 2019
4	System Service	1.8	**DP/TPS** – Increase in Integrity work $18M **Growth** – Decrease in spend for Kingsville ($8M) and Owen Sound ($10M) offset by other minor variances $2M
5	Overheads	7.5	Increase as a result to change in presentation of loadings $20M due to Capitalization Study alignment and reduced allocations from O&M $12M
6	**Total - Union Rate Zones**	**(77.8)**	

[2] EB-2020-0181, Exhibit B, Tab 2, Schedule 1, Table 2, Filed: 2020-10-15.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 1,

Question:

a) How many meters of existing NPS 42 pipeline has EGI (Union and Enbridge) replaced (i.e., like for like) in each year 2017 through 2021.

Response

a) Union Gas Rate Zone

2020	Replaced three sections of pipe on the NPS 42 Trafalgar Pipeline through the integrity dig program. Lengths were 19m, 10m, and 47m respectively.

EGD Rate Zone

There were no like for like replacements of NPS 42 pipe in the EGD Rate Zone from 2017-2021.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Interrogatory

Reference:

Exhibit B, Tab 2, Appendix C

"*Enbridge Gas has identified the need to replace the existing NPS 4 Kirkland Lake Lateral ("Existing Line") running through the Municipality of Kirkland Lake in the District of Timiskaming with 8 km of NPS 4 pipeline…."*

"The NPS 4 Kirkland Lake Lateral was installed in 1958. The NPS 8 Kirkland Lake Loop was installed in 1990. Various sections, totaling approximately 4 km of the total 12 km of the Existing Line were replaced in 2018…."

Question:

a) EGI states that the Kirkland Lake project is a like for like replacement. For each year 2018 through 2021 how many kilometers of NPS 4 pipeline has EGI (Union/Enbridge zones) replaced like for like.

Response

a) Enbridge Gas has provided the following information to be as responsive as possible but notes that its Work and Asset Management Systems does not track the information as requested in the question. For this reason the details of how the information has been gathered are included.

Enbridge Rate Zone

Work orders that are categorized as Main Replacement with NPS 4 pipe have been included – both plastic (PE) and steel (ST). Work orders can also be categorized as Main Reinforcement and Main Relocation and the assumption is made that the like for like replacements will have been categorized as Main Replacement. All lengths are in metres.

Year	Length (m.)		
	PE	ST	Total
2018	1,417	507	1,924
2019	6,549	314	6,863
2020	4,331	532	4,863
2021	3,995	1,069	5,065

Union Gas Rate Zone

Projects classified as New Business and Reinforcements have been removed from the numbers below, leaving only the Replacements category.

Year	Length (m.)		
	PE	ST	Total
2018	21,185	3,484	24,669
2019	17,285	2,198	19,483
2020	9,470	1,043	10,512
2021	13,600	659	14,259

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Interrogatory

Reference:

Exhibit D, Tab 1, Schedule 1. Page 2-3

Table 1: Estimated Project Costs

Item No.	Description	Cost
1.0	Material Costs	$4,893,000
2.0	Contractor Labour Costs	$8,428,000
3.0	Internal Labour Costs	$180,000
4.0	Third Party Services	$1,111,000
5.0	Land Acquisition Costs	$277,000
6.0	Contingency Costs	$1,781,000
7.0	**Project Cost**	**$16,670,000**
8.0	Indirect Overheads	$3,648,311
9.0	IDC	$62,517
10.0	**Total Project Costs**	**$20,380,828**

"The project cost has increased from the previous estimate reported in the Asset Management Plan.1 This is largely due to: (i) reclassification of the cost estimate from a Class 5 estimate (based on historical project costs and rangeability of -50% to +100%) to a Class 1 estimate, (ii) increased civil scope based on Site Plan Approval consultations, (iii) increased scope due to land acquisition agreement; and (iv) increased construction labour costs as a result of project construction being spread over two years."

Question:

a) Please provide the previous estimate referenced above.

Response

a)

Table 1:
Estimated Project Costs as filed in
EB-2020-0181,
Exhibit C, Tab 2, Schedule 1.

Item No.	Description	Cost
1.0	Material Costs	$1,756,619
2.0	Contractor Labour Costs	$2,502,024
3.0	Internal Labour Costs	$86,788
4.0	Third Party Services	$1,678,736
5.0	Land Acquisition Costs	$252,500
6.0	Contingency Costs	$1,711,547
7.0	**Project Cost**	**$8,550,000**

The cost estimate outlined above is a Class 5 estimate (based on historical project costs and rangeability of -50% to +100%) and includes a 25% contingency applied to all direct capital costs.

Note that the indirect overheads and IDC were not calculated at the time of the Class 5 estimate.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedule 3 EGI Asset Management Plan Addendum – 2022

Question:

a) Please provide a listing, with a short description of all projects planned to begin construction in 2022 which are currently costed at $19 million or above.

b) Please provide the same listing for all the projects begun in 2020 and (separately) in 2021.

Response

The investments listed in part a) and b) have a total cost of $19M (including overheads) or above.

a) Construction Start Date in 2022

1. St Laurent Phase 3 – Main Replacement
    - Vintage steel mains have shown signs of declining health due to the cumulative effective of poor manufactured coating performance, construction practices, latent third-party damages to pipe coating, and the effect of stray currents from transit infrastructure such as subway and streetcars. As noted in the ICM Evidence (Exhibit B, Tab 2, Schedule 1) the pipeline services over 165,000 customers in Ottawa, Ontario and Gatineau, Quebec. Project details can be found in the Leave to Construct for this project (EB-2020-0293).

2. Dawn - Cuthbert - ECDA to ILI Retrofit NPS 42
    - The existing NPS 42 pipeline between Dawn Compressor station and Cuthbert Road receiver site cannot be inspected using in-line-inspection (ILI) tools. This project will replace this section of NPS 42 transmission pipe to allow for the pipeline segment to be in-line inspected to assess condition.

3. Kirkland Lake Lateral Replacement
    - The Kirkland Lake Lateral is 12 km of NPS 4 steel pipe of late 1950s vintage (1957/1958) operating at an MOP of 6895KPa / 1000psig (>30%SMYS) and is considered a transmission main under the Transmission Integrity Management Program (TIMP)

4. SCOR:Meter Area-Upgrade (Phase 2)
    - The work at the Corunna facility has been completed in two phases, the first phase going into service in 2021. These projects are driven by the concerns about high gas velocities which can lead to vibration in the pipe, and the need to remove certain assets as the area is no longer used to metering.

5. Panhandle Regional Expansion Project
    - EGI has identified the need for 19 km extension of NPS 36, looping the existing NPS 20 from Dover Transmission station towards Windsor, as well as 12 km of NPS 16 to interconnect the three laterals in Leamington/Kingsville.

6. Kennedy Road Expansion
    - The adjacent property to the existing site has been purchased (approximately 2 acres), and construction will begin in 2022 to demolish the existing buildings on site, and build a new facility on the combined site.

7. New London Site
    - New land has been purchased for the consolidated site and construction will begin in 2022 to build a combined facility on the new site.

b) <u>Construction Start Date of 2020</u>

1. Windsor Lines
    - This project replaced 61.4 kilometers of the existing Windsor 10” pipeline, with a new ~65-kilometer, 6” distribution line operating at a higher operating pressure, between Windsor and Port Alma.

2. Station B
    - The Station B project will build a new building while maintaining the area of the existing yard to correct the identified deficiencies, eliminating the identified risks.

3. Owen Sound Reinforcement
    - Addition of 34.5km of new NPS 12 pipeline from Durham Gate Station to Chatsworth in Grey County to support in-franchise growth and Epcor supply to Kincardine.

<u>Construction Start Date of 2021</u>

1. NPS 20 Lake Shore Replacement (Cherry to Bathurst)
    - The NPS 20 Lake Shore Replacement project from Cherry St. to Bathurst St. addresses vintage steel mains installed in 1954. As noted in ICM Evidence (Exhibit B, Tab 2, Schedule 1), these pipelines serve the highest density population in the Enbridge Gas franchise – an area that is also one of Canada's largest economic centres.

2. Byron Transmission Stn (13N-501)
    - The project is not subject to a Leave to Construct approval requirement. The Station accepts gas from the Dawn Parkway System and supplies natural gas to the majority of the London, St. Thomas and Port Stanley systems. The project is driven largely by integrity concerns related to the heating system, as well as noise concerns.

3. 2021 Sarnia Industrial Line Reinforcement
    - The project is to install approximately 1.2 km of NPS 20 pipeline and ancillary facilities from the Dow Valve site to the Bluewater Interconnect including tie-ins to the existing Sarnia Industrial Line system.

4. London Lines
    - This project installed 83.5 km of NPS 6 & NPS 4 steel pipe with a MOP of 3450 kpa (500 psi) from Dawn Compressor Station to Komoka Transmission Station, replacing the two pipelines known collectively as the London Lines.

5. SMOC/Coventry Facility Consolidation
    - This project will consolidate the South Merivale Operations Centre (SMOC) and Coventry Road facilty. The new property was purchased in 2021 and the new building will be constructed in 2023.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Interrogatory

Reference:

Exhibit D, Tab 1, Schedule 1

Table 1: Estimated Project Costs

Item No.	Description	Cost
1.0	Material Costs	$1,982,400
2.0	Labour Costs	$7,728,000
3.0	External Permitting, Land	$168,000
4.0	Outside Services	$3,074,400
5.0	Direct Overheads	$487,200
6.0	Contingency Costs	$3,360,000
7.0	**Project Cost**	**$16,800,000**
8.0	Indirect Overheads	$ 3,750,059
9.0	IDC	$116,281
10.0	**Total Project Costs**	**$20,666,340**

Question:

a) What Class estimate (Cost Estimating and Management Standard) is the Kirkland Lake project cost estimate?

Response

a) The Kirkland Lake project cost estimate is considered a class 5 at the time of application.