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VIA EMAIL and RESS

June 30, 2022

Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario, M4P 1E4

Dear Nancy Marconi:

Re: Enbridge Gas Inc. (Enbridge Gas)
Ontario Energy Board (OEB) File No. EB-2022-0086
Dawn to Corunna Replacement Project
Interrogatory Responses - Redacted

Enclosed please find the redacted interrogatory responses for the Dawn to Corunna Replacement Project (Project).

In accordance with the OEB's *Practice Direction on Confidential Filings* (PD), Enbridge Gas is requesting confidential treatment of the following exhibits. Details of the specific information and reasons for confidential treatment are set out below:

Exhibit	Description of Document	Confidential Information Location	Brief Description	Basis for Confidentiality
Exhibit I.CAEPLA-DCLC.4	Interrogatory response to CAEPLA-DCLC.4	Page 3 of 3	Information Pertaining to Public Security	The redactions relate to the geographic coordinates of an Enbridge Gas pipeline. Enbridge Gas has consistently treated such information as confidential in order to protect public safety and security.
Exhibit I.FRPO.19 Attachment 1	Interrogatory response to FRPO.19	Pages 14, 18 and 19	Commercially Sensitive Information	The redactions relate to information that is commercially sensitive to DNV and consists of DNV unit pricing (presumptively confidential per Appendix B of the PD) and a list of DNV's projects for other clients, not related to the Project.

The unredacted confidential exhibits will be sent separately via email to the OEB.

Also, please note an excel version of the following exhibits have been included with this submission.

- Exhibit I.ED.15, Attachment 1
- Exhibit I.SEC.14, Attachment 1

The above noted submission has been filed electronically through the OEB's RESS.

If you have any questions, please contact the undersigned.

Sincerely,

(Original Signed)

Adam Stiers
Manager Regulatory Applications - Leave to Construct Applications

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit A, Tab 2, Schedule 1, Page 1
Exhibit B, Tab 1, Schedule 1, Page 11
Exhibit E, Tab 1, Schedule 1, Page 3

Preamble:

Enbridge Gas has applied for leave to construct approximately 20 kilometres of 36-inch diameter natural gas pipeline from its Dawn Operations Centre in the Township of Dawn-Euphemia to its Corunna Compressor Station in St. Clair Township to retire a number of compressors at its Corunna Compressor Station (Project). The Project also includes the installation of an in-line inspection tool launcher and receiver, and station work to tie-in the new pipeline at each of the Dawn Operations Centre and the Corunna Compressor Station.

Enbridge Gas says the proposed project is needed to address reliability, obsolescence and safety concerns associated with a number of compressors at its Corunna Compressor Station. Enbridge Gas says that installing a new pipeline to replace the equivalent capacity of the compressors will increase overall system reliability, resiliency, and efficiency.

Question:

a) Please quantify the total amount of surplus compression capacity currently available at the Dawn Operations Centre.

b) Please explain why there is surplus compression capacity at the Dawn Operations Centre and how long the surplus has existed.

c) Please explain who paid for the surplus compression capacity currently available at the Dawn Operations Centre. Is the surplus capacity part of Enbridge Gas's regulated or unregulated storage operations? If both, how is the surplus allocated between regulated or unregulated storage operations?

d) Please confirm that the Project does not necessitate any kind of compressor upgrades at the Dawn Operations Centre. If this cannot be confirmed, then please explain the scope, cost and timing of any compressor upgrades at the Dawn Operations Centre, how the costs will be allocated between regulated and unregulated operations for ratemaking purposes, and whether the costs were included in the Project budget (and if not, why not).

<u>Response</u>

a) All 8 compressor plants at Dawn are required as part of Enbridge Gas's design day analysis. Table 1 details the compressor utilization based on the Winter 2021/2022 design day analysis.

Table 1

Type of Horsepower	Design Day Horsepower	Surplus	Utilization
Storage	105,800	4,200	96%
Transmission	112,188	11,737	90%
LCU[1]	38,400	0	n/a
Total	**256,388**	**15,937**	n/a

<u>NOTES:</u>
[1] Enbridge Gas employs a loss of critical unit ("LCU") strategy at Dawn that can accommodate an outage of any single compressor, including on a design day. The intent of the LCU strategy is to accommodate shorter term outages, LCU is not intended to accommodate compressor reliability issues that result in long-term compression outages and is not intended to substitute for prudent long term asset planning.

b) Storage horsepower utilization is calculated as part of the design day analysis based upon the annual supply and demand on the storage system. Actual horsepower utilization fluctuates from year to year based upon supplies and demands. The current transmission horsepower surplus has existed since the construction of Dawn H in 2017. Manufacturers design compressor packages to be marketable for a wide range of customers/purposes (e.g., power generation or marine applications), and offer packages in different blocks of horsepower. New units are sized to meet forecasted demand at the time of need and may result in some excess horsepower due to the nature of the packages offered by the manufacturer (in this case Siemens).

c) Enbridge Gas does not maintain a split of design day horsepower between utility and non-utility operations. As noted in the OEB's Natural Gas Electricity Interface Review ("NGEIR"), functional separation of utility and non-utility operations was not necessary. The cost of the Company's compression assets have been split between utility and non-utility operations consistent with the OEB findings in the NGEIR Decision. Please also see the response at Exhibit I.SEC.18.

d) Confirmed.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("OEB")

INTERROGATORY

Reference:

Exhibit A, Tab 2, Schedule 1, Page 1
Exhibit B, Tab 1, Schedule 1, Page 3

Preamble:

Enbridge Gas states that it has identified the need to abandon, remove and replace up to seven reciprocating compressor units located at the Corunna Compressor Station due to identified reliability, obsolescence and safety concerns. [Emphasis added.] Enbridge Gas also states that the scope of the project includes the retirement and abandonment of 7 of the 11 existing reciprocating compressor units at the Corunna Compressor Station. [Emphasis added.]

Question:

a) Please confirm that Enbridge Gas proposes to retire seven compressor units at the Corunna Compressor Station.

b) Please confirm that the units that will remain at the Corunna Compressor Station are natural gas fueled reciprocating compressor units.

c) Does Enbridge Gas currently have any reciprocating compressor units in any of its other compressor stations? If so, please provide a table that summarizes the station names, station locations, and the number and approximate vintage of the reciprocating compressors at each station.

d) Does Enbridge Gas have future plans to replace any reciprocating compressor units its other compressor stations? If so, are the future replacement plans part of any kind of Asset Management Plan? If so, please provide excerpts from the plan that explain the scope of the future replacement plan and its timing. If not, why not? Also, if not, please provide an explanation for the scope and timeline for the future replacements.

e) Does Enbridge Gas have plans to retire any other compressor units and replace their capacity using pipelines? If so, please describe the plans and at a minimum include in the response the compressor station names, the numbers and locations of compressor units to be retired, approximate timelines, and estimated capital costs.

Response

a) Confirmed. Enbridge proposes to retire CCS compressor units K701-K703 and K705-K708.

b) Confirmed.

c) Yes, please see Table 1 which summarizes existing Enbridge Gas reciprocating compressor units.

Table 1

Station	**Unit**	**Year of Install**	**Location**
Sombra Compressor Station	K-801	1997	Wilkesport
Sombra Compressor Station	K-802	1997	Wilkesport
Sombra Compressor Station	K-803	2009	Wilkesport
Chatham D Compressor Station	K-901	1998	Dresden
Crowland Compressor Station	K-601	1970	Port Colborne
Airport Compressor 13G503	Airport	2009	Petrolia
Heritage Compressor 11F109	Heritage	2009	Sombra
Tipperary Compressor 21L602	Unit 1	2007	Goderich
Tipperary Compressor 21L602	Unit 2	2007	Goderich
Waubuno Compressor 11G102	Waubuno	1985[1]	Brigden
Enniskillen Compressor 11G203	Enniskillen	1989	Brigden
Edys Mills Compressor 11H506	Edys Mills	1993	Dawn Township
Dow A Compressor 13F602	Dow A	1991	Sarnia
167 Compressor 11H602	167	1976	Dawn Township
Oil Springs East Compressor Station 11H303	Unit 1	1990	Enniskillen Township
Oil Springs East Compressor Station 11H303	Unit 2	1990	Enniskillen Township
Hagar Compressor J536491	Boil Off	1967	Hagar
Hagar Compressor J536491	Cycle	1967	Hagar

d) Yes, Enbridge Gas plans to replace four more reciprocating compressors over the course of the next 10 years at: (i) Crowland; (ii) Waubuno; and (iii) Hagar (2 units). These were identified in the Company's 2021-2025 Asset Management Plan at EB-2020-0181, Exhibit C, Tab 2, Schedule 1.

[1] Unit was purchased used in 1985. The manufacture date of the unit was 1975.

i. Crowland – The facility condition of the aging Crowland compressor station is considered poor. The compressor station suffers from process safety concerns, obsolescence issues, code concerns and property clearance concerns related to neighbouring buildings and the nearby rail line. The strategy includes reviewing alternatives considering future operation of storage both with and without compression.[2]

The compressor station would be rebuilt in place including:[3]
- Installation of a new administration building, auxiliary building, compressor building, utilities, site safety and security system.
- Decommissioning of the compressor system.
- Dehydration system instrumentation and controls upgrade.

Work would include full project gating cycle due to scale and complexity including stakeholder consultations, planning, detailed design, community consultations, permit applications, environmental assessments, procurement, retaining a construction contractor, isolating the system, demolition of structures/equipment to be replaced, erecting buildings, prefabricating piping, hydrotesting at shop, installing new piping and equipment, NDE as required, coating as required, inspection, training staff, energizing the system, remediating the site, and performing records updates.

Investment is currently proposed to begin in 2022.

ii. Waubuno – The aging storage compressor at the Waubuno station is used to inject natural gas into the Waubuno storage pool. The compressor is over 30 years old and becoming difficult to maintain. Sourcing replacement parts is difficult and continued manufacturer support is limited. To ensure a reliable storage injection and withdrawal service, the compression provided by this unit needs to be replaced to avoid a significant outage.[4]

This project includes constructing 6.5 kilometres of NPS 16 between the Waubuno pool measurement station and the Bluewater, Airport, & Mandaumin NPS16 pipeline. The high-pressure pipe links Waubuno directly to Dawn compression. This results in increased operational flexibility, reduced cycle time and increased reliability.[5]

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[2] EB-2020-0181, Exhibit C, Tab 2, Schedule 1, p. 196, Crowland Station Renewal
[3] EB-2020-0181, Exhibit C, Tab 2, Schedule 1, Appendix, Scope of Work
[4] EB-2020-0181, Exhibit C, Tab 2, Schedule 1, p. 196, Waubuno Compression Life Cycle
[5] EB-2020-0181, Exhibit C, Tab 2, Schedule 1, Appendix, Scope of Work

Since the development of the 2021-2025 Asset Management Plan, further modelling indicates that the proposed NPS 16 pipe diameter introduces velocity concerns in the station and can be mitigated with an upsize to NPS 20. With the implementation of the Project, the proposed pipeline route to replace Waubuno compression can be reduced in length to approximately 1.6 kilometres as it will cross the Project corridor before reaching the Bluewater, Airport & Mandaumin pipeline. The in-service date for this alternative is proposed as 2025.

iii. Hagar – Enbridge Gas will continue to re-evaluate new technology to support a holistic plan for the modernization of the Hagar plant. The outcome of this analysis may result in an approach that favors broad plant renewal.[6]

This project involves replacement of the Boil Off Gas ("BOG") compressor to mitigate the risk of a system failure due to a non-repairable, critical compressor part. The BOG compressor is one of the two compressors used to power the refrigerant process which cools the natural gas feedstock to -160 Celsius (at which point the natural gas turns into a liquid). Over its more than 50 years of operation, the 240-horsepower Ingersoll Rand BOG compressor has amassed 325,000 operational hours and is deemed to be at the end of its design life. Although normal wear components are still available, core compressor replacement parts such as cylinders, crankshafts, pistons, etc., required to support a critical failure are no longer manufactured. In a critical failure, securing used parts (which are rare) or after-market custom machining services are the only options for repair. If custom machining services cannot repair the part, a custom-designed after-market casting option or complete replacement of the compressor will be required, rendering the LNG plant out of service for at least one operational season and unable to perform its regulated requirements.[7]

This project also involves replacement of the KVGR cycle gas compressor to mitigate the risk of a system failure due to a non-repairable, critical compressor part. The KVGR compressor is one of the two compressors used to power the refrigerant process (the other is the BOG compressor). Over its 50 years of operation, the 1,500-horsepower Ingersoll Rand KVGR cycle gas compressor has amassed 140,000 operational hours and is deemed to be at

[6] EB-2020-0181, Exhibit C, Tab 2, Schedule 1, p. 213
[7] EB-2020-0181, Exhibit C, Tab 2, Schedule 1, p. 213 , JVG Boil-off Gas (BOG) Compressor Replacement

the end of its design life. This replacement is required for the same reasons as the BOG compressor.[8]

e) Enbridge Gas plans to retire the Waubuno compressor unit and replace its capacity with a pipeline using compression at Dawn. As outlined in the response to part c) above, the Waubuno Compressor Station (11G-102) has a single reciprocating compressor and is located in Brigden, Ontario. Please see the response to part d) above, for details pertaining to the approximate timelines and estimated capital costs of Waubuno compressor unit retirement and replacement.

[8] EB-2020-0181, Exhibit C, Tab 2, Schedule 1, p. 213, KVGR Cycle Gas Compressor Replacement

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, Page 8

Preamble:

Currently, there are two NPS 30 pipelines (TR1 and TR2), approximately 20 km in length, that connect the Corunna Compressor Station to Dawn for Injection and Withdrawal Modes. The Sombra Compressor Station is also connected to the Corunna Compressor Station through a series of NPS 16 pipelines.

Question:

a) Please quantify any surplus compression capacity currently available at the Sombra Compressor Station? How is any surplus at this station allocated between regulated and unregulated storage operations?

b) Please explain why the existing NPS 16 and 30 pipelines are not capable of providing the capacity for which the new NPS 36 pipeline has been proposed to provide.

c) When sizing the proposed NPS 36 pipeline, did Enbridge Gas account for any ability for the Sombra Compressor Station and the existing NPS 16 and 30 pipelines to provide support such that the proposed pipeline could be downsized? If not, why not?

Response

a) & b)
The Sombra Compressor Station ("SCS"), which contains three compressor units (K801, K802 and K803), is 100% utilized as part of the design day analysis. In other words, there is no surplus compression capacity currently available at the SCS that might be leveraged via the series of NPS 16 pipelines connecting the SCS with the

CCS. Similarly, the NPS 16 (TSLE – connecting SCS to Dawn) and NPS 30 (TR 1 and TR 2) pipelines are fully utilized and do not have any excess capacity.

In addition, the proposed TR 7 pipeline has a higher MOP than the existing NPS 30 to allow for higher injection pressures from Dawn during injection operations. The higher injection pressure facilitates the retirement of compression at the CCS required during the injection season.

c) Yes, the Sombra Compressor Station and the existing NPS 16 and NPS 30 pipelines are included in the analysis that was used to select the size of the Project. Enbridge Gas completed its analysis considering the entirety of the Company's relevant storage system/facilities in developing the Project. Pipeline size was selected to replace the deliverability and storage capacity of the 7 existing CCS compressor units proposed for retirement. If a smaller pipeline size were selected there would be a shortfall in design day capacity.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, Pages 11, 23

Preamble:

Enbridge Gas has undertaken comprehensive studies, including a site-wide quantitative risk assessment (QRA) to determine the severity of the increasing safety risks at the Corunna Compressor Station, and has determined that the current configuration of compressor units (which includes multiple compressor units in close proximity within a single building), results in an excessive level of process safety risk. The QRA applied industry best practices as recommended by Enbridge Gas's consultant, DNV. The key inputs of the QRA are the amount of equipment on site, operating conditions, locations of buildings, and time spent on-site by various employees.

Question:

Is the current configuration of compressor units out of compliance with any applicable legislation or any code/standard adopted by an applicable regulatory authority. If so, please explain.

Response

No, the current configuration of compressor units is not out of compliance with any applicable legislation or any code/standard adopted by an applicable regulatory authority. However, such regulations represent the minimum safety requirements for operational purposes and do not necessarily reflect current industry best-practices. It is not unusual for such regulations to not include all best practices, since the nature of natural gas pipeline and storage companies across the country and their respective operating environments differs widely. Also, the sophistication and approach to risk management varies across the industry.

Ensuring the safety of the public and Company personnel remains of paramount importance to Enbridge Gas. In Enbridge Gas's proactive approach to risk management, public and Company safety are two of several factors considered in the risk management process outlined in greater detail within the response at Exhibit I.CME.2 part a). Accordingly, the Company will continue to focus on prioritizing improvements to its existing processes, practices and facilities in this regard going forward.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, Page 21

Preamble:

Enbridge Gas states that the combined compressor downtime during Injection Mode across a 5-year assessment period is 606 days and that this means that at least one compressor is down for maintenance or repair 77% of the time during the injection season.

Enbridge Gas states that the combined compressor downtime during Withdrawal Mode across a 5-year assessment period is 695 days and that this means that at least one compressor is down for maintenance or repair 90% of the time during the withdrawal season.

Question:

a) Please provide an explanation for how the 77% was calculated.

b) Please provide an explanation for how the 90% was calculated.

Response

a) & b)
Table 4 at Exhibit B, Tab 1, Schedule 1, p. 21, provides total modeled downtime as 606 days for the injection season and 695 days for the withdrawal season over a 5-year period.

Table 4.1 at Exhibit B, Tab 1, Schedule 1, Attachment 2, p. 16, provides Average Time in Mode for different operating modes. The compression operating mode is used to calculate percentage downtime across the period that the compressors are operating.

For the injection season this represents 157 days of the year that compression is planned to operate and 154 days for the withdrawal season. Over a 5-year period this equates to 785 days and 770 days for injection and withdrawal, respectively.

- To calculate the percentage downtime based on planned compression operating time; 606 days of downtime divided by 785 days of operation equals 77% downtime.

- To calculate the percentage downtime based on planned compression operating time; 695 days of downtime divided by 770 days of operation equals 90% downtime.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit B, Tab 2, Schedule 1, Page 5-7
Exhibit C, Tab 1, Schedule 1, Attachment 2, Page 12

Preamble:

Enbridge Gas states that in accordance with the OEB's Natural Gas and Electric Interface Review[1] and Enbridge Gas's Mergers, Amalgamations, Acquisitions and Divestitures proceedings[2], total underground storage capacity reserved for the legacy EGD rate zone in-franchise customers is 99.4 PJ. The physical storage capacity reserved for legacy EGD rate zone customers has the following injection and withdrawal characteristics:

a) In-franchise storage withdrawals are limited to 1.9 PJ/d at storage capacities between 99.4 to 43.5 PJ. Below 43.5 PJ the deliverability decreases linearly until reaching a lower limit of 0.5 PJ/d at 0.5 PJ.
b) In-franchise storage injections are limited to 0.84 PJ/d at storage capacity between 0 PJ to 74.5 PJ. Above 74.5 PJ, injectability decreases linearly until reaching a lower limit of 0.297 PJ/d at 99.1 PJ.

Accordingly, Enbridge Gas holds 43.5 PJ of inventory in storage annually in order to provide 1.89 PJ/d of in-franchise deliverability to serve EGD rate zone customers on February 28 design day (typically the peak of winter seasonal demand).

Enbridge Gas states that, according to its 2021 Annual Gas Supply Plan Update[3], it continues to forecast storage requirements for bundled in-franchise customers in excess of the allocated cost-based storage space (most recently requiring the acquisition of an additional 26.5 PJ of storage capacity at market-based rates).

[1] EB-2005-0551, NGEIR Decision with Reasons, November 7, 2006, pp. 74 & 83
[2] EB-2017-0306/EB-2017-0307, MAADs Decision and Order, August 30, 2018, p. 51
[3] EB-2021-0004

Enbridge Gas states that forecast customer demand is projected to increase[4], the requirement for storage space in excess of the allocated-cost based storage is expected to continue for the foreseeable future and indicates no reduction in space required at this time.

<u>Question</u>:

Please briefly explain how Enbridge Gas is currently able to meet its obligation to reserve 99.4 PJ of storage for legacy EGD rate zone in-franchise customers if it only holds 43.5 PJ of inventory in storage annually.

<u>Response</u>

Enbridge Gas reserves 99.4 PJ of storage space for the EGD rate zone in-franchise customers and fills this space on an annual basis to meet the needs of the in-franchise customers. As part of its Gas Supply Plan Enbridge Gas plans to have 43.5 PJ of gas remaining in storage on design day to provide 1.9 PJ/d of in-franchise deliverability to serve EGD rate zone customers annually. Below 43.5 PJ the deliverability decreases linearly until reaching a lower limit of 0.5 PJ/d at 0.5 PJ.

[4] EB-2021-0004, 2021 Annual Gas Supply Plan Update, Table 1, p. 22

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, Attachment 2, Page 8
Exhibit C, Tab 1, Schedule 1, Page 21

Preamble:

The RAM Study Report states that despite the expected increase in deterioration each year, which results in higher number of failures each year, it is forecasted that both the gas injection and gas withdrawal shortfall will decrease from 2022 to 2026 (the horizon of the five-year assessment). The report also states that:

- The efficiency of the Corunna compressor facilities during injection mode is approximately 98% and the during the Withdrawal mode is approximately 99%
- There is a 95% chance of exceeding injection efficiency of approximately 95%, and that every 14.6 years, it is predicted that the gas injection shortfall will exceed 5%

Question:

Please explain the apparent contradiction between an increasing number of failures per year and a decreasing gas injection and gas withdrawal shortfall.

Response

Please see Exhibit B, Tab 1, Schedule 1, Attachment 2, pp. 31 and 38, for Injection and Withdrawal key observations respectively.

The higher levels of shortfall in the first few years of the projected timeframe are largely due to the occurrence of the first major failure (i.e., K704 foundation in relation to injection shortfall). Following the failure, the appropriate repair activity occurs and restores the reliability and availability of the unit thus resulting in a decrease in shortfall in the subsequent years, until the next failure occurs.

It is important to note that it is the combination of frequency of failures and duration of failures (not the frequency of failures only), that together determine the level of shortfall that occurs. For example, a foundation failure, such as the one expected for K704 in the near term will result in a significant amount of downtime to repair, which creates commensurate level of shortfall. There are also many more frequent failures that will occur but have a shorter associated repair time (compared to a foundation failure), each of which results in a less significant amount of shortfall.

The RAM Study accounts for all the different potential failure modes, the expected time to repair and through the Monte Carlo simulation produces an expected shortfall as a result.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit C, Tab 1, Schedule 1, Page 1
Exhibit C, Tab 1, Schedule 1, Attachment 2, Page 6 (ICF Report)

Preamble:

Enbridge Gas states that the Project would provide an equivalent amount of storage withdrawal/deliverability capacity as the existing Corunna Compressor Station compressor units proposed to be retired/abandoned, which is approximately 680 TJ/d. Enbridge Gas states that the current withdrawal/deliverability capacity as the existing Corunna Compressor Station compressor units is:

- Withdrawal capacity of 1.89 PJ/d
- Injection capacity of 0.84 PJ/d

The ICF report says that decommissioning of the compressors at Corunna Compressor Station would reduce Enbridge Gas's access to storage working gas space from about 99.4 PJ to 84.7 PJ and would reduce the withdrawal capacity at full working gas inventory from 1.89 PJ/day to 1.23 PJ/day.

Question:

a) Please explain how the Project's capacity of 680 TJ/d is equivalent to the current capacity of between 0.84 and 1.89 PJ/d?

b) Please reconcile Enbridge Gas's capacity numbers with those of ICF's.

Response

a) & b)
Please see Table 1 below a comparison of capacity numbers presented in the ICF report Page 1 and and Enbridge Gas's pre-filed evidence at Exhibit C, Tab 1, Schedule 1.

Table 1

Row		ICF	Exhibit C Tab 1 Schedule 1
1	Current withdrawal Capacity	1,894 TJ/d	1,894 TJ/d
2	Withdrawal Capacity with Compressor Abandonment	1,228 TJ/d	1,228 TJ/d
3	Reduced Withdrawal Capacity (1 - 2)	666 TJ/d	666 TJ/d
4	Working Capacity	99.4 PJ	99.4 PJ
5	Reduced Injection Capacity (1)	14.7 PJ	14.7 PJ
6	Available Working Gas (4 – 5)	84.7 PJ	84.7 PJ
7	Reduced Withdrawal Capacity (1)	5.7 PJ	5.7 PJ
8	Final Available Space (6-7)	79.1 PJ	79.1 PJ

(1) In total there is 20 PJ of space not accessible due to the decreased injection and withdrawal capability. This is split between the inability to fill 14.7 PJ on injection and the inability to empty an additional 5.7 PJ on withdrawal. Since Enbridge Gas plans to hold more than 5.7 PJ of inventory at the end of the withdrawal season there are currently financial consequences of losing the 5.7 PJ of space on the withdrawal side when analyzing supply side alternatives.

ICF and Enbridge Gas used the same storage withdrawal, injection, and working gas capacity values for their analysis.

The current maximum withdrawal deliverability with the compressors is 1,894 TJ/d (1.89 PJ/d) and the current maximum injection capacity is 840 TJ/d (0.84 PJ/d) with the compressors. 680 TJ/d is the approximate withdrawal deliverability that will be lost if the compressors are retired and not replaced. 99.4 PJ is the current regulated working gas capacity of the facility; this is not a deliverability or flow rate but rather the amount of gas the facility can hold that can be used to serve in-franchise customers of Enbridge Gas's regulated business. These values are shown in Figures 1 and 2 on pages 4 and 5 of Exhibit C in the project application (EB-2022-0086, Exhibit C, Tab 1, Schedule 1, pp. 4-5).

The ICF report states that “decommissioning of the compressors at Corunna would reduce Enbridge’s access to storage working gas space at Tecumseh from 99,400 TJ to 84,673 TJ and would reduce the withdrawal capacity at Tecumseh at full working gas inventory from 1,894 TJ/day to 1,228 TJ/day.” The reduction in withdrawal capacity from 1,894 TJ/d (1.89 PJ/d) to 1,228 TJ/d (1.23 TJ/d) is equal to the approximately 680 TJ/d reduction in withdrawal capacity cited in Enbridge’s application. ICF used the exact difference (666 TJ/d) shown in Figure 1 on page 4 of Exhibit C in the project application. 84.7 PJ (84,673 TJ) is the amount of storage working gas space that will remain if the compressors are retired without a replacement. This is calculated by using the reduced injection capacity shown in Figure 2 on page 5 of Exhibit C in the project application. If the compressors are retired and no additional injection capacity is added, the maximum working gas capacity will be 84.7 PJ because that will be the highest storage level that the storage will be able to be reliability refilled to after the withdrawal season. This is shown in Exhibit 2-1 of ICF’s report (EB-2022-0086, Exhibit C, Tab 1, Schedule 1, Attachment 2, p. 15).

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, Page 3
Exhibit C, Tab 1, Schedule 1, Pages 2, 18 and 20
Exhibit D, Tab 1, Schedule 1, Page 2

Preamble:

Enbridge Gas states that because its storage facilities are fully integrated, the seven Corunna Compressor Station compressor units in question serve both EGD rate zone customers (regulated or cost-based storage) and non-utility customers (unregulated or market-based storage). Costs for all of the seven CCS compressor units were paid for by EGD rate zone customers.

The total estimated capital cost the proposed project is $250.7 million, including indirect overheads and "loadings". This total includes 13.6% contingency applied to all direct capital costs.

When assessing alternatives, it appears that Enbridge Gas compared the total costs of the alternatives without overheads and loadings.
No discounted cash flow assessment was completed because the project maintains design day storage capacity/deliverability and equivalent injectability and "will not create any incremental design day space."

Enbridge Gas states that the cost estimate is a Class 4 estimate following its Cost Estimating and Management Standard.

Question:

a) Please provide a definition for the term "loadings".

b) For rate making purposes, how will the cost of the Project be allocated between Enbridge Gas's regulated and unregulated storage operations?

c) Please explain why Enbridge Gas chose to compare the alternatives based on costs that do not include overheads and loadings? To what extent would the costs of the alternatives have changed had overheads and loadings been included?

d) Please confirm that the Project will not result in Enbridge Gas's ability to offer any new or expanded market-based storage services. If this cannot be confirmed, the please explain the nature and extent of any new or expanded market-based storage services that may be offered.

e) Please confirm that Enbridge Gas's uses the American Association of Cost Engineers International Cost Estimate Classification System as part of its Cost Estimating and Management Standard, and that, in effect, Enbridge Gas's Class 4 estimate is the same as an American Association of Cost Engineers Class 4 estimate. If not, please explain.

f) Please describe any controls that will be used to help manage that capital costs of the Project, if it is approved by the OEB issues its decision (e.g., fixed bid contract, Owner's Engineer).

Response

a) The term "loadings" can also be referred to as a "burden rate". The Enbridge Gas Overhead Capitalization Policy applies burden rates to direct company labour hours in order to allocate indirect human resource costs (including pension and benefit costs) directly to capital projects.

b) As per OEB Decision and Order (EB-2020-0256) dated April 22, 2021, the allocation of costs between utility and non-utility operations will be addressed as part of Enbridge Gas's 2024 rebasing application.

c) Please note that Item # 9.0 of Table 1 of Exhibit D, Tab 1, Schedule 1 does not include loadings. This item only includes indirect overheads.

   Enbridge Gas compared the alternatives based on costs that do not include indirect overheads in order to assess the alternatives on an incremental cost basis in accordance with OEB Guidelines. By including indirect overheads, the analysis would be including costs that are not incremental to the Project. As such, it would not be appropriate to attempt to determine the extent to which the costs of the alternatives would have changed had indirect overheads been included.

d) Confirmed.

The Project replaces the existing system capacity and does not provide ability for Enbridge Gas to offer new or expanded market-based services.

e) Confirmed.

f) Some of the controls that will be used to help manage that capital costs of the Project include:

- The Project will utilize project management principles for cost, schedule and scope change management. The Project will establish a baseline for cost and schedule and any changes to either will require approval.
- The Project will include earned value management ("EVM") and will report schedule performance index ("SPI") and cost performance index ("CPI") for the general contractor monthly.
- As a contracting cost management strategy, a unit price will be used for the pipeline costs and a lump sum will be used for the ancillary scope. The contractor will also have Enbridge Gas construction management present to provide daily oversight, with a focus on managing the costs and quality of construction.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, Page 17

Preamble:

The retirement of the seven compressors would allow Enbridge Gas to avoid planned maintenance capital expenditures estimated at more than $16 million from 2023-2032 as well as any unplanned maintenance costs resulting from unit failures.

Question:

a) Please provide an explanation for how the $16 million in avoided planned maintenance capital expenditures was estimated.

b) Is it reasonable to assume that the Project will increase the planned maintenance, capital expenditures, or unplanned maintenance costs at the Dawn Operations Centre? If so, please explain and quantify the costs for comparison.

Response

a) Figure 1 below contains a list of planned maintenance capital investments for CCS compressor units K701, K702, K703, K705, K706, K707 and K708 that can be avoided during 2023-2032.

Figure 1

Row Labels	Sum of Sum Total
All	$ 1,220,996
SCOR:622xx Bypass Valve-Upgrade 2025	$ 131,999
SCOR:622xx Bypass Valve-Upgrade 2026	$ 264,000
SCOR:Unit Pre-Heat-Convrt	$ 274,999
	$ 274,999
	$ 274,999
K701	$ 2,678,461
MOD Valves	$ 500,000
Recycle Valve	$ 70,000
SCOR- 6100xx Engine Vibration Upgrade	$ 100,000
SCOR:62201-PSV-008-Increase Set Pressure	$ 14,583
SCOR:62201-PSV-013-Decrease Set Pressure	$ 211,312
SCOR:641 JWC VFD-Install	$ 622,566
SCOR:641xx Utility Valves-Replace	$ 65,000
Unit Valves	$ 120,000
SCOR:60001-Fdn Blk-Repair	$ 750,000
PLC Upgrades	$ 225,000
K702	$ 1,305,895
MOD Valves	$ 500,000
Recycle Valve	$ 70,000
SCOR- 6100xx Engine Vibration Upgrade	$ 100,000
SCOR:62202-PSV-008-Increase Set Pressure	$ 14,583
SCOR:62202-PSV-013-Decrease Set Pressure	$ 211,312
SCOR:641xx Utility Valves-Replace	$ 65,000
Unit Valves	$ 120,000
PLC Upgrades	$ 225,000
K703	$ 1,305,895
MOD Valves	$ 500,000
Recycle Valve	$ 70,000
SCOR- 6100xx Engine Vibration Upgrade	$ 100,000
SCOR:62203-PSV-008-Increase Set Pressure	$ 14,583
SCOR:62203-PSV-013-Decrease Set Pressure	$ 211,312
SCOR:641xx Utility Valves-Replace	$ 65,000
Unit Valves	$ 120,000
PLC Upgrades	$ 225,000
K705	$ 725,991
SCOR:62205-PSV-008-Increase Set Pressure	$ 518,117
SCOR:62205-PSV-013-Decrease Set Pressure	$ 207,874
K706	$ 2,582,173
SCOR:60006 iBalance-Upgrade	$ 1,174,500
SCOR:61006 Top End-O/H incl. Cam Upgrade	$ 380,000
SCOR:62006 Comp-Major O/H	$ 355,000
SCOR:62206-PSV-013-Decrease Set Pressure	$ 138,862
SCOR:64106 JWC-Replace	$ 533,811
K707	$ 2,835,934
SCOR:60007 iBalance-Upgrade	$ 1,174,500
SCOR:61007 Top End-O/H incl. Cam Upgrade	$ 380,000
SCOR:62007 Comp-Major O/H	$ 324,999
SCOR:62207-PSV-008-Increase Set Pressure	$ 211,312
SCOR:62207-PSV-013-Decrease Set Pressure	$ 211,312
SCOR:64107 JWC-Replace	$ 533,811
K708	$ 1,281,434
SCOR:62008 Comp-Major O/H	$ 324,999
SCOR:62208-PSV-008-Increase Set Pressure	$ 211,312
SCOR:62208-PSV-013-Decrease Set Pressure	$ 211,312
SCOR:64108 JWC-Replace	$ 533,811
K705-K708	$ 2,310,000
SM:100MOD Hdr Valves-Replace	$ 2,310,000
Grand Total	$ 16,246,779

b) Most preventative maintenance on the compressor units is completed on a fixed interval basis and therefore would not be affected by any increase in run time due to the Project. There are run hour based preventative maintenance schedules at the 1,000, 8,000, 24,000, and 50,000 hour-interval. The 1,000 and 8,000 hour inspections are completed internally, limited in scope and will not have a significant impact on operating cost. The average cost for a 1,000 hour inspection is about $800 and an 8,000 hour is $1400.

The increased storage flow rate on a typical storage day may result in increased run time on our larger storage units at Dawn. However, these hours are likely to be offset by reducing run time on smaller units currently used during storage season, resulting in limited impacts to planned and unplanned maintenance costs and capital expenditures,

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, Attachment 2, Table 4.4
Exhibit B, Tab 1, Schedule 1, Page 9

Preamble:

Table 4.4 summarizes the results of a Weibull analysis to determine the risk of compressor failure. It is the understanding of OEB staff that the parameter beta represents the shape of the Weibull distribution. If beta is greater than 1 then the failure rate increases with time; if beta is equal to 1 then failure rate is constant.
Table 4.4 reports that:
• Compressors K701-708 & K711 have a beta of 1.4
• Compressor K709 & K710 have a beta of 2.03

The seven compressors that are proposed to be replaced are K701-K703 and K705-K708. Units K704, K709, K710 and K711 provide a specific operational fit and cannot be replaced as part of the Project.

Question:

a) Please confirm that K709 and K710, which are not proposed to be replaced, have a greater likelihood of failure than the compressors that are proposed to be replaced.

b) Please confirm that part of Enbridge Gas's plans for K709 and K710 would be to keep them operational using spares for and salvaged parts from the compressors that are proposed to be abandoned.

c) Please confirm that Enbridge Gas took into consideration the risks of K709 and K710 failure and the costs to keep these compressors operational in its economic assessment of the alternatives to the Project. If this cannot be confirmed, please explain why not.

d) What are Enbridge Gas's long-term plans for units K709 and K710? Given the specific operational fit of these units, will these compressors eventually need to be replaced by new compressors? If not, what else could they be replace with? If so, would those replacement units be natural gas fueled reciprocating compressors or some other type?

Response

a) CCS compressor units K709 and K710 have revealed a higher failure rate (higher beta) than other CCS units. However, these two units have been operating for approximately 30%-50% of other CCS units' operating hours. Therefore, as demonstrated in AHR results summarized in Table 3, EB -2022 -0086 Exhibit B, Tab 1, Schedule 1, Page 20 of 31, the likelihood of failure in CCS compressor units K709 and K710 are either in the same range or lower than other units

   As discussed in Exhibit B, Tab 1, Schedule 1, pp. 9-11, units K704, K709, K710 and K711 provide a specific operational fit as part of the CCS injection and withdrawal seasonal cycles and cannot be replaced as part of the Project. On injection, units K704 and K711 will continue to be required after completion of the Project to compress gas arriving from Dawn to fill the top end of the pools to their Planned Maximum Operating Pressure. On withdrawal, units K709 and K710 will be required to provide a low suction pressure from the CCS to allow the storage pools to reach cushion pressure or minimum operating pressure. These compressors (or equivalent horsepower) will always be required at CCS to achieve a full cycle of the 9 storage pools connected to the CCS, including after the completion of the Project.

b) To the extent that they are interchangeable, the parts that are salvaged as a result of retiring the compressor units K701-K703 and K705-K708 will provide spares for some critical components that may otherwise be challenging to procure having long lead times and known obsolescence issues. However, there are some salvageable parts that are unique to each unit (not interchangeable); therefore, some of the critical spares required for these remaining CCS units will continue to be managed as they are today (e.g., sourced from OEMs or custom fabricated).

c) The residual risks associated with units K709 and K710 are included in the Results and Conclusions section of the report filed in response to Exhibit I.CME.1 Attachment 4 – DNV Dawn-Corunna Modifications Project QRA Report (May 17, 2022).

   The costs to keep K709 and K710 operational were not included in the economic assessment of the alternatives for the Project because the assessment is agnostic in this regard; both the Project and alternatives assume K709 and K710 remain in operation given their unique operational fit (as discussed in part a) above). Maintenance Capital costs associated with the continued operation of units K709 and K710 can be found in the Asset Management Plan.[1]

d) It is expected that K709 and K710 will need to be replaced in the future (exact timing currently unknown) with compressors that provide a similar capability and capacity at the CCS. At such time that the Company determines it necessary to replace these units it will consider their ongoing need and will assess all relevant/available options.

[1] 2021-2025 Asset Management Plan at EB-2020-0181, Exhibit C, Tab 2, Schedule 1.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit E, Tab 1, Schedule 1, Page 1

Preamble:

Enbridge Gas states that within the Dawn Operations Centre measurement facilities are no longer required and will be physically removed. The removal will involve demolition of the building, as well as removal of all measurement, associated equipment, piping and telemetry.

Question:

Please confirm that the cost to physically remove the Tecumseh measurement facilities is included in the Project cost. If this cannot be confirmed, please provide a cost estimate for the work and explain how the cost would be allocated between Enbridge Gas's regulated and unregulated storage operations for rate making purposes.

Response

Confirmed.

The costs to remove the Tecumseh measurement facilities are included in the Project cost. The full cost of the Tecumseh measurement facilities are included in utility operations and Enbridge Gas proposes that the costs for removal of the Tecumseh measurement facilities be treated in a consistent manner.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit F, Tab 1, Schedule 1, Page 4

Preamble:

Enbridge Gas states that a Stage 1 AA was completed by Stantec and submitted to the MHSTCI for review on September 21, 2021 and entered onto the Ontario Public Register on September 22, 2021.

Enbridge Gas states that a Stage 2 AA is required based on the findings of the Stage 1 AA.

Enbridge Gas states that it proposes to "complete the majority of the AA's during the 2021/2022 field seasons" and, upon completion, the AAs will be submitted to the MHSTCI for review and entered onto the Ontario Public Register.

Question:

a) Please confirm that when Enbridge Gas says that "the majority of the AA's during the 2021/2022 field seasons" it is referring to Stage 2 AAs and not Stage 1 AAs. If this cannot be confirmed, then please explain for what parts of the Project Stage 1 AAs have been completed and when the balance of AAs will be submitted.

b) What is the current status of the Stage 2 AA work?

Response

a) Confirmed.

b) Stage 2 AA work has been initiated, and is anticipated to be complete during the 2022 field season.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, Page 8
Exhibit G, Tab 1, Schedule 1, Pages 1-4 and Attachment 1
Exhibit H, Tab 1, Schedule 1, Attachment 1, Page 2

Preamble:

There are currently two NPS 30 pipelines (TR1 and TR2), approximately 20 km in length, that connect the Corunna Compressors Station to Dawn Operations Centre for injection and withdrawal modes.

The proposed pipeline is approximately 20 km in length. Where possible, the proposed pipeline will be located within existing easements. Temporary working space, construction yards and laydown areas are required adjacent to these areas to facilitate the movement and storage of equipment necessary for construction.

The proposed pipeline will require approximately 95.68 hectares (236.44 acres) of permanent easement. Enbridge Gas plans to acquire the land rights to 42.14 hectares (104.13 acres) of the required permanent easement. Enbridge Gas will also require approximately 53.54 hectares (132.31 acres) of temporary land use for construction and topsoil storage purposes.

Question:

a) Please confirm that Enbridge Gas's use of the term "acquire" means purchase fee simple.

b) Approximately what percentage of the length of the proposed pipeline would be located within existing permanent easements? Why was it not possible to locate the proposed pipeline entirely within existing permanent easements?

Response

a) Not confirmed.

   Enbridge Gas will attempt to acquire easements (rights-of-way) on private lands.

b) Enbridge Gas is proposing to acquire new easements for the proposed Project and will not be locating the proposed pipeline within existing easements. The pipeline requires a new easement to position it a safe distance from existing infrastructure.

   Please also see the response at Exhibit I.CAEPLA.3 a).

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit G, Tab 1, Schedule 1, Page 1
Exhibit E, Tab 1, Schedule 1, Attachment 1

Preamble:

Enbridge Gas has initiated meetings with landowners to inform them of the Project, to answer any questions that they may have, and to obtain early access to complete survey work. At the time of filing its application, formal land rights negotiations had not yet commenced.

Question:

a) Please provide an update on the status of land negotiations. Include in the response any concerns raised by landowners and Enbridge Gas's responses.

b) The Project schedule lists "land expropriation". Does EGI anticipate the need for a subsequent expropriation application? Please explain.

Response

a) Enbridge Gas has initiated preliminary discussions with CAEPLA but has not initiated formal land negotiations at this stage of the Project. Enbridge Gas will commence formal negotiations with landowners once survey drawings are completed.

b) Enbridge Gas will negotiate in good faith with all stakeholders to reach agreements with landowners. At the time of filing, land negotiations had not commenced (and have not yet commenced as of the time of filing this response). Enbridge Gas anticipates that agreements will be reached with all landowners. However, if the Company is unable to reach agreements with landowners for the Project, a subsequent expropriation application may be filed.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit H, Tab 1, Schedule 1, Pages 1-2

Preamble:

In January 2021, Enbridge Gas provided the Ontario Ministry of Energy (MOE) with a description of the Project to determine if there are any duty to consult requirements. In February 2021, Enbridge Gas received a letter from the MOE indicating that it had delegated the procedural aspects of consultation to Enbridge Gas for the Project. The Delegation Letter identified five Indigenous communities to be consulted in relation to the Project. At the time it filed its application, Enbridge Gas had not received a letter from the MOE with its opinion on the sufficiency of Indigenous consultation.

Question:

Please provide a status update on any communication from the MOE regarding Indigenous consultation for the Project.

Response

Enbridge Gas sent an email to the MOE providing the Indigenous consultation summary and log when the Project was filed on March 21, 2022. On May 30, 2022, Enbridge Gas provided another copy of the Indigenous consultation summary and log to the MOE. Enbridge Gas has not had any further correspondence with the MOE regarding Indigenous consultation for the Project.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit F, Tab 1, Schedule 1, Attachment 2

Preamble:

In August 2021, Enbridge Gas submitted Project information to the Technical Standards and Safety Authority (TSSA) for its review.

Question:

Please provide a status update on the TSSA's review of the Project.

Response

In August 2021, Enbridge Gas submitted preliminary project information to the TSSA. The basis of the information submitted was to make the TSSA aware of Project scope. The TSSA has responded to Enbridge Gas and requested information in four areas:

1. Request to submit design and piping specification when they are available.
2. Submit the High Consequence Area analysis once the route in finalized.
3. Provide a detailed construction schedule when available.
4. Provide details for material selection, pipe wall thickness, stress levels and maximum operating pressure.

Project design is currently at 90%. The technical details requested by TSSA will be submitted over the next several weeks as Project design is finalized.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Association of Energy and Pipeline Landowner Associations ("CAEPLA") and its subcommittee, the Dawn Corunna Landowner Committee ("DCLC")

INTERROGATORY

Reference:

Enbridge Application, Exhibit E, Tab 1, Schedule 1, Page 2 of 5 – Engineering and Construction

Enbridge Gas Inc. Application, Exhibit E, Tab 1, Schedule 1, Page 4 of 5 – Engineering and Construction

Preamble:

Enbridge Gas Inc. states:
C.9. All design, installation and testing of the proposed pipeline will be in accordance with the specifications outlined in Enbridge Gas's Construction and Maintenance Manual ("Specifications") and with the requirements of Ontario Regulation 210/01 Oil and Gas Pipeline Systems under the Technical Standards and Safety Act, 2000.

C.21. Enbridge Gas will construct the proposed pipeline in compliance with engineering design, its current construction procedures and specifications, environmental mitigation identified in the ER, permit conditions and commitments to regulators and landowners. Enbridge Gas continuously updates and refines its construction procedures and specifications and complies with environmental mitigation recommended to minimize potential impacts to the environment.

C.22. An Enbridge Gas Lands Agent will contact each directly affected landowner along the route prior to construction to obtain site specific requirements such as livestock fencing and access points. This information is included in the construction contract so that the pipeline contractor is contractually obligated to fulfill all commitments made to the landowner.

Question:

a) Please provide a copy of Enbridge Gas Inc.'s Construction and Maintenance Manual.

b) Please provide a copy of Enbridge Gas Inc.'s landowner construction protocol agreement or Letter of Understanding ("LOU") proposed for this project. If no agreement is proposed, please explain why not.

c) Please provide a copy of the construction contract for this project.

Response

a) The Enbridge Gas Construction and Maintenance Manuals are voluminous and contain detailed documents which are continually updated.[1] The Company believes that these documents are outside the scope of this proceeding and are not relevant to the approvals sought by Enbridge Gas.

b) The LOU is a privately negotiated agreement between Enbridge Gas and landowners affected by the Project which outlines the obligations of parties with respect to:

1. The form of easement agreement and temporary land use agreement;
2. The construction of the Project (e.g., soil testing, topsoil stripping, depth of cover, topsoil replacement, tree replacement, etc.);
3. Remediation of the Landowner's property; and
4. Compensation to the Landowner for various damages as a result of the construction of the Project.

A draft LOU for the Project has been provided to CAEPLA outside of the current OEB proceeding and is actively being negotiated by parties. Enbridge Gas will continue to work directly with CAEPLA to address any comments and concerns regarding the LOU until an agreement is reached. The final LOU agreed upon by all parties will be provided to all landowners affected by the Project for their consideration.

The obligations of parties outlined in the LOU are consistent with the pre-filed evidence of Enbridge Gas. Further, the form of easement agreement and temporary land use agreement are the basis of the Company's request with regard to Section 97 of the OEB Act, and thus the only aspect requiring the approval of the OEB. For these reasons, Enbridge Gas will not file the LOU given that it is the basis of ongoing private negotiation and the matters noted (other than compensation) are already largely set out in evidence before the OEB.

[1] Please note that separate manuals exist for Union Gas Ltd. rate zones and Enbridge Gas Distribution Inc. rate zones.

c) Contracts between Enbridge Gas and various Contractors and service providers that may be required for construction of the Project in the future, are not relevant to the approvals sought in the current OEB proceeding.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Association of Energy and Pipeline Landowner Associations ("CAEPLA") and its subcommittee, the Dawn Corunna Landowner Committee ("DCLC")

INTERROGATORY

Reference:

OEB Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario, 7th Edition 2016, Section 4.3.14, pages 42 et ff., Cumulative Effects

OEB Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario, 7th Edition 2016, Section 6.2.2, page 66, Monitoring Reports
Enbridge Gas Inc. Application, Exhibit B, Tab 1, Schedule 1, Page 1 of 31, Footnote 1, Adobe page 11

Stantec Dawn-Corunna Project: Environmental Report, Cumulative Effects Assessment – Adobe page 85 et ff.

Preamble:

Cumulative Effects Assessment
The OEB Guidelines include the following guidelines and recommendations with respect to the assessment of cumulative effects of a project:

> Cumulative impacts may result from pipeline projects which loop existing systems and should be addressed. This may include an examination of areas of known soil erosion, soil compaction or soil productivity problems. It may mean the examination of impacts associated with continued loss of hedgerows and woodlots in the same area. As well, it could mean the increased loss of enjoyment of property because of disruptions caused by the construction of successive pipelines on a landowner's property. There may also be heightened sensitivities as a result of improper or ineffective practices and mitigation measures in the past.

AND

Cumulative effects, when identified as part of the assessment process, should be integrated in the appropriate section of the ER (e.g. soil impacts.)"

"The following is a list that encompasses some of the cumulative effects of pipeline construction:

a) Incremental increase of easement width when adding new parallel pipelines to reinforce the systems;
b) Additive effects of vegetation removal including riparian vegetation, forest cover, agricultural crops;
c) Repetitive disturbance of soils including soil compaction, drainage systems damages, loss of soil fertility, crop yield reduction;
d) Streams and groundwater degradation and effects on water wells;

Residual effects caused by the removal of forest edge and interior, such as reduced species diversity and other habitat alterations.

AND

The Final Monitoring Report should address any potential cumulative effects which may arise for pipelines, these may include for example, reduced soil productivity over easements which overlap, land-use restrictions due to increased easement widths or additional above ground facilities and/or the repeated construction through sensitive areas.

The Stantec Environmental Report acknowledges the requirement to identify and discuss cumulative effects:
The recognition of cumulative effects assessment as a best practice is reflected in many regulatory and guidance documents. Regarding the development of hydrocarbon pipelines in Ontario, the OEB Environmental Guidelines (2016) notes that cumulative effects should be identified and discussed in the ER.

Building upon the intent of the OEB Environmental Guidelines (2016), the OEB has specified that only those effects that are additive or interact with the effects that have already been identified as resulting from the project are to be considered under cumulative effects. In such cases, it will be necessary to determine whether these effects warrant mitigation measures. The cumulative effects assessment has been prepared with consideration of this direction from the OEB.

Although a number of existing pipelines are in operation on the properties affected by the proposed pipeline (including one or more Union Gas Limited pipelines), the Stantec Environmental Report does not appear to include any consideration of adjacent pipelines and pipeline easements in its analysis of cumulative effects associated with the proposed project.

<u>Question</u>:

a) For each CAEPLA-DCLC property affected by the proposed project, please provide a property map or diagram showing the location of the new proposed pipeline, easement and temporary land use area as well as the location of all existing pipelines on the lands, including the location of pipes and the boundaries of the easements for each pipeline.

b) For each of the existing pipelines located along the proposed route for the new project, please provide the pipe material and grade, depth of cover at time of construction, wall thickness, and operating pressure.

c) Please provide a detailed chronology of pipeline development each of the CAEPLA-DCLC properties affected by the proposed project including: dates of construction, widths of individual easements obtained or acquired, total width of corridor, projected economic life of each pipeline.

d) Please provide copies of interim and final monitoring reports for the existing pipelines located on the CAEPLA-DCLC properties affected by the proposed project.

e) Please provide details of damage caused to soils by previous pipeline construction projects and pipeline operations and maintenance on the CAEPLA-DCLC properties affected by the proposed project.

f) What is Enbridge Gas Inc. doing to investigate and remediate residual damage from past projects on the CAEPLA-DCLC properties affected by the proposed project?

g) What are the cumulative effects on soil capability of carrying out construction activities on and in soils previously disturbed by pipeline construction?

h) Has Enbridge Gas Inc. or its predecessor(s) studied crop yield effects from previous pipeline constructions in the Project corridor, including on the lands to be affected by the new construction? Please provide any reports, data, results, conclusions, analyses, etc. in connection with such study.

i) Will Enbridge Gas Inc. agree to strip and store topsoil from areas not affected by previous pipeline constructions separately from topsoil stripped from areas affected by previous pipeline constructions? If not, please explain why not.

j) Will Enbridge Gas Inc. agree to restore soils affected by previous pipeline constructions to a condition comparable to soils on adjacent lands not affected by previous pipeline constructions? If not, please explain why not.

k) Please explain what provision is made by Enbridge Gas Inc. for post-construction crop yield monitoring on the construction areas for the Project. If no provision is made, will Enbridge agree to implement post-construction yield monitoring? If not, please explain why not.

l) What are the cumulative effects that would result from the abandonment or discontinuance of operation of one or more of the pipelines within the corridor?

m) Why do neither the Environmental Report nor the Application include a cumulative effects assessment of the interaction between existing pipelines and the proposed pipeline?

Response

a) Enbridge Gas is currently finalizing the route plans for individual properties affected by the Project. Once these plans are completed, they will be provided to affected landowners. Since filing its Application and pre-filed evidence, Enbridge Gas has made certain advancements to the design of the proposed Project. Accordingly, the updated alignment drawings set out at Attachment 1 to this response represent best available information (including existing pipelines and easements) as of the time of this filing.

b) & c)
The existing Enbridge Gas pipelines located along the proposed route for the Project are NPS 30 steel pipelines designated TR1 and TR2.[1] These pipelines have the following material characteristics:

TR 1 –

- 1964 original construction
- Steel Grade 414 MPa
- Wall Thickness 8.26 mm
- Typical operating pressure ranges from 650 – 850 Psig
- Anticipated to be fully depreciated in 2030
- Approximate width of easement is 60 feet

[1] TR 1 and TR 2 are shown in Exhibit B, Tab 1, Schedule 1, Figure 1 and are discussed in Exhibit C, Tab 1, Schedule 1, Paragraph 49.

TR 2 –

- 1977 original construction
- Steel Grade 414 MPa
- Wall Thickness 9.27 mm
- Typical operating pressure ranges from 650 – 850 Psig
- Anticipated to be fully depreciated in 2043
- Approximate width of easement is 75 feet

The approximate combined width of the easements for the TR 1 and TR 2 pipelines (considering 16 feet overlap) is 119 feet (36.3 m).

The Company was unable to produce records confirming depth of cover at the time of construction.

d) According to the E.B.L.O. 50 (Tecumseh Gas Storage Limited Application for TR 1) Reasons for Decision and the E.B.L.O. 182 (Tecumseh Gas Storage Limited Application for TR 2) Reasons for Decision, there was no condition of approval issued by the OEB for Enbridge Gas to produce an interim monitoring or final monitoring report for either pipeline.[2]

e) f) & j)
Enbridge Gas was not able to find any record of damage caused to soils or residual damage having been caused by previous Enbridge Gas pipeline construction projects on these properties.

Typically, when notified by a landowner that potential residual damage from an Enbridge Gas project exists, the Company conducts an investigation to confirm whether or not its past construction or maintenance activities are the cause. If confirmed, the Company works directly with affected landowners to reach a resolution.

g) Since 1976, Enbridge Gas (formerly Union Gas Limited) has compiled a database on assessed soil properties, quality, and crop yield for various properties on agricultural land affected by construction and for adjacent lands (not affected by construction). It has been found that reduced crop yields are more pronounced where construction workspace overlaps with previous construction easements. As a result of these studies, as well as improved construction practices (e.g. soil monitoring, wet soil shut down practice, and subsoil decompaction) and mitigation

[2] E.B.L.O. 50, January 23, 1964, Reasons for Decision and E.B.L.O. 182, June 10, 1977, Reasons for Decision.

measures implemented on agricultural lands, Enbridge Gas has observed significant improvements in soil properties and crop yield over time.

h) Enbridge Gas is not aware of, nor has it conducted, any crop yield studies from previous pipeline construction within the Project corridor.

i) No, Enbridge Gas has processes in place to minimize any admixing of topsoil and therefore separation of topsoil piles is not necessary.

k) Enbridge Gas currently has not made provisions for post-construction crop yield monitoring. Enbridge Gas agrees to develop and implement a post-construction crop yield monitoring study.

l) The effects of pipeline abandonment would be determined at the time of such action being taken, in accordance with regulations and policy guidance available at that time.

m) Developments already in place are assessed as existing conditions, which is provided in Section 4: Impact Identification, Assessment and Mitigation of the Environmental Report. Where residual effects from impacts on these existing conditions remain after mitigation, they are carried forward to the cumulative effect assessment.

RIGHT-OF-WAY
ENBRIDGE FILE NUMBER
OWNERSHIP/AGENCY
PIN: NUMBER

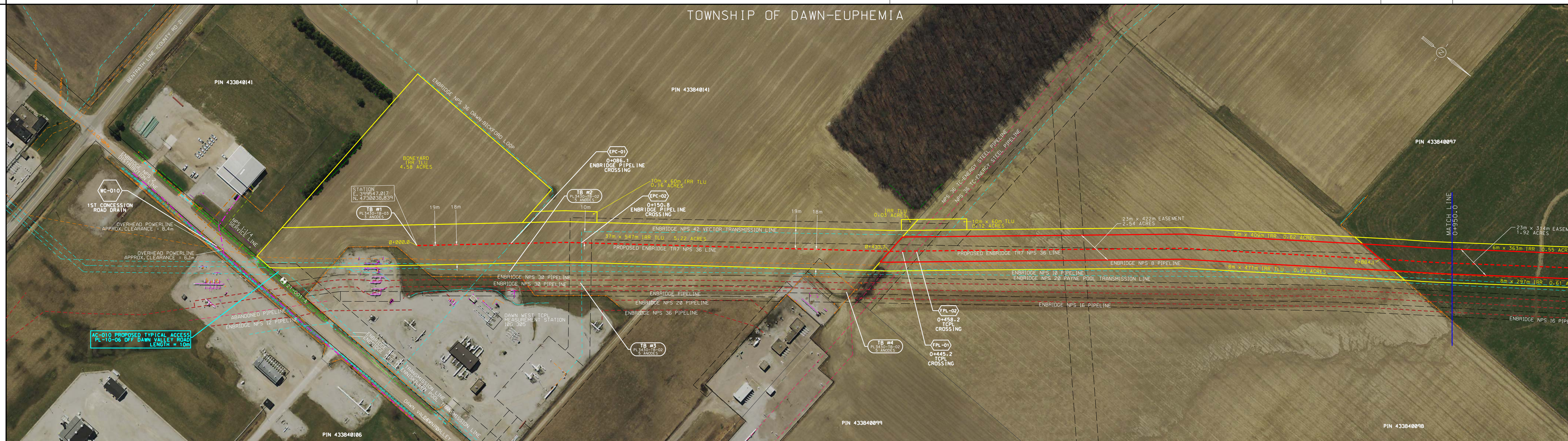
DAWN STATION TIE-IN 0+000.0 | PIN: 43384-0141 | 0+433.7 | PIN: 43384-0098 | 0+884.1 | PIN: 43384-0097 | 0+950.0 MATCH LINE

CURRENT CLASS LOCATION: 2
LOCATION FACTOR: 0.9
TILE PLAN NUMBER

ALIGNMENT DETAIL

LEGEND:
- PROPOSED ENBRIDGE TR7 NPS 36 PIPELINE
- TRANSMISSION/DISTRIBUTION PIPELINE
- FOREIGN PIPELINE
- EXISTING EASEMENT
- ENBRIDGE PIPELINE
- PROPOSED ENBRIDGE EASEMENT
- TEMPORARY ACCESS LANEWAY
- DRAIN/STREAM/WATERCOURSE CENTRE
- HYDRO EASEMENTS
- DRAINAGE DITCH BOTTOM/TOP
- RETAINING WALL/BRIDGE ABUTMENT
- ASPHALT/GRAVEL EDGE
- BUILDING
- POST/HYDRO POLE
- TELEPHONE BURIED CABLE/MISC CABLE
- FENCE
- OVERHEAD/BURIED HYDRO LINES
- WATERMAIN
- BOTTOM/TOP OF SLOPE
- TELEPHONE MARKER/BELL PEDESTAL
- CULVERT/CATCH BASIN/WATER VALVE
- SIGN/MAILBOX
- HYDRO TOWER
- PROPERTY LINE/ROAD ALLOWANCE
- PROPOSED ROAD/WATERCOURSE CROSSING
- PROPOSED HYDRO CROSSING
- PROPOSED ENBRIDGE PIPELINE CROSSING
- PROPOSED FOREIGN PIPELINE CROSSING
- PROPOSED BOREHOLE/MONITORING WELL
- TEST POST
- PIPELINE KILOMETRE POST
- TREE

PIPELINE PLAN SCALE 1:2000

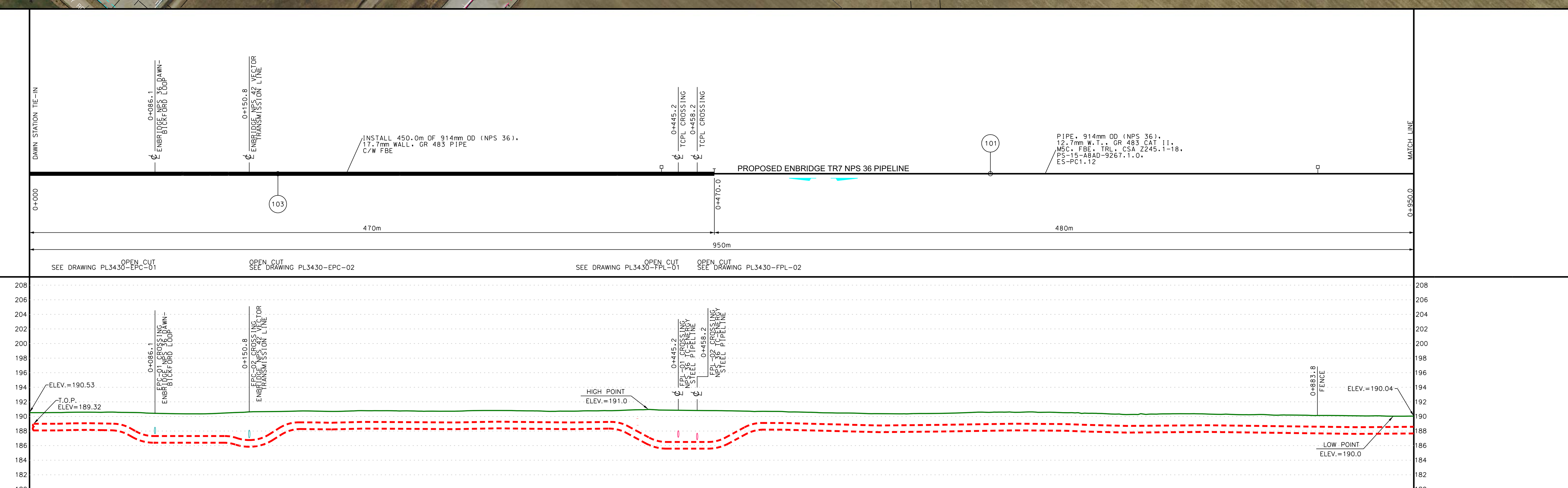


PIPELINE SCHEMATIC

LEGEND:
- HEAVY WALL PIPE
- PIPESAK
- TRANSITION WELD
- PIPELINE WARNING SIGN
- MATERIAL ITEM
- MAINLINE VALVE
- SIDE VALVE

PIPELINE DATA

P/L PROFILE HORIZ 1:2000 VERT 1:400



DESIGN PARAMETERS (NEW PIPING ONLY)

DESIGN
- DESIGNED TO CSA Z662-19
- DESIGN FACTOR – 0.8
- LOCATION FACTOR – 0.900 / 0.625 (CLASS 2)
- DESIGN TEMPERATURE – M5C
- DESIGN PRESSURE – 9308 kPa

HYDROSTATIC TEST PRESSURE
PIPING
- STRENGTH – 13,032 kPa (1890 psig) MIN.
- LEAK – 10,239 kPa (1485 psig) MIN.
- DURATION – EXPOSED PIPING – 1 HOUR AT STRENGTH TEST PRESSURE MINIMUM
- BURIED PIPING – 4 HOUR AT STRENGTH TEST PRESSURE FOLLOWED BY 4 HOUR AT LEAK TEST PRESSURE MINIMUM

HYDROSTATIC TEST DATE – TBD

CONSTRUCTION
START DATE – JUNE 1, 2023
PLACED IN SERVICE – NOVEMBER 1, 2023

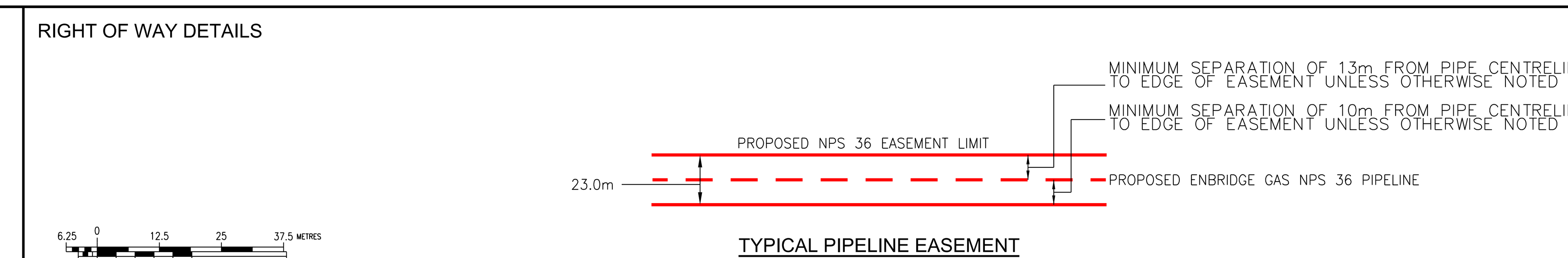
BILL of MATERIAL

Item No	Material No	Qty	Size	Description
101-150	Material No	Qty	Size	**PIPE**
101	~	480m	36	PIPE, 914mm OD (NPS 36), 12.7mm W.T., GR 483 CAT II, M5C, FBE, QRL, CSA Z245.1-18, PS-15-A8AD-9267.1.0, ES-PC1.12
103	~	470m	36	PIPE, 914mm OD (NPS 36), 17.7mm W.T., GR 483 CAT II, M5C, FBE, QRL, CSA Z245.1-18, PS-15-A8AD-9267.1.0, ES-PC1.12
701-800	Material No	Qty	Size	**OTHER MATERIAL**
702	130968	~	610mm x 304.8m roll	(24"x1000') ROLL YELLOW TERRA TAPE IMPRINT LAYOUT LINE 1: "CAUTION CAUTION CAUTION" (HEIGHT 3") LINE 2: " ENBRIDGE GAS INC: (HEIGHT2") LINE 3: "NATURAL GAS PIPELINE BURIED BELOW" (HEIGHT 1 1/2") ALL THREE LINES TO BE CENTERED 36" REPEATS
703	125139	2	406.4 x 406.4	STANDARD STO BURIED PIPELINE SYSTEM SIGNAGE, Phone number required 1-800-265-5260 AS PER LUG C&M 18.6
704	125111	2	3 m	SIGN POST, GALV U CHANNEL POST HOT ROLLED & DIPPED 80 M PSI C/W SIGN HDWE PER DWG.E974 (10FT.)
705	~	~	36	PIPELINE WEIGHTS, NPS 36, SADDLE DESIGN, GRAVEL FILLED

CONSTRUCTION NOTES:

1) CONTRACTOR RESPONSIBLE FOR ALL UTILITY LOCATES.
2) ALL CULVERTS, END WALL TREATMENT AND TILE DRAINS REMOVED DURING CONSTRUCTION ARE TO BE RESTORED TO MATCH EXISTING CONDITIONS.
3) RESTORATION INCLUDES TOPSOIL AND SEEDING.
4) RESTORE DRIVEWAYS TO MATCH EXISTING.
5) ALL ASPHALT AREAS TO BE RESTORED TO MATCH EXISTING.
6) RESTORE ALL OPEN DRAINS TO MATCH ORIGINAL GRADE AND CONTOUR CONDITIONS.
7) ALL WORK MUST BE IN ACCORDANCE WITH THE LATEST ENBRIDGE GAS SPECIFICATIONS.
8) ALL WELDS TO BE NON-DESTRUCTIVELY EXAMINED, AS PER COMPANY SPECIFICATIONS.
9) ALL DIMENSIONS ARE IN METERS UNLESS OTHERWISE NOTED.
10) CONTRACTOR TO FIELD VERIFY ALL DIMENSIONS.
11) MAINTAIN MIN. 300mm CLEARANCE BETWEEN PROPOSED MAIN AND OTHER UTILITIES AND UNDERGROUND STRUCTURES THAT ARE CROSSED.
12) GENERAL DEPTH OF COVER IS 1.2m (MIN) FROM ORIGINAL GRADE AND 1.0m (MIN) FROM CONSTRUCTION GRADE UNLESS OTHERWISE STATED.

RIGHT OF WAY DETAILS



TYPICAL PIPELINE EASEMENT
N.T.S.

REVISION

NO.	DESCRIPTION	DATE	BY	CHK	APPR
	FOR INFORMATION ONLY	2022-06-29	N.C.	--	--

--	2022-06-30	FOR INFORMATION ONLY
		ISSUED FOR BID
		ISSUED FOR CONSTRUCTION
		ISSUED FOR CONSTRUCTION 2
APP'D	DATE	AS BUILT: AS BUILT BY: / CHECKED BY:

DRAWN: NICO CARIATI — DATE: 2020:10:06
CHECKED: CAROLE GAGNE — DATE: --
APP'D BY: GRANT STRACHAN — DATE: --
WBS: XX-XX-XXX — SCALE: 1:2000

ENGINEER: GRANT STRACHAN

PRELIMINARY

ENBRIDGE
Life Takes Energy

DAWN TO CORUNNA TR7 - NPS 36 PIPELINE
2023 CONSTRUCTION - DAWN/EUPHEMIA & ST. CLAIR
PIPELINE CONSTRUCTION ALIGNMENT
0+000.0 TO MATCH LINE 0+950.0

FILE REVISION DATE: 2022-06-29
DRAWING NUMBER: PL3430-AL-001

RIGHT-OF-WAY

ENBRIDGE FILE NUMBER
OWNERSHIP/AGENCY
PIN: NUMBER

	0+950.0 to 1+220.0	1+220.0 to 1+955.7	1+955.7 to 1+995.8	1+995.8 to 2+125.0
RIGHT-OF-WAY (PIN)	PIN: 43384-0097	PIN: 43384-0096	MANDAUMIN RD (COUNTY RD 26)	PIN 43392-0096
CURRENT CLASS LOCATION	2	2	2	2
LOCATION FACTOR	0.9	0.9	0.625	0.9
TILE PLAN NUMBER				

ALIGNMENT DETAIL

LEGEND:
- PROPOSED ENBRIDGE TR7 NPS 36 PIPELINE
- TRANSMISSION/DISTRIBUTION PIPELINE
- FOREIGN PIPELINE
- EXISTING EASEMENT
- ENBRIDGE PIPELINE
- PROPOSED ENBRIDGE EASEMENT
- TEMPORARY ACCESS LANEWAY
- DRAIN/STREAM/WATERCOURSE CENTRE
- HYDRO EASEMENTS
- DRAINAGE DITCH BOTTOM/TOP
- RETAINING WALL/BRIDGE ABUTMENT
- ASPHALT/GRAVEL EDGE
- BUILDING
- POST/HYDRO POLE
- TELEPHONE BURIED CABLE/MISC CABLE
- FENCE
- OVERHEAD/BURIED HYDRO LINES
- WATERMAIN
- BOTTOM/TOP OF SLOPE
- TELEPHONE MARKER/BELL PEDESTAL
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- SIGN/MAILBOX
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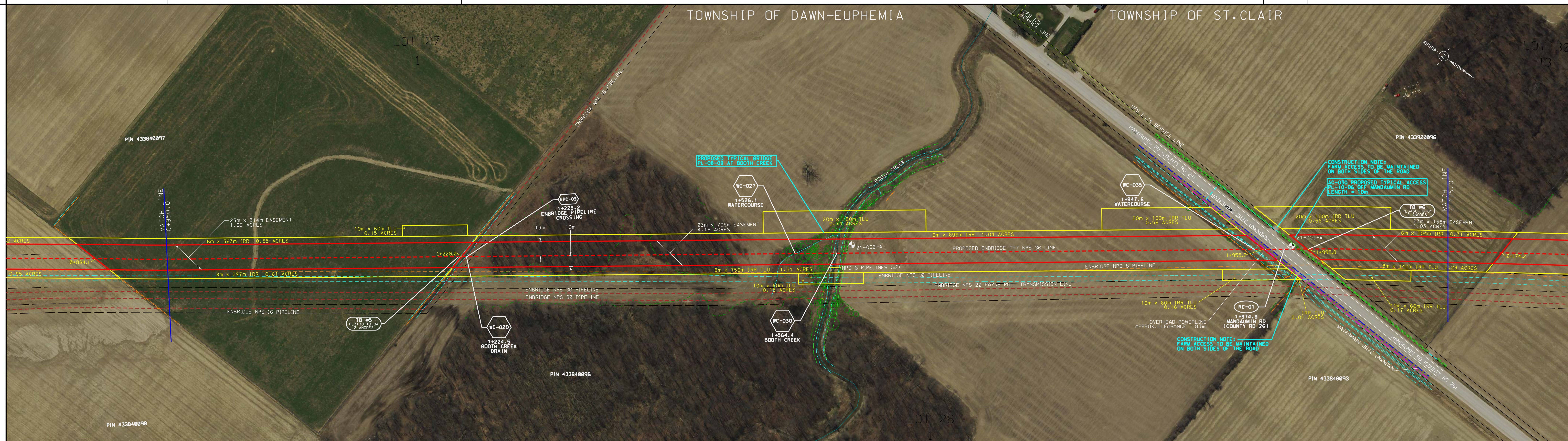
- PROPOSED ROAD/WATERCOURSE CROSSING
- PROPOSED HYDRO CROSSING
- PROPOSED ENBRIDGE PIPELINE CROSSING
- PROPOSED FOREIGN PIPELINE CROSSING
- PROPOSED BOREHOLE/MONITORING WELL
- TEST POST
- PIPELINE KILOMETRE POST
- TREE

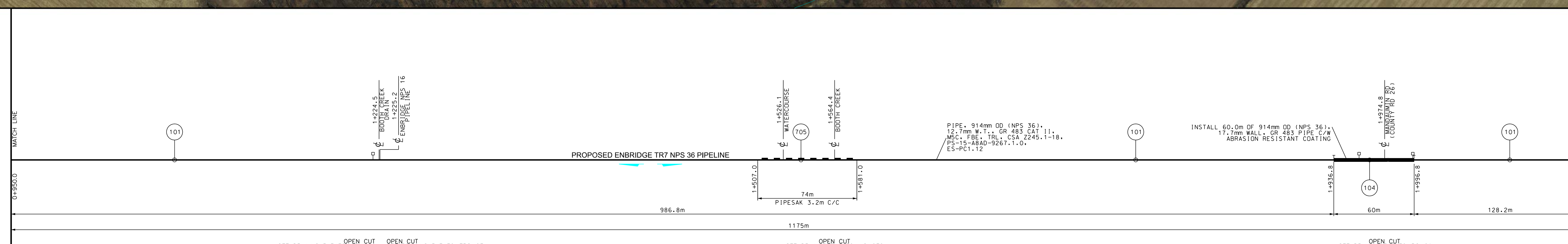
PIPELINE PLAN SCALE 1:2000



PIPELINE SCHEMATIC

LEGEND:
- HEAVY WALL PIPE
- PIPESAK
- TRANSITION WELD
- PIPELINE WARNING SIGN
- MATERIAL ITEM
- MAINLINE VALVE
- SIDE VALVE

PIPELINE DATA



DESIGN PARAMETERS (NEW PIPING ONLY)

DESIGN
- DESIGNED TO CSA Z662-19
- DESIGN FACTOR – 0.8
- LOCATION FACTOR – 0.900 / 0.625 (CLASS 2)
- DESIGN TEMPERATURE – M5C
- DESIGN PRESSURE – 9308 kPa

HYDROSTATIC TEST PRESSURE

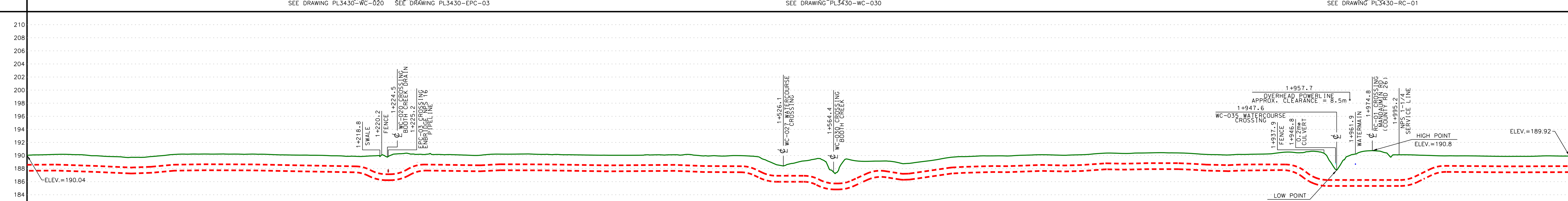
PIPING
- STRENGTH – 13,032 kPa (1890 psig) MIN.
- LEAK – 10,239 kPa (1485 psig) MIN.
- DURATION – EXPOSED PIPING – 1 HOUR AT STRENGTH TEST PRESSURE MINIMUM
- BURIED PIPING – 4 HOUR AT STRENGTH TEST PRESSURE FOLLOWED BY 4 HOUR AT LEAK TEST PRESSURE MINIMUM

HYDROSTATIC TEST DATE – TBD

CONSTRUCTION

START DATE – JUNE 1, 2023
PLACED IN SERVICE – NOVEMBER 1, 2023

P/L PROFILE HORIZ 1:2000 VERT 1:400



BILL of MATERIAL

Item No	Material No	Qty	Size	Description
101-150	Material No	Qty	Size	**PIPE**
101	~	1115m	36	PIPE, 914mm OD (NPS 36), 12.7mm W.T., GR 483 CAT II, M5C, FBE, QRL, CSA Z245.1-18, PS-15-A8AD-9267.1.0, ES-PC1.12
104	~	60m	36	PIPE, 914mm OD (NPS 36), 17.7mm W.T., GR 483 CAT II, M5C, ARO, QRL, CSA Z245.1-18, PS-15-A8AD-9267.1.0, ES-PC7.3
701-800	Material No	Qty	Size	**OTHER MATERIAL**
702	130968	~	610mm x 304.8m roll	(24"x1000') ROLL YELLOW TERRA TAPE IMPRINT LAYOUT LINE 1: "CAUTION CAUTION CAUTION" (HEIGHT 3") LINE 2: " ENBRIDGE GAS INC. (HEIGHT2") LINE 3: "NATURAL GAS PIPELINE BURIED BELOW" (HEIGHT 1 1/2") ALL THREE LINES TO BE CENTERED 36" REPEATS
703	125139	2	406.4 x 406.4	STANDARD STO BURIED PIPELINE SYSTEM SIGNAGE, Phone number required 1-800-265-5260 AS PER LUG C&M 18.6
704	125111	2	3 m	SIGN POST, GALV U CHANNEL POST HOT ROLLED & DIPPED 80 M PSI C/W SIGN HDWE PER DWG.E974 (10FT.)
705	~	25	36	PIPELINE WEIGHTS, NPS 36, SADDLE DESIGN, GRAVEL FILLED

CONSTRUCTION NOTES:

1) CONTRACTOR RESPONSIBLE FOR ALL UTILITY LOCATES.
2) ALL CULVERTS, END WALL TREATMENT AND TILE DRAINS REMOVED DURING CONSTRUCTION ARE TO BE RESTORED TO MATCH EXISTING CONDITIONS.
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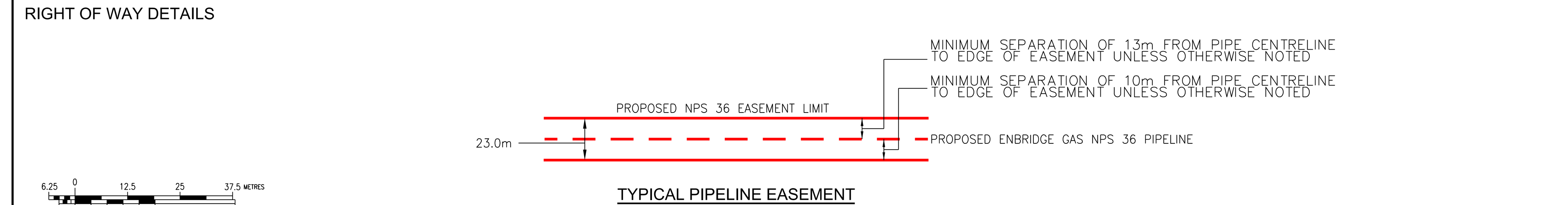
12) GENERAL DEPTH OF COVER IS 1.2m (MIN) FROM ORIGINAL GRADE AND 1.0m (MIN) FROM CONSTRUCTION GRADE UNLESS OTHERWISE STATED.

RIGHT OF WAY DETAILS



TYPICAL PIPELINE EASEMENT
N.T.S.

REVISION

NO.	DESCRIPTION	DATE	BY	CHK	APPR
	FOR INFORMATION ONLY	2022-06-29	N.C.	--	--

--	2022-06-30	FOR INFORMATION ONLY
		ISSUED FOR BID
		ISSUED FOR CONSTRUCTION
		ISSUED FOR CONSTRUCTION 2
APP'D	DATE	AS BUILT — AS BUILT BY: / CHECKED BY:

DRAWN	NICO CARIATI	DATE	2020:10:06
CHECKED	CAROLE GAGNE	DATE	--
APP'D BY	GRANT STRACHAN	DATE	--
WBS	XX-XX-XXX	SCALE	1:2000

ENGINEER: GRANT STRACHAN

PRELIMINARY

ENBRIDGE
Life Takes Energy

DAWN TO CORUNNA TR7 - NPS 36 PIPELINE
2023 CONSTRUCTION - DAWN/EUPHEMIA & ST. CLAIR
PIPELINE CONSTRUCTION ALIGNMENT
0+950.0 TO MATCH LINE 2+125.0

FILE REVISION DATE: 2022-06-29
DRAWING NUMBER: PL3430-AL-002

RIGHT-OF-WAY
ENBRIDGE FILE NUMBER
OWNERSHIP/AGENCY
PIN: NUMBER

MATCH LINE 2+125.0 | PIN 43392-0096 | 2+174.2 | PIN 43392-0119 | 2+484.5 | PIN 43392-0095 | 2+988.1 | PIN 43392-0099 | 3+026.6 | MCCALLUM LINE | 3+051.5 | PIN 43392-0081 | 3+300.0 MATCH LINE

CURRENT CLASS LOCATION		2	2	2
LOCATION FACTOR		0.9	0.625	0.9
TILE PLAN NUMBER				

ALIGNMENT DETAIL

LEGEND:
- PROPOSED ENBRIDGE TR7 NPS 36 PIPELINE
- TRANSMISSION/DISTRIBUTION PIPELINE
- FOREIGN PIPELINE
- EXISTING EASEMENT
- ENBRIDGE PIPELINE
- PROPOSED ENBRIDGE EASEMENT
- TEMPORARY ACCESS LANEWAY
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- HYDRO EASEMENTS
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- PROPOSED HYDRO CROSSING
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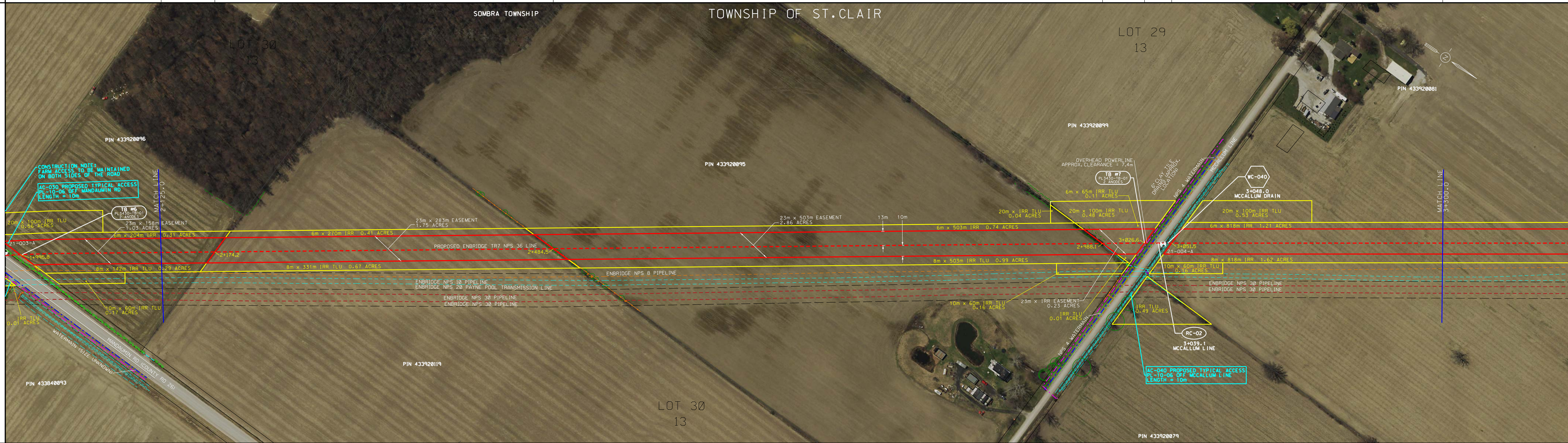
- PROPOSED FOREIGN PIPELINE CROSSING
- PROPOSED BOREHOLE/MONITORING WELL
- TEST POST
- PIPELINE KILOMETRE POST
- TREE

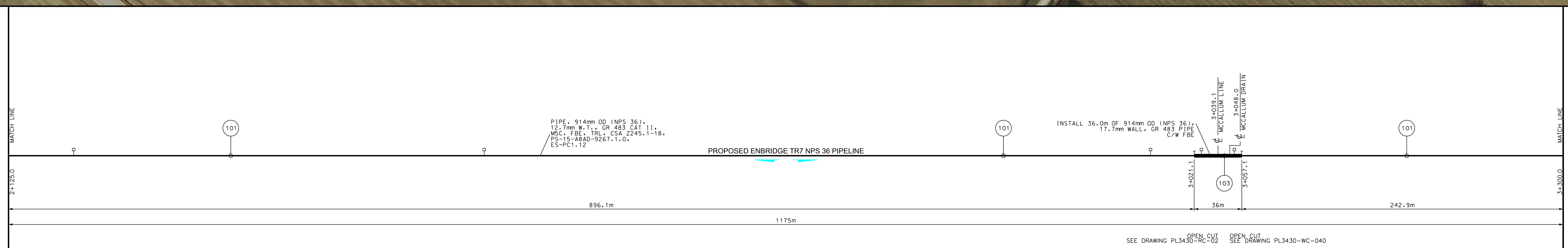
PIPELINE PLAN SCALE 1:2000



PIPELINE SCHEMATIC

LEGEND:
- HEAVY WALL PIPE
- PIPESAK
- TRANSITION WELD
- PIPELINE WARNING SIGN
- MATERIAL ITEM
- MAINLINE VALVE
- SIDE VALVE

PIPELINE DATA



DESIGN PARAMETERS (NEW PIPING ONLY)

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- DESIGN FACTOR – 0.8
- LOCATION FACTOR – 0.900 / 0.625 (CLASS 2)
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- DESIGN PRESSURE – 9308 kPa

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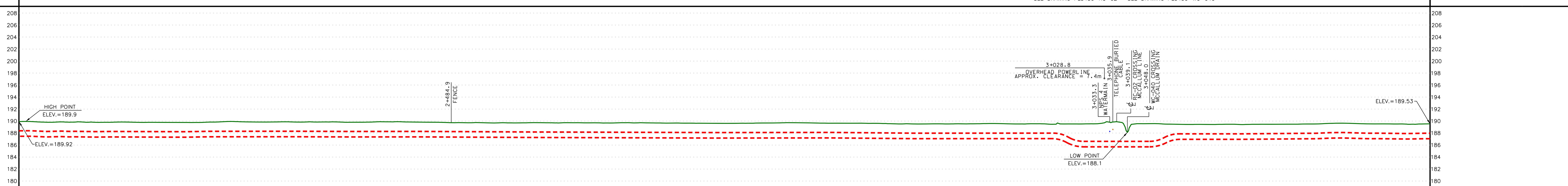
HYDROSTATIC TEST DATE – TBD

CONSTRUCTION
START DATE – JUNE 1, 2023
PLACED IN SERVICE – NOVEMBER 1, 2023

P/L PROFILE HORIZ 1:2000 VERT 1:400



BILL of MATERIAL

Item No	Material No	Qty	Size	Description
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103	~	36m	36	PIPE, 914mm OD (NPS 36), 17.7mm W.T., GR 483 CAT II, M5C, FBE, QRL, CSA Z245.1-18, PS-15-A8AD-9267.1.0, ES-PC1.12
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704	125111	5	3 m	SIGN POST, GALV U CHANNEL POST HOT ROLLED & DIPPED 80 M PSI C/W SIGN HDWE PER DWG.E974 (10FT.)
705	~	~	36	PIPELINE WEIGHTS, NPS 36, SADDLE DESIGN, GRAVEL FILLED

CONSTRUCTION NOTES:

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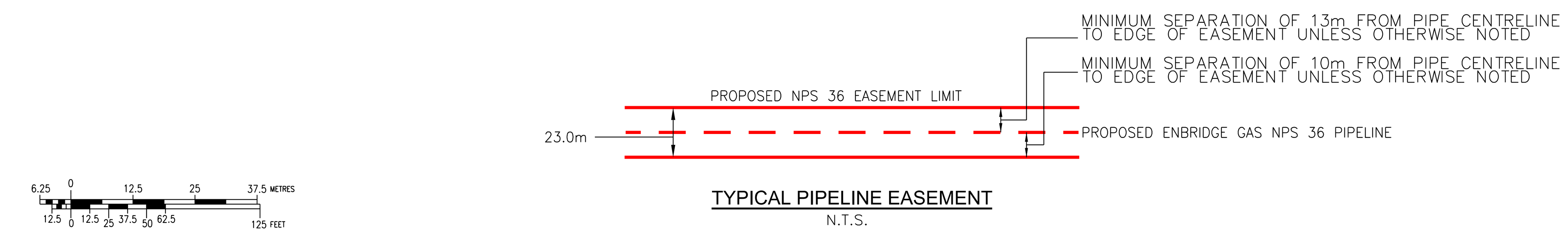
RIGHT OF WAY DETAILS



TYPICAL PIPELINE EASEMENT
N.T.S.

REVISION

NO.	DESCRIPTION	DATE	BY	CHK	APPR
	FOR INFORMATION ONLY	2022-06-29	N.C.	--	--

--	2022-06-30	FOR INFORMATION ONLY
		ISSUED FOR BID
		ISSUED FOR CONSTRUCTION
		ISSUED FOR CONSTRUCTION 2
APP'D	DATE	AS BUILT — AS BUILT BY: / CHECKED BY:

DRAWN	NICO CARIATI	DATE	2020:10:06
CHECKED	CAROLE GAGNE	DATE	--
APP'D BY	GRANT STRACHAN	DATE	--
WBS	XX-XX-XXX	SCALE	1:2000

ENGINEER: GRANT STRACHAN

PRELIMINARY

ENBRIDGE
Life Takes Energy

DAWN TO CORUNNA TR7 – NPS 36 PIPELINE
2023 CONSTRUCTION – DAWN/EUPHEMIA & ST. CLAIR
PIPELINE CONSTRUCTION ALIGNMENT
2+125.0 TO MATCH LINE 3+300.0

FILE REVISION DATE 2022-06-29
DRAWING NUMBER PL3430-AL-003

RIGHT-OF-WAY

ENBRIDGE FILE NUMBER
OWNERSHIP/AGENCY
PIN: NUMBER

MATCH LINE 3+300.0 | 3+866.2 | 4+625.0 MATCH LINE

PIN 43392-0081 | PIN 43392-0080

CURRENT CLASS LOCATION	2
LOCATION FACTOR	0.9
TILE PLAN NUMBER	

ALIGNMENT DETAIL

LEGEND:
- PROPOSED ENBRIDGE TR7 NPS 36 PIPELINE
- TRANSMISSION/DISTRIBUTION PIPELINE
- FOREIGN PIPELINE
- EXISTING EASEMENT
- ENBRIDGE PIPELINE
- PROPOSED ENBRIDGE EASEMENT
- TEMPORARY ACCESS LANEWAY
- DRAIN/STREAM/WATERCOURSE CENTRE
- HYDRO EASEMENTS
- DRAINAGE DITCH BOTTOM/TOP
- RETAINING WALL/BRIDGE ABUTMENT
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- BUILDING
- POST/HYDRO POLE
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- TELEPHONE MARKER/BELL PEDESTAL
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- PROPOSED FOREIGN PIPELINE CROSSING
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- TEST POST
- PIPELINE KILOMETRE POST
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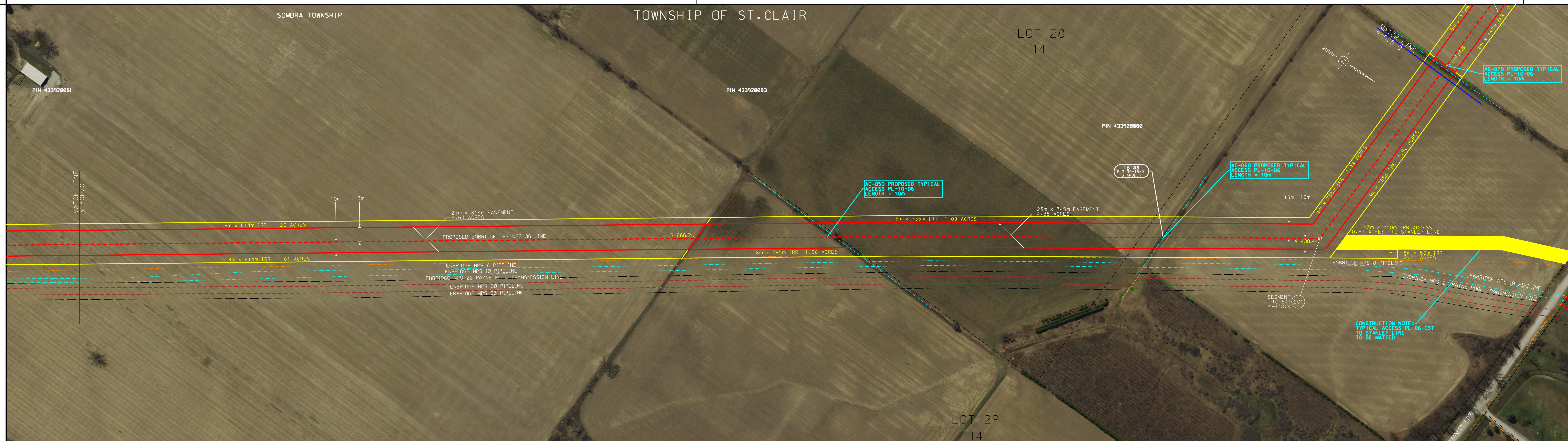
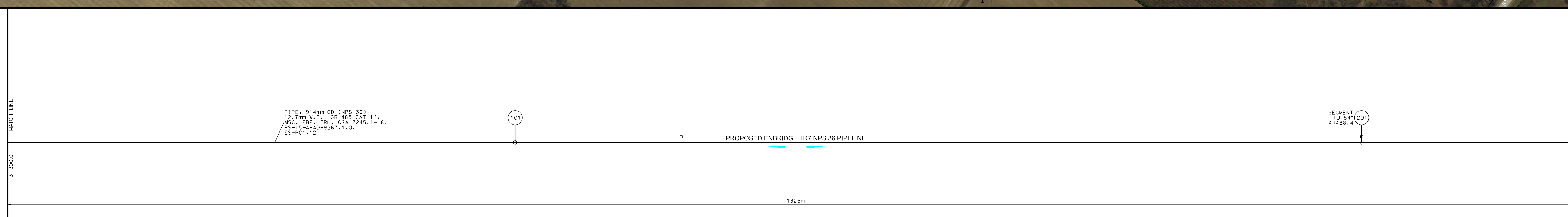
PIPELINE PLAN SCALE 1:2000



PIPELINE SCHEMATIC

LEGEND:
- HEAVY WALL PIPE
- PIPESAK
- TRANSITION WELD
- PIPELINE WARNING SIGN
- MATERIAL ITEM
- MAINLINE VALVE
- SIDE VALVE

PIPELINE DATA



DESIGN PARAMETERS (NEW PIPING ONLY)

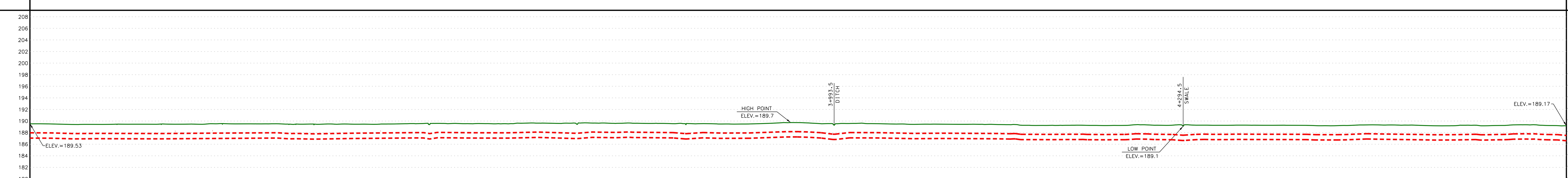
DESIGN
- DESIGNED TO CSA Z662-19
- DESIGN FACTOR – 0.8
- LOCATION FACTOR – 0.900 / 0.625 (CLASS 2)
- DESIGN TEMPERATURE – M5C
- DESIGN PRESSURE – 9308 kPa

HYDROSTATIC TEST PRESSURE
PIPING
- STRENGTH – 13,032 kPa (1890 psig) MIN.
- LEAK – 10,239 kPa (1485 psig) MIN.
- DURATION – EXPOSED PIPING – 1 HOUR AT STRENGTH TEST PRESSURE MINIMUM
- BURIED PIPING – 4 HOUR AT STRENGTH TEST PRESSURE FOLLOWED BY 4 HOUR AT LEAK TEST PRESSURE MINIMUM

HYDROSTATIC TEST DATE – TBD

CONSTRUCTION
START DATE – JUNE 1, 2023
PLACED IN SERVICE – NOVEMBER 1, 2023

P/L PROFILE HORIZ 1:2000 VERT 1:400



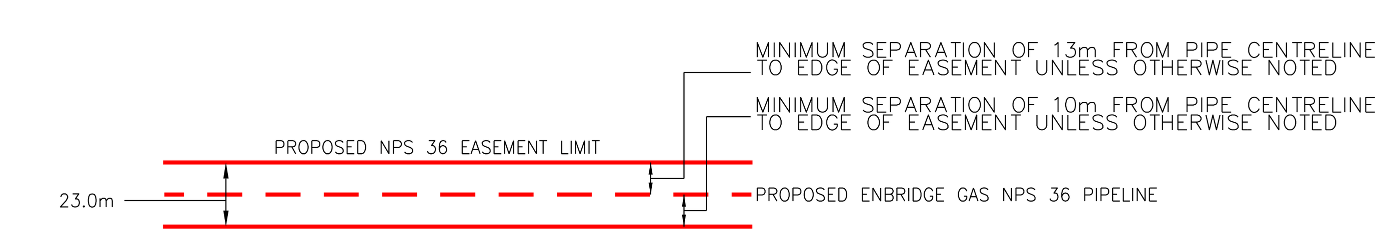
BILL of MATERIAL

Item No	Material No	Qty	Size	Description
101-150	Material No	Qty	Size	**PIPE**
101	~	1325m	36	PIPE, 914mm OD (NPS 36), 12.7mm W.T., GR 483 CAT II, M5C, FBE, QRL, CSA Z245.1-18, PS-15-A8AD-9267.1.0, ES-PC1.12
201-350	Material No	Qty	Size	**FITTINGS**
201	~	1	36	ELBOW, NPS 36, 90 DEGREES, TO MATCH 914mm OD (NPS 36), 12.7mm W.T., GR 483 CAT II M5C PIPE, I.D. CONTROLLED AND SEGMENTABLE XLR (3D), BE, CSA Z245.11, PS-1E-1B1A-0B1B
701-800	Material No	Qty	Size	**OTHER MATERIAL**
702	130968	~	610mm x 304.8m roll	(24"x1000') ROLL YELLOW TERRA TAPE IMPRINT LAYOUT LINE 1: "CAUTION CAUTION CAUTION" (HEIGHT 3") LINE 2: " ENBRIDGE GAS INC: (HEIGHT2") LINE 3: "NATURAL GAS PIPELINE BURIED BELOW" (HEIGHT 1 1/2") ALL THREE LINES TO BE CENTERED 36" REPEATS
703	125139	1	406.4 x 406.4	STANDARD STO BURIED PIPELINE SYSTEM SIGNAGE, Phone number required 1-800-265-5260 AS PER LUG C&M 18.6
704	125111	1	3 m	SIGN POST, GALV U CHANNEL POST HOT ROLLED & DIPPED 80 M PSI C/W SIGN HDWE PER DWG.E974 (10FT.)
705	~	~	36	PIPELINE WEIGHTS, NPS 36, SADDLE DESIGN, GRAVEL FILLED

CONSTRUCTION NOTES:

1) CONTRACTOR RESPONSIBLE FOR ALL UTILITY LOCATES.
2) ALL CULVERTS, END WALL TREATMENT AND TILE DRAINS REMOVED DURING CONSTRUCTION ARE TO BE RESTORED TO MATCH EXISTING CONDITIONS.
3) RESTORATION INCLUDES TOPSOIL AND SEEDING.
4) RESTORE DRIVEWAYS TO MATCH EXISTING.
5) ALL ASPHALT AREAS TO BE RESTORED TO MATCH EXISTING.
6) RESTORE ALL OPEN DRAINS TO MATCH ORIGINAL GRADE AND CONTOUR CONDITIONS.
7) ALL WORK MUST BE IN ACCORDANCE WITH THE LATEST ENBRIDGE GAS SPECIFICATIONS.
8) ALL WELDS TO BE NON-DESTRUCTIVELY EXAMINED, AS PER COMPANY SPECIFICATIONS.
9) ALL DIMENSIONS ARE IN METERS UNLESS OTHERWISE NOTED.
10) CONTRACTOR TO FIELD VERIFY ALL DIMENSIONS.
11) MAINTAIN MIN. 300mm CLEARANCE BETWEEN PROPOSED MAIN AND OTHER UTILITIES AND UNDERGROUND STRUCTURES THAT ARE CROSSED.
12) GENERAL DEPTH OF COVER IS 1.2m (MIN) FROM ORIGINAL GRADE AND 1.0m (MIN) FROM CONSTRUCTION GRADE UNLESS OTHERWISE STATED.

RIGHT OF WAY DETAILS



TYPICAL PIPELINE EASEMENT
N.T.S.

6.25 0 12.5 25 37.5 METRES
12.5 0 12.5 25 37.5 50 62.5 125 FEET

REVISION

NO.	DESCRIPTION	DATE	BY	CHK	APPR
	FOR INFORMATION ONLY	2022-06-29	N.C.	--	--

--	2022-06-30	FOR INFORMATION ONLY
		ISSUED FOR BID
		ISSUED FOR CONSTRUCTION
		ISSUED FOR CONSTRUCTION 2
APP'D	DATE	AS BUILT — AS BUILT BY: / CHECKED BY:

DRAWN	NICO CARIATI	DATE	2020:10:06
CHECKED	CAROLE GAGNE	DATE	--
APP'D BY	GRANT STRACHAN	DATE	--
WBS	XX-XX-XXX	SCALE	1:2000

ENGINEER: GRANT STRACHAN

PRELIMINARY

ENBRIDGE
Life Takes Energy

DAWN TO CORUNNA TR7 – NPS 36 PIPELINE
2023 CONSTRUCTION – DAWN/EUPHEMIA & ST. CLAIR
PIPELINE CONSTRUCTION ALIGNMENT
3+300.0 TO MATCH LINE 4+625.0

FILE REVISION DATE 2022-06-29

DRAWING NUMBER PL3430-AL-004

RIGHT-OF-WAY

ENBRIDGE FILE NUMBER
OWNERSHIP/AGENCY
PIN: NUMBER

MATCH LINE 4+625.0 | PIN 433920080 | 4+634.6 | PIN 43392-0084 | 4+784.6 | PIN 43392-0085 | 5+219.6 | STANLEY LINE | 5+239.7 | PIN 43392-0066 | 5+625.0 MATCH LINE

CURRENT CLASS LOCATION	2	2	2	
LOCATION FACTOR	0.9	0.625	0.9	
TILE PLAN NUMBER				

ALIGNMENT DETAIL

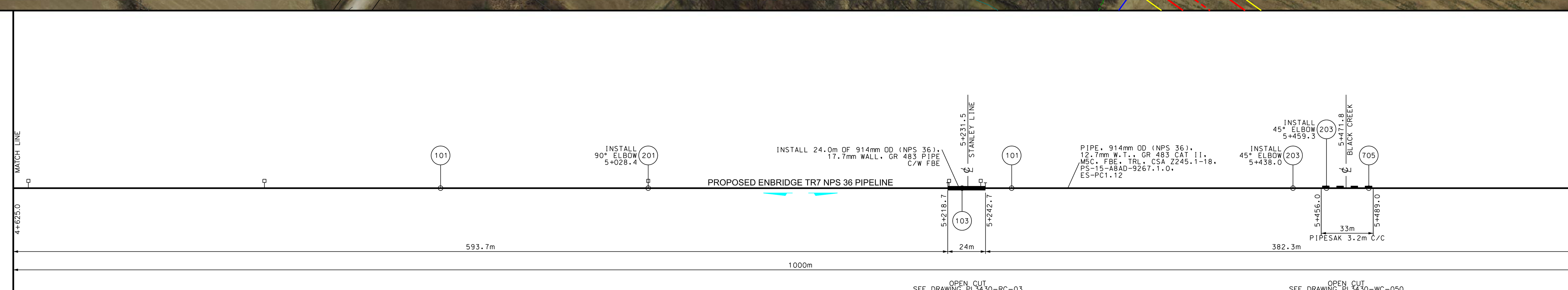
LEGEND:
PROPOSED ENBRIDGE TR7 NPS 36 PIPELINE
TRANSMISSION/DISTRIBUTION PIPELINE
FOREIGN PIPELINE
EXISTING EASEMENT
ENBRIDGE PIPELINE
PROPOSED ENBRIDGE EASEMENT
TEMPORARY ACCESS LANEWAY
DRAIN/STREAM/WATERCOURSE CENTRE
HYDRO EASEMENTS
DRAINAGE DITCH BOTTOM/TOP
RETAINING WALL/BRIDGE ABUTMENT
ASPHALT/GRAVEL EDGE
BUILDING
POST/HYDRO POLE
TELEPHONE BURIED CABLE/MISC CABLE
FENCE
OVERHEAD/BURIED HYDRO LINES
WATERMAIN
BOTTOM/TOP OF SLOPE
TELEPHONE MARKER/BELL PEDESTAL
CULVERT/CATCH BASIN/WATER VALVE
SIGN/MAILBOX
HYDRO TOWER
PROPERTY LINE/ROAD ALLOWANCE
PROPOSED ROAD/WATERCOURSE CROSSING (RC-XX) (WC-XX)
PROPOSED HYDRO CROSSING (HCS-XX)
PROPOSED ENBRIDGE PIPELINE CROSSING (EPC-XX)
PROPOSED FOREIGN PIPELINE CROSSING (FPL-XX)
PROPOSED BOREHOLE/MONITORING WELL
TEST POST (TB # PL3430-TB-XX)
PIPELINE KILOMETRE POST
TREE

PIPELINE PLAN
SCALE 1:2000

PIPELINE SCHEMATIC

LEGEND:
HEAVY WALL PIPE
PIPESAK
TRANSITION WELD
PIPELINE WARNING SIGN
MATERIAL ITEM (112)
MAINLINE VALVE
SIDE VALVE

PIPELINE DATA



DESIGN PARAMETERS (NEW PIPING ONLY)

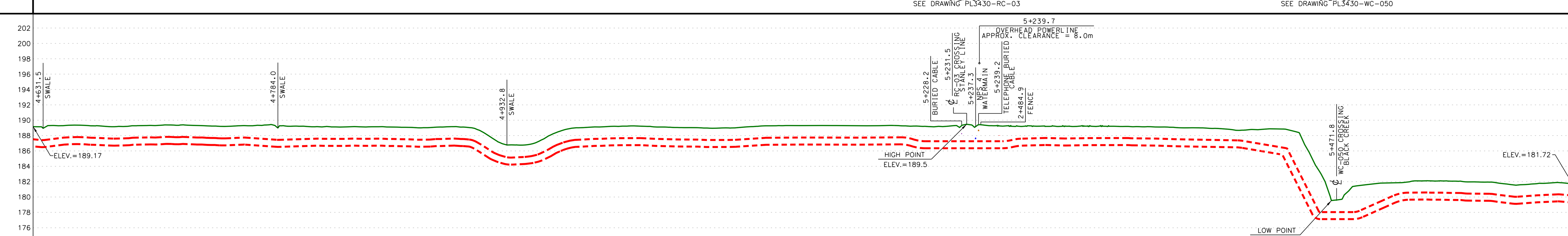
DESIGN
- DESIGNED TO CSA Z662-19
- DESIGN FACTOR – 0.8
- LOCATION FACTOR – 0.900 / 0.625 (CLASS 2)
- DESIGN TEMPERATURE – M5C
- DESIGN PRESSURE – 9308 kPa

HYDROSTATIC TEST PRESSURE
PIPING
- STRENGTH – 13,032 kPa (1890 psig) MIN.
- LEAK – 10,239 kPa (1485 psig) MIN.
- DURATION – EXPOSED PIPING – 1 HOUR AT STRENGTH TEST PRESSURE MINIMUM
- BURIED PIPING – 4 HOUR AT STRENGTH TEST PRESSURE FOLLOWED BY 4 HOUR AT LEAK TEST PRESSURE MINIMUM

HYDROSTATIC TEST DATE – TBD

CONSTRUCTION
START DATE – JUNE 1, 2023
PLACED IN SERVICE – NOVEMBER 1, 2023

P/L PROFILE
HORIZ 1:2000 VERT 1:400



BILL of MATERIAL

Item No	Material No	Qty	Size	Description
101-150	Material No	Qty	Size	**PIPE**
101	~	976m	36	PIPE, 914mm OD (NPS 36), 12.7mm W.T., GR 483 CAT II, M5C, FBE, QRL, CSA Z245.1-18, PS-15-A8AD-9267.1.0, ES-PC1.12
103	~	24m	36	PIPE, 914mm OD (NPS 36), 17.7mm W.T., GR 483 CAT II, M5C, FBE, QRL, CSA Z245.1-18, PS-15-A8AD-9267.1.0, ES-PC1.12
201-350	Material No	Qty	Size	**FITTINGS**
201	~	1	36	ELBOW, NPS 36, 90 DEGREES, TO MATCH 914mm OD (NPS 36), 12.7mm W.T., GR 483 CAT II M5C PIPE, I.D. CONTROLLED AND SEGMENTABLE XLR (3D), BE, CSA Z245.11, PS-1E-1B1A-0B1B
203		2	36	ELBOW, NPS 36, 45 DEGREES, TO MATCH 914mm OD (NPS 36), 12.7mm W.T., GR 483 CAT II M5C PIPE, I.D. CONTROLLED AND SEGMENTABLE XLR (3D), BE, CSA Z245.11, PS-1E-1B1A-0B1B **(8 EXTRA)**
701-800	Material No	Qty	Size	**OTHER MATERIAL**
702	130968	~	610mm x 304.8m roll	(24"x1000') ROLL YELLOW TERRA TAPE IMPRINT LAYOUT LINE 1: "CAUTION CAUTION CAUTION" (HEIGHT 3") LINE 2: " ENBRIDGE GAS INC: (HEIGHT2") LINE 3: "NATURAL GAS PIPELINE BURIED BELOW" (HEIGHT 1 1/2") ALL THREE LINES TO BE CENTERED 36" REPEATS
703	125139	4	406.4 x 406.4	STANDARD STO BURIED PIPELINE SYSTEM SIGNAGE, Phone number required 1-800-265-5260 AS PER LUG C&M 18.6
704	125111	4	3 m	SIGN POST, GALV U CHANNEL POST HOT ROLLED & DIPPED 80 M PSI C/W SIGN HDWE PER DWG.E974 (10FT.)
705	~	12	36	PIPELINE WEIGHTS, NPS 36, SADDLE DESIGN, GRAVEL FILLED

CONSTRUCTION NOTES:

1) CONTRACTOR RESPONSIBLE FOR ALL UTILITY LOCATES.
2) ALL CULVERTS, END WALL TREATMENT AND TILE DRAINS REMOVED DURING CONSTRUCTION ARE TO BE RESTORED TO MATCH EXISTING CONDITIONS.
3) RESTORATION INCLUDES TOPSOIL AND SEEDING.
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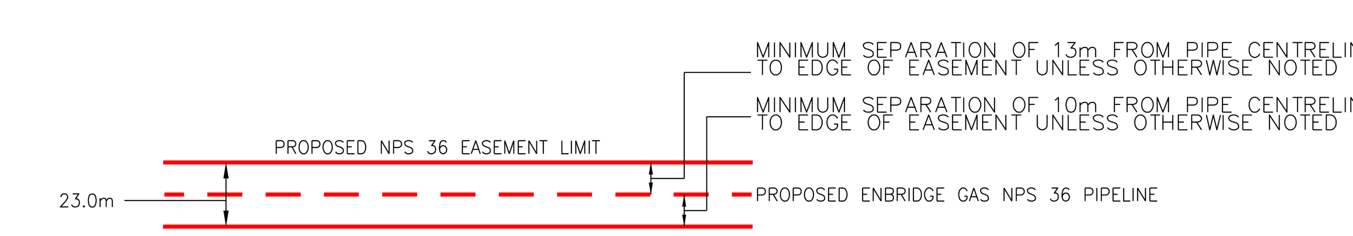
10) CONTRACTOR TO FIELD VERIFY ALL DIMENSIONS.
11) MAINTAIN MIN. 300mm CLEARANCE BETWEEN PROPOSED MAIN AND OTHER UTILITIES AND UNDERGROUND STRUCTURES THAT ARE CROSSED.
12) GENERAL DEPTH OF COVER IS 1.2m (MIN) FROM ORIGINAL GRADE AND 1.0m (MIN) FROM CONSTRUCTION GRADE UNLESS OTHERWISE STATED.

RIGHT OF WAY DETAILS



TYPICAL PIPELINE EASEMENT
N.T.S.

6.25 0 12.5 25 37.5 METRES
12.5 0 12.5 25 37.5 50 62.5 125 FEET

REVISION					
NO.	DESCRIPTION	DATE	BY	CHK	APPR
	FOR INFORMATION ONLY	2022-06-29	N.C.	--	--

--	2022-06-30	FOR INFORMATION ONLY
		ISSUED FOR BID
		ISSUED FOR CONSTRUCTION
		ISSUED FOR CONSTRUCTION 2
APP'D	DATE	AS BUILT — AS BUILT BY: / CHECKED BY:

DRAWN	NICO CARIATI	DATE	2020:10:06
CHECKED	CAROLE GAGNE	DATE	--
APP'D BY	GRANT STRACHAN	DATE	--
WBS	XX-XX-XXX	SCALE	1:2000

ENGINEER: GRANT STRACHAN

PRELIMINARY

ENBRIDGE
Life Takes Energy

DAWN TO CORUNNA TR7 – NPS 36 PIPELINE
2023 CONSTRUCTION – DAWN/EUPHEMIA & ST. CLAIR
PIPELINE CONSTRUCTION ALIGNMENT
4+625.0 TO MATCH LINE 5+625.0

FILE REVISION DATE 2022-06-29
DRAWING NUMBER PL3430-AL-005

RIGHT-OF-WAY

ENBRIDGE FILE NUMBER
OWNERSHIP/AGENCY
PIN: NUMBER

RIGHT-OF-WAY (MATCH LINE 5+625.0 – 5+945.6)	PIN 43392-0066				
5+945.6 – 6+448.5	PIN 43392-0065				
6+448.5 – 6+738.6	PIN 43392-0062				
6+738.6 – 6+763.8	BICKFORD LINE				
6+763.8 – 6+966.7	PIN 43315-0082				
6+966.7 – 6+975.0 MATCH LINE	PIN 43315-0081				

CURRENT CLASS LOCATION	2	2	2
LOCATION FACTOR	0.9	0.625	0.9
TILE PLAN NUMBER			

ALIGNMENT DETAIL

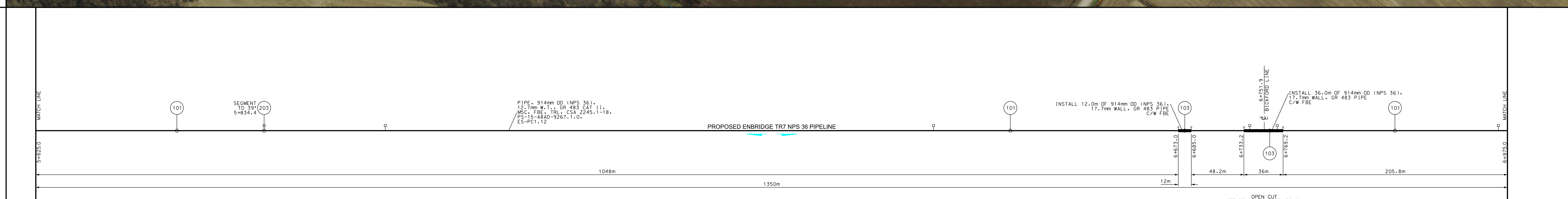
LEGEND:
- PROPOSED ENBRIDGE TR7 NPS 36 PIPELINE
- TRANSMISSION/DISTRIBUTION PIPELINE
- FOREIGN PIPELINE
- EXISTING EASEMENT
- ENBRIDGE PIPELINE
- PROPOSED ENBRIDGE EASEMENT
- TEMPORARY ACCESS LANEWAY
- DRAIN/STREAM/WATERCOURSE CENTRE
- HYDRO EASEMENTS
- DRAINAGE DITCH BOTTOM/TOP
- RETAINING WALL/BRIDGE ABUTMENT
- ASPHALT/GRAVEL EDGE
- BUILDING
- POST/HYDRO POLE
- TELEPHONE BURIED CABLE/MISC CABLE
- FENCE
- OVERHEAD/BURIED HYDRO LINES
- WATERMAIN
- BOTTOM/TOP OF SLOPE
- TELEPHONE MARKER/BELL PEDESTAL
- CULVERT/CATCH BASIN/WATER VALVE
- SIGN/MAILBOX
- HYDRO TOWER
- PROPERTY LINE/ROAD ALLOWANCE
- PROPOSED ROAD/WATERCOURSE CROSSING
- PROPOSED HYDRO CROSSING
- PROPOSED ENBRIDGE PIPELINE CROSSING
- PROPOSED FOREIGN PIPELINE CROSSING
- PROPOSED BOREHOLE/MONITORING WELL
- TEST POST
- PIPELINE KILOMETRE POST
- TREE

PIPELINE PLAN
SCALE 1:2000

PIPELINE SCHEMATIC

LEGEND:
- HEAVY WALL PIPE
- PIPESAK
- TRANSITION WELD
- PIPELINE WARNING SIGN
- MATERIAL ITEM
- MAINLINE VALVE
- SIDE VALVE

PIPELINE DATA



DESIGN PARAMETERS (NEW PIPING ONLY)

DESIGN
- DESIGNED TO CSA Z662-19
- DESIGN FACTOR – 0.8
- LOCATION FACTOR – 0.900 / 0.625 (CLASS 2)
- DESIGN TEMPERATURE – M5C
- DESIGN PRESSURE – 9308 kPa

HYDROSTATIC TEST PRESSURE

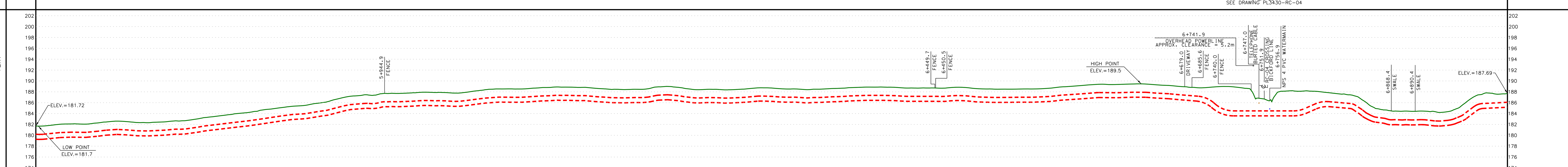
PIPING
- STRENGTH – 13,032 kPa (1890 psig) MIN.
- LEAK – 10,239 kPa (1485 psig) MIN.
- DURATION – EXPOSED PIPING – 1 HOUR AT STRENGTH TEST PRESSURE MINIMUM
- BURIED PIPING – 4 HOUR AT STRENGTH TEST PRESSURE FOLLOWED BY 4 HOUR AT LEAK TEST PRESSURE MINIMUM

HYDROSTATIC TEST DATE – TBD

CONSTRUCTION

START DATE – JUNE 1, 2023
PLACED IN SERVICE – NOVEMBER 1, 2023

P/L PROFILE
HORIZ 1:2000 VERT 1:400



BILL of MATERIAL

Item No	Material No	Qty	Size	Description
101-150	Material No	Qty	Size	PIPE
101	~	1302m	36	PIPE, 914mm OD (NPS 36), 12.7mm W.T., GR 483 CAT II, M5C, FBE, QRL, CSA Z245.1-18, PS-15-A8AD-9267.1.0, ES-PC1.12
103	~	48m	36	PIPE, 914mm OD (NPS 36), 17.7mm W.T., GR 483 CAT II, M5C, FBE, QRL, CSA Z245.1-18, PS-15-A8AD-9267.1.0, ES-PC1.12
201-350	Material No	Qty	Size	FITTINGS
203		1	36	ELBOW, NPS 36, 45 DEGREES, TO MATCH 914mm OD (NPS 36), 12.7mm W.T., GR 483 CAT II M5C PIPE, I.D. CONTROLLED AND SEGMENTABLE XLR (3D), BE, CSA Z245.11, PS-1E-1B1A-0B1B **(8 EXTRA)**
701-800	Material No	Qty	Size	OTHER MATERIAL
702	130968	~	610mm x 304.8m roll	(24"x1000') ROLL YELLOW TERRA TAPE IMPRINT LAYOUT LINE 1: "CAUTION CAUTION CAUTION" (HEIGHT 3") LINE 2: " ENBRIDGE GAS INC: (HEIGHT2") LINE 3: "NATURAL GAS PIPELINE BURIED BELOW" (HEIGHT 1 1/2") ALL THREE LINES TO BE CENTERED 36" REPEATS
703	125139	5	406.4 x 406.4	STANDARD STO BURIED PIPELINE SYSTEM SIGNAGE, Phone number required 1-800-265-5260 AS PER LUG C&M 18.6
704	125111	5	3 m	SIGN POST, GALV U CHANNEL POST HOT ROLLED & DIPPED 80 M PSI C/W SIGN HDWE PER DWG.E974 (10FT.)
705	~	~	36	PIPELINE WEIGHTS, NPS 36, SADDLE DESIGN, GRAVEL FILLED

CONSTRUCTION NOTES:

1) CONTRACTOR RESPONSIBLE FOR ALL UTILITY LOCATES.
2) ALL CULVERTS, END WALL TREATMENT AND TILE DRAINS REMOVED DURING CONSTRUCTION ARE TO BE RESTORED TO MATCH EXISTING CONDITIONS.
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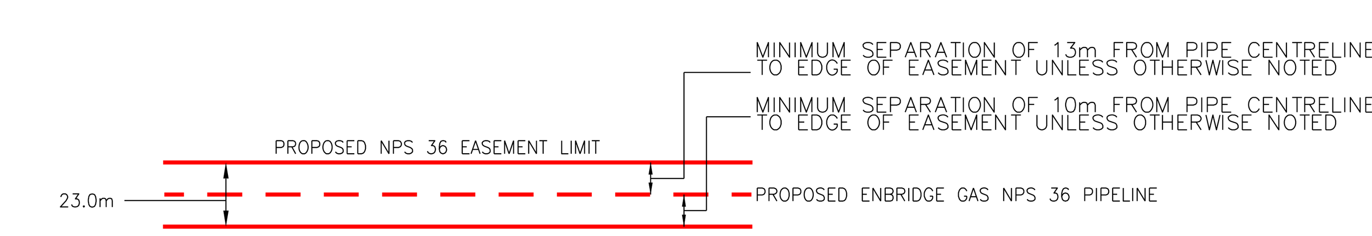
RIGHT OF WAY DETAILS



TYPICAL PIPELINE EASEMENT
N.T.S.

6.25 0 12.5 25 37.5 METRES
12.5 0 12.5 25 37.5 50 62.5 125 FEET

REVISION

NO.	DESCRIPTION	DATE	BY	CHK	APPR
	FOR INFORMATION ONLY	2022-06-29	N.C.	--	--

--	2022-06-30	FOR INFORMATION ONLY
		ISSUED FOR BID
		ISSUED FOR CONSTRUCTION
		ISSUED FOR CONSTRUCTION 2
APP'D	DATE	AS BUILT — AS BUILT BY: / CHECKED BY:

DRAWN	NICO CARIATI	DATE	2020:10:06
CHECKED	CAROLE GAGNE	DATE	--
APP'D BY	GRANT STRACHAN	DATE	--
WBS	XX-XX-XXX	SCALE	1:2000

ENGINEER: GRANT STRACHAN

PRELIMINARY

ENBRIDGE
Life Takes Energy

DAWN TO CORUNNA TR7 – NPS 36 PIPELINE
2023 CONSTRUCTION – DAWN/EUPHEMIA & ST. CLAIR
PIPELINE CONSTRUCTION ALIGNMENT
5+625.0 TO MATCH LINE 6+975.0

FILE REVISION DATE: 2022-06-29
DRAWING NUMBER: PL3430-AL-006

RIGHT-OF-WAY

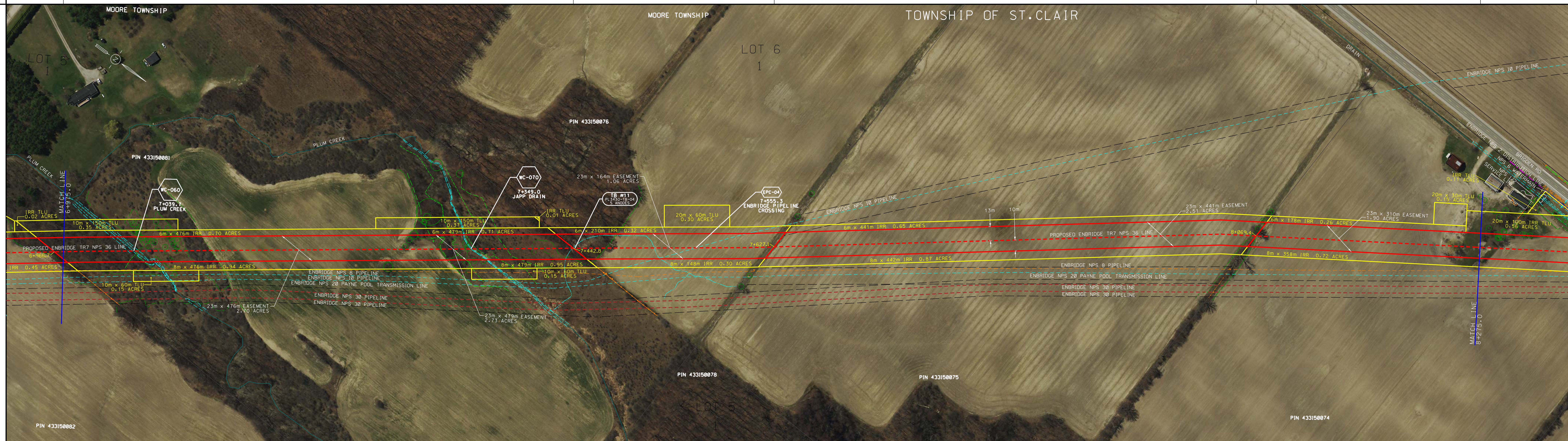
ENBRIDGE FILE NUMBER OWNERSHIP/AGENCY PIN: NUMBER	MATCH LINE 6+975.0 — PIN 43315-0081	7+442.8 — PIN 43315-0076	7+627.1 — PIN 43315-0075	8+069.4 — PIN 43315-0074	8+275.0 MATCH LINE
CURRENT CLASS LOCATION	2				
LOCATION FACTOR	0.9				
TILE PLAN NUMBER					

ALIGNMENT DETAIL

LEGEND:

- PROPOSED ENBRIDGE TR7 NPS 36 PIPELINE
- TRANSMISSION/DISTRIBUTION PIPELINE
- FOREIGN PIPELINE
- EXISTING EASEMENT
- ENBRIDGE PIPELINE
- PROPOSED ENBRIDGE EASEMENT
- TEMPORARY ACCESS LANEWAY
- DRAIN/STREAM/WATERCOURSE CENTRE
- HYDRO EASEMENTS
- DRAINAGE DITCH BOTTOM/TOP
- RETAINING WALL/BRIDGE ABUTMENT
- ASPHALT/GRAVEL EDGE
- BUILDING
- POST/HYDRO POLE
- TELEPHONE BURIED CABLE/MISC CABLE
- FENCE
- OVERHEAD/BURIED HYDRO LINES
- WATERMAIN
- BOTTOM/TOP OF SLOPE
- TELEPHONE MARKER/BELL PEDESTAL
- CULVERT/CATCH BASIN/WATER VALVE
- SIGN/MAILBOX
- HYDRO TOWER
- PROPERTY LINE/ROAD ALLOWANCE
- PROPOSED ROAD/WATERCOURSE CROSSING
- PROPOSED HYDRO CROSSING
- PROPOSED ENBRIDGE PIPELINE CROSSING
- PROPOSED FOREIGN PIPELINE CROSSING
- PROPOSED BOREHOLE/MONITORING WELL
- TEST POST
- PIPELINE KILOMETRE POST
- TREE

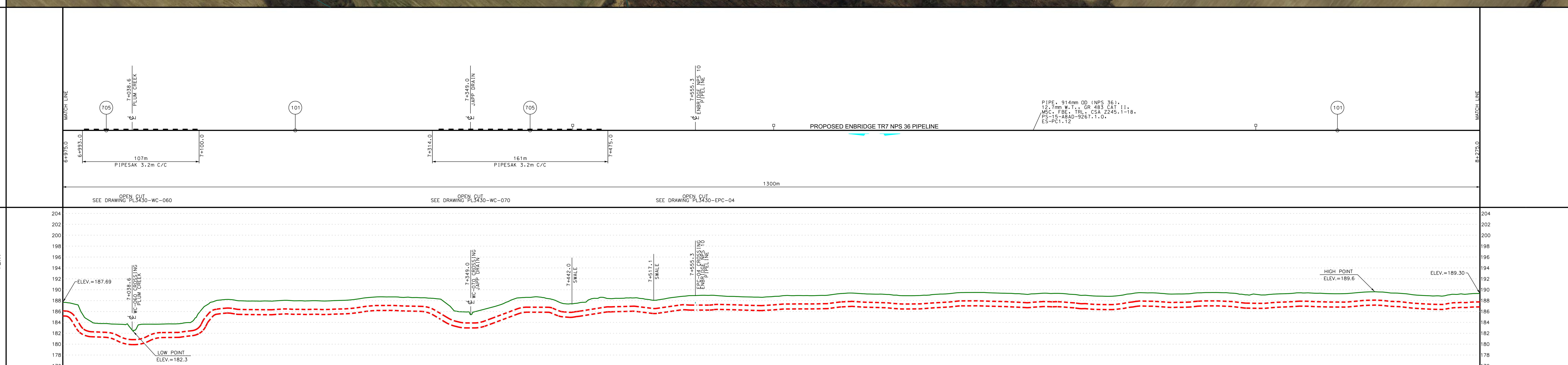
PIPELINE PLAN SCALE 1:2000



PIPELINE SCHEMATIC

LEGEND:

- HEAVY WALL PIPE
- PIPESAK
- TRANSITION WELD
- PIPELINE WARNING SIGN
- MATERIAL ITEM
- MAINLINE VALVE
- SIDE VALVE



DESIGN PARAMETERS (NEW PIPING ONLY)

DESIGN

- DESIGNED TO CSA Z662-19
- DESIGN FACTOR – 0.8
- LOCATION FACTOR – 0.900 / 0.625 (CLASS 2)
- DESIGN TEMPERATURE – M5C
- DESIGN PRESSURE – 9308 kPa

HYDROSTATIC TEST PRESSURE

PIPING

- STRENGTH – 13,032 kPa (1890 psig) MIN.
- LEAK – 10,239 kPa (1485 psig) MIN.
- DURATION – EXPOSED PIPING – 1 HOUR AT STRENGTH TEST PRESSURE MINIMUM
- BURIED PIPING – 4 HOUR AT STRENGTH TEST PRESSURE FOLLOWED BY 4 HOUR AT LEAK TEST PRESSURE MINIMUM

HYDROSTATIC TEST DATE – TBD

CONSTRUCTION

START DATE – JUNE 1, 2023
PLACED IN SERVICE – NOVEMBER 1, 2023

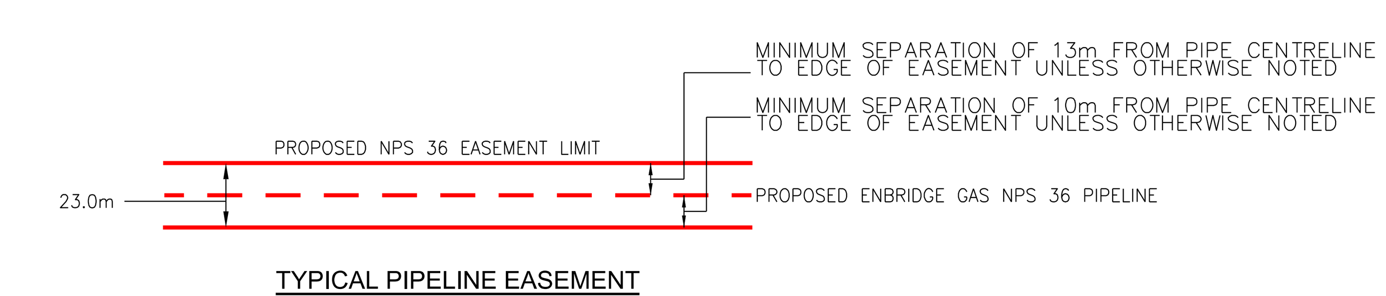
BILL of MATERIAL

Item No	Material No	Qty	Size	Description
101-150	Material No	Qty	Size	**PIPE**
101	~	1300m	36	PIPE, 914mm OD (NPS 36), 12.7mm W.T., GR 483 CAT II, M5C, FBE, QRL, CSA Z245.1-18, PS-15-A8AD-9267.1.0, ES-PC1.12
701-800	Material No	Qty	Size	**OTHER MATERIAL**
702	130968	~	610mm x 304.8m roll	(24"x1000') ROLL YELLOW TERRA TAPE IMPRINT LAYOUT LINE 1: "CAUTION CAUTION CAUTION" (HEIGHT 3") LINE 2: " ENBRIDGE GAS INC: (HEIGHT2") LINE 3: "NATURAL GAS PIPELINE BURIED BELOW" (HEIGHT 1 1/2") ALL THREE LINES TO BE CENTERED 36" REPEATS
703	125139	3	406.4 x 406.4	STANDARD STO BURIED PIPELINE SYSTEM SIGNAGE, Phone number required 1-800-265-5260 AS PER LUG C&M 18.6
704	125111	3	3 m	SIGN POST, GALV U CHANNEL POST HOT ROLLED & DIPPED 80 M PSI C/W SIGN HDWE PER DWG.E974 (10FT.)
705	~	87	36	PIPELINE WEIGHTS, NPS 36, SADDLE DESIGN, GRAVEL FILLED

CONSTRUCTION NOTES:

1) CONTRACTOR RESPONSIBLE FOR ALL UTILITY LOCATES.
2) ALL CULVERTS, END WALL TREATMENT AND TILE DRAINS REMOVED DURING CONSTRUCTION ARE TO BE RESTORED TO MATCH EXISTING CONDITIONS.
3) RESTORATION INCLUDES TOPSOIL AND SEEDING.
4) RESTORE DRIVEWAYS TO MATCH EXISTING.
5) ALL ASPHALT AREAS TO BE RESTORED TO MATCH EXISTING.
6) RESTORE ALL OPEN DRAINS TO MATCH ORIGINAL GRADE AND CONTOUR CONDITIONS.
7) ALL WORK MUST BE IN ACCORDANCE WITH THE LATEST ENBRIDGE GAS SPECIFICATIONS.
8) ALL WELDS TO BE NON-DESTRUCTIVELY EXAMINED, AS PER COMPANY SPECIFICATIONS.
9) ALL DIMENSIONS ARE IN METERS UNLESS OTHERWISE NOTED.
10) CONTRACTOR TO FIELD VERIFY ALL DIMENSIONS.
11) MAINTAIN MIN. 300mm CLEARANCE BETWEEN PROPOSED MAIN AND OTHER UTILITIES AND UNDERGROUND STRUCTURES THAT ARE CROSSED.
12) GENERAL DEPTH OF COVER IS 1.2m (MIN) FROM ORIGINAL GRADE AND 1.0m (MIN) FROM CONSTRUCTION GRADE UNLESS OTHERWISE STATED.

RIGHT OF WAY DETAILS



TYPICAL PIPELINE EASEMENT
N.T.S.

REVISION

NO.	DESCRIPTION	DATE	BY	CHK	APPR
	FOR INFORMATION ONLY	2022-06-29	N.C.	--	--

--	2022-06-30	FOR INFORMATION ONLY
		ISSUED FOR BID
		ISSUED FOR CONSTRUCTION
		ISSUED FOR CONSTRUCTION 2
APP'D	DATE	AS BUILT — AS BUILT BY: / CHECKED BY:

DRAWN	NICO CARIATI	DATE	2020:10:06
CHECKED	CAROLE GAGNE	DATE	--
APP'D BY	GRANT STRACHAN	DATE	--
WBS	XX-XX-XXX	SCALE	1:2000

ENGINEER: GRANT STRACHAN

PRELIMINARY

ENBRIDGE
Life Takes Energy

DAWN TO CORUNNA TR7 – NPS 36 PIPELINE
2023 CONSTRUCTION – DAWN/EUPHEMIA & ST. CLAIR
PIPELINE CONSTRUCTION ALIGNMENT
6+975.0 TO MATCH LINE 8+275.0

FILE REVISION DATE: 2022-06-29
DRAWING NUMBER: PL3430-AL-007

RIGHT-OF-WAY

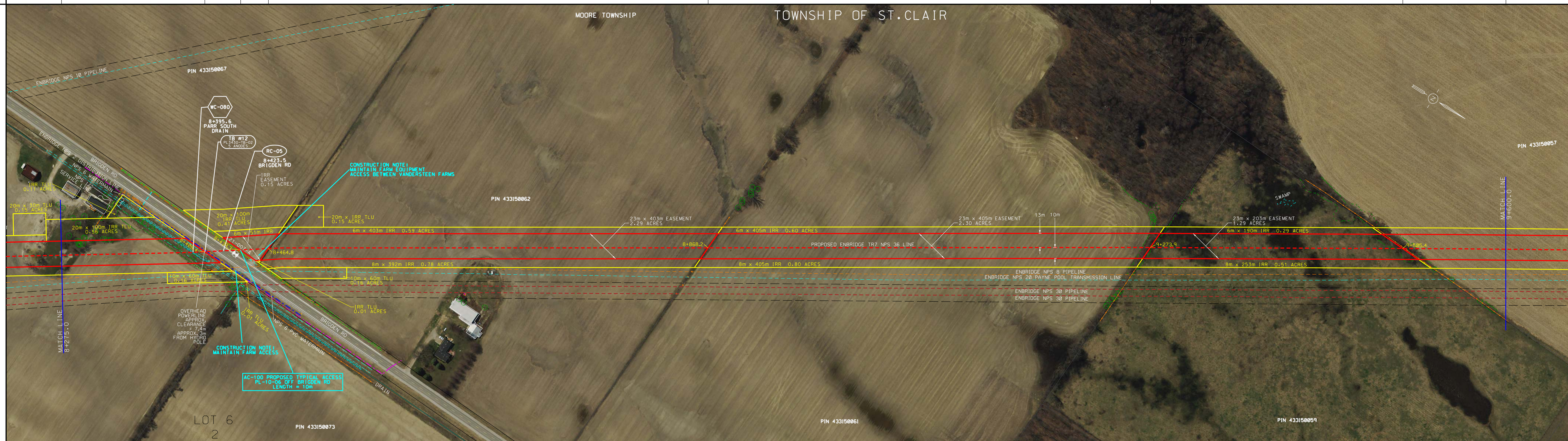
ENBRIDGE FILE NUMBER
OWNERSHIP/AGENCY
PIN: NUMBER

Station	8+275.0 MATCH LINE – 8+406.4	8+406.4 BRIGDEN RD – 8+439.3	8+439.3 – 8+464.8	8+464.8 – 8+868.2	8+868.2 – 9+273.9	9+273.9 – 9+505.4	9+505.4 – 9+600.0 MATCH LINE
PIN	43315-0074		43315-0067	43315-0062	43315-0061	43315-0059	43315-0057
CURRENT CLASS LOCATION	2	2	2				
LOCATION FACTOR	0.9	0.625	0.9				
TILE PLAN NUMBER							

ALIGNMENT DETAIL

LEGEND:
- PROPOSED ENBRIDGE TR7 NPS 36 PIPELINE
- TRANSMISSION/DISTRIBUTION PIPELINE
- FOREIGN PIPELINE
- EXISTING EASEMENT
- ENBRIDGE PIPELINE
- PROPOSED ENBRIDGE EASEMENT
- TEMPORARY ACCESS LANEWAY
- DRAIN/STREAM/WATERCOURSE CENTRE
- HYDRO EASEMENTS
- DRAINAGE DITCH BOTTOM/TOP
- RETAINING WALL/BRIDGE ABUTMENT
- ASPHALT/GRAVEL EDGE
- BUILDING
- POST/HYDRO POLE
- TELEPHONE BURIED CABLE/MISC CABLE
- FENCE
- OVERHEAD/BURIED HYDRO LINES
- WATERMAIN
- BOTTOM/TOP OF SLOPE
- TELEPHONE MARKER/BELL PEDESTAL
- CULVERT/CATCH BASIN/WATER VALVE
- SIGN/MAILBOX
- HYDRO TOWER
- PROPERTY LINE/ROAD ALLOWANCE
- PROPOSED ROAD/WATERCOURSE CROSSING
- PROPOSED HYDRO CROSSING
- PROPOSED ENBRIDGE PIPELINE CROSSING
- PROPOSED FOREIGN PIPELINE CROSSING
- PROPOSED BOREHOLE/MONITORING WELL
- TEST POST
- PIPELINE KILOMETRE POST
- TREE

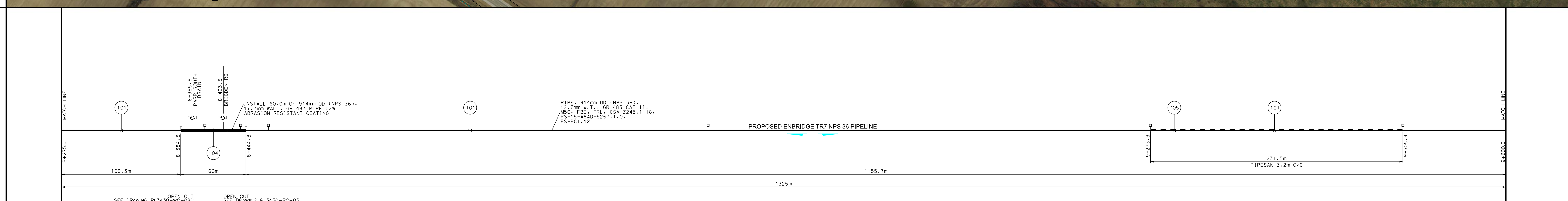
PIPELINE PLAN
SCALE 1:2000



PIPELINE SCHEMATIC

LEGEND:
- HEAVY WALL PIPE
- PIPESAK
- TRANSITION WELD
- PIPELINE WARNING SIGN
- MATERIAL ITEM
- MAINLINE VALVE
- SIDE VALVE

PIPELINE DATA



DESIGN PARAMETERS (NEW PIPING ONLY)

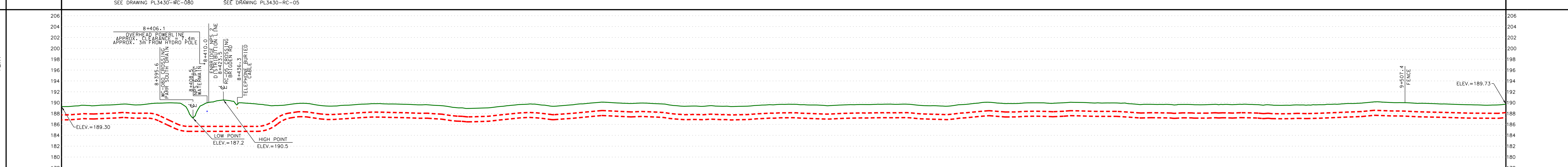
DESIGN
- DESIGNED TO CSA Z662-19
- DESIGN FACTOR – 0.8
- LOCATION FACTOR – 0.900 / 0.625 (CLASS 2)
- DESIGN TEMPERATURE – M5C
- DESIGN PRESSURE – 9308 kPa

HYDROSTATIC TEST PRESSURE
PIPING
- STRENGTH – 13,032 kPa (1890 psig) MIN.
- LEAK – 10,239 kPa (1485 psig) MIN.
- DURATION – EXPOSED PIPING – 1 HOUR AT STRENGTH TEST PRESSURE MINIMUM
- BURIED PIPING – 4 HOUR AT STRENGTH TEST PRESSURE FOLLOWED BY 4 HOUR AT LEAK TEST PRESSURE MINIMUM

HYDROSTATIC TEST DATE – TBD

CONSTRUCTION
START DATE – JUNE 1, 2023
PLACED IN SERVICE – NOVEMBER 1, 2023

P/L PROFILE
HORIZ 1:2000 VERT 1:400



BILL of MATERIAL

Item No	Material No	Qty	Size	Description
101-150	Material No	Qty	Size	**PIPE**
101	~	1265m	36	PIPE, 914mm OD (NPS 36), 12.7mm W.T., GR 483 CAT II, M5C, FBE, QRL, CSA Z245.1-18, PS-15-A8AD-9267.1.0, ES-PC1.12
104	~	60m	36	PIPE, 914mm OD (NPS 36), 17.7mm W.T., GR 483 CAT II, M5C, ARO, QRL, CSA Z245.1-18, PS-15-A8AD-9267.1.0, ES-PC7.3
701-800	Material No	Qty	Size	**OTHER MATERIAL**
702	130968	~	610mm x 304.8m roll	(24"x1000') ROLL YELLOW TERRA TAPE IMPRINT LAYOUT LINE 1: "CAUTION CAUTION CAUTION" (HEIGHT 3") LINE 2: " ENBRIDGE GAS INC: (HEIGHT2") LINE 3: "NATURAL GAS PIPELINE BURIED BELOW" (HEIGHT 1 1/2") ALL THREE LINES TO BE CENTERED 36" REPEATS
703	125139	6	406.4 x 406.4	STANDARD STO BURIED PIPELINE SYSTEM SIGNAGE, Phone number required 1-800-265-5260 AS PER LUG C&M 18.6
704	125111	6	3 m	SIGN POST, GALV U CHANNEL POST HOT ROLLED & DIPPED 80 M PSI C/W SIGN HDWE PER DWG.E974 (10FT.)
705	~	74	36	PIPELINE WEIGHTS, NPS 36, SADDLE DESIGN, GRAVEL FILLED

CONSTRUCTION NOTES:

1) CONTRACTOR RESPONSIBLE FOR ALL UTILITY LOCATES.
2) ALL CULVERTS, END WALL TREATMENT AND TILE DRAINS REMOVED DURING CONSTRUCTION ARE TO BE RESTORED TO MATCH EXISTING CONDITIONS.
3) RESTORATION INCLUDES TOPSOIL AND SEEDING.
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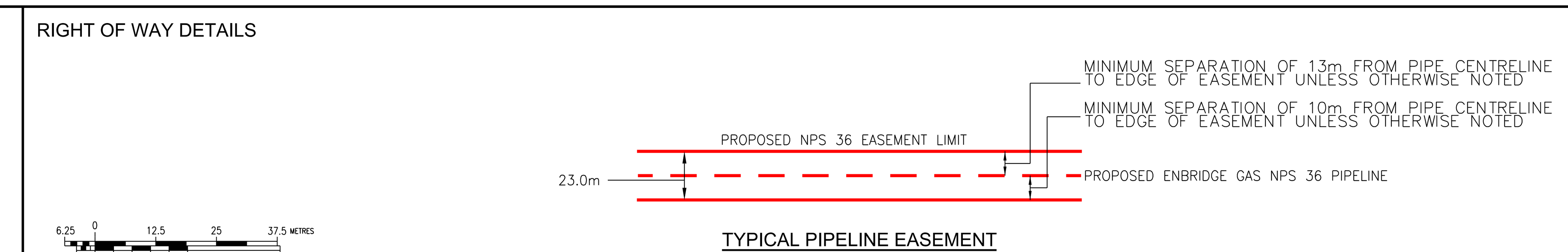
11) MAINTAIN MIN. 300mm CLEARANCE BETWEEN PROPOSED MAIN AND OTHER UTILITIES AND UNDERGROUND STRUCTURES THAT ARE CROSSED.
12) GENERAL DEPTH OF COVER IS 1.2m (MIN) FROM ORIGINAL GRADE AND 1.0m (MIN) FROM CONSTRUCTION GRADE UNLESS OTHERWISE STATED.

RIGHT OF WAY DETAILS



TYPICAL PIPELINE EASEMENT
N.T.S.

REVISION

NO.	DESCRIPTION	DATE	BY	CHK	APPR
	FOR INFORMATION ONLY	2022-06-29	N.C.	--	--

APP'D	DATE	
--	2022-06-30	FOR INFORMATION ONLY
		ISSUED FOR BID
		ISSUED FOR CONSTRUCTION
		ISSUED FOR CONSTRUCTION 2
		AS BUILT – AS BUILT BY:
		AS BUILT – CHECKED BY:

DRAWN	NICO CARIATI	DATE	2020:10:06
CHECKED	CAROLE GAGNE	DATE	--
APP'D BY	GRANT STRACHAN	DATE	--
WBS	XX-XX-XXX	SCALE	1:2000

ENGINEER: GRANT STRACHAN

PRELIMINARY

ENBRIDGE
Life Takes Energy

DAWN TO CORUNNA TR7 - NPS 36 PIPELINE
2023 CONSTRUCTION - DAWN/EUPHEMIA & ST. CLAIR
PIPELINE CONSTRUCTION ALIGNMENT
8+275.0 TO MATCH LINE 9+600.0

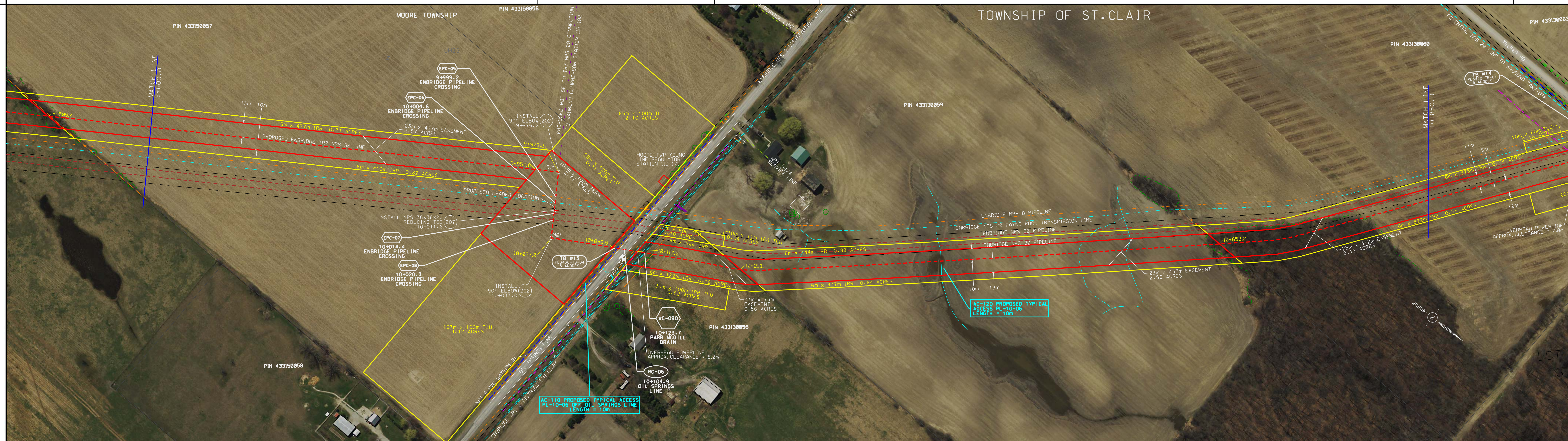
FILE REVISION DATE: 2022-06-29
DRAWING NUMBER: PL3430-AL-008

RIGHT-OF-WAY ENBRIDGE FILE NUMBER OWNERSHIP/AGENCY PIN: NUMBER	MATCH LINE 9+600.0	PIN: 43315-0057	9+954.8	PROPOSED HEADER LOCATION	OIL SPRINGS LINE 10+093.5 / 10+117.0	PIN: 43313-0056	10+213.1	PIN: 43313-0059	10+653.2	PIN: 43313-0060	10+850.0 MATCH LINE
CURRENT CLASS LOCATION		2		2	2			2			
LOCATION FACTOR		0.9		0.625	0.625			0.9			
TILE PLAN NUMBER											

ALIGNMENT DETAIL

LEGEND:
- PROPOSED ENBRIDGE TR7 NPS 36 PIPELINE
- TRANSMISSION/DISTRIBUTION PIPELINE
- FOREIGN PIPELINE
- EXISTING EASEMENT
- ENBRIDGE PIPELINE
- PROPOSED ENBRIDGE EASEMENT
- TEMPORARY ACCESS LANEWAY
- DRAIN/STREAM/WATERCOURSE CENTRE
- HYDRO EASEMENTS
- DRAINAGE DITCH BOTTOM/TOP
- RETAINING WALL/BRIDGE ABUTMENT
- ASPHALT/GRAVEL EDGE
- BUILDING
- POST/HYDRO POLE
- TELEPHONE BURIED CABLE/MISC CABLE
- FENCE
- OVERHEAD/BURIED HYDRO LINES
- WATERMAIN
- BOTTOM/TOP OF SLOPE
- TELEPHONE MARKER/BELL PEDESTAL
- CULVERT/CATCH BASIN/WATER VALVE
- SIGN/MAILBOX
- HYDRO TOWER
- PROPERTY LINE/ROAD ALLOWANCE
- PROPOSED ROAD/WATERCOURSE CROSSING
- PROPOSED HYDRO CROSSING
- PROPOSED ENBRIDGE PIPELINE CROSSING
- PROPOSED FOREIGN PIPELINE CROSSING
- PROPOSED BOREHOLE/MONITORING WELL
- TEST POST
- PIPELINE KILOMETRE POST
- TREE

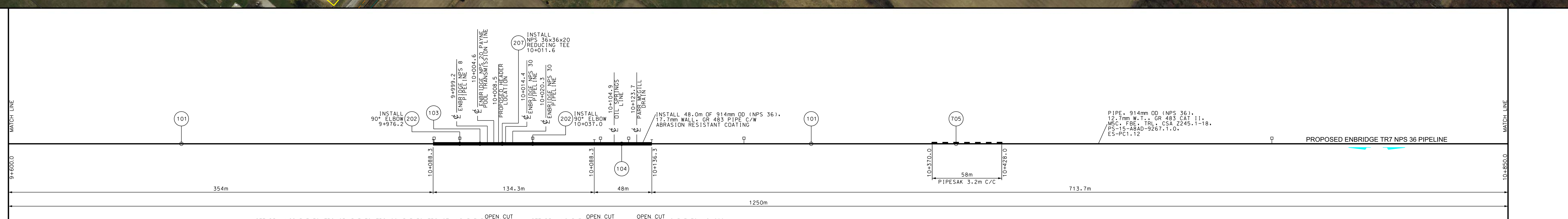
PIPELINE PLAN SCALE 1:2000



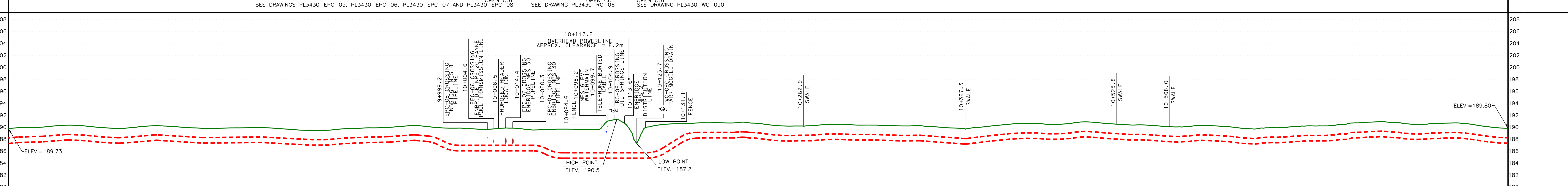
PIPELINE SCHEMATIC

LEGEND:
- HEAVY WALL PIPE
- PIPESAK
- TRANSITION WELD
- PIPELINE WARNING SIGN
- MATERIAL ITEM
- MAINLINE VALVE
- SIDE VALVE

PIPELINE DATA



P/L PROFILE HORIZ 1:2000 VERT 1:400



DESIGN PARAMETERS (NEW PIPING ONLY)

DESIGN
- DESIGNED TO CSA Z662-19
- DESIGN FACTOR – 0.8
- LOCATION FACTOR – 0.900 / 0.625 (CLASS 2)
- DESIGN TEMPERATURE – M5C
- DESIGN PRESSURE – 9308 kPa

HYDROSTATIC TEST PRESSURE
PIPING
- STRENGTH – 13,032 kPa (1890 psig) MIN.
- LEAK – 10,239 kPa (1485 psig) MIN.
- DURATION – EXPOSED PIPING – 1 HOUR AT STRENGTH TEST PRESSURE MINIMUM
- BURIED PIPING – 4 HOUR AT STRENGTH TEST PRESSURE FOLLOWED BY 4 HOUR AT LEAK TEST PRESSURE MINIMUM

HYDROSTATIC TEST DATE – TBD

CONSTRUCTION
START DATE – JUNE 1, 2023
PLACED IN SERVICE – NOVEMBER 1, 2023

BILL of MATERIAL

Item No	Material No	Qty	Size	Description
101-150	Material No	Qty	Size	**PIPE**
101	~	1067m	36	PIPE, 914mm OD (NPS 36), 12.7mm W.T., GR 483 CAT II, M5C, FBE, QRL, CSA Z245.1-18, PS-15-A8AD-9267.1.0, ES-PC1.12
103	~	135m	36	PIPE, 914mm OD (NPS 36), 17.7mm W.T., GR 483 CAT II, M5C, FBE, QRL, CSA Z245.1-18, PS-15-A8AD-9267.1.0, ES-PC1.12
104	~	48m	36	PIPE, 914mm OD (NPS 36), 17.7mm W.T., GR 483 CAT II, M5C, ARO, QRL, CSA Z245.1-18, PS-15-A8AD-9267.1.0, ES-PC7.3
201-350	Material No	Qty	Size	**FITTINGS**
202	~	2	36	ELBOW, NPS 36, 90 DEGREES, TO MATCH 914mm OD (NPS 36), 17.7mm W.T., GR 483 CAT II M5C PIPE, I.D. CONTROLLED AND SEGMENTABLE XLR (3D), BE, CSA Z245.11, PS-1E-1B1A-0B1B
207	~	1	36x36x20	TEE, REDUCING, NPS 36x36x20, 17.7 mm x 17.7 mm x 12.7 mm W.T., GR 483, CAT II, M5C, c/w SCRAPPER BARS
701-800	Material No	Qty	Size	**OTHER MATERIAL**
702	130968	~	610mm x 304.8m roll	(24"x1000') ROLL YELLOW TERRA TAPE IMPRINT LAYOUT LINE 1: "CAUTION CAUTION CAUTION" (HEIGHT 3") LINE 2: " ENBRIDGE GAS INC: (HEIGHT2") LINE 3: "NATURAL GAS PIPELINE BURIED BELOW" (HEIGHT 1 1/2") ALL THREE LINES TO BE CENTERED 36" REPEATS
703	125139	7	406.4 x 406.4	STANDARD STO BURIED PIPELINE SYSTEM SIGNAGE, Phone number required 1-800-265-5260 AS PER LUG C&M 18.6
704	125111	7	3 m	SIGN POST, GALV U CHANNEL POST HOT ROLLED & DIPPED 80 M PSI C/W SIGN HDWE PER DWG.E974 (10FT.)
705	~	20	36	PIPELINE WEIGHTS, NPS 36, SADDLE DESIGN, GRAVEL FILLED

CONSTRUCTION NOTES:

1) CONTRACTOR RESPONSIBLE FOR ALL UTILITY LOCATES.
2) ALL CULVERTS, END WALL TREATMENT AND TILE DRAINS REMOVED DURING CONSTRUCTION ARE TO BE RESTORED TO MATCH EXISTING CONDITIONS.
3) RESTORATION INCLUDES TOPSOIL AND SEEDING.
4) RESTORE DRIVEWAYS TO MATCH EXISTING.
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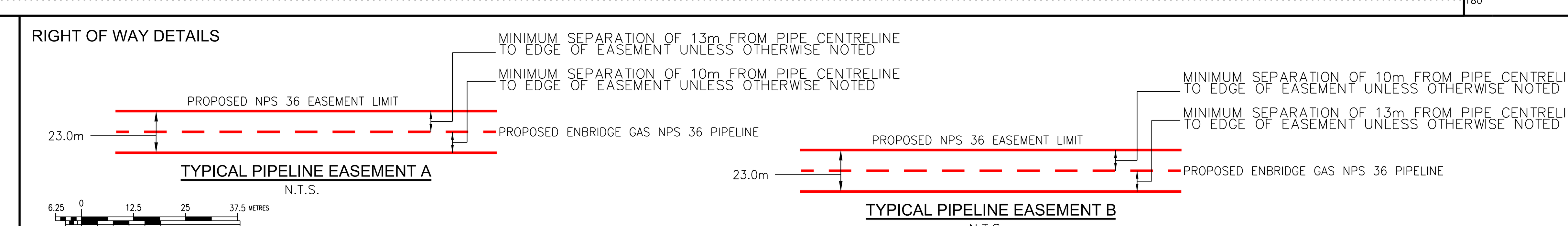
9) ALL DIMENSIONS ARE IN METERS UNLESS OTHERWISE NOTED.
10) CONTRACTOR TO FIELD VERIFY ALL DIMENSIONS.
11) MAINTAIN MIN. 300mm CLEARANCE BETWEEN PROPOSED MAIN AND OTHER UTILITIES AND UNDERGROUND STRUCTURES THAT ARE CROSSED.
12) GENERAL DEPTH OF COVER IS 1.2m (MIN) FROM ORIGINAL GRADE AND 1.0m (MIN) FROM CONSTRUCTION GRADE UNLESS OTHERWISE STATED.

RIGHT OF WAY DETAILS



TYPICAL PIPELINE EASEMENT A
N.T.S.

TYPICAL PIPELINE EASEMENT B
N.T.S.

REVISION					
NO.	DESCRIPTION	DATE	BY	CHK	APPR
	FOR INFORMATION ONLY	2022-06-29	N.C.	--	--

--	2022-06-30	FOR INFORMATION ONLY
		ISSUED FOR BID
		ISSUED FOR CONSTRUCTION
		ISSUED FOR CONSTRUCTION 2
APP'D	DATE	AS BUILT — AS BUILT BY: / CHECKED BY:

DRAWN	NICO CARIATI	DATE	2020:10:06
CHECKED	CAROLE GAGNE	DATE	--
APP'D BY	GRANT STRACHAN	DATE	--
WBS	XX-XX-XXX	SCALE	1:2000

ENGINEER: GRANT STRACHAN

PRELIMINARY

ENBRIDGE
Life Takes Energy

DAWN TO CORUNNA TR7 - NPS 36 PIPELINE
2023 CONSTRUCTION - DAWN/EUPHEMIA & ST. CLAIR
PIPELINE CONSTRUCTION ALIGNMENT
9+600.0 TO MATCH LINE 10+850.0

FILE REVISION DATE: 2022-06-29
DRAWING NUMBER: PL3430-AL-009

RIGHT-OF-WAY

ENBRIDGE FILE NUMBER
OWNERSHIP/AGENCY
PIN: NUMBER

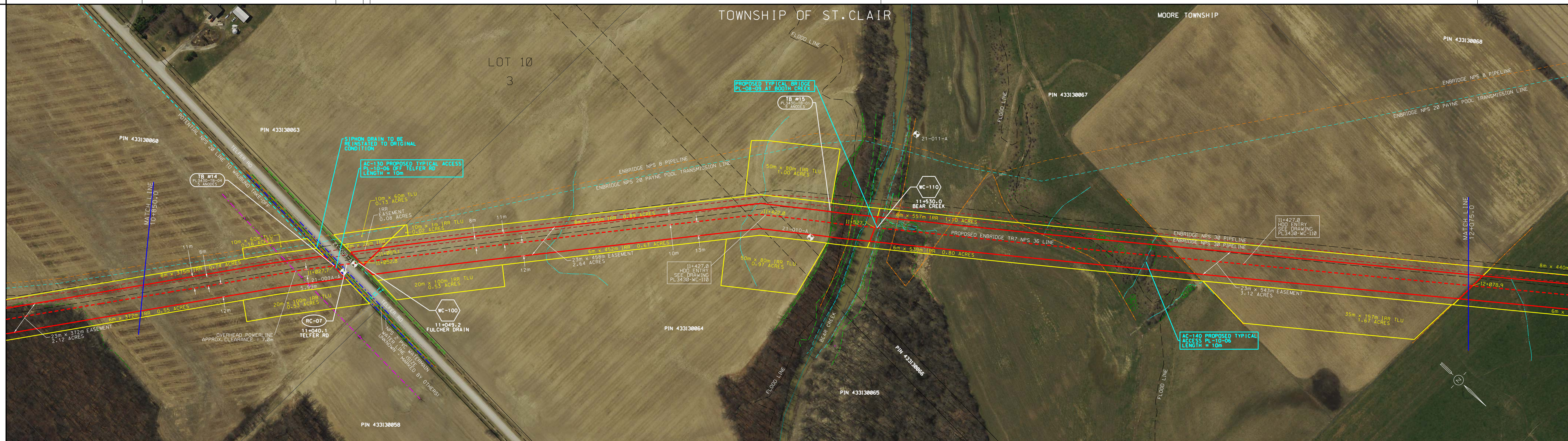
RIGHT-OF-WAY	PIN: 43313-0060	TELFER RD	PIN: 43313-0063	PIN: 43313-0064	PIN: 43313-0067
CURRENT CLASS LOCATION	2	2		2	
LOCATION FACTOR	0.9	0.625		0.9	
TILE PLAN NUMBER					

MATCH LINE 10+850.0 · 11+027.7 · 11+052.8 · 11+059.1 · 11+527.7 · 12+075.0 MATCH LINE

ALIGNMENT DETAIL

LEGEND:
- PROPOSED ENBRIDGE TR7 NPS 36 PIPELINE
- TRANSMISSION/DISTRIBUTION PIPELINE
- FOREIGN PIPELINE
- EXISTING EASEMENT
- ENBRIDGE PIPELINE
- PROPOSED ENBRIDGE EASEMENT
- TEMPORARY ACCESS LANEWAY
- DRAIN/STREAM/WATERCOURSE CENTRE
- HYDRO EASEMENTS
- DRAINAGE DITCH BOTTOM/TOP
- RETAINING WALL/BRIDGE ABUTMENT
- ASPHALT/GRAVEL EDGE
- BUILDING
- POST/HYDRO POLE
- TELEPHONE BURIED CABLE/MISC CABLE
- FENCE
- OVERHEAD/BURIED HYDRO LINES
- WATERMAIN
- BOTTOM/TOP OF SLOPE
- TELEPHONE MARKER/BELL PEDESTAL
- CULVERT/CATCH BASIN/WATER VALVE
- SIGN/MAILBOX
- HYDRO TOWER
- PROPERTY LINE/ROAD ALLOWANCE
- PROPOSED ROAD/WATERCOURSE CROSSING (RC-XX) (WC-XX)
- PROPOSED HYDRO CROSSING (HCS-XX)
- PROPOSED ENBRIDGE PIPELINE CROSSING (EPC-XX)
- PROPOSED FOREIGN PIPELINE CROSSING (FPL-XX)
- PROPOSED BOREHOLE/MONITORING WELL
- TEST POST (TB # PL3430-TB-XX)
- PIPELINE KILOMETRE POST
- TREE

PIPELINE PLAN
SCALE 1:2000

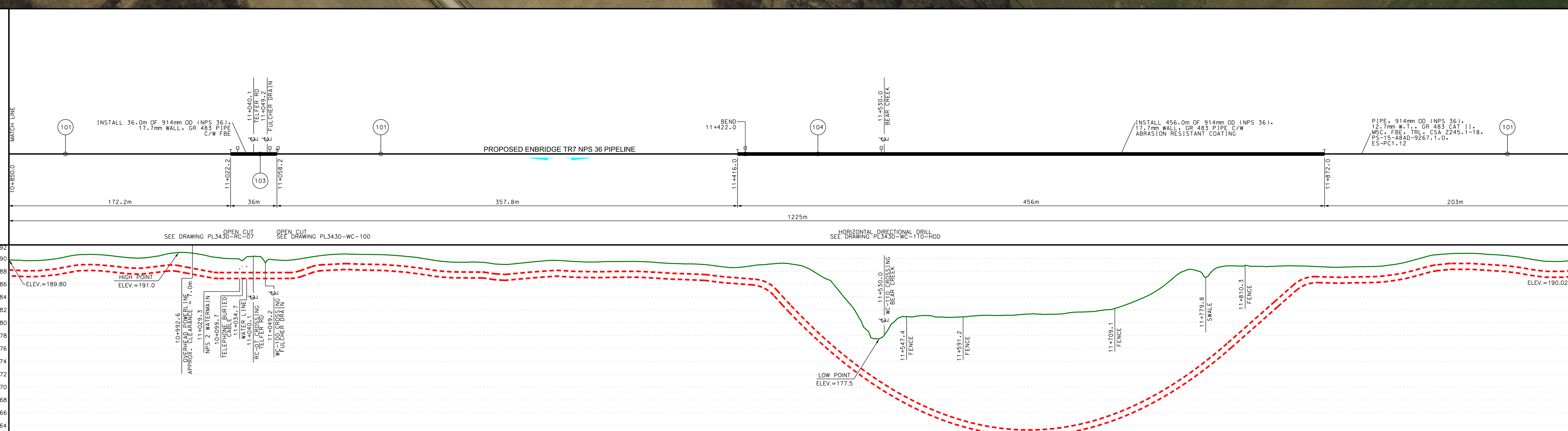


PIPELINE SCHEMATIC

LEGEND:
- HEAVY WALL PIPE
- PIPESAK
- TRANSITION WELD
- PIPELINE WARNING SIGN
- MATERIAL ITEM
- MAINLINE VALVE
- SIDE VALVE

PIPELINE DATA

P/L PROFILE
HORIZ 1:2000 VERT 1:400



DESIGN PARAMETERS (NEW PIPING ONLY)

DESIGN
- DESIGNED TO CSA Z662-19
- DESIGN FACTOR – 0.8
- LOCATION FACTOR – 0.900 / 0.625 (CLASS 2)
- DESIGN TEMPERATURE – M5C
- DESIGN PRESSURE – 9308 kPa

HYDROSTATIC TEST PRESSURE
PIPING
- STRENGTH – 13,032 kPa (1890 psig) MIN.
- LEAK – 10,239 kPa (1485 psig) MIN.
- DURATION – EXPOSED PIPING – 1 HOUR AT STRENGTH TEST PRESSURE MINIMUM
- BURIED PIPING – 4 HOUR AT STRENGTH TEST PRESSURE FOLLOWED BY 4 HOUR AT LEAK TEST PRESSURE MINIMUM

HYDROSTATIC TEST DATE – TBD

CONSTRUCTION
START DATE – JUNE 1, 2023
PLACED IN SERVICE – NOVEMBER 1, 2023

BILL of MATERIAL

Item No	Material No	Qty	Size	Description
101-150	Material No	Qty	Size	**PIPE**
101	~	733m	36	PIPE, 914mm OD (NPS 36), 12.7mm W.T., GR 483 CAT II, M5C, FBE, QRL, CSA Z245.1-18, PS-15-A8AD-9267.1.0, ES-PC1.12
103	~	36m	36	PIPE, 914mm OD (NPS 36), 17.7mm W.T., GR 483 CAT II, M5C, FBE, QRL, CSA Z245.1-18, PS-15-A8AD-9267.1.0, ES-PC1.12
104		456m	36	PIPE, 914mm OD (NPS 36), 17.7mm W.T., GR 483 CAT II, M5C, ARO, QRL, CSA Z245.1-18, PS-15-A8AD-9267.1.0, ES-PC7.3
701-800	Material No	Qty	Size	**OTHER MATERIAL**
702	130968	~	610mm x 304.8m roll	(24"x1000') ROLL YELLOW TERRA TAPE IMPRINT LAYOUT LINE 1: "CAUTION CAUTION CAUTION" (HEIGHT 3") LINE 2: " ENBRIDGE GAS INC: (HEIGHT2") LINE 3: "NATURAL GAS PIPELINE BURIED BELOW" (HEIGHT 1 1/2") ALL THREE LINES TO BE CENTERED 36" REPEATS
703	125139	5	406.4 x 406.4	STANDARD STO BURIED PIPELINE SYSTEM SIGNAGE, Phone number required 1-800-265-5260 AS PER LUG C&M 18.6
704	125111	5	3 m	SIGN POST, GALV U CHANNEL POST HOT ROLLED & DIPPED 80 M PSI C/W SIGN HDWE PER DWG.E974 (10FT.)
705	~	~	36	PIPELINE WEIGHTS, NPS 36, SADDLE DESIGN, GRAVEL FILLED

CONSTRUCTION NOTES:

1) CONTRACTOR RESPONSIBLE FOR ALL UTILITY LOCATES.
2) ALL CULVERTS, END WALL TREATMENT AND TILE DRAINS REMOVED DURING CONSTRUCTION ARE TO BE RESTORED TO MATCH EXISTING CONDITIONS.
3) RESTORATION INCLUDES TOPSOIL AND SEEDING.
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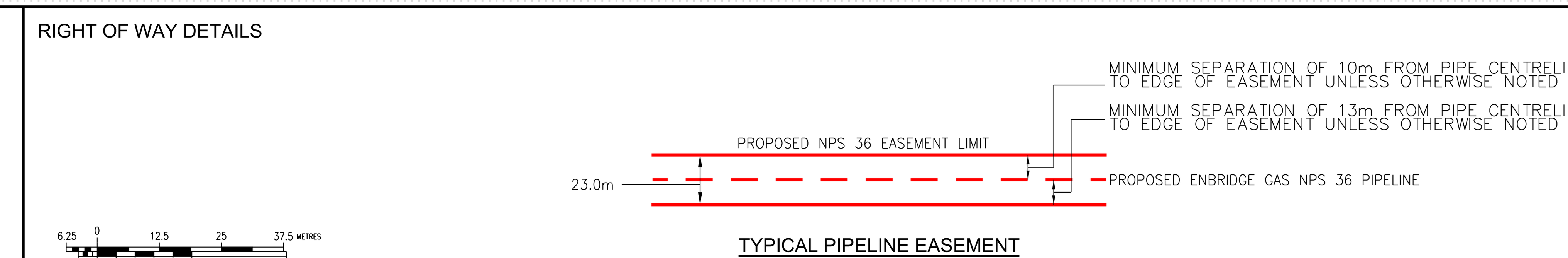
9) ALL DIMENSIONS ARE IN METERS UNLESS OTHERWISE NOTED.
10) CONTRACTOR TO FIELD VERIFY ALL DIMENSIONS.
11) MAINTAIN MIN. 300mm CLEARANCE BETWEEN PROPOSED MAIN AND OTHER UTILITIES AND UNDERGROUND STRUCTURES THAT ARE CROSSED.
12) GENERAL DEPTH OF COVER IS 1.2m (MIN) FROM ORIGINAL GRADE AND 1.0m (MIN) FROM CONSTRUCTION GRADE UNLESS OTHERWISE STATED.

RIGHT OF WAY DETAILS



TYPICAL PIPELINE EASEMENT
N.T.S.

6.25 0 12.5 25 37.5 METRES
12.5 0 12.5 25 37.5 50 62.5 125 FEET

REVISION					
NO.	DESCRIPTION	DATE	BY	CHK	APPR
	FOR INFORMATION ONLY	2022-06-29	N.C.	--	--

--	2022-06-30	FOR INFORMATION ONLY
		ISSUED FOR BID
		ISSUED FOR CONSTRUCTION
		ISSUED FOR CONSTRUCTION 2
APP'D	DATE	AS BUILT — AS BUILT BY: / CHECKED BY:

DRAWN	NICO CARIATI	DATE	2020:10:06
CHECKED	CAROLE GAGNE	DATE	--
APP'D BY	GRANT STRACHAN	DATE	--
WBS	XX-XX-XXX	SCALE	1:2000

ENGINEER: GRANT STRACHAN

PRELIMINARY

ENBRIDGE
Life Takes Energy

DAWN TO CORUNNA TR7 - NPS 36 PIPELINE
2023 CONSTRUCTION - DAWN/EUPHEMIA & ST. CLAIR
PIPELINE CONSTRUCTION ALIGNMENT
10+850.0 TO MATCH LINE 12+075.0

FILE REVISION DATE: 2022-06-29
DRAWING NUMBER: PL3430-AL-010

RIGHT-OF-WAY

ENBRIDGE FILE NUMBER
OWNERSHIP/AGENCY
PIN: NUMBER

MATCH LINE 12+075.0 | PIN: 43313-0067 | 12+078.9 | PIN: 43313-0078 | 12+519.8 | PIN: 43313-0079 | 13+275.0 MATCH LINE

CURRENT CLASS LOCATION: 2
LOCATION FACTOR: 0.9
TILE PLAN NUMBER

ALIGNMENT DETAIL

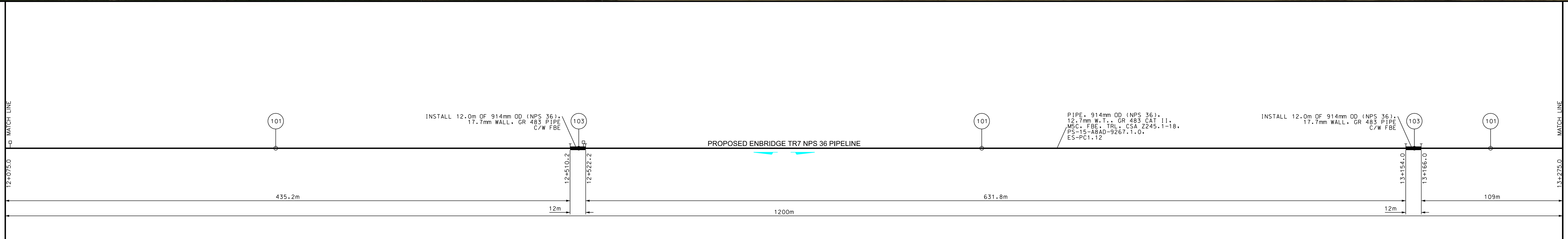
LEGEND:
- PROPOSED ENBRIDGE TR7 NPS 36 PIPELINE
- TRANSMISSION/DISTRIBUTION PIPELINE
- FOREIGN PIPELINE
- EXISTING EASEMENT
- ENBRIDGE PIPELINE
- PROPOSED ENBRIDGE EASEMENT
- TEMPORARY ACCESS LANEWAY
- DRAIN/STREAM/WATERCOURSE CENTRE
- HYDRO EASEMENTS
- DRAINAGE DITCH BOTTOM/TOP
- RETAINING WALL/BRIDGE ABUTMENT
- ASPHALT/GRAVEL EDGE
- BUILDING
- POST/HYDRO POLE
- TELEPHONE BURIED CABLE/MISC CABLE
- FENCE
- OVERHEAD/BURIED HYDRO LINES
- WATERMAIN
- BOTTOM/TOP OF SLOPE
- TELEPHONE MARKER/BELL PEDESTAL
- CULVERT/CATCH BASIN/WATER VALVE
- SIGN/MAILBOX
- HYDRO TOWER
- PROPERTY LINE/ROAD ALLOWANCE
- PROPOSED ROAD/WATERCOURSE CROSSING
- PROPOSED HYDRO CROSSING
- PROPOSED ENBRIDGE PIPELINE CROSSING
- PROPOSED FOREIGN PIPELINE CROSSING
- PROPOSED BOREHOLE/MONITORING WELL
- TEST POST
- PIPELINE KILOMETRE POST
- TREE

PIPELINE PLAN SCALE 1:2000

PIPELINE SCHEMATIC

LEGEND:
- HEAVY WALL PIPE
- PIPESAK
- TRANSITION WELD
- PIPELINE WARNING SIGN
- MATERIAL ITEM
- MAINLINE VALVE
- SIDE VALVE

PIPELINE DATA



DESIGN PARAMETERS (NEW PIPING ONLY)

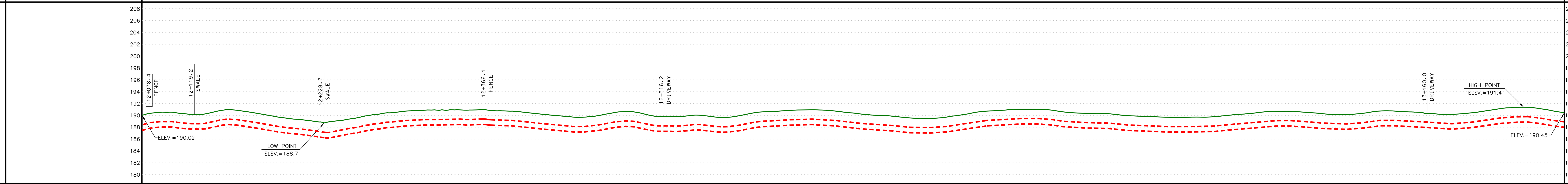
DESIGN
- DESIGNED TO CSA Z662-19
- DESIGN FACTOR – 0.8
- LOCATION FACTOR – 0.900 / 0.625 (CLASS 2)
- DESIGN TEMPERATURE – M5C
- DESIGN PRESSURE – 9308 kPa

HYDROSTATIC TEST PRESSURE
PIPING
- STRENGTH – 13,032 kPa (1890 psig) MIN.
- LEAK – 10,239 kPa (1485 psig) MIN.
- DURATION – EXPOSED PIPING – 1 HOUR AT STRENGTH TEST PRESSURE MINIMUM
- BURIED PIPING – 4 HOUR AT STRENGTH TEST PRESSURE FOLLOWED BY 4 HOUR AT LEAK TEST PRESSURE MINIMUM

HYDROSTATIC TEST DATE – TBD

CONSTRUCTION
START DATE – JUNE 1, 2023
PLACED IN SERVICE – NOVEMBER 1, 2023

P/L PROFILE HORIZ 1:2000 VERT 1:400



BILL of MATERIAL

Item No	Material No	Qty	Size	Description
101-150	Material No	Qty	Size	**PIPE**
101	~	1176m	36	PIPE, 914mm OD (NPS 36), 12.7mm W.T., GR 483 CAT II, M5C, FBE, QRL, CSA Z245.1-18, PS-15-A8AD-9267.1.0, ES-PC1.12
103	~	24m	36	PIPE, 914mm OD (NPS 36), 17.7mm W.T., GR 483 CAT II, M5C, FBE, QRL, CSA Z245.1-18, PS-15-A8AD-9267.1.0, ES-PC1.12
701-800	Material No	Qty	Size	**OTHER MATERIAL**
702	130968	~	610mm x 304.8m roll	(24"x1000') ROLL YELLOW TERRA TAPE IMPRINT LAYOUT LINE 1: "CAUTION CAUTION CAUTION" (HEIGHT 3") LINE 2: " ENBRIDGE GAS INC: (HEIGHT2") LINE 3: "NATURAL GAS PIPELINE BURIED BELOW" (HEIGHT 1 1/2") ALL THREE LINES TO BE CENTERED 36" REPEATS
703	125139	1	406.4 x 406.4	STANDARD STO BURIED PIPELINE SYSTEM SIGNAGE, Phone number required 1-800-265-5260 AS PER LUG C&M 18.6
704	125111	1	3 m	SIGN POST, GALV U CHANNEL POST HOT ROLLED & DIPPED 80 M PSI C/W SIGN HDWE PER DWG.E974 (10FT.)
705	~	~	36	PIPELINE WEIGHTS, NPS 36, SADDLE DESIGN, GRAVEL FILLED

CONSTRUCTION NOTES:

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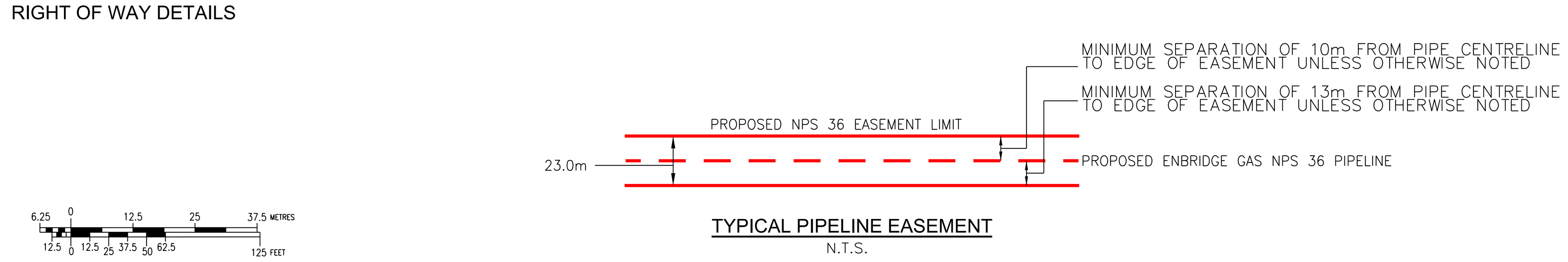
12) GENERAL DEPTH OF COVER IS 1.2m (MIN) FROM ORIGINAL GRADE AND 1.0m (MIN) FROM CONSTRUCTION GRADE UNLESS OTHERWISE STATED.

RIGHT OF WAY DETAILS



TYPICAL PIPELINE EASEMENT
N.T.S.

REVISION

NO.	DESCRIPTION	DATE	BY	CHK	APPR
	FOR INFORMATION ONLY	2022-06-29	N.C.	--	--

--	2022-06-30	FOR INFORMATION ONLY
		ISSUED FOR BID
		ISSUED FOR CONSTRUCTION
		ISSUED FOR CONSTRUCTION 2
APP'D	DATE	AS BUILT — AS BUILT BY: / CHECKED BY:

DRAWN	NICO CARIATI	DATE	2020:10:06
CHECKED	CAROLE GAGNE	DATE	--
APP'D BY	GRANT STRACHAN	DATE	--
WBS	XX-XX-XXX	SCALE	1:2000

ENGINEER: GRANT STRACHAN

PRELIMINARY

ENBRIDGE
Life Takes Energy®

DAWN TO CORUNNA TR7 – NPS 36 PIPELINE
2023 CONSTRUCTION – DAWN/EUPHEMIA & ST. CLAIR
PIPELINE CONSTRUCTION ALIGNMENT
12+075.0 TO MATCH LINE 13+275.0

FILE REVISION DATE: 2022-06-29
DRAWING NUMBER: PL3430-AL-011

RIGHT-OF-WAY

ENBRIDGE FILE NUMBER
OWNERSHIP/AGENCY
PIN: NUMBER

MATCH LINE 13+275.0 | PIN: 43313-0079 | 13+306.4 | PIN: 43313-0077 | 13+546.0 | PIN: 43313-0076 | 13+859.1 | COURTRIGHT LINE (COUNTY RD 80) | 13+892.6 | PIN: 43302-0105 | 14+068.2 | PIN: 43302-0270 | 14+105.2 | PIN: 43302-0104 | 14+206.6 | WAUBUNO RD | 14+235.4 | PIN: 43302-0079 | 14+525.0 MATCH LINE

CURRENT CLASS LOCATION: 2 | 2 | 2 | 2 | 2

LOCATION FACTOR: 0.9 | 0.625 | 0.9 | 0.625 | 0.9

TILE PLAN NUMBER

ALIGNMENT DETAIL

LEGEND:

- PROPOSED ENBRIDGE TR7 NPS 36 PIPELINE
- TRANSMISSION/DISTRIBUTION PIPELINE
- FOREIGN PIPELINE
- EXISTING EASEMENT
- ENBRIDGE PIPELINE
- PROPOSED ENBRIDGE EASEMENT
- TEMPORARY ACCESS LANEWAY
- DRAIN/STREAM/WATERCOURSE CENTRE
- HYDRO EASEMENTS
- DRAINAGE DITCH BOTTOM/TOP
- RETAINING WALL/BRIDGE ABUTMENT
- ASPHALT/GRAVEL EDGE
- BUILDING
- POST/HYDRO POLE
- TELEPHONE BURIED CABLE/MISC CABLE
- FENCE
- OVERHEAD/BURIED HYDRO LINES
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- BOTTOM/TOP OF SLOPE
- TELEPHONE MARKER/BELL PEDESTAL
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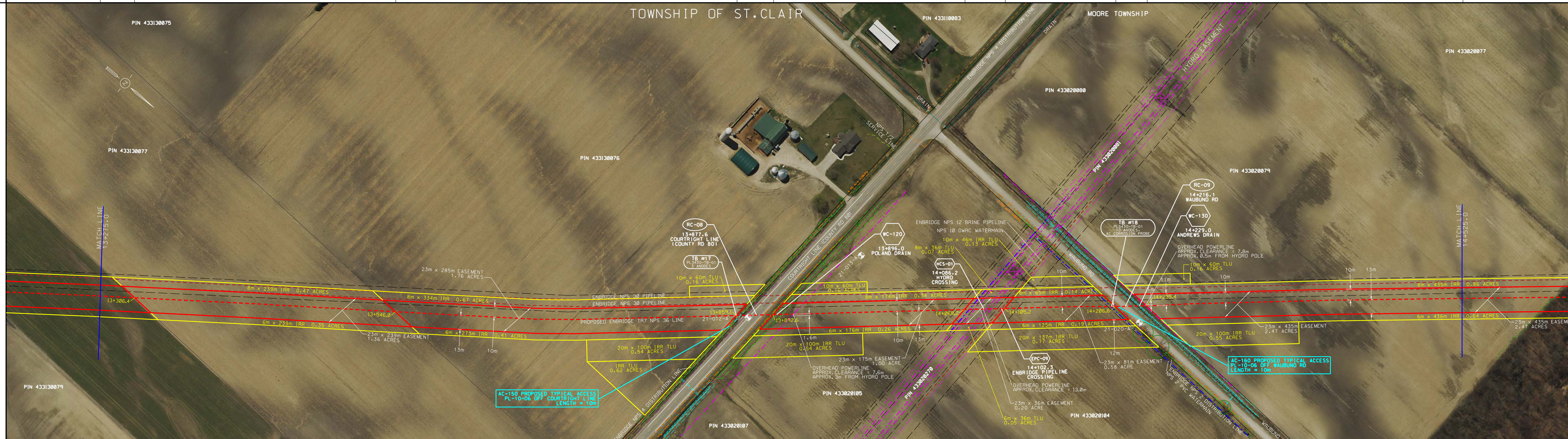
- PROPOSED ENBRIDGE PIPELINE CROSSING
- PROPOSED FOREIGN PIPELINE CROSSING
- PROPOSED BOREHOLE/MONITORING WELL
- TEST POST
- PIPELINE KILOMETRE POST
- TREE

PIPELINE PLAN SCALE 1:2000



PIPELINE SCHEMATIC

LEGEND:

- HEAVY WALL PIPE
- PIPESAK
- TRANSITION WELD
- PIPELINE WARNING SIGN
- MATERIAL ITEM
- MAINLINE VALVE
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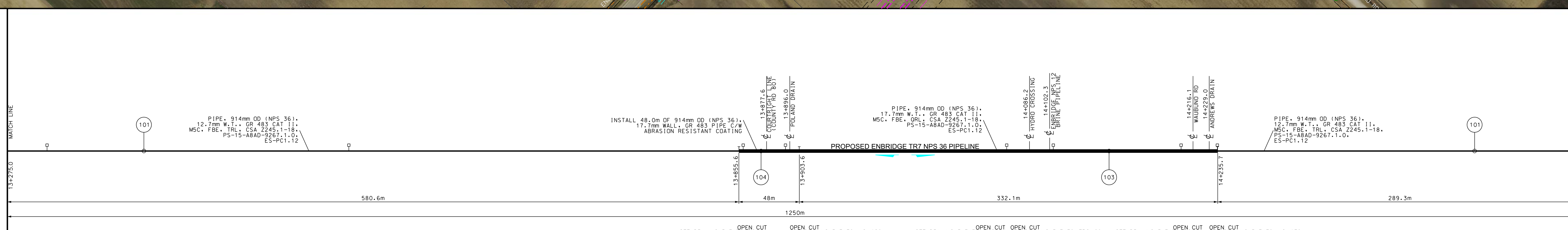
PIPELINE DATA



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- DESIGN FACTOR – 0.8
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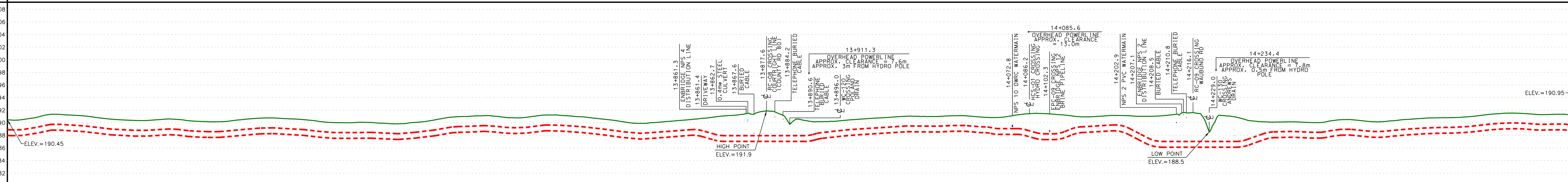
HYDROSTATIC TEST DATE – TBD

CONSTRUCTION

START DATE – JUNE 1, 2023
PLACED IN SERVICE – NOVEMBER 1, 2023

P/L PROFILE HORIZ 1:2000 VERT 1:400



BILL of MATERIAL

Item No	Material No	Qty	Size	Description
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103	~	332m	36	PIPE, 914mm OD (NPS 36), 17.7mm W.T., GR 483 CAT II, M5C, FBE, QRL, CSA Z245.1-18, PS-15-A8AD-9267.1.0, ES-PC1.12
104	~	48m	36	PIPE, 914mm OD (NPS 36), 17.7mm W.T., GR 483 CAT II, M5C, ARO, QRL, CSA Z245.1-18, PS-15-A8AD-9267.1.0, ES-PC7.3
701-800	Material No	Qty	Size	**OTHER MATERIAL**
702	130968	~	610mm x 304.8m roll	(24"x1000') ROLL YELLOW TERRA TAPE IMPRINT LAYOUT LINE 1: "CAUTION CAUTION CAUTION" (HEIGHT 3") LINE 2: " ENBRIDGE GAS INC: (HEIGHT2") LINE 3: "NATURAL GAS PIPELINE BURIED BELOW" (HEIGHT 1 1/2") ALL THREE LINES TO BE CENTERED 36" REPEATS
703	125139	7	406.4 x 406.4	STANDARD STO BURIED PIPELINE SYSTEM SIGNAGE, Phone number required 1-800-265-5260 AS PER LUG C&M 18.6
704	125111	7	3 m	SIGN POST, GALV U CHANNEL POST HOT ROLLED & DIPPED 80 M PSI C/W SIGN HDWE PER DWG.E974 (10FT.)
705	~	~	36	PIPELINE WEIGHTS, NPS 36, SADDLE DESIGN, GRAVEL FILLED

CONSTRUCTION NOTES:

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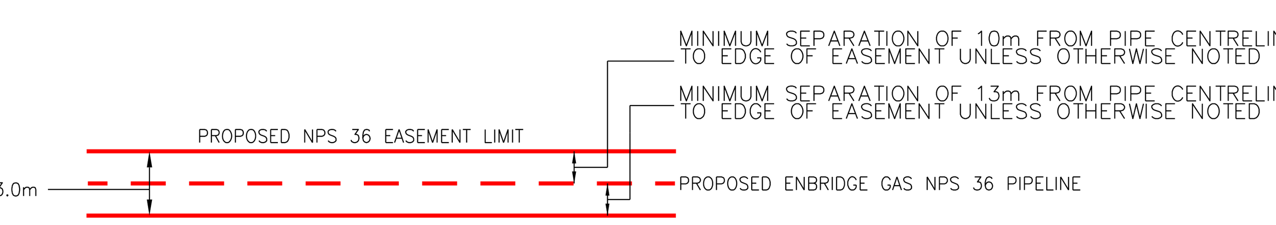
RIGHT OF WAY DETAILS



TYPICAL PIPELINE EASEMENT
N.T.S.

6.25 0 12.5 25 37.5 METRES
12.5 0 12.5 25 37.5 50 62.5 125 FEET

REVISION

NO.	DESCRIPTION	DATE	BY	CHK	APPR
	FOR INFORMATION ONLY	2022-06-29	N.C.	--	--

--	2022-06-30	FOR INFORMATION ONLY
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		ISSUED FOR CONSTRUCTION 2
APP'D	DATE	AS BUILT — AS BUILT BY: / CHECKED BY:

DRAWN	NICO CARIATI	DATE	2020:10:06
CHECKED	CAROLE GAGNE	DATE	--
APP'D BY	GRANT STRACHAN	DATE	--
WBS	XX-XX-XXX	SCALE	1:2000

ENGINEER: GRANT STRACHAN

PRELIMINARY

ENBRIDGE
Life Takes Energy

DAWN TO CORUNNA TR7 – NPS 36 PIPELINE
2023 CONSTRUCTION – DAWN/EUPHEMIA & ST. CLAIR
PIPELINE CONSTRUCTION ALIGNMENT
13+275.0 TO MATCH LINE 14+525.0

FILE REVISION DATE 2022-06-29

DRAWING NUMBER PL3430-AL-012

RIGHT-OF-WAY

ENBRIDGE FILE NUMBER
OWNERSHIP/AGENCY
PIN: NUMBER

MATCH LINE 14+525.0 | PIN: 43302-0079 | 14+670.6 | PIN: 43302-0077 | 14+834.2 | PIN: 43302-0286 | 15+725.0 MATCH LINE

CURRENT CLASS LOCATION: 2

LOCATION FACTOR: 0.9

TILE PLAN NUMBER

ALIGNMENT DETAIL

LEGEND:

- PROPOSED ENBRIDGE TR7 NPS 36 PIPELINE
- TRANSMISSION/DISTRIBUTION PIPELINE
- FOREIGN PIPELINE
- EXISTING EASEMENT
- ENBRIDGE PIPELINE
- PROPOSED ENBRIDGE EASEMENT
- TEMPORARY ACCESS LANEWAY
- DRAIN/STREAM/WATERCOURSE CENTRE
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- PROPOSED FOREIGN PIPELINE CROSSING
- PROPOSED BOREHOLE/MONITORING WELL
- TEST POST
- PIPELINE KILOMETRE POST
- TREE

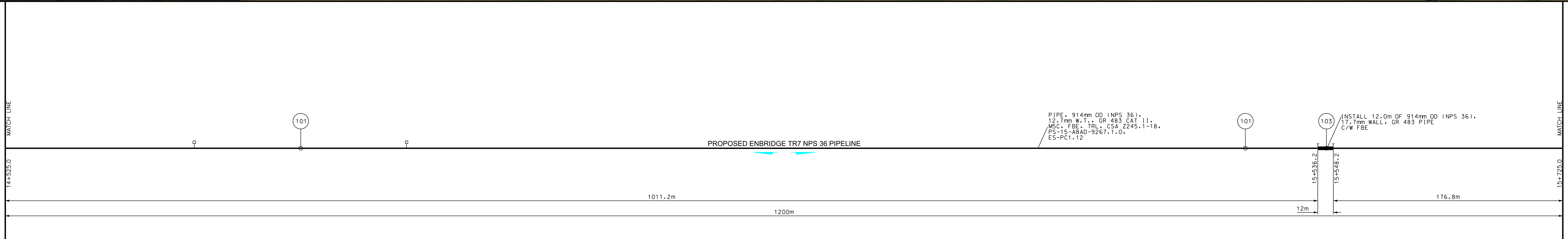
PIPELINE PLAN SCALE 1:2000

PIPELINE SCHEMATIC

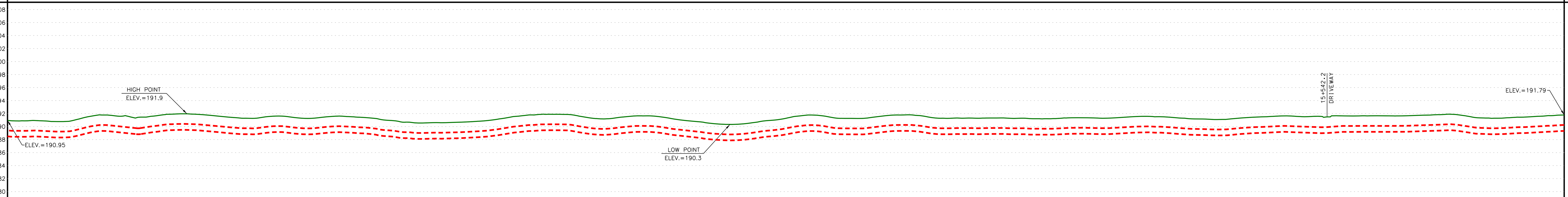
LEGEND:

- HEAVY WALL PIPE
- PIPESAK
- TRANSITION WELD
- PIPELINE WARNING SIGN
- MATERIAL ITEM
- MAINLINE VALVE
- SIDE VALVE

PIPELINE DATA



P/L PROFILE HORIZ 1:2000 VERT 1:400



DESIGN PARAMETERS (NEW PIPING ONLY)

DESIGN

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- DESIGN FACTOR – 0.8
- LOCATION FACTOR – 0.900 / 0.625 (CLASS 2)
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HYDROSTATIC TEST DATE – TBD

CONSTRUCTION

START DATE – JUNE 1, 2023
PLACED IN SERVICE – NOVEMBER 1, 2023

BILL of MATERIAL

Item No	Material No	Qty	Size	Description
101-150	Material No	Qty	Size	**PIPE**
101	~	1188m	36	PIPE, 914mm OD (NPS 36), 12.7mm W.T., GR 483 CAT II, M5C, FBE, QRL, CSA Z245.1-18, PS-15-A8AD-9267.1.0, ES-PC1.12
103	~	12m	36	PIPE, 914mm OD (NPS 36), 17.7mm W.T., GR 483 CAT II, M5C, FBE, QRL, CSA Z245.1-18, PS-15-A8AD-9267.1.0, ES-PC1.12
701-800	Material No	Qty	Size	**OTHER MATERIAL**
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703	125139	2	406.4 x 406.4	STANDARD STO BURIED PIPELINE SYSTEM SIGNAGE, Phone number required 1-800-265-5260 AS PER LUG C&M 18.6
704	125111	2	3 m	SIGN POST, GALV U CHANNEL POST HOT ROLLED & DIPPED 80 M PSI C/W SIGN HDWE PER DWG.E974 (10FT.)
705	~	~	36	PIPELINE WEIGHTS, NPS 36, SADDLE DESIGN, GRAVEL FILLED

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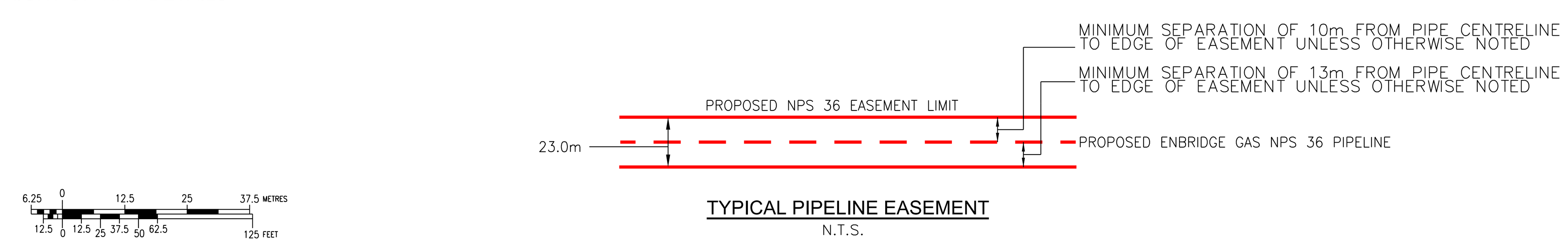
RIGHT OF WAY DETAILS



TYPICAL PIPELINE EASEMENT
N.T.S.

REVISION

NO.	DESCRIPTION	DATE	BY	CHK	APPR
	FOR INFORMATION ONLY	2022-06-29	N.C.	--	--

-- 2022-06-30	FOR INFORMATION ONLY
	ISSUED FOR BID
	ISSUED FOR CONSTRUCTION
	ISSUED FOR CONSTRUCTION 2
AS BUILT	AS BUILT BY:
	CHECKED BY:

DRAWN	NICO CARIATI	DATE	2020:10:06
CHECKED	CAROLE GAGNE	DATE	--
APP'D BY	GRANT STRACHAN	DATE	--
WBS	XX-XX-XXX	SCALE	1:2000

ENGINEER: GRANT STRACHAN

PRELIMINARY

ENBRIDGE
Life Takes Energy

DAWN TO CORUNNA TR7 - NPS 36 PIPELINE
2023 CONSTRUCTION - DAWN/EUPHEMIA & ST. CLAIR
PIPELINE CONSTRUCTION ALIGNMENT
14+525.0 TO MATCH LINE 15+725.0

FILE REVISION DATE: 2022-06-29

DRAWING NUMBER: PL3430-AL-013

RIGHT-OF-WAY
ENBRIDGE FILE NUMBER
OWNERSHIP/AGENCY
PIN: NUMBER

PIN: 43302-0286 | PIN: 43302-0057 | PIN: 43302-0055 | PIN: 43302-0053 | PIN: 43303-0091

CURRENT CLASS LOCATION: 2 | 2 | 2
LOCATION FACTOR: 0.9 | 0.625 | 0.9
TILE PLAN NUMBER

ALIGNMENT DETAIL

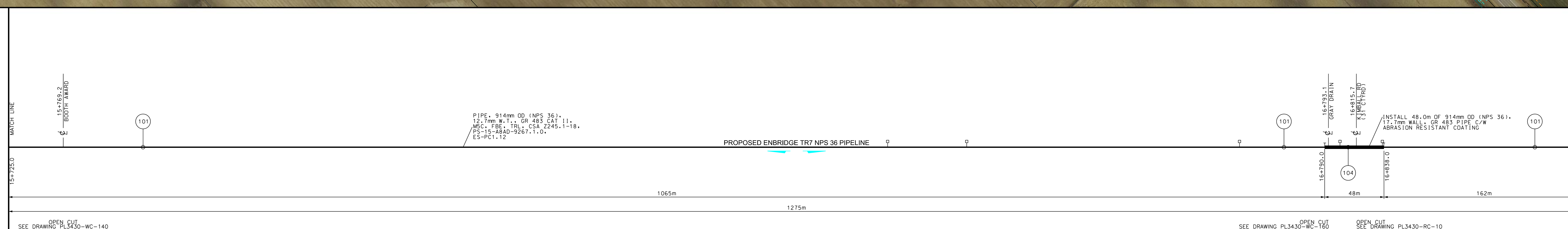
LEGEND:
- PROPOSED ENBRIDGE TR7 NPS 36 PIPELINE
- TRANSMISSION/DISTRIBUTION PIPELINE
- FOREIGN PIPELINE
- EXISTING EASEMENT
- ENBRIDGE PIPELINE
- PROPOSED ENBRIDGE EASEMENT
- TEMPORARY ACCESS LANEWAY
- DRAIN/STREAM/WATERCOURSE CENTRE
- HYDRO EASEMENTS
- DRAINAGE DITCH BOTTOM/TOP
- RETAINING WALL/BRIDGE ABUTMENT
- ASPHALT/GRAVEL EDGE
- BUILDING
- POST/HYDRO POLE
- TELEPHONE BURIED CABLE/MISC CABLE
- FENCE
- OVERHEAD/BURIED HYDRO LINES
- WATERMAIN
- BOTTOM/TOP OF SLOPE
- TELEPHONE MARKER/BELL PEDESTAL
- CULVERT/CATCH BASIN/WATER VALVE
- SIGN/MAILBOX
- HYDRO TOWER
- PROPERTY LINE/ROAD ALLOWANCE
- PROPOSED ROAD/WATERCOURSE CROSSING
- PROPOSED HYDRO CROSSING
- PROPOSED ENBRIDGE PIPELINE CROSSING
- PROPOSED FOREIGN PIPELINE CROSSING
- PROPOSED BOREHOLE/MONITORING WELL
- TEST POST
- PIPELINE KILOMETRE POST
- TREE

PIPELINE PLAN
SCALE 1:2000

PIPELINE SCHEMATIC

LEGEND:
- HEAVY WALL PIPE
- PIPESAK
- TRANSITION WELD
- PIPELINE WARNING SIGN
- MATERIAL ITEM
- MAINLINE VALVE
- SIDE VALVE

PIPELINE DATA



DESIGN PARAMETERS (NEW PIPING ONLY)

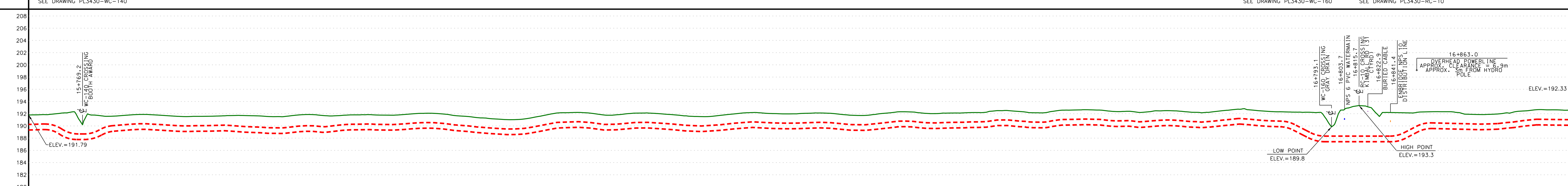
DESIGN
- DESIGNED TO CSA Z662-19
- DESIGN FACTOR - 0.8
- LOCATION FACTOR - 0.900 / 0.625 (CLASS 2)
- DESIGN TEMPERATURE - M5C
- DESIGN PRESSURE - 9308 kPa

HYDROSTATIC TEST PRESSURE
PIPING
- STRENGTH - 13,032 kPa (1890 psig) MIN.
- LEAK - 10,239 kPa (1485 psig) MIN.
- DURATION - EXPOSED PIPING - 1 HOUR AT STRENGTH TEST PRESSURE MINIMUM
- BURIED PIPING - 4 HOUR AT STRENGTH TEST PRESSURE FOLLOWED BY 4 HOUR AT LEAK TEST PRESSURE MINIMUM

HYDROSTATIC TEST DATE - TBD

CONSTRUCTION
START DATE - JUNE 1, 2023
PLACED IN SERVICE - NOVEMBER 1, 2023

P/L PROFILE
HORIZ 1:2000 VERT 1:400



BILL of MATERIAL

Item No	Material No	Qty	Size	Description
101-150	Material No	Qty	Size	**PIPE**
101	~	1227m	36	PIPE, 914mm OD (NPS 36), 12.7mm W.T., GR 483 CAT II, M5C, FBE, QRL, CSA Z245.1-18, PS-15-A8AD-9267.1.0, ES-PC1.12
104		48m	36	PIPE, 914mm OD (NPS 36), 17.7mm W.T., GR 483 CAT II, M5C, ARO, QRL, CSA Z245.1-18, PS-15-A8AD-9267.1.0, ES-PC7.3
701-800	Material No	Qty	Size	**OTHER MATERIAL**
702	130968	~	610mm x 304.8m roll	(24"x1000') ROLL YELLOW TERRA TAPE IMPRINT LAYOUT LINE 1: "CAUTION CAUTION CAUTION" (HEIGHT 3") LINE 2: " ENBRIDGE GAS INC: (HEIGHT2") LINE 3: "NATURAL GAS PIPELINE BURIED BELOW" (HEIGHT 1 1/2") ALL THREE LINES TO BE CENTERED 36" REPEATS
703	125139	5	406.4 x 406.4	STANDARD STO BURIED PIPELINE SYSTEM SIGNAGE, Phone number required 1-800-265-5260 AS PER LUG C&M 18.6
704	125111	5	3 m	SIGN POST, GALV U CHANNEL POST HOT ROLLED & DIPPED 80 M PSI C/W SIGN HDWE PER DWG.E974 (10FT.)
705	~	~	36	PIPELINE WEIGHTS, NPS 36, SADDLE DESIGN, GRAVEL FILLED

CONSTRUCTION NOTES:

1) CONTRACTOR RESPONSIBLE FOR ALL UTILITY LOCATES.
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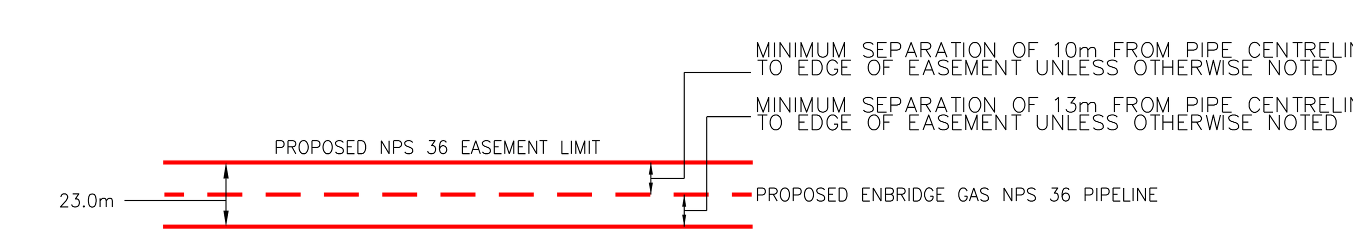
12) GENERAL DEPTH OF COVER IS 1.2m (MIN) FROM ORIGINAL GRADE AND 1.0m (MIN) FROM CONSTRUCTION GRADE UNLESS OTHERWISE STATED.

RIGHT OF WAY DETAILS



TYPICAL PIPELINE EASEMENT
N.T.S.

6.25 0 12.5 25 37.5 METRES
12.5 0 12.5 25 37.5 50 62.5 125 FEET

REVISION

NO.	DESCRIPTION	DATE	BY	CHK	APPR
	FOR INFORMATION ONLY	2022-06-29	N.C.	--	--

--	2022-06-30	FOR INFORMATION ONLY
		ISSUED FOR BID
		ISSUED FOR CONSTRUCTION
		ISSUED FOR CONSTRUCTION 2
APP'D	DATE	AS BUILT — AS BUILT BY: / CHECKED BY:

DRAWN	NICO CARIATI	DATE	2020:10:06
CHECKED	CAROLE GAGNE	DATE	--
APP'D BY	GRANT STRACHAN	DATE	--
WBS	XX-XX-XXX	SCALE	1:2000

ENGINEER: GRANT STRACHAN

PRELIMINARY

ENBRIDGE
Life Takes Energy

DAWN TO CORUNNA TR7 - NPS 36 PIPELINE
2023 CONSTRUCTION - DAWN/EUPHEMIA & ST. CLAIR
PIPELINE CONSTRUCTION ALIGNMENT
15+725.0 TO MATCH LINE 17+000.0

FILE REVISION DATE: 2022-06-29
DRAWING NUMBER: PL3430-AL-014

RIGHT-OF-WAY

ENBRIDGE FILE NUMBER
OWNERSHIP/AGENCY
PIN: NUMBER

MATCH LINE 17+000.0 | PIN: 43384-0091 | 17+051.9 | PIN: 43303-0090 | 17+443.0 | PIN: 43303-0089 | 17+647.9 | PIN: 43303-0088 | 17+718.2 | MOORE LINE | 17+747.7 | PIN: 43298-0113 | 17+857.2 | PIN: 43298-0112 | 18+060.7 | PIN: 43298-0124 | 18+225.0 MATCH LINE

CURRENT CLASS LOCATION	2	2	2
LOCATION FACTOR	0.9	0.625	0.9
TILE PLAN NUMBER			

ALIGNMENT DETAIL

LEGEND:

- PROPOSED ENBRIDGE TR7 NPS 36 PIPELINE
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- FOREIGN PIPELINE
- EXISTING EASEMENT
- ENBRIDGE PIPELINE
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- TEST POST
- PIPELINE KILOMETRE POST
- TREE

PIPELINE PLAN
SCALE 1:2000

PIPELINE SCHEMATIC

LEGEND:

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- PIPESAK
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- PIPELINE WARNING SIGN
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- MAINLINE VALVE
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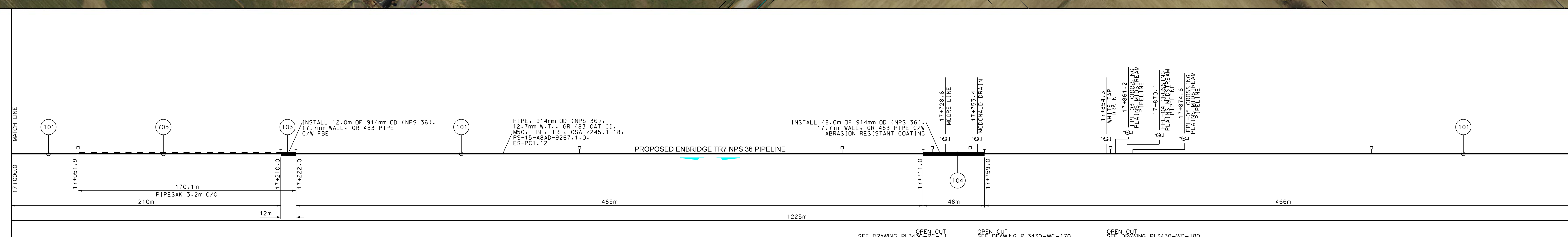
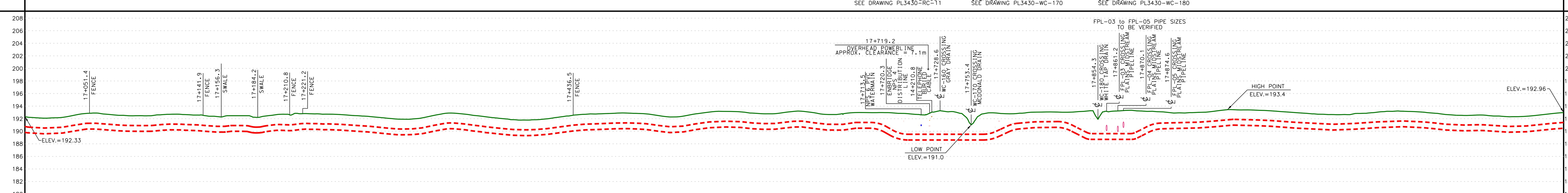
PIPELINE DATA



P/L PROFILE
HORIZ 1:2000 VERT 1:400



DESIGN PARAMETERS (NEW PIPING ONLY)

DESIGN

- DESIGNED TO CSA Z662-19
- DESIGN FACTOR – 0.8
- LOCATION FACTOR – 0.900 / 0.625 (CLASS 2)
- DESIGN TEMPERATURE – M5C
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HYDROSTATIC TEST DATE – TBD

CONSTRUCTION

START DATE – JUNE 1, 2023
PLACED IN SERVICE – NOVEMBER 1, 2023

BILL of MATERIAL

Item No	Material No	Qty	Size	Description
101-150	Material No	Qty	Size	PIPE
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703	125139	7	406.4 x 406.4	STANDARD STO BURIED PIPELINE SYSTEM SIGNAGE, Phone number required 1-800-265-5260 AS PER LUG C&M 18.6
704	125111	7	3 m	SIGN POST, GALV U CHANNEL POST HOT ROLLED & DIPPED 80 M PSI C/W SIGN HDWE PER DWG.E974 (10FT.)
705	~	54	36	PIPELINE WEIGHTS, NPS 36, SADDLE DESIGN, GRAVEL FILLED

CONSTRUCTION NOTES:

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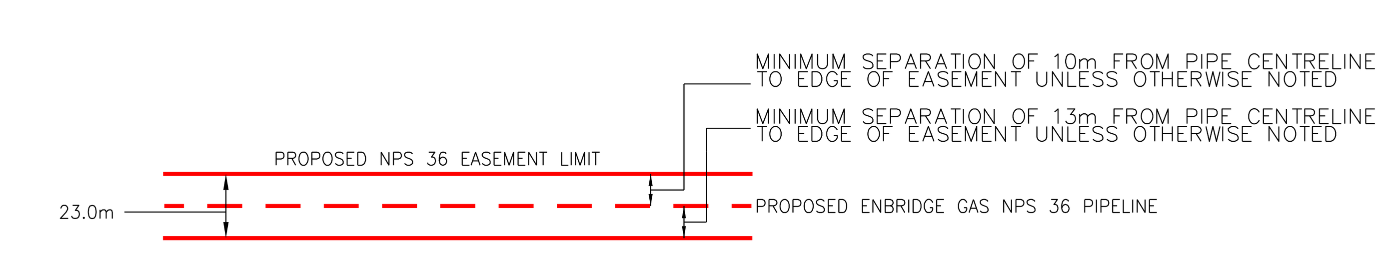
RIGHT OF WAY DETAILS



TYPICAL PIPELINE EASEMENT
N.T.S.

6.25 0 12.5 25 37.5 METRES
12.5 0 12.5 25 37.5 50 62.5 125 FEET

REVISION

NO.	DESCRIPTION	DATE	BY	CHK	APPR
	FOR INFORMATION ONLY	2022-06-29	N.C.	--	--

--	2022-06-30	FOR INFORMATION ONLY
		ISSUED FOR BID
		ISSUED FOR CONSTRUCTION
		ISSUED FOR CONSTRUCTION 2
APP'D	DATE	AS BUILT — AS BUILT BY: / CHECKED BY:

DRAWN	NICO CARIATI	DATE	2020:10:06
CHECKED	CAROLE GAGNE	DATE	--
APP'D BY	GRANT STRACHAN	DATE	--
WBS	XX-XX-XXX	SCALE	1:2000

ENGINEER: GRANT STRACHAN

PRELIMINARY

ENBRIDGE
Life Takes Energy

DAWN TO CORUNNA TR7 - NPS 36 PIPELINE
2023 CONSTRUCTION - DAWN/EUPHEMIA & ST. CLAIR
PIPELINE CONSTRUCTION ALIGNMENT
17+000.0 TO MATCH LINE 18+225.0

FILE REVISION DATE: 2022-06-29
DRAWING NUMBER: PL3430-AL-015

RIGHT-OF-WAY
ENBRIDGE FILE NUMBER
OWNERSHIP/AGENCY
PIN: NUMBER

MATCH LINE 18+225.0	PIN: 43298-0124	18+264.9	PIN: 43298-0123	18+468.7	PIN: 43298-0125	18+884.7	PIN: 43298-0107	19+084.4	PIN: 43298-0106	19+173.1 CORUNNA COMPRESSOR STATION TIE-IN

CURRENT CLASS LOCATION: 2
LOCATION FACTOR: 0.9
TILE PLAN NUMBER

ALIGNMENT DETAIL

LEGEND:
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- PIPELINE KILOMETRE POST
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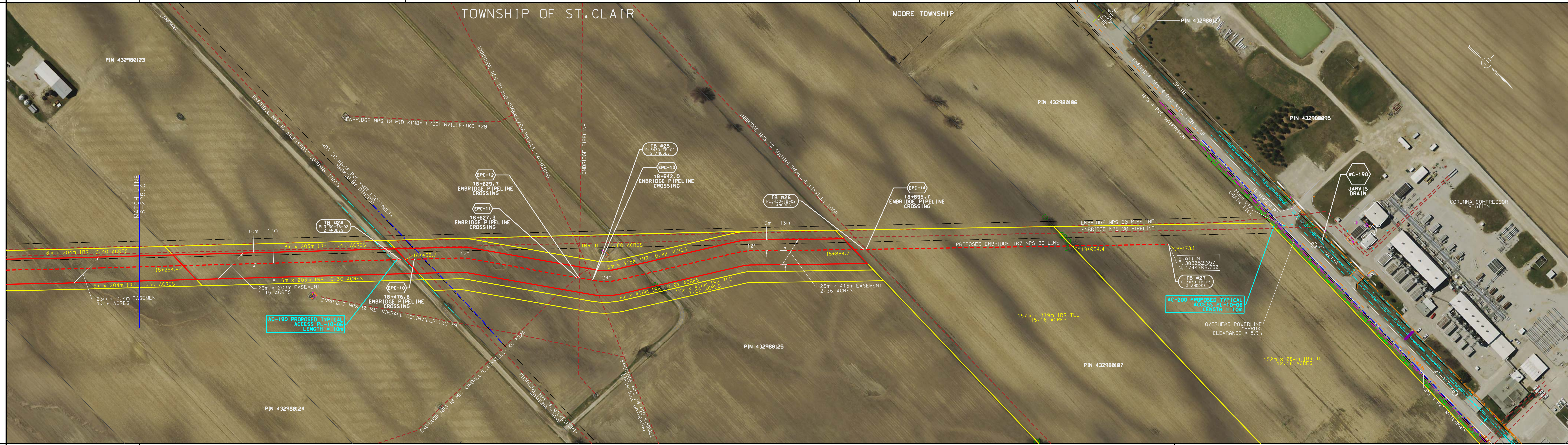
PIPELINE PLAN SCALE 1:2000



PIPELINE SCHEMATIC

LEGEND:
- HEAVY WALL PIPE
- PIPESAK
- TRANSITION WELD
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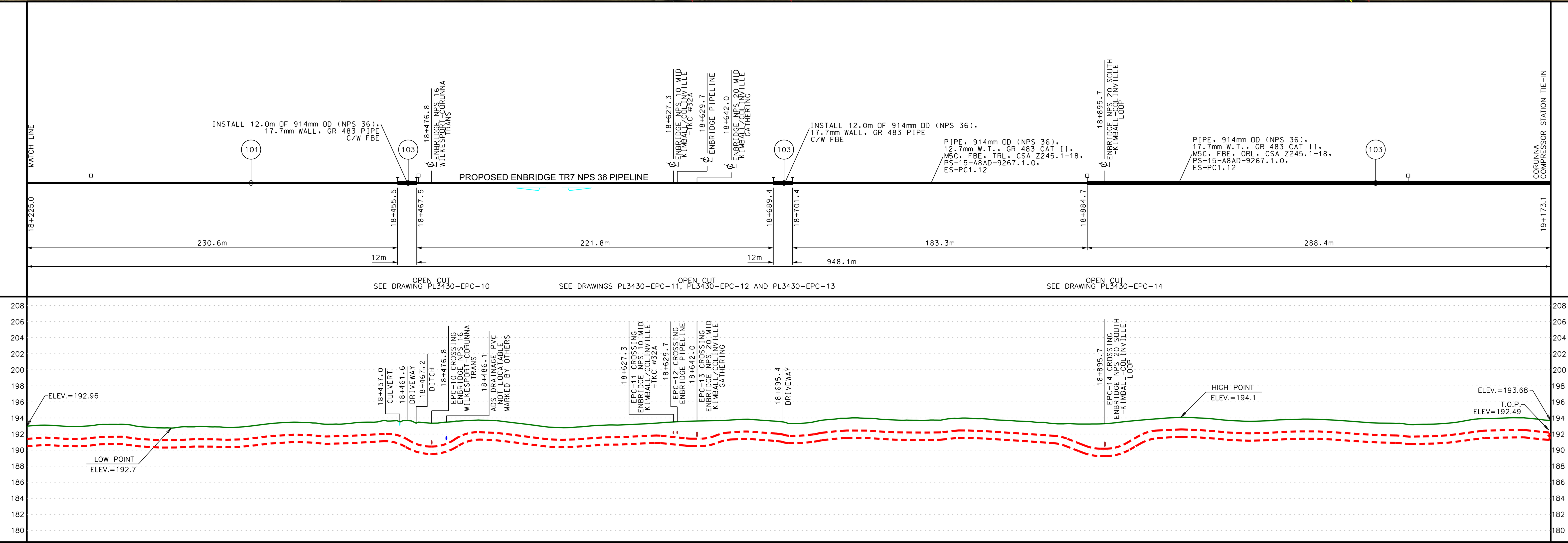
PIPELINE DATA

P/L PROFILE HORIZ 1:2000 VERT 1:400



DESIGN PARAMETERS (NEW PIPING ONLY)

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HYDROSTATIC TEST DATE – TBD

CONSTRUCTION
START DATE – JUNE 1, 2023
PLACED IN SERVICE – NOVEMBER 1, 2023

BILL of MATERIAL

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705	~	~	36	PIPELINE WEIGHTS, NPS 36, SADDLE DESIGN, GRAVEL FILLED

CONSTRUCTION NOTES:

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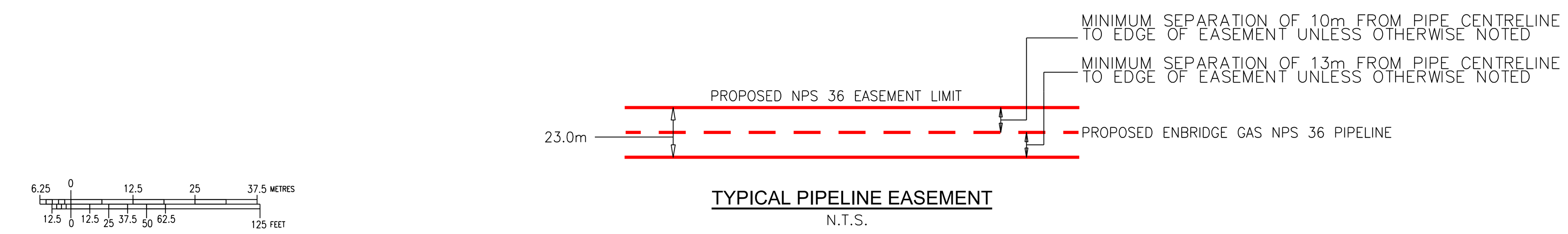
RIGHT OF WAY DETAILS



TYPICAL PIPELINE EASEMENT
N.T.S.

REVISION

NO.	DESCRIPTION	DATE	BY	CHK	APPR
	FOR INFORMATION ONLY	2022-06-29	N.C.	--	--

--	2022-06-30	FOR INFORMATION ONLY
		ISSUED FOR BID
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		ISSUED FOR CONSTRUCTION 2
APP'D	DATE	AS BUILT — AS BUILT BY: / CHECKED BY:

DRAWN	NICO CARIATI	DATE	2020:10:06
CHECKED	CAROLE GAGNE	DATE	--
APP'D BY	GRANT STRACHAN	DATE	--
WBS	XX-XX-XXX	SCALE	1:2000

ENGINEER: GRANT STRACHAN

PRELIMINARY

ENBRIDGE
Life Takes Energy

DAWN TO CORUNNA TR7 – NPS 36 PIPELINE
2023 CONSTRUCTION – DAWN/EUPHEMIA & ST. CLAIR
PIPELINE CONSTRUCTION ALIGNMENT

FILE REVISION DATE: 2022-06-29
DRAWING NUMBER: PL3430-AL-016

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Association of Energy and Pipeline Landowner Associations (“CAEPLA”) and its subcommittee, the Dawn Corunna Landowner Committee (“DCLC”)

INTERROGATORY

Reference:

OEB Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario, 7th Edition 2016, Section 4.3.14, pages 42 et ff., Cumulative Effects

OEB Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario, 7th Edition 2016, Section 6.2.2, page 66, Monitoring Reports

Enbridge Gas Inc. Application, Exhibit B, Tab 1, Schedule 1, Page 1 of 31, Footnote 1, Adobe page 11

Stantec Dawn-Corunna Project: Environmental Report, Cumulative Effects Assessment – Adobe page 85 et ff.

Enbridge Application, Exhibit F, Tab 1, Schedule 1, Attachment 3, page 30 of 48 – Response to AFN Comments

Preamble:

Enbridge Gas Inc. states in its response to AFN:
Preference is given to overlapping adjacent pipeline easements to the greatest extent possible, to avoid impacts on previously undisturbed lands.

Question:

a) Is a complete overlap of the new permanent pipeline easement with an existing adjacent pipeline easement proposed for the CAEPLA-DCLC properties? If not, please explain why not.

b) Is a complete overlap of the new permanent pipeline easement with an existing adjacent pipeline easement technically possible for the CAEPLA-DCLC properties? If not, please explain why not.

c) Is a complete overlap of the new permanent pipeline easement with an existing adjacent pipeline easement technically feasible for the CAEPLA-DCLC properties? If not, please explain why not.

d) Please provide copies of the all easement agreements and/or expropriation orders in place for the existing pipelines on the CAEPLA-DCLC properties affected by the proposed project.

Response

a) No, for this project Enbridge Gas is proposing a new easement adjacent to or overlapping the existing easement for the CAEPLA-DCLC properties. A new easement is required to meet necessary setbacks from existing infrastructure for safety reasons.

b) – c)
A new easement is required for CAEPLA-DCLC properties in order to meet necessary setbacks from existing infrastructure for safety reasons and to facilitate integrity digs and maintenance work around the proposed pipeline. Where appropriate, Enbridge Gas has proposed to overlap the new easement with existing easements.

d) Agreements that are registered on title can be obtained by CAEPLA-DCLC through Ontario Land Registry.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Association of Energy and Pipeline Landowner Associations ("CAEPLA") and its subcommittee, the Dawn Corunna Landowner Committee ("DCLC")

INTERROGATORY

Reference:

Enbridge Gas Inc. Application, Exhibit E, Tab 1, Schedule 1, Page 3 of 5 – Engineering and Construction

OEB Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario, 7th Edition 2016, Section 5.5.1, page 50, Agricultural Drains

Preamble:

Enbridge Gas Inc. states:

> C.13. The minimum depth of cover specified is 1.0 m from top of pipeline in general locations and 1.2 m under roads. Additional depth of cover will be provided to accommodate planned or existing underground facilities, or in specific areas in compliance with applicable regulated standards. In agricultural areas, the minimum depth of cover will be 1.2 m.

The OEB Guidelines require that:

> The depth of the proposed pipeline should be compatible with existing and planned drainage systems.

Question:

a) Please provide a copy of Enbridge Gas Inc.'s depth of cover monitoring program document(s).

b) What is the depth of cover monitoring program proposed for the proposed pipeline?

c) What is the minimum depth of cover that will be maintained by Enbridge Gas Inc. over the proposed pipeline following construction (i.e., during operation)?

d) Please provide details of all locations along the existing pipelines on the lands affected by the proposed project where Enbridge Gas Inc. or its predecessor(s) has identified insufficient depth of cover of less than 24 inches and all identified locations in the affected lands with less than the minimum depth of cover proposed and/or required at the time leave to construct was granted.

e) With respect to those locations where depth of cover is insufficient, what steps, if any, has Enbridge Gas Inc. or its predecessor(s) taken to establish sufficient depth of cover? Provide details of any such operations including copies of any reports prepared.

f) Are there locations on the properties along the route for the Project where Enbridge Gas Inc. or its predecessor(s), due to the presence of insufficient cover or other factors, has indicated to landowners that they should exercise extra caution when carrying out activities, including farming operations, above the pipeline? Please provide details of any such communications made to landowners including: location affected, copies of correspondence, records of responses from landowners.

g) Are there any locations along the route for the Project where Enbridge Gas Inc. or its predecessor(s) has restricted land use above the pipeline due to insufficient depth of cover or the condition of the pipe itself? Provide details of the location, the nature of the deficiency (depth of cover, etc.), and the nature of the restriction imposed on land use.

h) Please explain how Enbridge Gas Inc. determined compatibility of the proposed depth of the pipeline proposed for this project with existing and planned drainage systems on affected lands? Please provide a copy of any study or analysis prepared.

<u>Response</u>

a) & b)
The proposed pipeline will be included within the Company's Transmission Integrity Management Program ("TIMP") depth of cover monitoring program. The pipeline will be monitored via the depth of cover survey interval based on the Depth of Cover Operating Standard (please see Attachment 1 to this response).

c) Enbridge Gas will endeavor to maintain a minimum cover of 60 cm in all areas of the pipeline including agriculture land with the exception of areas under the travel portion of a road, which require a minimum of 90 cm of cover.

d) - g)
Enbridge Gas is currently aware of a single instance of insufficient depth of cover in the area of the proposed Project (see Table 1 below). To ensure the safety of its facilities Enbridge Gas has redacted the geographic coordinates of the aforementioned pipeline.

Table 1

Pipeline Name	Lat.	Long.
NPS 10 Waubuno Pool Transmission	[redacted]	

The location of this instance of insufficient depth is currently undergoing a loading assessment (calculation of stress), the purpose of which is to determine whether external loadings (e.g., vehicles crossing the pipeline right of way) could cause damage. As this assessment is not yet complete, Enbridge Gas is unable to produce any reporting. In this instance Enbridge Gas has indicated that the landowner should exercise extra caution when carrying out activities above the pipeline. Enbridge Gas continues to work with the landowner to assess remediation options which may include pipe lowering, crop loss payments, limiting use and additional signage/markers. Enbridge Gas respectfully declines to produce copies of correspondence with this landowner regarding this instance of insufficient depth of cover as they have no relevance to the approvals sought by Enbridge Gas in this proceeding.

When insufficient depth of cover over a pipeline is found, Enbridge Gas typically works with the landowner to determine what remediation work is required (i.e., adding soil, lowering pipe, etc.). If remediation work cannot be completed immediately, then temporary arrangements are made with the landowner to limit activity around the pipeline (this may include installing fencing or other suitable alternatives).

h) Enbridge Gas is currently working with all landowners to obtain information relating to existing drainage systems on their lands. Once this information is obtained, the Company will work with each landowner to coordinate a plan to align drainage systems in a manner that allows the Project to proceed while avoiding effects on current drainage systems. As of the time of this filing, the Company has not identified a need for and thus has not prepared any such study or analysis.

Depth of Cover Operating Standard

1 Purpose

This Standard defines the frequency of depth of cover surveys and establishes the maximum time to complete mitigations for pipelines within the Transmission Integrity Management Program (TIMP).

As part of TIMP quarterly risk reviews, locations identified with high risk may drive additional depth of cover mitigation requirements and activities, in addition to those specified in this document.

2 Scope

This Standard applies to all TIMP pipelines.

3 Responsibilities

The responsibilities for this Standard include:

Table 3-1: Responsibilities

Role	Responsibilities
TIMP Engineer	• Identification of pipelines requiring a depth of cover survey • Analyze and maintain depth of cover data • Identify areas that require mitigation • Identify DCVG survey areas • Create annual plan for permanent mitigation activities • Monitor the status of depth of cover surveys and mitigation activities
Distribution Protection	• Completion of depth of cover surveys • Completion of DCVG surveys
Pipeline Engineering	• Review areas of low cover under road travelled surfaces
Executing Group	• Determine cost and timing for mitigation activities • Oversee the implementation of mitigation activities

4 Terms and Definitions

Terms found in this document and their definitions include:

Agricultural Lands: Lands that are currently being worked with mechanical farm equipment to produce crops or for grazing farm animals. Pasturelands are considered agricultural since such lands may be periodically worked with similar equipment to croplands.

Depth of Cover (DoC): The depth from the ground surface to the top of the pipe.

DCVG: Direct Current Voltage Gradient Survey

Used to assess pipeline coating condition

ECDA: External Corrosion Direct Assessment survey

Executing Group: The group or department that is responsible for a mitigation, including costing, scheduling, and implementation. Includes System Improvement, Operations, and any other necessary department.

ILI: Inline Inspection

ROW: Right of Way

SMYS: Specified Minimum Yield Strength

TIMP: Transmission Integrity Management Program

5 Requirements

5.1 Depth of Cover Surveys

A TIMP Engineer is responsible for maintaining the depth of cover survey schedule and the list of pipeline segments to be surveyed.

All TIMP pipelines segments must be surveyed for depth of cover in accordance with approved locating and surveying procedures at the intervals shown:

Table 5-1: Depth of Cover Survey Frequency

Location Description	Maximum Inspection Interval
Sections of pipeline through Agricultural Lands with <75 cm of cover	5 years
Sections of pipeline with <75 cm of cover	5 years
All other pipelines through Agricultural lands	10 years
All other pipelines	15 years

Depth of cover surveys must be completed by the end of the calendar year in which the inspection is due.

In addition to the survey frequency above, sections that require mitigations require an increased survey frequency, as described in 5.3 Depth of Cover Mitigation on page 3.

Detailed survey specifications are found in the *Depth of Cover Survey Requirements* document provided by the TIMP Engineer. A TIMP Engineer is responsible to reviewing the results to ensure that the data conforms with the requirements, and to ensure that all targeted pipeline segments were inspected.

Any discrepancies must be reported to the survey provider for correction, prior to accepting the survey results.

5.2 Depth of Cover Requirements

Depth of cover survey results are compared to three sets of criteria to determine where mitigations are required.

Level 1 Criteria: TSSA Compliance

Any pipeline section in Agricultural Lands with <60 cm of cover (Ontario Regulation 210/01).

Level 2 Criteria: EGI Minimum Requirements

Any pipeline section with <60 cm of cover.

Level 3 Criteria: Road ROW Requirements

Any pipeline section having <90cm of cover under the travelled portion of a road.

5.3 Depth of Cover Mitigation

Temporary Mitigation

Temporary mitigations are required within the time period shown in Table 5-2: Temporary Mitigation Timing on page 3 for Levels 1 and 2. No temporary mitigiations are required for Level 3 areas.

Table 5-2: Temporary Mitigation Timing

Level	Maximum Time to Implement
1	3 months
2	6 months
3	Not required

Temporary mitigations are determined by a TIMP Engineer.

The TIMP Engineer coordinates the temporary mitigation with the Executing Group. Once the temporary mitigations are in place, the Executing Group notifies the TIMP Engineer.

DCVG Survey

DCVG surveys are required for Level 1 and 2 locations on pipelines that do not have ILI or ECDA data available. At the discretion of the TIMP Engineer, a DCVG survey may also be conducted on a pipeline with existing ILI or ECDA data if there is an indication that an unauthorized ground disturbance may have occurred since the last inspection.

If required, the DCVG survey must be completed within one year of discovery and prior to any permanent mitigation to identify any coating damage that may have been caused by third parties. DCVG readings over 35% IR must be investigated and considered for excavation by the TIMP Engineer.

Permanent Mitigation

Permanent mitigations are required for Level 1 and 2 locations and must be identified within 1 year of discovery. All permanent mitigations must be implemented within 5 years of discovery.

Level 3 locations will be referred to Pipeline Engineering for further review and analysis.

Sections with insufficient depth of cover must also be inspected on increased frequency until all permanent mitigations are completed, as shown in Table 5-3: Increased Inspection Requirements on page 4.

Table 5-3: Increased Inspection Requirements

Level	Maximum Reinspection Interval Pending Permanent Mitigation
1	1 year
2	2 years
3	No additional requirements

Permanent mitigations are determined by a TIMP Engineer.

The TIMP Engineer consults with the Executing Groups to determine the annual plan to implement the permanent mitigations. The annual plan is based on design and permitting requirements, workload, site risk, and budgetary considerations.

Once the permanent mitigations are in place, the Executing Group notifies the TIMP Engineer and provides details of the final mitigation action.

6 References

- *Ontario Regulation 210/01, Oil and Gas Pipeline Systems Code Adoption Document, July 2016,*
  - *Clause 10.6.5.5*
- *CSA Z662-19, Oil and Gas Pipeline Systems*
  - *Section 10.6.1*
  - *Annex N, N.1.10.2*

7 Document Control and Maintenance

For document control and maintenance purposes, the following table captures important information related to this document:

Category	Value
Owned by:	Integrity Department
Review interval:	Every 5 years

8 Revision History

Date	Summary of Changes	Prepared by:	Approved by:
2020-09	Initial release	David Shaw Sr. TIMP Engineer	Mike Wagle Chief Engineer

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Association of Energy and Pipeline Landowner Associations ("CAEPLA") and its subcommittee, the Dawn Corunna Landowner Committee ("DCLC")

INTERROGATORY

Reference:

OEB Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario, 7th Edition 2016, Section 5.5.2, pages 50, Agricultural Drains

Stantec Dawn-Corunna Project: Environmental Report, Adobe page 33, Section 4.3.6 Agricultural Tile Drainage

Stantec Dawn-Corunna Project: Environmental Report, Table 5.1: Potential Impacts and Recommended Mitigation and Protective Measures, Adobe pages 63 et ff.

Enbridge Gas Inc. Application, Exhibit E, Tab 1, Schedule 1, Page 5 of 5 – Engineering and Construction

Preamble:

The OEB Guidelines require:

> If agricultural land that is extensively tile drained cannot be avoided, mitigation plans must be developed and implemented prior to construction. The plans should be designed to maintain proper subsurface drainage during and after pipeline construction.
>
> Consultation with the landowner prior to construction is necessary to determine the location of existing and planned tile drains. If a landowner is not aware of the location or existence of tile drains, OMAFRA may be contacted or a knowledgeable local tile contractor should be consulted, in order to verify the depth and frequency of any installed tiles. The depth of the proposed pipeline should be compatible with existing and planned drainage systems.
>
> Tile drains that are cut during the trenching operation must be flagged and suitably plugged to prevent the entry of foreign material into the drainage system. Plans for maintaining proper surface and subsurface drainage

> during the construction which are acceptable to the landowner are required.
>
> Following construction, the applicant must repair or replace any damaged or disrupted tiles. It is recommended that qualified tile drainage consultants and licensed tiling contractors be used for this work. Where the number of tile drains crossing the pipeline trench or their angle of crossing makes individual repair difficult, the installation of headers (sub-mains) should be considered. All open drainage ditches should be restored, utilizing appropriate soil stabilization procedures including, but not limited to, the use of geo-fabrics, wood or straw mulch, hydro seeding and rock or gravel blankets.
> Stantec reports and recommends:
>
> Agricultural tile drains are perforated tubing inserted into the ground below the topsoil with the intentions of improving drainage in the upper root zone. Across the Study Area, agricultural tile drainage is commonly installed below the agricultural fields to improve agricultural productivity. Drains typically discharge into adjacent watercourses or maintained ditches. Of the mapped tile drainage along the PPR, the majority (78%) is mapped as systematic tile drainage while the rest (22%) is mapped as random tile drainage.

Agricultural tile drains are mapped in Figure 9, Appendix C.

AND

> Enbridge Gas should undertake consultation with landowners of agricultural fields to confirm where systematic tile drainage is present. If tile drainage is present, Enbridge Gas should undertake standard mitigation during trenching, including:

- Develop site specific tile plans with an independent tile contractor
- Conduct pre-tiling, and install header tile to maintain tile system function
- Excavate the pipeline trench to a depth that allows clearance between the top of the proposed pipeline and the bottom of existing drainage systems
- Record and flag severed or crushed tile drains
- If a main drain, header drain, or large diameter drain is severed, maintain field drainage and prevent flooding of the work area and adjacent lands through temporary repairs
- Cap both sides of severed drains that cross the trench to prevent the entry of soil, debris and rodents, as required
- Repair damaged and severed drains following construction

- After repair and before backfilling, invite the landowner to inspect and approve the repair construction

Enbridge Gas Inc. states:

> C.23. As part of the construction plan, each landowner with agricultural land directly impacted by the Project will be consulted to understand the impact to field tiling. This could result in the need to install tiling prior to construction (pre-construction tiling) to ensure field drainage systems and farm operations are not disrupted during construction. Enbridge Gas retains a qualified drainage consultant to determine if a property that contains a field drainage system could benefit from pre-construction tiling. The Enbridge Gas drainage consultant will contact landowners to discuss their tile needs. Landowner approval is required for tiling work conducted outside of the easement. The drainage consultant will prepare a tiling plan and provide a copy of the plan to both Enbridge Gas and the landowner.

Question:

a) Will Enbridge Gas Inc. agree to be responsible for as long as its easement is in place for the repair and replacement of all tile drainage facilities affected by the proposed project? If not, please explain why not.

b) Please explain what requirements will be imposed by Enbridge Gas Inc., if any, on landowners who plan to repair or replace existing tile drainage facilities within or adjacent to the pipeline easement in the future?

c) Please explain what requirements will be imposed by Enbridge Gas Inc., if any, on landowners who plan to install new tile drainage facilities within or adjacent to the pipeline easement in the future?

Response

a) - c)
The Company will be responsible for the repair and replacement of all tile drainage facilities affected by the Project until either:[1]
(i) the pipeline is removed and restoration of the lands required by this agreement are complete; or
(ii) the pipeline is considered abandoned and the transferor does not exercise their option to have the pipeline removed.

In accordance with the pipeline easement agreement for the Project, provided at Exhibit G, Tab 1, Schedule 1, Attachment 3, pp. 2 & 3:

> Any gates, fences and tile drains, curbs, gutters, asphalt paving, lock stone, patio tiles interfered with by the Transferee shall be restored by the Transferee at its expense as closely as reasonably possible to the condition and function in which they existed immediately prior to such interference by the Transferee and in the case of tile drains, such restoration shall be performed in accordance with good drainage practice and applicable government regulations.
>
> … the Transferee upon request shall consent to the Transferor erecting or repairing fences, hedges, pavement, lockstone constructing or repairing tile drains and domestic sewer pipes, water pipes, and utility pipes and constructing or repairing lanes, roads, driveways, pathways, and walks across, on and in the Lands or any portion or portions thereof, provided that before commencing any of the work referred to in this sentence the Transferor shall (a) give the Transferee at least (30) clear days' notice in writing describing the work desired so as to enable the Transferee to evaluate and comment on the work proposed and to have a representative inspect the site and/or be present at any time or times during the performance of the work, (b) shall follow the instructions of such representative as to the performance of such work without damage to the Pipeline, (c) shall exercise a high degree of care in carrying out any such work and, (d) shall perform any such work in such a manner as not to endanger or damage the Pipeline as may be required by the Transferee.

Any changes or modifications to existing tile drainage facilities would require the landowner to: (i) provide Enbridge Gas at least 30 days notice, giving the Company an opportunity to evaluate and comment on the work proposed and be present at the time of work, ii) follow the instructions of an Enbridge Gas representative during work performed to avoid damage to the pipeline, iii) exercise a high degree of care in

[1] In accordance with the pipeline easement agreement for the Project, provided at Exhibit G, Tab 1, Schedule 1, Attachment 3, pp. 1-2:

> The Transferee and the Transferor shall surrender the Easement and the Transferee shall remove the Pipeline at the Transferor's option where the Pipeline has been abandoned. The Pipeline shall be deemed to be abandoned where: (a) corrosion protection is no longer applied to the Pipeline, or, (b) the Pipeline becomes unfit for service in accordance with Ontario standards. The Transferee shall, within 60 days of either of these events occurring, provide the Transferor with notice of the event. Upon removal of the Pipeline and restoration of the Lands as required by this agreement, the Transferor shall release the Transferee from further obligations in respect of restoration.

carrying out work, iv) carry out the work in such a manner that it does not endanger the pipeline and v) restore the lands as closely as reasonably possible to their previous condition and function in accordance with good drainage practice and applicable government regulations.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Association of Energy and Pipeline Landowner Associations ("CAEPLA") and its subcommittee, the Dawn Corunna Landowner Committee ("DCLC")

INTERROGATORY

Reference:

Stantec Dawn-Corunna Project: Environmental Report, Table 5.1: Potential Impacts and Recommended Mitigation and Protective Measures, Adobe pages 63 et ff.

Preamble:

Stantec recommends:

> Soil Stripping
> Topsoil depths should be measured prior to stripping so that the proper depth of topsoil is removed and replaced. Where stripping is undertaken on agricultural lands, topsoil and subsoil should be stripped and stockpiled separately to avoid mixing. Where the pipeline crosses woodlands the organic and duff layer should be stripped where feasible, given local substrate conditions. Where stripping is undertaken in woodlands, organic material and subsoil should be stripped and stockpiled separately to avoid mixing. If clean-up is not practical during the construction year, it should be undertaken in the year following construction, starting once the soils have sufficiently dried. Interim soil protection measures should be implemented in sensitive areas to stabilize the RoW for over-wintering.
>
> Soil Compaction
> Within agricultural lands where soil has been compacted by the construction process, an agrologist should determine where decompaction may be necessary. Compaction can be alleviated by using farm equipment such as an agricultural subsoiler prior to replacing the topsoil. Sub-soiling with an agricultural subsoiler, followed by discing, chisel ploughing and cultivating, to smooth the surface, should be considered on agricultural lands. In high traffic areas of the RoW where deep compaction persists, additional deep tillage or subsoiling may be required on a site specific basis. Soil density and/or penetrometer measurements on and off the easement may be used as a means of assessing the relative degree

of soil compaction caused by construction along the RoW as well as determining that the RoW has been sufficiently decompacted.

Question:

a) Please provide detailed drawings showing the soils handling procedures, including storage of stripped topsoil and subsoil(s), proposed to be used by Enbridge Gas Inc. for this project.

b) Please provide details of Enbridge Gas Inc.'s proposed methodology for compaction testing on soils for the project.

Response

a) The detailed drawings requested by CAEPLA (including specific detailed cross-sections) are not yet complete. The Company typically does not complete such documents until closer to project construction (included in Issued for Construction materials).

b) Relative soil compaction is measured using a soil penetrometer. Measurements are taken, in triplicate, at various locations along the easement. First, measurements are taken along the spoil side, then along the workspace, and finally in a control area immediately off-easement adjacent to the workspace. These sets of measurements are repeated until the edge of the field is reached. If the easement measurements are comparable to the off-easement control measurements, then no further soil decompaction is required. If the easement measurements are still higher than the control measurements, then further soil decompaction is required. After the additional soil decompaction is completed, then the soil penetrometer measurements will be taken again.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Association of Energy and Pipeline Landowner Associations ("CAEPLA") and its subcommittee, the Dawn Corunna Landowner Committee ("DCLC")

INTERROGATORY

Reference:

Stantec Dawn-Corunna Project: Environmental Report, Table 5.1: Potential Impacts and Recommended Mitigation and Protective Measures, Adobe pages 63 et ff.

OEB Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario, 7th Edition 2016, Section 5.5.1, page 49, Soils

Preamble:

Stantec recommends:

> To the extent feasible, construction activities should occur during drier times of the year. Lands affected by heavy rainfall events should be monitored for wet soil conditions, to avoid the potential for topsoil and subsoil mixing and loss of structure. Construction activities should be temporarily halted on agricultural lands where excessively wet soil conditions are encountered. Enbridge Gas' on-site inspection team should determine when construction activities may be resumed. If a situation develops that protection measures should be implemented, such as confining construction activity to the narrowest area practical, installing surface protection measures, and using wide tracked or low ground pressure vehicles.

The OEB Guidelines require:

> The worst impacts of construction occur at high soil moisture levels. Consequently, construction during the driest period of the year is desirable. The applicant is required to establish and implement a wet - weather shutdown policy to minimize adverse impacts of construction on soil productivity. During wet weather conditions, contact with topsoil should be avoided and a total restriction placed on all rubber tired vehicles

and equipment traveling on the ROW. If, due to delays, construction must continue under wet soil conditions to meet an in-service date, terms and conditions must be discussed with the landowner. The wet -weather shutdown policy or decision-making process must take into account the nature of the impacts, the concerns of the landowner, agricultural interest groups, the pipeline contractor and the applicant, when determining the need to continue construction under adverse weather conditions.

Question:

Please provide a copy of Enbridge Gas Inc.'s proposed Wet Soils Shutdown Procedure or equivalent policy.

Response

The Company's Environmental Guidelines for Construction / 5.18 Wet / Thawed Soil set out at Attachment 1 to this response apply to pipeline construction, repair and maintenance on agricultural lands.

Environmental Guidelines for Construction

—

5.18 Wet / Thawed Soil

[30 April 2020]

ENBRIDGE

Document Version Register

VERSION NO.	VERSION DATE	APPROVED BY	SECTION NO. AND TITLE	DETAILS OF VERSION
1.0	30 April 2020	Les Miskolzie		Harmonized and modularized the Canadian versions of the Enbridge Environmental Guidelines for Construction and the Spectra Environmental Manual for Construction Projects

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5.18: Wet / Thawed Soil

Construction during wet or thawing soil conditions can lead to rutting and/or compaction concerns, which may result in a reduction in soil productivity. In order to limit terrain disturbance and soil structure damage, additional mitigative measures are warranted during periods of wet or thawing conditions. When feasible, work undertaken within areas of wet terrain should be carried out during frozen conditions to minimize effects.

For more detailed information, see the project Environmental Protection Plan (EPP), and consult with the Enbridge Project Environment Lead (PEL) for project-specific wet and thawed soil requirements and considerations.

GENERAL MITIGATION MEASURES

The following mitigation measures apply to all construction activities:

- **Minimize Disturbance**: Minimize disturbance in areas of wet terrain by:
  - Discussing with the PEL when terrain is too wet to continue work (see Inspection and Shut Down Decision and the associated Criteria for Suspension tables (Tables 1 and 2), below);
  - Using approved access around the areas;
  - Narrowing the width of temporary workspace used for the construction activity;
  - Choosing previously disturbed sites;
  - Scheduling construction activity during frozen conditions; and
  - Using ramps to support equipment and minimize rutting.
- **Extra Work Space**: Extra work areas such as areas for equipment staging areas and additional spoil storage will be avoided in areas of wet terrain. If standing water or saturated soils are present, or if construction equipment causes excessive rutting, use low ground-weight construction equipment or operate equipment on timber riprap, prefabricated equipment mats or swamp mats.
- **Snow Management**: Pack snow on the right-of-way (RoW) to increase ground frost penetration. Avoid packing the trench area.
- **Clearing**: Cut trees and other vegetation just above ground level and, if necessary, grind stumps to ground level leaving existing root systems in place. Remove all cut trees and branches and stockpile in an upland area for disposal. Minimize construction traffic in areas of wet terrain to only that required for construction activity. Use upland access roads around wet terrain, wherever available.
- **Corduroy**: Use harvested timber for corduroy wherever equipment support is necessary in wet terrain. It is preferable that nonmerchantable timber be used when feasible. Measures to maintain adequate cross drainage will be implemented where required.
- **Dewatering**: Dewater the trench, if warranted, when laying pipe in muskeg or areas with high water tables. Pump water onto stable and well-vegetated areas in a manner that does not cause erosion or any unfiltered or dirty water to enter a watercourse/wetland or to re-enter the work area. If high inflow is encountered, using clay plugs for trench sections may be required. If dewatering in winter, pump to cleared areas to avoid frost kill of tree species. Monitor water discharge during trench dewatering and suspend, reduce flow, or re-locate discharge if necessary to prevent erosion, sedimentation or flooding.
- **Erosion and Sediment Control**: Install sediment barriers immediately after initial ground disturbance at the following locations:
  - Within the RoW at the edge of the boundary between wetland or watercourses and upland;
  - Along the edge of the RoW, where the RoW slopes toward a wetland or watercourse, to protect any adjacent, off RoW wetlands and watercourses; and,
  - Along the edge of the RoW, as necessary, to contain spoil and sediment within the RoW through wetlands or near watercourses.
- **Trench Plugs**: Install trench plugs and/or seal the trench bottom as necessary to maintain the original hydrology at locations where the pipeline trench may act as a drain.
- **Wetlands**: See 3.4 – Watercourse and Wetland Crossings for wetland-specific considerations and mitigation measures.

INSPECTION AND SHUT DOWN DECISION

Soils are considered to be excessively wet when the planned activity could cause damage to soils either due to: rutting by traffic through the topsoil layer into the subsoil; soil structure damage during soil handling; compaction and associated pulverization of topsoil; and topsoil structure damage due to heavy traffic.

Enbridge will assign EIs with sufficient training and soils-related experience to be able to identify soils that are too wet for a particular activity, and when the soils are sufficiently dry to allow the activity to resume. The decision to continue or suspend particular pipeline construction activities on lands with excessively wet/thawed soils will be made by the Enbridge Construction Lead or designate in consultation with the EI. The EI or Enbridge Construction Lead or designate will employ the criteria presented in Tables 1 and 2, to guide the application of contingency measures. Operators, foremen, activity inspectors, contractors, etc., will be made aware of their responsibility in notifying their supervisors, managers or the EI of poor ground conditions (*e.g.*, pooling water, rutting) to minimize potential lag times before a decision is made.

Where topsoil has been replaced, all heavy traffic is to be suspended during excessively wet/thawed soil conditions (see Tables 1 and 2). A record of the location, timing, and reason for implementation of the procedures to address Wet / Thawed Soils will be maintained by the EI. In the event that activities are suspended, the landowner, and the appropriate regulatory authorities, if warranted, will be notified as soon as practical.

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TABLE 1 – CRITERIA FOR THE SUSPENSION OF ACTIVITIES DUE TO EXCESSIVELY WET SOIL CONDITIONS

LAND USE(S)	TOPSOIL SALVAGE STATUS	CONSTRUCTION ACTIVITY	SUSPEND ACTIVITY FOR ENVIRONMENTAL ISSUE?
Cultivated, Poorly-sodded Hay, Tame Pasture, Native Prairie and Bush-Pasture	No salvage conducted	Soils handling (topsoil salvage / replacement)	Yes
	No salvage conducted	Pipe stringing	Yes
	Trench and spoil area salvaged	Pipe stringing	No, if stringing truck traffic is restricted to the stripped area
	Trench and spoil, and work area salvaged	Pipe stringing	No
	No salvage conducted	Welding	Yes
	Trench and spoil area salvaged	Welding	Yes
	Trench and spoil, and work area salvaged	Welding	No
	Trench and spoil area salvaged	Trenching	No
	Trench and spoil area salvaged	Lowering-in	Yes
	Trench and spoil, and work area salvaged	Lowering-in	No
	Trench and spoil area salvaged	Backfilling	No, if backfilling with back hoes or clean-up bucket Yes if dozers are used.
	Trench and spoil, and work area salvaged	Backfilling	No
	Trench and spoil area salvaged	Testing	Yes (Testing would not be initiated but would continue if filling with test water has begun)
	Trench and spoil, and work area salvaged	Testing	No
	Topsoil replaced	Testing	Yes (Testing would not be initiated but would continue if filling with test water has begun)
	Topsoil replaced	Clean-up	Yes - heavy traffic not permitted; No - quad traffic likely acceptable
Well-sodded Lands; Hay, Tame Pasture, Native Prairie and Bush-Pasture	No salvage conducted	Soils handling (topsoil salvage / replacement)	Yes
	No salvage conducted	Pipe stringing	Yes
	Blade width salvage conducted	Pipe stringing	No, if stringing truck traffic is restricted to the salvaged area
	Blade width and work area salvaged	Pipe stringing	No
	No salvage conducted	Welding	No - activity to be closely monitored and suspended if warranted
	Blade width salvage conducted	Welding	No - activity to be closely monitored and suspended if warranted
	Blade width and work area salvaged	Welding	No
	Blade width salvage conducted	Trenching	No
	Blade width salvage conducted	Lowering-in	No - activity to be closely monitored and suspended if warranted
	Blade width and work area salvaged	Lowering-in	No
	Blade width salvage conducted	Backfilling	Yes
	Blade width and work area salvaged	Backfilling	Yes
	Blade width salvage conducted	Testing	No
	Blade width and work area salvaged	Testing	No
	Topsoil replaced	Testing	Yes (Testing would not be initiated but would continue if filling with test water has begun)
	Topsoil replaced	Clean-up	Yes - heavy traffic not permitted; No - quad traffic likely acceptable

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TABLE 2 – CRITERIA FOR THE SUSPENSION OF ACTIVITIES DUE TO THAWED SOIL CONDITIONS

LAND USE	TOPSOIL SALVAGE STATUS	CONSTRUCTION ACTIVITY	SUSPEND ACTIVITY FOR ENVIRONMENTAL ISSUE?
Cultivated and Poorly-sodded Hay, Tame Pasture, Native Prairie and Bush-Pasture	No salvage conducted	Soils handling (topsoil salvage / replacement)	Yes
	No salvage conducted	Pipe stringing	Yes
	Blade width salvage conducted	Pipe stringing	No - if stringing truck traffic is restricted to the salvaged area
	No salvage conducted	Welding	Yes
	Blade width salvage conducted	Welding	Yes
	Blade width salvage conducted	Trenching	No
	Blade width salvage conducted	Lowering-in	Yes
	Blade width salvage conducted	Backfilling	Yes
	Blade width salvage conducted	Testing	Yes - testing would not be initiated but would continue if filling with test water has begun
	Topsoil replaced	Testing	Yes - testing would not be initiated but would continue if filling with test water has begun
	Topsoil replaced	Clean-up	Yes - heavy traffic not permitted; No - quad traffic likely acceptable
Well-sodded Lands; Hay, Tame Pasture, Native Prairie and Bush-Pasture	No salvage conducted	Soils handling (topsoil salvage / replacement)	Yes
	No salvage conducted	Pipe stringing	Yes
	Blade width salvage conducted	Pipe stringing	No - if stringing truck traffic is restricted to the salvaged area
	No salvage conducted	Welding	No - activity to be closely monitored and suspended if warranted
	Blade width salvage conducted	Welding	No - activity to be closely monitored and suspended if warranted
	Blade width salvage conducted	Trenching	No
	Blade width salvage conducted	Lowering-in	No - activity to be closely monitored and suspended if warranted
	Blade width salvage conducted	Backfilling	Yes
	Blade width salvage conducted	Testing	No
	Topsoil replaced	Testing	Yes - testing would not be initiated but would continue if filling with test water has begun
	Topsoil replaced	Clean-up	Yes - heavy traffic not permitted; No - quad traffic likely acceptable

CONTINGENCY MEASURES

Contingency measures will be implemented once one of the following indicators occurs:

- Rutting of topsoil to the extent that admixing may occur;
- Excessive wheelslip;
- Excessive build-up of mud on tires and cleats;
- Formation of puddles; or
- Tracking of mud as vehicles leave the RoW.

Where weather conditions are such that excessively wet/thawed soil conditions are likely to occur, contingency measures may, if warranted and practicable, be implemented before the above indicators occur.

The contingency measures listed below will be implemented individually or in combination, if warranted, based on site-specific conditions.

Wet Soil Contingency Measures (e.g., during nonfrozen soil conditions)

- Restrict construction traffic, where feasible, to equipment with low-ground pressure tires or wide pad tracks.
- Work only in lower-risk areas, such as well-drained soil or well-sodded lands, until conditions improve.
- Install geotextiles, swamp mats or corduroy constructed from nonsalvageable timber in problem areas. Record all areas where geotextiles, swamp mats or corduroy have been installed.
- Consider salvaging an additional width of topsoil in problem areas.
- Suspend construction until soils dry out.

Thawed Soil Contingency Measures (e.g., during frozen soil conditions)

- Restrict construction traffic, where feasible, to equipment with low-ground pressure tires or wide pad tracks.
- Work only in lower-risk areas, such as frozen or well-drained soils, until conditions improve.
- Postpone construction until evening or early morning when the ground is frozen.
- Install geotextiles, swamp mats or corduroy constructed from nonsalvageable timber in problem areas. Record all areas where geotextiles, swamp mats or corduroy have been installed.
- Employ frost inducement measures such as snow packing or plowing to increase the load-bearing capacity of thawed ground.
- Suspend construction until soils dry out or freeze.

RESUMING CONSTRUCTION

Work can continue when the indicators of excessively wet/thawed soil conditions are no longer evident.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Association of Energy and Pipeline Landowner Associations (“CAEPLA”) and its subcommittee, the Dawn Corunna Landowner Committee (“DCLC”)

INTERROGATORY

Reference:

Enbridge Gas Inc. Application, Exhibit F, Tab 1, Schedule 1, Attachment 4, Page 5 of 8 – Response to WIFN Comments

Stantec Dawn-Corunna Project: Environmental Report, Adobe page 33 – Section 4.3.7 Soybean Cyst Nematode (SCN)

Stantec Dawn-Corunna Project: Environmental Report, Table 5.1: Potential Impacts and Recommended Mitigation and Protective Measures, Adobe pages 63 et ff.

Preamble:

Enbridge Gas Inc. states:

> Details on requirements for invasive species management will be determined following the 2022 field surveys. At a minimum, all equipment used for the Project is required to be clean and free of potential invasive species before arriving on site.

Stantec describes Soybean Cyst Nematode (“SCN”) as follows:

> Soybean cyst nematode (Heterodera glycines) (SCN) is a soil borne parasite that can significantly impact soybean yields. It may be present in some fields in the Study Area.
>
> Where equipment is moving from one agricultural field to another there is the potential for the spread of SCN to previously uncontaminated fields. Once a field has been infested there is significant potential for soybean crop loss and there is no effective method of eradication.

Stantec recommends:

> In consultation with the landowner and an agrologist, Enbridge Gas should develop and implement a soil sampling plan on agricultural lands for potential pests and/or diseases that are known to the area. If the results indicate an issue or concern, in consultation with the landowner, Enbridge Gas should work with the agrologist to develop a best practice protocol. Any imported topsoil used for rehabilitation should also have a composite sample analyzed for identified concerns before it is placed on the easement.
>
> AND
>
> Enbridge Gas should consult with landowners of agriculture fields to determine if they would like to proceed with soil sampling for SCN. If requested and agreed to by the landowner, soil sampling for SCN is recommended where construction activity is planned on agricultural crop lands. If a field is identified as having SCN, in consultation with potentially impacted landowners, the following mitigation measures should be considered:
>
> - To the extent feasible restrict construction activity to the non-agricultural pipeline construction area.
> - If the pipeline route or an adjacent farm field is identified as having SCN all equipment and boots should be properly cleaned before moving to an area that has not been shown to be impacted by SCN. This may involve thorough washing before moving equipment from an impacted field to nonimpacted field.
> - All properties impacted with SCN should be identified and communicated to the Contractor. A best practice protocol should be developed to handle SCN, with assistance from Stantec.
> - Any topsoil imported for clean-up activities should be analyzed for SCN by collecting a composite sample, sending it to a lab for analysis and reviewing results before any imported topsoil is placed on the easement. Imported suitable fill (not containing topsoil) or granular materials do not need to be tested for SCN.

Question:

a) Please provide Enbridge Gas Inc.'s plan for dealing with SCN.

b) What is Enbridge Gas Inc.'s plan for the control and containment of other weed and/or disease infestations encountered during construction and operation of the proposed pipeline?

c) Was any SCN identified in the previous constructions along this corridor? Please provide details and copies of any reports or studies prepared.

d) What is the experience of Enbridge Gas Inc.'s and its predecessor(s) with the transfer of SCN and other weed and/or disease infestations from property to property during construction or as a result of construction? Please provide details.

e) Please provide details of any landowner complaints received with respect to SCN, weeds or diseases along this corridor. How were these resolved?

Response

a) As noted in Table 5.1 Potential Impacts and Recommended Mitigation and Protective Measures of the Environmental Report,[1] Enbridge Gas will conduct a pre-construction soil-sampling program to determine the presence of soybean cyst nematode ("SCN") on agricultural lands along the pipeline right of way. If SCN is found, best management practices will be developed in consultation with landowners and with consideration of local management practices. Local management practices may include pressure washing of equipment upon leaving an infested field and/or topsoil stripping of infested fields. Any imported topsoil will also be analyzed for SCN prior to placement.

b) Vegetation surveys are on-going to identify the presence of invasive species along the pipeline right of way. Should any invasive species be identified during these surveys or during construction, Enbridge Gas will work with the on-site Environmental Inspector and landowners to implement best management practices, taking local management practices into consideration. Management efforts may include: following a clean equipment protocol, flagging and avoidance of impacted areas, and the use of construction mats.

c) - e)
Enbridge Gas is not aware of any SCN having been identified during previous construction activities in the area of the proposed Project, nor is Enbridge Gas aware of any instances of SCN transfer during or as a direct result of its historical

[1] Exhibit F, Tab 1, Schedule 1, Attachment 1.

construction projects. As of the date of this filing, Enbridge Gas has not received any complaints with respect to SCN, weeds and diseases along the Project corridor.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Association of Energy and Pipeline Landowner Associations (“CAEPLA”) and its subcommittee, the Dawn Corunna Landowner Committee (“DCLC”)

INTERROGATORY

Reference:

OEB Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario, 7h Edition 2016, Section 5.4, page 47, Easement Preparation

Enbridge Application, Exhibit E, Tab 2, Schedule 1, Page 2 of 3 – General Techniques and Methods of Construction

Preamble:

The OEB Guidelines require:

> … if the landowner requires access across the easement for farm equipment and/or livestock during construction, this must be provided and noted in the ER and contract documents.

Enbridge states:

> 6. Trench Method: Trenching is done by using a trenching machine, backhoe or excavator depending upon the ground conditions. Provisions are made to allow residents access to their property, as required. All drainage tiles that are cut during the trench excavation are flagged to signify that a repair is required. All tiles are measured and recorded as to size, depth, type and quality and this information is kept on file.

Question:

a) Please describe Enbridge Gas Inc.’s plan to allow access across the pipeline construction area for agricultural land uses (including for agricultural equipment and livestock).

b) How will Enbridge Gas Inc. address circumstances in which access across the pipeline construction area cannot be safely provided? What mitigation measures will be implemented for loss of access and for stranded or gored lands?

Response

a) Enbridge Gas will work with all landowners to ensure that, wherever possible, sufficient access points for agricultural land uses are established across the proposed pipeline easement.

b) Enbridge Gas will, on a best-efforts basis, ensure access to all areas impacted by the Project is maintained. In instances where there are areas that cannot be accessed as a result of Project construction, the Company will consult directly with affected landowner(s) to determine an optimal solution. The Company compensates affected landowners for areas that are made inaccessible as a result of Project construction.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Association of Energy and Pipeline Landowner Associations (“CAEPLA”) and its subcommittee, the Dawn Corunna Landowner Committee (“DCLC”)

INTERROGATORY

Reference:

Stantec Dawn-Corunna Project: Environmental Report, Monitoring and Contingency Plans, Adobe page 90 – Section 7.1.1 Water Wells

Stantec Dawn-Corunna Project: Environmental Report, Table 5.1: Potential Impacts and Recommended Mitigation and Protective Measures, Adobe pages 63 et ff.

OEB Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario, 7th Edition 2016, Section 5.12, page 63, Restoration Plans

Preamble:

Stantec recommends:

Before construction, a private well survey should take place to assess domestic groundwater use near the Project and determine the need for a well monitoring program, as outlined in Table 5.1.

AND

A private well survey should be conducted to assess domestic groundwater use near the Project and a private well monitoring program may be recommended for residents who rely on overburden groundwater supply for domestic use. This monitoring program may include pre—construction water quality monitoring as well as water level monitoring, if available. Should a private water well be affected by project construction, a potable water supply should be provided, and the water well should be repaired or restored as required.

The OEB Guidelines require:

Permanent water service must be restored to landowners who experience any interference or interruption of water supply due to pipeline construction.

Question:

Please provide details of Enbridge Gas Inc.'s well monitoring program.

Response

The Company's well monitoring program includes:

- Retaining a hydrogeologist to review local hydrogeological conditions and existing water well records.
- Based on the findings of its review, the hydrogeologist develops a project-specific well monitoring program.
- The hydrogeologist is made available to landowners and/or residents throughout project construction to address any issues or concerns raised regarding project-specific impacts to water wells or water supplies.

In accordance with the Company's standard water well monitoring program, Enbridge Gas has retained a hydrogeologist to support the proposed Project. The hydrogeologist selected will develop and implement the Company's well monitoring program prior to the commencement of project construction and will continue to support the Company, landowners and residents through to Project completion.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Association of Energy and Pipeline Landowner Associations (“CAEPLA”) and its subcommittee, the Dawn Corunna Landowner Committee (“DCLC”)

INTERROGATORY

Reference:

OEB Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario, 7th Edition 2016, Section 5.9.3, page 60, Hydrostatic Testing

Stantec Dawn-Corunna Project: Environmental Report, Table 5.1: Potential Impacts and Recommended Mitigation and Protective Measures, Adobe pages 63 et ff. - Groundwater, Section 4.3.3

Preamble:

The OEB Guidelines require:

Discharging of water from the pipeline should be done at a rate not exceeding the rate of withdrawal from the source.

Stantec reports:

> Hydrostatic Testing and Dewatering
> The pipeline will be hydrostatically tested before commissioning. Select sections of pipe may also be pre-tested, such as at road crossings. Water required for the testing may be obtained from a municipal or natural source. Before the withdrawal of water from a municipal source, the municipality will be contacted to confirm the maximum rate of withdrawal. Where trenches encounter shallow groundwater conditions or following a large precipitation event, removing water from the trench (known as dewatering) may be necessary. During trench dewatering, discharge water will be released to the environment. An uncontrolled discharge of water could cause downstream flooding, erosion, sedimentation, or contamination. Other potential effects of uncontrolled discharge may include introduction of foreign aquatic organism to a drainage basin and

introduction of hazardous materials or pollutants to soils or bodies of water.

Question:

a) Does Enbridge Gas Inc. intend to discharge water from trench dewatering or hydrostatic testing onto any privately-held lands affected by the proposed project?

b) If so, please provide Enbridge Gas Inc.'s detailed plan for the discharge of water and any associated drawings.

Response

a) Yes, as of the time of this filing Enbridge Gas intends to discharge water from trench dewatering onto privately-held lands and to discharge water from hydrostatic testing onto lands owned by Enbridge Gas.

   In cases where water is discharged onto privately-held lands, consultation will occur with affected landowners and residents in advance of dewatering.

b) Detailed discharge and dewatering plans are not yet available for the Project. Such plans will be developed prior to the start of Project construction. All dewatering activities undertaken as part of the proposed Project will be done in compliance with applicable regulations, permits, and approvals (e.g., Water Resources Act), as well as best management practices (as known to Enbridge Gas and/or its environmental consultant(s)) to prevent property damage, soil erosion, and siltation.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Association of Energy and Pipeline Landowner Associations ("CAEPLA") and its subcommittee, the Dawn Corunna Landowner Committee ("DCLC")

INTERROGATORY

Reference:

OEB Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario, 7th Edition 2016, Section 5.12, page 62, Restoration Plans

Preamble:

The OEB Guidelines include the following with respect to the rehabilitation of the easement post-construction:

The landowner must be consulted and any reasonable request regarding rehabilitation of the easement complied with. Planting of soil-building cover crops should be considered. … It is recommended that a professional agronomist/agrologist be retained to review the proposed restoration technique and its application with the contractor and the landowner, in order to ensure that optimal results are achieved.

Question:

a) Has Enbridge Gas Inc. retained a professional agronomist and/or agrologist for this project?

b) If so, please provide his or her most recent resume or CV.

c) If not, when will a professional agronomist and/or agrologist be retained by Enbridge Gas Inc. for this project, and in what capacity?

Response

a) – c)
Yes, Enbridge Gas has retained a Professional Agrologist, Mr. Mozuraitis (P. Ag.), to support the Project.

Mr. Mozuraitis' resume is set out at Attachment 1.

Edward Mozuraitis P.Ag., CISEC

Project Manager, Agricultural Evaluation and

Rehabilitation Specialist

43 years of experience · Waterloo, Ontario

Ed Mozuraitis is a Professional Agrologist with over 41 years of environmental monitoring, agricultural, crop, and landscape consulting experience. He has extensive experience in soil management, land evaluation, land utilization, and site restoration projects and is skilled in linear facilities environmental site inspection and compliance monitoring. Ed is listed on MTO's RAQS registry as a qualified Environmental Monitor. He has managed projects and personnel involving interpretations for agronomic studies, agricultural impact assessment, linear development and aggregate development projects. He has managed numerous agricultural resource management projects and conducted numerous projects on the rehabilitation and re-vegetation of lands damaged by soil compaction, soil rutting and mixing, and soil erosion due to construction activities and rail car derailments.

Ed has also has conducted environmental inspections on pipeline and highway construction projects.

EDUCATION

B.Sc., (Honours), Agriculture, University of Guelph, Guelph, Ontario, 1979

Certification, Ontario Centre for Remote Sensing (OCRS) on airphoto interpretation of forest landscapes and ecosystems, Guelph, Ontario, Canada, 1991

Certification, First Aid/CPR Training, Guelph, Ontario, Canada, 2021

Certification, Yearly Pipeline Construction Inspection Courses/Safety Training (since 1991), Kingsville, Ontario, 2021

Bear Awareness Training, Stantec Consulting Ltd – Environmental Health and Safety Program, Edmonton, Alberta, Canada, 2009

Certification, WHMIS, Stantec Consulting Ltd – Environmental Health and Safety Program, Guelph, Ontario, Canada, 2021

ATV Training Course, Canada Safety Council, Melbourne, Ontario, Canada, 2009

Green Defensive Driving Course Online, Canada Safety Council, Guelph, Ontario, Canada, 2021

Pleasure Craft Operator Card, BoatSmart Canada, Guelph, ON, Canada, 2010

MEMBERSHIPS

Member, Certified Inspector of Sediment and Erosion Control (CAN-CISEC)

Member, Professional Agrologist (P.Ag.), Ontario Institute of Agrologists

Member, Canadian Land Reclamation Association

Member, Agricultural Institute of Canada

PROJECT EXPERIENCE

LANDFILL SERVICES

Renfrew County, Southern Ontario, Sanitary Landfill Site Selection | Agricultural Specialist / Soil Surveyor

Wellington County, Southern Ontario, Sanitary Landfill Site Selection | Project Manager, Agricultural Section

Victoria County, Southern Ontario, Sanitary Landfill Site Selection | Agricultural Specialist / Soil Surveyor

WASTEWATER RECLAMATION AND REUSE

Baseline Physical and Chemical Data and Site Suitability for the Spray Irrigation of Campground Sewage Lagoon Water | Soil Surveyor

Site Suitability for the Spray Irrigation of Milk Water and Cleaning Wastes from a Cheese Processing Facility | Project Manager

SOIL CLASSIFICATION

Soil Survey Upgrade | Simcoe and Dufferin County, Ontario | Soil Surveyor/Pedologist

Soil profile descriptions and soil mapping along potential electrical transmission line corridors.

Soil Survey of Kent County* | Kent County, Ontario | Soil Surveyor/Pedologist

Preliminary mapping using soil transect method.

Soil Mapping and Land Suitability Studies* | Project Soil Scientist

Soil mapping and land suitability studies under various agricultural production models in Indonesia

Nabiye Project: Soil Survey Upgrade of Portions of the Imperial Oil Resources Ltd. Cold Lake Operation Area | Soil Surveyor/Pedologist and Sector Team Lead

Detailed Soil profile descriptions at various location within the proposed hydrocarbon facilities.

Soil Survey Upgrade | Oxford County, Ontario | Project Manager; Soil Surveyor/Pedologist

Soil survey upgrade using digital topographic mapping and soil profile ground truthing.

** denotes projects completed with other firms*

Detailed Soil Survey of Various Properties | Ontario | Soil Surveyor/Pedologist

Soil profile description and soil mapping of numerous properties to refine existing soil mapping and soil capability for agriculture mapping.

Proposed Burlington Quarry Extension, Nelson Aggregate Co. | Nelson Aggregate Co. | Burlington, Ontario | 2005-2008 | Lead Soil Surveyor

Provided soil profile descriptions of hand augered soil profiles to complete the characterization of mapped ELC units within the proposed quarry lands.

Assessment of Soils and Soil Capability for Agriculture at Various Sites, JCM Solar | JCM Solar | Ontario | 2011 | Lead Soil Surveyor

Conducted soils surveys at sites in Ontario. Assessments included reconnaissance soils surveys with CLI interpretations as part of the Ontario Power Authority Requirements under the Green Energy Act. Sites included:
- Forfar Road Site, part of Lots 25 and 26, Concession 4, geographic Township of Bastard, Township of Rideau Lakes
- Christie Lake Road Site, part of Lot 17, Concession 2, geographic Township of Bathurst, Township of Tay Valley

Soils and Surficial Geology Overview of Various Sites, Tioga Energy | Tioga Energy | Ontario | 2009 | Lead Soil Surveyor

Conducted soil surveys at various sites in Ontario. Assessments included soil surveys with CLI interpretations as part of the Ontario Power Authority requirements under the Green Energy Act. Sites included:
- Site #1, Lots 16 and 17, Concession 2, Township of Drummond, Lanark County
- Site #2, Lot 15, Concession 10, Township of Elmsley, Lanark County
- Site #3, Lots 8 and 9, Concession 10, Township of Elmsley, Lanark County
- Site #4, Lot 6, Concession 2, Township of Kitley, Leeds County
- Site #5, Lots 8 and 9, Concession 3, Township of Kitley, Leeds County

Assessment of Soils and Soil Capability for Agriculture, CBEX Renewables | CBEX Renewables | Fargo, Ontario | 2010 | Lead Soil Surveyor

Conducted a soil survey of part of Lots 19 and 20, west side of Concession 1, geographic Township of Harwich, Chatham-Kent. Assessment included a soil survey with CLI interpretations as part of the Ontario Power Authority requirements under the Green Energy Act.

Dufferin Aggregates Acton Quarry Extension Natural Environment Studies | Dufferin Aggregates | Acton, Ontario, Canada | 2006-2007 | Lead Soil Surveyor

Provided soil profile descriptions of hand augered soil profiles to complete the characterization of mapped ELC units within the proposed quarry lands.

Proposed Quarry | Canada Building Materials | Flamborough, Ontario | 2007 | Lead Soil Surveyor

Provided soil profile descriptions of hand augered soil profiles to complete the characterization of mapped ELC units within the proposed quarry lands.

Soils and Soil Capability for Agriculture Study, GDF SUEZ North America Inc. | GDF Suez North America Inc | Almonte, Ontario | 2011 | Lead Soil Surveyor

Conducted a soil survey of part of the east half of Lot 3, Concession 8, geographic Township of Ramsay, Town of Mississippi Mills, Lanark County. Assessment included a soil survey with CLI interpretations as part of the Ontario Power Authority requirements under the Green Energy Act. Also gave an opinion of the agricultural viability of the property as a whole.

Soils and Soil Capability for Agriculture Study, County of Lanark | Almonte, Ontario | 2011 | Lead Soil Surveyor

Conducted a soil survey of part of the east half of Lot 3, Concession 8, geographic Township of Ramsay, Town of Mississippi Mills. Assessment included a soil survey with CLI interpretations as part of the Ontario Power Authority requirements under the Green Energy Act. Provided opinion of the agricultural viability of the property as a whole.

AGRICULTURAL IMPACT ASSESSMENTS

ICRC Agricultural Assessment and Justification Report, Regional Municipality of Peel | City of Brampton, Ontario | 2005-2006 | Lead Field Technologist

Conducted an agricultural impact assessment of 2626 Mayfield Road, 1.54 hectares (3 acres) of land located on the north side of Mayfield Road (County Road 14), just west of Hurontario Street (Highway 10). Assessment included a review of the published soil survey report with CLI interpretations, agricultural land use, and structure survey, and an MDS I assessment.

Parkway West Expansion Agricultural Impact Assessment, Halton Region | Union Gas Limited | Town of Milton, Ontario | 2012-2013 | Lead Field Technologist

Conducted an agricultural impact assessment of part of the west half of lots 9 and 10, Concession 9. Assessment included an agricultural land use survey and an MDS I assessment along with interpretation of agricultural planning documents. Published soil survey and CLI interpretations were also used in the assessment.

The Highland Companies Proposed Melancthon Quarry | Dufferin County, Ontario | 2008-2011 | Lead Field Technologist

Conducted an agricultural impact assessment of the proposed quarry lands and several adjacent lands. Assessment included 364 hand augered soil profiles with descriptions, four of which were later excavated for detailed soil profile pit descriptions and analyses; a CLI interpretation of the sampled soils; and an agricultural land use and structures survey.

Town of Caledon Recreation Complex Agricultural Impact Assessment, Regional Municipality of Peel | Township of Albion, Town of Caledon, Ontario | 2008 | Lead Field Technologist

Conducted an agricultural assessment of part of the east half of Lot 2, Concession 2. Assessment included a soil survey with CLI interpretations, agricultural land us survey and an MDS I assessment.

Chelmsford Agricultural Reserve Agricultural Assessment | Sudbury, Ontario | 2008-2009 | Project Manager and Lead Field Technologist

Conducted an agricultural impact assessment of REM PCL 4873, PCL 6529, and PCL 1584. Assessment included a soil survey with CLI interpretations and an agricultural land use survey.

Background Agricultural Report for King Township (Pitway) Site Generation Project, Regional Municipality of York | Township of King, Ontario | 2008 | Lead Field Technologist

Conducted an agricultural impact assessment of Lots 5 and 6, Concession 3 old survey. Assessment included a soil survey with CLI Interpretations, agricultural land use survey, and an MDS I assessment.

Tutela Heights Secondary Plan | Walton International Group | County of Brant, Ontario | 2007 | Lead Field Technologist

Conducted a desktop agricultural review of lands included in the area bounded by Tutela Heights Road and the Grand River on the north, Cockshutt Road on the east, Blossom Avenue on the south, and Mount Pleasant Road on the west, totalling some 1,450 acres of land. The assessment included a review of the existing soil capability mapping and tile drainage mapping to determine soil capability of the subject property. An onsite agricultural structure and livestock survey was also conducted to determine MDS I implications.

Background Agricultural Report for King Township (Miller-Crang) Site Generation Project, Regional Municipality of York | Township of King, Ontario | 2008 | Lead Field Technologist

Conducted an agricultural impact assessment of 1170 Miller's Side Road, part of Lot 6, Concession 2 old survey. Assessment included a soil survey with CLI interpretations, agricultural land use survey, and an MDS I assessment.

Westlin Farms Site Agricultural Impact Assessment, Regional Municipality of York | Westlin Farms Inc. | Township of King, Ontario | 2020 | Project Manager and Lead Field Technologist

Conducted an agricultural impact assessment of part of Lot 2, Concession 6. Assessment included a soil survey with CLI interpretations, agricultural land use survey and an MDS I assessment.

Agricultural Impact Assessment, County of Simcoe | Township of Clearview, Ontario | 2008-2009 | Project Manager and Lead Field Technologist

Conducted an agricultural impact assessment of part of Lots 22 and 23, Concessions 7 and 8. Assessment included a soil survey with CLI interpretations, agricultural land use survey, and an MDS I assessment.

Background Agricultural Report for East Gwillimbury Generation Project, Regional Municipality of York | Northland Power Inc. | Town of East Gwillimbury, Ontario | 2007 | Lead Field Technologist

Conducted an agricultural impact assessment of east half of Lot 25, Concession 3 (southwest corner of Leslie Street and Holborn Road). Assessment included a soil survey with CLI interpretations, agricultural land use survey, and an MDS I assessment.

Durham Region Police Services Clarington Site Agricultural Impact Study, Durham Region | Township of Darlington, Municipality of Clarington, Ontario | 2011 | Project Manager and Lead Field Technologist

Conducted an agricultural impact assessment of part of the south portion of Lot 19, Concession 2. Assessment included a soil survey with CLI interpretations, agricultural land use survey, and an MDS I assessment.

Minimum Distance Separation (MDS) I Assessment - Hamlet of Waldemar Expansion | Ontario | Project Manager and Lead Field Technologist

Conducted an agricultural land use survey and an MDS I assessment.

Minimum Distance Separation (MDS) I and II Assessment – Crowsfoot Corner Settlement Area | Regional Municipality of Waterloo, Ontario | Project Manager and Lead Field Technologist

Conducted an agricultural land use survey and an MDS I and MDS II assessment studies of Crook's Tract, Part of Lot 8, Concession 1, Township Road 52.

Minimum Distance Separation (MDS) I Assessment – Part of Lot 20, Concession 4 | Township of Beckwith, County of Lanark, Ontario

Conducted an agricultural impact assessment for a proposed rural subdivision development. Assessment included a review of existing soil survey and CLI interpretations, agricultural land use survey and an MDS I assessment.

Agricultural Impact Study, 9678 6/7 Nottawasaga Sideroad North | Clearview, Ontario | Project Manager and Lead Field Technologist

Conducted an agricultural impact assessment of proposed two lot residential development. Assessment included a review of existing soil survey and CLI interpretations, agricultural land use survey and an MDS I assessment.

CONTAMINATED SITE DEVELOPMENT / INVESTIGATION

Phase III Remediation of Crude Oil Leak Site, Vertical and Horizontal Delineation of Contamination and Obtaining Confirmatory Sampling for Analysis | Field Technician

Phase II Environmental Investigations of Abandoned Hydroelectric Diesel Generating Stations on First Nations Reserves in Northern Ontario | Field Technician

ENVIRONMENTAL INSPECTION

2017 Panhandle Reinforcement Project | Chatham-Kent and Lambton County, Ontario | Agricultural & Environmental and Topsoil Management Inspector

During pipeline replacement ensured that brush and trees were cleared under favorable environmental and agricultural conditions, in compliance with permits, including construction within designated timing windows, proper installation of sedimentation ad erosion control structures, avoiding impacts to species at risk, and containment of drilling mud and fluids. Ensured proper topsoil handling and storage, soil decompaction and topsoil replacement. Conducted early morning soil evaluations to determine whether wet soil shutdown was to be called. Designed site-specific slope stabilization plans, and fertilizer and reseeding programs. Duration: 14 months (full time); 10 months year 1; 4 months year 2.

NPS 48 Brantford to Kirkwall Pipeline Project | Hamilton and Regional Municipality of Waterloo, Ontario | Agricultural & Environmental Inspector

Ensured that brush and trees were cleared under favorable environmental and agricultural conditions During pipeline replacement ensured that construction through watercourses and regulated areas was conducted in compliance with permits, including construction within designated timing windows, proper installation of sedimentation ad erosion control structures, avoiding impacts to species at risk, and containment of drilling mud and fluids. Ensured proper topsoil handling and storage, soil decompaction and topsoil replacement. Conducted early morning soil evaluations to determine whether wet soil shutdown is to be called. Designed site-specific slope stabilization plans, and fertilizer and reseeding programs. Duration: 8 months (full time)

NPS 12 Owen Sound Replacement Project | City of Kitchener, City of Waterloo, and Regional Municipality of Waterloo, Ontario | Agricultural & Environmental Inspector

During pipeline replacement ensured that construction through watercourses and regulated areas was conducted in compliance with permits, including construction within designated timing windows, proper installation of sedimentation ad erosion control structures, avoiding impacts to species at risk, and containment of drilling mud and fluids. Ensured proper topsoil handling and storage, soil decompaction and topsoil replacement. Conducted early morning soil evaluations to determine whether wet soil shutdown is to be called. Designed site-specific slope stabilization plans, and fertilizer and reseeding programs. Duration: 5 months (full time)

NPS 10 Genesis Pipeline Extension Project - New Pipeline Installation | Corunna, Lambton County, Ontario | Environmental Inspector

During pipeline installation ensured that construction through watercourses and regulated areas was conducted in compliance with permits, including construction within designated timing windows, proper installation of sedimentation and erosion control structures, avoiding impacts to species at risk, and containment of drilling mud and fluids. Duration: 10 weeks (full time)

NPS 20 Bluewater River Crossing Replacement | Corunna, Lambton County, Ontario | Environmental Inspector

Ensured that construction through watercourses was conducted in compliance with permits, including construction within designated timing windows, proper installation of sedimentation and erosion control structures, avoiding impacts to species at risk, undertaking in-water monitoring for inadvertent returns, and containment of drilling mud and fluids, minimize debris and mud, grading land after construction and reseeding. Duration: 9 weeks (full time)

Highway 24 Resurfacing and Culvert and Bridge Reconstruction, Glen Morris Road to Footbridge Road (MTO Contract No. 2011-3034) | Regional Municipality of Waterloo, Ontario | Senior Environmental Inspector

Construction administration work included ensuring that approved environmental protection measures were in place, maintained and working as planned. The tasks included general environmental monitoring, avian monitoring, sediment and erosion control, and aquatic monitoring. Ensured compliance monitoring and managed environmental emergencies. Prepared monthly reports and environmental reports as required. Duration: monthly inspections, plus intermittent inspections during critical issues.

NPS 20 Halton Hills Generating Station Natural Gas Pipeline Project, New Pipeline Installation | Milton, Regional Municipality of Halton, Ontario | Environmental Inspector

Conducted environmental and agricultural inspection. Ensured that construction through watercourses was conducted in compliance with permits, including construction within designated timing windows, proper installation of sedimentation and erosion control structures, downstream fish transfer, and stream bank stabilization and seeding. Other tasks included ensuring proper topsoil handling and storage, and soil decompaction and topsoil replacement. Duration: 3 months (intermittent)

Highway401 Widening and Bridge Reconstruction, Oxford County Road 3 to Cedar Creek Road (MTO Contract No. 2005-0331), | Middlesex County, Ontario | Senior Environmental Inspector

Construction administration of highway widening. Responsible for ensuring that approved environmental protection measures were in place, maintained and working as planned. Tasks included general environmental monitoring, avian monitoring, and sediment control and aquatics monitoring. Ensured compliance monitoring and managed environmental emergencies. Prepared monthly reports and environmental reports as required. Duration: monthly inspections, plus intermittent inspections during critical issues.

NPS 48 Strathroy to Lobo Natural Gas Pipeline Project, New Pipeline Installation | Middlesex County, Ontario | Agricultural and Topsoil Inspector

Ensured proper topsoil handling and storage, and soil decompaction and topsoil replacement. Conducted early morning soil evaluations for determination of need for wet soil shutdown. Designed site-specific slope stabilization plans and fertilizer and re-seeding programs. Duration: 5 months (full time)

NPS 48 Brooke to Strathroy Natural Gas Pipeline Project, New Pipeline Installation | Lambton and Middlesex Counties, Ontario | Agricultural and Topsoil Inspector

Ensured proper topsoil handling and storage, and soil decompaction and topsoil replacement. Conducted early morning soil evaluations for determination of need for wet soil shutdown. Designed site-specific slope stabilization plans and fertilizer and re-seeding programs. Duration: 6 months (full time)

NPS 10, 47-49 Pool Natural Gas Pipeline Replacement | Lambton County, Ontario | Environmental, Agricultural, and Topsoil Inspector

Ensured that trees cut down in hedgerows did not support migratory bird nests. Sampled interior of existing pipe to determine composition of oily residue. Ensured proper topsoil handling and storage, and soil decompaction and topsoil replacement. Conducted early morning soil evaluations for determination of need for wet soil shutdown. Designed site-specific slope stabilization plans, and fertilizer and re-seeding programs. Duration: 3 weeks (full time)

NPS 16 Replacement of Refined Petroleum Products Pipeline | Rivière Beaudette to Saint-Clet, Municipalité Régionale de Comté de Vaudreuil-Soulanges, Quebec | Environmental Inspector

Ensured that construction through watercourses was conducted in compliance with permits. These included construction within designated timing windows, proper installation of sedimentation and erosion control structures, downstream fish transfer, and stream bank and stream bed stabilization and re-seeding. Ensured that extraneous soil and gravel material was certified clean for fill purposes. Sampled all potentially contaminated soils and ensured that soil materials were properly stored and hauled to a certified waste site. Duration: 13 weeks (full time)

NPS 48 Owen Sound T.O. to Brantford V.S. Natural Gas Pipeline Project New Pipeline Installation | Regional Municipality of Waterloo, Ontario | Agricultural and Topsoil Inspector

Ensured proper topsoil handling and storage, and soil decompaction and topsoil replacement. Conducted early morning soil evaluations for determination of need for wet soil shutdown. Designed site-specific slope stabilization plans and fertilizer and re-seeding programs. Duration: 10 weeks (full time)

NPS 48 Beachville T.S. to Bright C.S. Natural Gas Pipeline Project New Pipeline Installation | Oxford County, Ontario | Agricultural and Topsoil Inspector

Ensured proper topsoil handling and storage, and soil decompaction and topsoil replacement. Conducted early morning soil evaluations for determination of need for wet soil shutdown. Designed site-specific slope stabilization plans and fertilizer and re-seeding programs. Duration: 4 months (full time)

NPS 16 Mandaumin Pool / Blue Water Pool Natural Gas Pipeline Project New Pipeline Installation | Lambton County, Ontario | Environmental, Agricultural and Topsoil Inspector

Ensured proper topsoil handling and storage, and soil decompaction and topsoil replacement. Conducted early morning soil evaluations for determination of need for wet soil shutdown. Designed site-specific slope stabilization plans and fertilizer and re-seeding programs. Duration: 2 months (full time)

Century Pool II and Oil City Pool Natural Gas Pipeline Project New Pipeline Installation | Union Gas Limited | Lambton County, Ontario | 2000 | Agricultural and Topsoil Inspector

Ensured proper topsoil handling and storage, and soil decompaction and topsoil replacement. Designed site-specific slope stabilization plans and fertilizer and re-seeding programs. Duration: 5 weeks (intermittent)

NPS 48 Dawn C.S. to Enniskillen V.S. Natural Gas PIpeline Project New Pipeline Installation | Lambton County, Ontario | Agricultural and Topsoil Inspector

Agricultural and topsoil inspection (during construction and after clean-up). Ensured proper topsoil handling and storage, and soil decompaction and topsoil replacement. Conducted early morning soil evaluations for determining need for wet soil shutdown. Designed site-specific slope stabilization plans and fertilizer and re-seeding programs. Duration: 5 months (1999, full time); 2 months (2000, full time)

NPS 24 Lennox Natural Gas Pipeline Project New Pipeline Installation | County of Lennox & Addington, Ontario | Agricultural and Topsoil Inspector

Agricultural and topsoil inspection (during construction and year after clean-up). Ensured proper topsoil handling and storage, and soil decompaction and topsoil replacement. Conducted early morning soil evaluations for determining need for wet soil shutdown. Designed site-specific slope stabilization plans, and fertilizer and re-seeding programs. Duration: 5 months (full time)

NPS 30 Bentpath / NPS20 Rosedale Pools Natural Gas Pipeline Project New Pipeline Installation | Lambton County, Ontario | Agricultural and Topsoil Inspector

Agricultural and topsoil inspection (during construction and year after clean-up). Ensured proper topsoil handling and storage, and soil decompaction and topsoil replacement. Conducted early morning soil evaluations for determining need for wet soil shutdown. Designed site-specific slope stabilization plans, and fertilizer and re-seeding programs. Duration: 4 months (full time)

NPS 48 Bright C.S. to Owen Sound T.S. Natural Gas Pipeline Project New Pipeline Project | Oxford County and Regional Municipality of Waterloo, Ontario | Agricultural and Topsoil Inspector

Agricultural and topsoil inspection (during construction and year after clean-up). Ensured proper topsoil handling and storage, and soil decompaction and topsoil replacement. Conducted early morning soil evaluations for determining need for wet soil shutdown. Designed site-specific slope stabilization plans, and fertilizer and re-seeding programs. Duration: 5 months (1997, full time); 1.5 months (1998, full time)

NPS 48 Enniskillen V.S. to Brooke V.S. Natural Gas Pipeline Project New Pipeline Installation | Lambton County, Ontario | Agricultural and Topsoil Inspector

Ensured proper topsoil handling and storage, and soil decompaction and topsoil replacement. Conducted early morning soil evaluations for determining need for wet soil shutdown. Designed site-specific slope stabilization plans, and fertilizer and re-seeding programs. Duration: 4 months (full time)

NPS 48 St. Marys V.S. to Beachville T.S. Natural Gas Pipeline Project New Pipeline Installation | Middlesex County and Oxford County, Ontario | Agricultural and Topsoil Inspector

Ensured proper topsoil handling and storage, and soil decompaction and topsoil replacement. Conducted early morning soil evaluations for determining need for wet soil shutdown. Designed site-specific slope stabilization plans, and fertilizer and re-seeding programs. Duration: 4 months (full time)

NPS 48 Milton V.S. to Parkway C.S. Natura Gas Pipeline Project New Pipeline Installation, and NPS 26 & 34 Replacements | Regional Municipality of Halton, Ontario | Environmental, Agricultural, and Topsoil Inspector

Construction year and year after clean-up. Ensured proper topsoil handling and storage, and soil decompaction and topsoil replacement. Conducted early morning soil evaluations for determination of need for wet soil shutdown. Designed site specific slope stabilization plans and fertilizer and reseeding programs. Ensured that stream bank, flood plains and slopes were properly seeded and stabilized. Duration: 1991 - 7 months (full time); 1992 - 2 months (full time)

NPS 12 Bickford Pool C.S. to Sombra Pool Natural Gas Pipeline Project New Pipeline Installation | Lambton County, Ontario | Environmental, Agricultural, and Topsoil Inspector

Ensured proper topsoil handling and storage, and soil decompaction and topsoil replacement. Conducted early morning soil evaluations for determination of need for wet soil shutdown. Prepared 'Post Construction Environmental Report'. Duration: 1 month (full time)

NPS 24 St. Clair V.S. to Bickford Pool C.S. Natural Gas Pipeline Project New Pipeline Installation | Lambton County, Ontario | Environmental, Agricultural, and Topsoil Inspector

Construction year (1998) and year after clean up (1990). Ensured proper topsoil handling and storage, and soil decompaction and topsoil replacement. Designed site-specific slope stabilization plans and fertilizer and reseeding programs. Ensured that stream bank, flood plains, and slopes were properly seeded and stabilized. Served as acting onsite Lands Agent during construction. Prepared 'Interim Monitoring Report' (1990), and 'Final Post Construction Monitoring Report' (1991). Duration: 1989 - 2 months (full time); 1990 - 2 months (full time)

NPS 26 & 34 Trafalgar System Pipeline Replacement Project, 5 Spreads | Regional Municipality of Halton, Regional Municipality of Hamilton-Wentworth, Ontario | Environmental, Agricultural, and Topsoil Inspector

Pipeline replacements at Trafalgar, Milton, Kilbride, Carlisle, and Highway 8. Ensured proper topsoil handling and storage, and soil decompaction and topsoil replacement. Conducted early morning soil evaluations for determination of wet soil shutdown. Ensured that stream bank, flood plains, and slopes were properly seeded and stabilized. Duration: 6 weeks (full time)

NPS 42 Milton V.S. to Parkway C.S. Natural Gas Pipeline Project New Pipeline Installation | Regional Municipality of Halton , Ontario | Agricultural and Topsoil Inspector

Ensured proper topsoil handling and storage, and soil decompaction and topsoil replacement. Conducted early morning soil evaluations for determination of need for wet soil shutdown. Duration: 4 months (full time)

NPS 42 Strathroy V.S. to Lobo C.S. Natural Gas Pipeline Project New Pipeline Installation | Middlesex County, Ontario | Agricultural and Topsoil Inspector

Ensured proper topsoil handling and storage, and soil decompaction and topsoil replacement. Conducted early morning soil evaluations for determination of need for wet soil shutdown. Duration: 5 weeks (full time)

ENVIRONMENTAL INSPECTION / POST CONSTRUCTION MONITORING

NPS 42 Dawn to Kerwood Natural Gas Pipeline 10 Year Soil Rehabilitation Program | Union Gas Limited | Lambton County, Ontario | 1993-2003 | Environmental, Agricultural, and Topsoil Inspector

A study and rehabilitation program was conducted to ameliorate soil properties and improve agricultural crop yields over a pipeline easement more than 15 years post construction. Study was comprised of five parts: landowner survey provided background to farm management practices; examination of soil properties; recommendations for soil remediation; evaluation of previous rehabilitation; and initiation of a 10 year crop rotation program to ameliorate soil properties and improve crop yields.

NPS 48 Strathroy to Lobo Natural Gas Pipeline Project Post Construction Crop Monitoring | Union Gas Limited | Middlesex County, Ontario | 2009-2013 | Project Manager and Lead Field Technologist

Comparison of on-easement with off-easement crop yields at ten selected easement sites. Soil properties were also evaluated during the first year after construction.

48 inch Water Line Construction Project Post Construction Crop Monitoring | Ontario Clean Water Agency | Middlesex County and Huron County, Ontario | 1998 | Lead Field Technologist

Comparison of on-easement with off-easement crop yields. Soil properties were also evaluated.

NPS 42 Beachville to Bright Natural Gas Pipeline Post Construction Crop Monitoring | Union Gas Limited | Oxford County, Ontario | 1993 | Project Manager and Lead Field Hand

Soil monitoring on easement locations with particularly large yield losses based on the 1991 crop sampling results; evaluation included soil compaction, soil mixing, and soil fertility.

NPS 42 Strathroy to Lobo Natural Gas Pipeline Post Construction Monitoring | Union Gas Limited | Middlesex County, Ontario | 1993 | Project Manager and Lead Field Hand

Soil monitoring on easement locations with particularly large yield losses based on the 1991 crop sampling results; evaluation included soil compaction, soil mixing, and soil fertility.

NPS 42 Beachville T.S. to Bright C.S. Natural Gas Pipeline Project Post Construction Crop Monitoring | Union Gas Limited | Oxford County, Ontario | 1994 | Project Manager and Lead Field Technologist

Evaluation of sweet corn production in response to landowner concern, initiated on short notice. Field had already been harvested; estimate of yield levels was provided.

NPS 48 Kirkwall to Hamilton Natural Gas Pipeline Post Construction Crop Monitoring | Union Gas Limited | Regional Municipality of Hamilton-Wentworth, Ontario | 1992-1993 | Project Manager and Lead Field Hand

Soil monitoring on easement locations with particularly large yield losses based on the 1991 crop sampling results; evaluation included soil compaction, soil mixing, and soil fertility.

NPS 48 Milton to Parkway Natural Gas Pipeline Post Construction Monitoring | Union Gas Limited | Regional Municipality of Halton, Ontario | 1992-1993 | Project Manager and Lead Field Hand

Evaluation of compaction and soil fertility, soil mixing on several agricultural properties. Soil monitoring conducted largely during a wet fall in 1992 with the remainder completed in spring 1993. Crop yield levels evaluated on and off easement in 1993.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Association of Energy and Pipeline Landowner Associations ("CAEPLA") and its subcommittee, the Dawn Corunna Landowner Committee ("DCLC")

INTERROGATORY

Reference:

Enbridge Gas Inc. Application, Exhibit E, Tab 2, Schedule 1, Page 3 of 3 – General Techniques and Methods of Construction

Enbridge Gas Inc. Application, Exhibit G, Tab 1, Schedule 1, Page 3 of 4 – Land Matters

Preamble:

Enbridge Gas Inc. states:

The final construction activity is restoration of lands. The work area is graded to the original contour and topsoil returned on agricultural lands, sod is replaced in lawn areas and other grassed areas are re-seeded. Where required, concrete, asphalt and gravel are replaced and all areas affected by the construction of the pipeline are returned to as close to original condition as possible. As a guide to show the original condition of the area, photos and/or a video will be taken before any work commences. When the clean-up is completed, the approval of landowners or appropriate government authority is obtained.

AND

D.12. When Project cleanup is completed, landowners will be asked by Enbridge Gas to sign a clean-up acknowledgement form if satisfied with the clean-up. This form, when signed, releases the Pipeline Contractor, allowing payment for clean-up on the property. This form in no way releases Enbridge Gas from its obligation for tile repairs, compensation for damages and/or further clean-up as required due to erosion or subsidence directly related to pipeline construction.

Question:

Please provide a copy of Enbridge Gas Inc.'s Clean-up Acknowledgement Form.

Response

Please see Attachment 1 to this response.

ENBRIDGE®

Clean-Up Acknowledgement

50 Keil Drive North, Chatham, Ont. N7M 5M1 352-3100

WBS #	Easement/Lease/CAP Number	
Owner's Name		Yr. Mo. Da. 20
Lot	Concession	Township	County
Project		

I acknowledge that ______________________________ has completed clean-up on my property and their work is satisfactory. I understand this is not a release for damages, but merely an acknowledgement that their clean-up work and repair of fences is satisfactory, subject to any conditions defined in Items 1 and 2 below:

Item 1 - On Easement

____

____

____

____

____

____

Item 2 - Off Easement

____

____

____

____

____

____

Authorizing Signature of Owner/Tenant	Telephone No.
Address	Postal Code

Contractor Representative	Date	Company Representative/Originator	Date

White - Lands Dept., Union Yellow - Landowner

0543 - 2016/09

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Association of Energy and Pipeline Landowner Associations (“CAEPLA”) and its subcommittee, the Dawn Corunna Landowner Committee (“DCLC”)

INTERROGATORY

Reference:

Enbridge Application, Exhibit E, Tab 1, Schedule 1, Page 5 of 5 – Engineering and Construction

Preamble:

Enbridge Gas Inc. states:

> C.24. All necessary permits, approvals and authorizations will be obtained by Enbridge Gas at the earliest appropriate opportunity. Enbridge Gas expects to receive all required approvals prior to commencing construction of the Project.
>
> Enbridge Gas will assign inspection staff to ensure that contractual obligations between Enbridge Gas and the pipeline contractor, provincial ministries, municipal government and landowners are complied with.

Question:

Will Enbridge agree to the appointment of an Independent Construction Monitor by landowners, Enbridge and the OEB to be on site continuously to monitor construction with respect to all issues of concern to landowners, to be available to landowners and to Enbridge at all times, and to file interim and final reports with the OEB? If not, please explain why not.

Response

Subject to gaining an understanding of the qualifications of the Independent Construction Monitor (“ICM”), the defined scope of responsibilities and obligations of an ICM relative to Enbridge Gas and to landowners, and the frequency of reporting to the OEB, Enbridge Gas would agree to the appointment of an ICM for the Project.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Association of Energy and Pipeline Landowner Associations ("CAEPLA") and its subcommittee, the Dawn Corunna Landowner Committee ("DCLC")

INTERROGATORY

Reference:

Stantec Dawn-Corunna Project: Environmental Report, Section 6.4.2 Operation and Maintenance – Year 2024-2074 – Adobe page 88 et ff.

Enbridge Gas Inc. Application, Exhibit C, Tab 1, Schedule 1, Attachment 1, Page 1 of 3 – Net Present Value Assessment of Alternatives

Preamble:

Stantec's Environmental Report states the following about the impacts of future operation and maintenance of the proposed project:

> Development and maintenance activities which have a probability of proceeding during operation and maintenance of the project include:
>
> - Road works: Future road rehabilitation and resurfacing
> - Water works: Future installation of water and wastewater pipelines
> - Pipeline construction and maintenance: Future pipeline construction and maintenance of existing hydrocarbon pipelines
>
> Operation and maintenance activities undertaken by Enbridge Gas should be completed in co-ordination with the Enbridge Gas Environmental Planning Team and will consider potential impacts on natural heritage and socio-economic environment. Appropriate mitigation measures should be developed and implemented based on the proposed maintenance work. Enbridge Gas should obtain all necessary agency permits and approvals, as required. Given the limited scale of impact of any potential operation and maintenance activities, it is anticipated that residual impacts will be minimal and that should any interaction occur with other projects, significant adverse residual effects are not anticipated to be significant.

Enbridge Gas Inc. included consideration of the costs of operation and maintenance expenses, including the costs of integrity digs, in its assessment of the proposed project:

> For the purposes of assessing the proposed Project (NPS 36 Pipeline), the Company:
>
> - Included the estimated cost of periodic cleaning and inspection as O&M expenses.
> - Included the cost of integrity digs and any required repairs as capital expenses.
> - Assumed that nine integrity digs would be required over the approximate 40-year life of the proposed Project.

Question:

a) Please provide details of Enbridge Gas Inc.'s proposed procedures for integrity digs and for other maintenance operations to be employed during the operation of the proposed project.

b) Will Enbridge Gas Inc. agree to offer to landowners an integrity dig agreement setting out construction procedures, off-easement access, compensation, etc.? If so, please provide Enbridge Gas Inc.'s proposed agreement. If not, please explain why not.

c) Will Enbridge Gas Inc. agree to offer to landowners a maintenance agreement setting out construction procedures, off-easement access, compensation, etc.? If so, please provide Enbridge Gas Inc.'s proposed agreement. If not, please explain why not.

Response

a) Enbridge Gas has a well-established Integrity Management Program that meets all applicable regulatory standards as well as all applicable codes and standards, including CSA Z662-19 and the TSSA Code Adoption Document. Inspection methods, such as in-line inspection ("ILI"), are used at periodic intervals to monitor the condition of the pipeline and integrity digs are completed when needed. Enbridge Gas periodically undertakes a number of survey activities, including: leak surveys, right-of-way surveys, and patrol programs as part of our Damage Prevention strategy.

b) Enbridge Gas does not intend to offer integrity dig agreements to all landowners affected by Project construction. Rather, the Company intends to coordinate with individual landowners in the future to gain access to the specific lands required in order to complete the integrity digs deemed necessary at that time.

c) The Easement Agreement set out at Exhibit G, Tab 1, Schedule 1, Attachment 3, deals with pipeline maintenance.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Association of Energy and Pipeline Landowner Associations ("CAEPLA") and its subcommittee, the Dawn Corunna Landowner Committee ("DCLC")

INTERROGATORY

Reference:

Stantec Dawn-Corunna Project: Environmental Report, Sign-off Sheet, Adobe page 2

Preamble:

Stantec's Environmental Report was prepared by Emily Hartwig and reviewed by Mark Knight and David Wesenger.

Question:

Please provide copies of the most recent resumes or CVs for Ms. Hartwig, Mr. Knight, and Mr. Wesenger.

Response

The resumes for Ms. Hartwig, Mr. Knight and Mr. Wesenger are set out at Attachment 1 to this response.

Emily Hartwig B.Sc., EP

Environmental Consultant
8 years of experience · Waterloo, Ontario

Emily Hartwig is an Environmental Consultant in the Approvals and Permitting Group with Stantec Consulting Ltd. She holds an Honours Bachelor of Science in Environmental Science from the University of Guelph, and a Graduate Certificate in Environmental Management and Assessment from Niagara College.

Emily has a working background in agriculture, and has previously worked as regulatory affairs analyst for a not-for-profit agricultural business accelerator, and as a research assistant for the Ontario Ministry of Agriculture, Food and Rural Affairs (OMAFRA), the University of Guelph, and for a private crop protection organization.

During her Undergraduate and Graduate Certificate programs, Emily gained practical and theoretical experience in environmental management systems, project management and technical report preparation.

EDUCATION

Graduate Certificate, Niagara College of Applied Arts and Technology, Niagara-on-the-Lake, ON, 2015

Honours Bachelor of Science in Environmental Science, University of Guelph, Guelph, ON, 2014

MEMBERSHIPS

Environmental Professional (EP), Environmental Careers Organization of Canada (ECO Canada), 2019-2024

PROJECT EXPERIENCE

PUBLIC CONSULTATION: REGULATORY AND PERMITTING

Kingsville Transmission Reinforcement | Union Gas Limited | Kingsville, Ontario | 2017 - 2018 | Environmental Consultant

Union Gas retained Stantec to prepare an Environmental Report for the construction and operation of the proposed pipeline to meet the intent of the OEB's Environmental Guidelines (2016). Provided Project Management assistance, coordinated stakeholder consultation activities.

Bobcaygeon Pipeline | Enbridge Gas Distribution Inc. | Bobcaygeon, Ontario | 2017 | Environmental Consultant

Enbridge retained Stantec to prepare an Environmental Report for the construction and operation of the proposed pipeline to meet the intent of the OEB's Environmental Guidelines (2016). Provided coordination of stakeholder consultation activities.

North Shore LNG Project | Town of Marathon | Manitouwadge, Marathon, Terrace Bay, Schreiber, Wawa, Ontario | 2019-Present | Project Coordinator

Coordinated the public consultation program for this project, including the coordination of the public open houses and notifications, and assisting with the Indigenous community consultation program.

Amherst Island Wind Farm - 74MW | Amherst Island, Ontario | 2017-present | Environmental Consultant

Coordinator and Facilitator of the Amherst Island Community Liaison Committee (CLC) and Community Working Group (CWG) meetings during construction activities for a 75 MW wind power project on Lake Ontario.

ENVIRONMENTAL ASSESSMENTS – OIL AND GAS

London Lines Replacement Project | Enbridge Gas Distribution | 2019, 2020 | Assistant Project Manager

North Shore LNG Project | Stantec Consulting Ltd. | Manitouwadge, Marathon, Terrace Bay, Schreiber, Wawa, Ontario | 2019-present | Project Coordinator

Coordinated Environmental Report writing and acted as the day-to-day Project Manager to produce five (5) Environmental Assessments; one report for each of the North Shore municipalities.

EPCOR - Southern Bruce | EPCOR Natural Gas Limited Partnership | Multiple Locations, Ontario | 2018 | Environmental Consultant

Assisted in the preparation of an Environmental Report and integrated information from technical reports, in accordance with the Ontario Energy Board's (OEB's) Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario (Environmental Guidelines 2016). Tasks included Project Management assistance, stakeholder consultation and coordination.

ASSESSMENTS, PERMITTING, AND COMPLIANCE

CN Milton Logistics Hub - Environmental Assessment | Canadian National Railway | Milton, Ontario, Canada | 2017-present | Environmental Consultant

Stantec completed an Environmental Impact Assessment (EIS) and supporting technical studies for submission to the Canadian Environmental Assessment Agency (CEAA) in support of a proposed intermodal terminal. Coordinated responses to Information Requests with technical leads as part of the Joint Review Panel process under the Canadian Environmental Assessment Act.

2017 Pipeline Integrity Dig Program - Permitting | Trans-Northern Pipelines Inc. | Various Cities | Environmental Consultant

Completed Ministry of Natural Resources and Forestry (MNRF) Notice of Activity (NoA) forms for the 2017 Integrity Dig Program.

2018 Pipeline Integrity Dig Program - Permitting | Trans-Northern Pipelines Inc. | Various Cities | Environmental Consultant

Completed Conservation Authority permit applications.

PUBLICATIONS

Charbonneau, P. and Hartwig, E. Sports Field Benchmarking and Permitting Hours Verification Project.. *Sports Turf Manager.*, 2015, pp. '1', '7', '9-17'.

Mark Knight MA, MCIP, RPP

Environmental Planner · 15 Years of Experience · Waterloo, Ontario

Mark is a registered environmental planner with experience in federal, provincial and class environmental assessments for the municipal, transportation, wind power, and oil and gas sectors. Project participation has involved managing environmental and socio-economic impact assessments and permitting, developing, and implementing consultation strategies, coordinating field studies and construction inspection, and applying knowledge of land use and environmental legislation and policies.

Mark is the Practice Leader for the Environmental Services team in Ontario.

EDUCATION

BA Honors, Geography, Wilfrid Laurier University, Waterloo, Ontario, Canada, 2002

Master of Arts, Geography, University of Waterloo, Waterloo, Ontario, Canada, 2006

MEMBERSHIPS

Member, Ontario Professional Planners Institute

Member, Ontario Association for Impact Assessment

PROJECT EXPERIENCE

Oil and Gas Pipelines

Ontario and National Energy Board/Canadian Energy Regulator, Oil and Gas Pipelines, Multiple Projects, Various Sites, Ontario

Project Manager or Senior Advisor for the preparation of Environmental Reports to either the federal or provincial energy regulators, including managing route selection, consultation programs, field investigations, permitting and construction inspection:

– Community Expansion Projects: Hidden Valley, Cedar Springs, Haldimand Shores
– 4.5 km Kingston Reinforcement Project, OEB
– Dawn Cuthbert Make Piggable Project
– 13 km Greenstone Pipeline Project, OEB
– 20 km Dawn to Corunna Natural Gas Pipeline, OEB
– 10 km Kirkwall to Hamilton Natural Gas Pipeline, OEB
– 59 km Windsor Pipeline Replacement, OEB
– 4.5 km Sarnia Pipeline, OEB
– 40 km Panhandle Reinforcement Natural Gas Pipeline, OEB
– 19 km Kingsville Reinforcement Natural Gas Pipeline, OEB
– Dover Centre Natural Gas Pipeline, OEB
– 19.5 km Hamilton to Milton Natural Gas Pipeline, OEB
– McCraney Creek Natural Gas Pipeline Replacement, OEB
– 13.5 km Burlington to Oakville Natural Gas Pipeline, OEB
– 4,600 km Energy East Pipeline Project, NEB (Ontario Coordinator)
– Ojibway Park Natural Gas Pipeline Replacement, OEB
– 30km Premier Mine Natural Gas Pipeline, OEB
– Strathroy-Caradoc Natural Gas Pipeline Replacement, OEB
– Highway 6 Natural Gas Pipeline Replacement, OEB
– 5 km Payne Sarnia Natural Gas Pipeline, OEB
– 14 km Brantford to Kirkwall Natural Gas Pipeline, OEB
– Shell Natural Gas Pipeline, OEB
– 450 m Natural Gas Pipeline HDD of St. Clair River, NEB
– 90 km Nanticoke GS Natural Gas Pipeline, OEB
– Sudbury Natural Gas Pipeline Relocation, OEB
– Woodford to Meaford Natural Gas Pipeline Relocation, OEB
– 17 km Thunder Bay Natural Gas Pipeline, OEB

Mark Knight MA, MCIP, RPP

Environmental Planner · 15 Years of Experience · Waterloo, Ontario

– 65 km Bayfield to Lobo Natural Gas Pipeline, OEB
– 12 km Bickford to Dawn Natural Gas Pipeline, NEB/OEB

Oil & Gas Midstream, Facilities

Ontario and National Energy Board/Canadian Energy Regulator, Oil & Gas Midstream, Facilities, Multiple Projects, Various Sites, Ontario

Environmental Planner for the preparation of Environmental Reports to either the federal or provincial energy regulators, including managing field investigations, consultation programs, permitting and construction inspection:
– Crowland DSA, Upgrades, OEB
– Dow Moore, Payne, and Kimball-Colinville DSAs, Upgrades, OEB
– Coveny and Kimball-Colinville DSA, Upgrades, OEB
– Nipigon and Vineland Meter Stations, New Build, CER
– Westover Station, Expansion, CER
– Nipigon and Vineland Meter Stations, New Build, CER
– DuPont Valve Station, Expansion, OEB
– Parkway West Compressor Station, New Build, OEB
– Lobo Compressor Station, Expansion, OEB
– Dawn Compressor Station, Expansion, OEB
– Bright Compressor Station, Expansion, OEB
– Empire Odourant Station, Abandonment, NEB

Class Assessments

Municipal Class Environmental Assessments, Multiple Projects, Various Sites, Ontario

Environmental Planner for the preparation of MEA Class Environmental Assessments:
– Williams Parkway Improvements from Torbram Road to Humberwest Parkway, Brampton, ON
– James Snow Parkway Improvements from RR25 to Boston Church Road, Halton Region, ON
– Goreway Drive Improvements from Brandon Gate Drive to Steeles Avenue, Brampton, ON
– Colchester Harbour and Marina Improvements, Colchester, ON
– Streetville Pumping Station and Reservoir Capacity* (Consultation Specialist)
– Milliken Pumping Station* (Consultation Specialist)

Infrastructure Ontario Class Assessments, Multiple Projects, Various Sites, Ontario

Environmental Planner for the preparation of IO Class Environmental Assessments:
– Glenorchy Natural Gas Pipeline Relocation
– Brantford-Kirkwall Pipeline
– William Halton Parkway
– 930 Erb St. West Commercial Development
– Mississauga Off-Road Trail
– Burlington Oakville Pipeline
– Franklin Boulevard Widening
- Dundas Street Widening

Provincial Highways Class and Individual Assessments, Multiple Projects, Various Sites, Ontario

Environmental Planner for the preparation of environmental studies under either the individual or Class Environmental Assessment process, including managing consultation programs:
– Multiple Improvements for the Amherst Island Wind Project, MTO Class EA
– Highway 406 Improvements from Port Robinson Road to East Main Street, MTO Class EA*
– Highway 401 Improvements from Highway 401/410/403 to Hurontario, MTO Class EA*
– Highway 427 Transportation Corridor, Individual EA*
– GTA West Transportation Corridor, Individual EA*
– Highway 401 Improvements from Sydenham Road to Montreal Street, MTO Class EA*

– Highway 534 Beatty Creek Bridge Replacement, MTO Class EA*
– Highway 542 Mindemoya Lake Bridge and Dam Replacement, MTO Class EA*
– Highway 105 Chukuni River Bridge Replacement, MTO Class EA*
– Highway 8 Rehabilitation, MTO Class EA*
– Highway 69 Route Planning Study, MTO Class EA*
– Highway 6 Four Mile Creek Bridge Replacement, MTO Class EA*
– Highway 60 Bridge Replacements, MTO Class EA*
– Niagara to GTA Transportation Corridor, Individual EA* (Consultation Specialist)

Renewable Energy

Renewable Energy Approval (REA), Multiple Projects, Various Sites, Ontario

Environmental Planner for the preparation of Renewable Energy Approval (REA) applications for on-shore wind projects, including managing consultation programs, field investigations and permitting:
– Grand Valley Phase 3 Wind Project, Grand Valley, ON (40 MW)
– White Pines Wind Project, Prince Edward County, ON (60 MW)
– Port Dover and Nanticoke Wind Project, Haldimand and Norfolk, ON (104 MW)
– Brooke-Alvinston Wind Project, Watford, ON (10 MW)

Transportation

Environmental Planner for the regulatory process and related consultation and environmental deliverables., Various Sites, Ontario, Various Sites, Ontario

- Linconville Layover Facility, Metrolinx
- Scarborough Junction, Metrolinx
- Scarborough Grade Separations, Metrolinx
- Milton Logistics Hub, CN
- Ontario Line, Metrolinx

David Wesenger B.E.S.

Senior Principal

Stantec

Over his 32-year career, David has worked as a business center managing leader, inter-disciplinary project team coordinator, senior environmental assessment specialist, and regulatory approvals and permits specialist. David's experience includes practical, project-specific application of environmental assessment methodologies. He has utilized these skills in facility siting, route selection, as well as facility planning, design and construction. David has extensive experience coordinating the public consultation component of projects through the planning, design and construction phases. He has assembled and managed multi-disciplinary teams in a diverse range of infrastructure planning and permitting studies as well as numerous environmental assessments and associated facilities siting and permitting investigations and preliminary design. David has extensive experience leading and overseeing the environmental approvals and permitting process for linear facilities under the Ontario Energy Board Act and National Energy Board Act.

EDUCATION

B.E.S., Environmental and Resource Studies, University of Waterloo, Waterloo, Ontario, 1988

PROJECT EXPERIENCE

Oil & Gas

Imperial Oil Limited Relocation Project, Leave to Construct (Application Senior Advisor, 2022)

Bobcaygeon Community Expansion Project (Senior Advisor, 2021)

Coveny and Kimball-Colinville Well Drilling Project (Senior Advisor, 2021)

East Sixteen Mile Creek NPS12 Pipeline Replacement Project, Environmental Report and Leave to Construct Application (Senior Advisor, 2021)

Don River Replacement (Keating Bridge) (Senior Advisor, 2021)

Haldimand Shores Community Expansion Project (Senior Advisor, 2021)

Storage Enhancement Project (Senior Advisor, 2021)

Various Site Specific Environmental Protection Plans (Independent Reviewer, 2021-2022)

Greenstone Pipeline Project (Senior Advisor, 2020)

Rockland Reinforcement Pipeline (Senior Advisor, 2020)

Windsor Pipeline Replacement (Senior Advisor, 2019)

Kingsville Transmission Pipeline Project (Senior Advisor, 2018)

Fenelon Falls Pipeline Project (Senior Advisor, 2018)

19.5 km Hamilton to Milton Natural Gas Pipeline OEB EA (Senior Advisor, 2016)

Shell Natural Gas Pipeline OEB EA (Senior Advisor)

Brantford to Kirkwall Natural Gas Pipeline OEB EA Addendum (Senior Advisor, 2016)

Parkway West Natural Gas Pipeline OEB EA (Senior Advisor, 2016)

Nanticoke Natural Gas Pipeline Environmental Route Selection (Senior Advisor, 2012)

Blue Water Pipeline - St Clair River Crossing (Senior Advisor, 2012)

Genesis Pipeline Extension Project (Senior Advisor, 2012)

NOVA 2020 Projects (Senior Advisor, 2012)

Glenorchy Natural Gas Pipeline Relocation (Senior Advisor, 2010)

Bayfield to Lobo Natural Gas Pipeline (Senior Advisor, 2010)

Strathroy to Lobo Natural Gas Pipeline Environmental Route Selection (Senior Advisor, 2010)

Sudbury Route Relocation Environmental Report (Senior Advisor, 2009)

Halton Hills Natural Gas Pipeline Environmental Report (Senior Advisor, 2009)

Dawn-Gateway Natural Gas Pipeline Environmental Route Selection (Senior Advisor, 2009)

St.Clair Energy Centre Natural Gas Transmission Pipeline (Project Manager, 2006)

Toronto Port Lands, Reinforcement Project: South Section. Natural Gas Transmission Pipeline, Enbridge Gas Distribution Inc. (Project Manager, 2006)

Thunder Bay Generating Station, 12" Natural Gas Pipeline, Union Gas Limited (Project Manager, 2005)

Environment and Socio-Economic Review of Integrity Dig Sites (Lines 7,8,9,10 and 11), Enbridge Pipelines Inc. (Project Manager)

Greenfield Energy Centre Natural Gas Transmission Pipeline, Union Gas Ltd. (Project Manager)

St. Clair Pool Development Project Environmental Report, Market Hub Partners Canada (Project Manager)

Southdown Station Natural Gas Transmission Pipeline, Sithe Southdown Pipelines Ltd. (Project Manager)

Goreway Station Natural Gas Transmission Pipeline, Sithe Canadian Pipelines Ltd. (Project Manager)

17 km Hamilton to Milton 48" Natural Gas Pipeline, Union Gas Limited (Project Manager)

20 km Strathroy to Lobo 48" Natural Gas Transmission Pipeline, Union Gas Limited (Project Manager)

7km Guelph Reinforcement 12" Natural Gas Pipeline, Union Gas Limited (Project Manager)

Sarnia Airport Pool Natural Gas Pipeline and Sarnia Airport Storage Pool Development Plan, Market Hub Partners Canada (Project Manager)

David Wesenger B.E.S.

Senior Principal

60 km PRISM Pipeline - 12” CAT Naptha Transmission Pipeline, Imperial Oil Limited (Project Manager)

832 km Line 9 Reversal - 30” Crude Oil Transportation Project, Enbridge Pipelines (Project Manager)

Toronto to Montreal - Oil Spill Control Point Manual, Enbridge Pipelines (Project Manager)

Tipperary Pool Natural Gas Pipeline and Tipperary Storage Pool Development Plan, Tribute Resources Inc. (Project Manager)

Tank 226 - 150,000 barrel Oil Storage Tank, Enbridge Pipelines (Project Manager)

Sarnia to Nanticoke - Oil Spill Control Point Manual, Enbridge Pipelines (Project Manager)

Route selection studies for more than 500 km of distribution pipeline for domestic natural gas delivery in Ontario (Project Manager)

Proposed Bryanston Natural Gas Compressor Station, InterCoastal Pipeline (Project Manager)

PRISM Pipeline - Oil Spill Control Control Point Manual, Imperial Oil (Project Manager)

PRISM Metering Station, Hamilton, Ontario, Imperial Oil Limited (Project Manager)

Line 9 Reversal Tank 227 - 150,000 barrel Oil Storage Tank, Enbridge Pipelines (Project Manager)

Ladysmith Pool Natural Gas Pipeline and Ladysmith Storage Pool Development Plan, Tecumseh Gas Storage (Project Manager)

Initiating Pump Station, Terrebonne, Quebec, Enbridge Pipelines (Project Manager)

Gretna to Wawina - Oil Spill Control Point Manual, Lakehead Pipelines (Project Manager)

Environmental Protection Plan for Mainline Construction, Vector Pipelines L.P. Limited (Project Manager)

Environmental Protection Plan for Directional Drilling the St. Clair River, Vector Pipelines L.P. Limited (Project Manager)

Environmental Management Manual, Maritimes and Northeast Pipelines (Project Manager)

Environmental Inspection, Kitchener-Waterloo West Line, NPS 16 Mainline Construction, Union Gas (Environmental Inspector)

Environmental Inspection, Kirkwall to Hamilton, NPS 48 Mainline Construction, Union Gas (Environmental Inspector)

Directional Drill of the St. Clair River, Vector Pipeline L.P. Limited (Project Manager)

Directional Drill of the St. Clair River, Niagara Gas Transmission Ltd. (Project Manager)

Directional Drill of the St. Clair River, InterCoastal Pipeline (Project Manager)

David Wesenger B.E.S.

Senior Principal

Coveny Pool Natural Gas Pipeline and Coveny Storage Pool Development Plan, Tecumseh Gas Storage (Project Manager)

75 km Millennium West - 36” Natural Gas Transmission Pipeline, St. Clair Pipelines (Project Manager)

30 km Ancaster to Canadian Gypsum Natural Gas Transmission Pipeline, Union Gas Limited (Project Manager)

225 km Line 8 Oil Products Transportation System, Enbridge Pipelines (Project Manager)

20 km Vector Pipeline - 42” Natural Gas Transmission Pipeline, Vector Pipelines L.P. Limited (Project Manager)

1992-93, 1993-94, 1995-96 Facilities Application, Environmental and Socio-Economic Assessments, TransCanada PipeLines Ltd. (Project Manager)

10 km Northland Power Cogeneration Transmission Pipeline, Centra Gas Limited (Project Manager)

13.5 km Burlington to Oakville Natural Gas Peipleine, OEB EA (Senior Advisor)

Ontario and National Energy Board, Oil & Gas Midstream, Facilities, Multiple Projects, Various Sites, Ontario

Senior Advisor for the preparation of Environmental
Reports to either the National or Ontario Energy Board,
including managing field investigations, consultation
programs, permitting and construction inspection:
– Parkway West Compressor Station, New Build, OEB
– Lobo Compressor Station, Expansion, OEB
– Empire Odourant Station, Abandonment, NEB
– Dawn Compressor Station, Expansion, OEB
– Bright Compressor Station, Expansion, OEB

40 KM Dawn to Dover Natural Gas Pipeline OEB EA (Senior Advisor)

Highway 6 Natural Gas Pipeline Replacement Environmental Review (Senior Advisor)

Expert Testimony

Expert Testimony, EB-2014-0261, Union Gas Limited, Dawn Parkway 2016 Expansion Project

Expert Testimony EB-2006-0305, Enbridge Portlands. Energy Centre Reinforcement Project, Leave to Construct Application. (Project Manager)

Expert Testimony, EB-2005-0550; Union Gas Limited, Trafalgar Facilities, Expansion Program, Leave to Construct Application (Project Manager, 2005)

Expert Testimony, EB-2005-0201, Union Gas Limited, Trafalgar Facilities Expansion Program Leave to Construct Application (Project Manager)

Expert Testimony, RP-2005-0022, EB-2005-0473; Union Gas Limited, Greenfield Energy Centre Natural Gas Pipeline, Leave to Construct Application (Project Manager, 2005)

Expert Testimony, RP-2001-0059, Imperial Oil Limited, PRISM Pipeline Leave to Construct Application (Project Manager)

David Wesenger B.E.S.

Senior Principal

Expert Testimony, RP-2000-0110, Union Gas Limited, Trafalgar Facilites Expansion Program Leave to Construct Application (Project Manager)

Expert Testimony, RP-1999-0047, Union Gas Limited, Century Pools Storage Development Phase II Leave to Construct Application (Project Manager)

Power

Port Alma Wind Power Project, Kruger Energy, Port Alma, ON (Project Manager)

Southdown Station, Mississauga, Ontario - 800 MW Power Plant, Sithe Energies Canadian Development (Project Manager)

Goreway Station, Brampton, Ontario - 800 MW Power Plant, Sithe Energies Canadian Development (Project Manager)

40 km Les Cedres Hydroelectric Development 500 kV Transmission Line, Hydro Quebec (Project Manager)

2 km 230kV Hydroelectric Transmission Line, Sithe Energies Canadian Development (Project Manager)

Management Consulting

Environmental Review Program, Enbridge Eastern Region (Project Manager, 1999)

Environmental Guidelines and Standards for Pipeline Construction, Enbridge Pipelines (Technical Support)

Environmental Management Manual for Environmental Protection, Enbridge Gas Distribution (Technical Support)

Environmental Inspector's Handbook, Union Gas Limited (Project Manager)

Environmental Guidelines for Access Roads and Gathering Lines, Tecumseh Gas Storage (Technical Support)

Environmental Code of Practice, Centra Gas Limited (Technical Support)

Corporate Environmental Policy, Centra Gas Limited (Technical Support)

Environmental Inspection / Post Construction Monitoring

Kirkwall to Hamilton Natural Gas Pipeline (Environmental Inspector)

Kitchener-Waterloo West Natural Gas Pipeline (Environmental Inspector)

PUBLICATIONS

P.G. Prier, D.S. Eusebi and D.P. Wesenger. Environmental Management System Challenge with Linear Facilities.. Seventh International Symposium on Environmental Concerns in Rights-of-Way Management p.263 to 266., 2000.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Association of Energy and Pipeline Landowner Associations (“CAEPLA”) and its subcommittee, the Dawn Corunna Landowner Committee (“DCLC”)

INTERROGATORY

Reference:

Enbridge Gas Inc. Application, Exhibit G, Tab 1, Schedule 1, Page 2 of 4 – Land Matters

Enbridge Gas Inc. Application, Exhibit G, Tab 1, Schedule 1, Attachment 3, Page 2 of 5 – Land Matters – Pipeline Easement

Enbridge Gas Inc. Application, Exhibit G, Tab 1, Schedule 1, Attachment 4, Page 2 of 5 – Land Matters – Temporary Land Use Agreement

Enbridge Gas Inc. Application for the Greenstone Pipeline Project (EB-2021-0205), Exhibit G, Tab 1, Schedule 1, Pages 2 and 3 of 3, Adobe pages 54-55 and Attachments 1-4

Ontario Energy Board Decision and Order for the Enbridge Gas Inc. Greenstone Pipeline Project (EB-2021-0205) dated March 17, 2022 at page 14 (Adobe page 16)

Preamble:

Enbridge Gas Inc. says the following about the landowner agreements proposed for approval by the OEB:

B.7. Enbridge Gas’s form of Pipeline Easement is included as Attachment 3 to this Exhibit. This agreement was approved by the OEB for use as part of the Company’s Greenstone Pipeline Project (EB-2021-0205) on March 17, 2022. This agreement covers the installation, operation, and maintenance of one pipeline. The major restrictions imposed on the landowner by the agreement are that the landowner cannot erect buildings or privacy fencing on the easement. In addition, the landowner cannot excavate on the easement or install field tile without prior notification to Enbridge Gas. The landowner is free to farm the easement or turn the easement into a laneway.

B.8. The Enbridge Gas form of Temporary Land Use agreement is included as Attachment 4 to this Exhibit. This agreement was approved by the OEB for use as part of the Company's Greenstone Pipeline Project (EB-2021-0205) on March 17, 2022. This agreement typically applies for a period of two years, beginning in the year of construction, allowing Enbridge Gas to return in the year following construction to perform clean-up work as required.

The landowner agreements proposed by Enbridge Gas Inc. and approved by the OEB for the Greenstone Pipeline Project were modified from earlier approved versions to replace the term "gross negligence" in the indemnity clauses with the term "negligence". Enbridge Gas Inc. submitted to the OEB that this change and other changes were "… minor and of housekeeping nature."

<u>Question</u>:

a) Will Enbridge Gas Inc. agree to restore the term "gross negligence" in the indemnity clauses of the landowner agreements for this project? If not, why not?

b) Please explain how the replacement of the term "gross negligence" with "negligence" in the indemnity clause for the protection of landowners was "minor" and of a "housekeeping nature".

<u>Response</u>

a) & b)
Enbridge Gas believes that negligence is the appropriate standard. The safety and integrity of our system is paramount, and landowners and other third parties are expected to exercise a reasonable standard of care while conducting activities in the vicinity of our pipelines and associated facilities. Enbridge Gas should not be liable for any losses, damages or injuries caused by landowners who fail to meet a reasonable standard of care.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Association of Energy and Pipeline Landowner Associations ("CAEPLA") and its subcommittee, the Dawn Corunna Landowner Committee ("DCLC")

INTERROGATORY

Reference:

Enbridge Gas Inc. Application, Exhibit A, Tab 2, Schedule 1, Page 1 of 4

Preamble:

The style of cause for Enbridge Gas Inc.'s Application includes reference to "Options for Temporary Land Use":

> AND IN THE MATTER OF an Application by Enbridge Gas Inc. for an Order or Orders approving the proposed forms of agreements for Pipeline Easement and Options for Temporary Land Use.

Question:

Does Enbridge Gas Inc. intend to request option agreements from landowners in respect of the permanent easement or the temporary land use area for the proposed project? If so, please provide copies of the proposed option agreement(s).

Response

Yes. Please see Attachment 1 to this response.

OPTION FOR EASEMENT

(hereinafter called the "Option")

BETWEEN [ ]
(hereinafter called the "Owner")

and

ENBRIDGE GAS INC.
(hereinafter called the "Company")

WHEREAS the Owner is the registered owner in fee simple of the lands hereinafter referred to as

PIN: [ ]

Legal Description: [ ]

(the "Lands")

AND WHEREAS the Company requires an easement, free of all liens, claims, charges or encumbrances over all or a portion of the Lands as more particularly shown on the sketch attached as, **Appendix "A".**

AND WHEREAS the Company wishes to obtain certain option rights to the Lands as more particularly set out herein;

NOW THEREFORE in consideration of the payment(s) made or to be made to the Owner by the Company in accordance with the provisions of this Option, the Owner agrees to grant to the Company an Option to acquire an easement from the Owner, over all or a portion of the Land (the "Easement") upon the terms and subject to the conditions hereinafter set forth in respect of which the Owner and the Company respectively covenant and agree as follows:

1. The Owner hereby grants to the Company an irrevocable and exclusive option (the "**Option**") to acquire an Easement over, in and through the Lands, substantially upon the terms and conditions set out in the Pipeline Easement attached hereto as **Appendix "B".** Upon the exercising of the Option by the Company the parties agree to be bound by the terms and conditions of the Easement Agreement.

2. The Company shall have the right at any time on or before 11:59 p.m. on the ___ day of ______________ 20__ (the "Expiry Date") to deliver a notice to the Owner, advising of the Company's intention to exercise the Option. If the Company does not give such a notice prior to the Expiry Date, or any extended date, then this Option shall terminate and neither the Owner nor the Company shall have any further obligations hereunder.

3. The price for the Option shall be **00/100 Dollars ($)** and shall be paid within 30 days of acceptance of this Option by the Owner.

4. The Owner hereby authorizes the Company to prepare and register a reference plan of survey of the Easement. The Owner and the Company agree that if and when such survey has been prepared such legal description based on such survey shall conclusively be deemed to constitute the full, true and accurate description of the Easement and such description will be substituted for the description or the sketch of the Easement contained in this Option.

5. The Owner covenants with the Company that the Owner has the sole right to grant the Option and convey the Easement.

6. The Owner hereby agrees that the Company's surveyors, engineers, and servants may enter on the Lands forthwith and at any time while this Option remains in effect for the purpose of performing soil tests, surveys, water exploration, environmental surveys, core drilling and archeological investigations. The Owner hereby agrees that immediately following the giving of the notice referred to in Clause 2 the Company shall have the immediate right to bring its equipment and equipment of its servants, agents and contractors upon the Lands to commence construction of its works.

7. The Owner hereby consents to registration of a notice of this Option, and the Easement, by the Company against title to the Lands.

8. All notices required or permitted to be given hereunder shall be in writing and delivered in person or by prepaid registered mail or courier in case of the Company to: Enbridge Gas Inc., 50 Keil Drive North, Chatham, Ontario, N7M 5M1 Attention: Lands Department and in the case of the Owner to: or to such other address as the Company and the Owner respectively may from time to time designate in writing and any such notice shall be deemed to have been given to and received by the addressee on the date on which it was delivered or if mailed shall be deemed to have been given to and received by the addressee on the fifth business day following the date on which it was deposited in the mail, except in the event of interruption of mail service after mailing, in which event it shall be deemed to have been given when actually received.

9. It is further agreed that the Company shall assume all liability and obligations for any and all loss, damage or injury, (including death) to persons or property that would not have happened but for this Option or anything done or maintained by the Company hereunder or intended so to be and the Company shall at all times indemnify and save harmless the Owner from and against all such loss, damage or injury and all actions, suits, proceedings, costs, charges, damages, expenses, claims or demands arising therefrom or connected therewith provided that the Company shall not be liable under the Clause to the extent to which such loss, damage or injury is caused or contributed to by the negligence or wilful misconduct of the Owner.

10. (a) The Company represents that it is registered for the purposes of the Harmonized Goods and Services Tax (hereinafter called "HST") in accordance with the applicable provisions in that regard and pursuant to the Excise Tax Act, (R.S.C., 1985, c. E-15), (hereinafter called "Excise Tax Act"), as amended.

    (b) The Company shall undertake to self-assess the HST payable in respect of this transaction pursuant to subparagraphs 221(2) and 228(4) of the Excise Tax Act, and to remit and file a return in respect of HST owing as required under the said Act for the reporting period in which the HST in this transaction became payable.

    (c) The Company shall indemnify and save harmless the Owner from and against any and all claims, liabilities, penalties, interest, costs and other legal expenses incurred, directly or indirectly, in connection with the assessment of HST payable in respect of the transaction contemplated by this Option. The Company's obligations under this Clause shall survive this Option.

11. Site Specific Notes: (if applicable) Click here to enter text.

DATED this _____ day of ____________________ 20__.

[Insert name of individuals or Corporation]

Signature (Owner)	Signature (Owner)
Print Name(s) (and position held if applicable)	Print Name(s) (and position held if applicable)
Choose an item.	Choose an item.
Address (Owner)	Address (Owner)

ENBRIDGE GAS INC.

Signature (Transferee)

[insert name of signing authority], Choose an item.

Name & Title (Enbridge Gas Inc.)

I have authority to bind the Corporation.

519-436-4673

Telephone Number (Enbridge Gas Inc.)

Additional Information: (if applicable)

Solicitor: ______________________

Telephone: ______________________

APPENDIX "A"

SKETCH

APPENDIX “B”

PIPELINE EASEMENT

PIPELINE EASEMENT

(hereinafter called the “Easement”)

Between [ ]
(hereinafter called the “Transferor”)

and

ENBRIDGE GAS INC.
(hereinafter called the “Transferee”)

This is an Easement in Gross.

WHEREAS the Transferor is the owner in fee simple of those lands and premises more particularly described as:

PIN: [ ]

Legal Description: [ ]

(hereinafter called the "Transferor's Lands").

The Transferor does hereby GRANT, CONVEY, TRANSFER AND CONFIRM unto the Transferee, its successors and assigns, to be used and enjoyed as appurtenant to all or any part of the lands, the right, liberty, privilege and easement on, over, in, under and/or through a strip of the Transferor's Lands more particularly described as:

BEING THE PIN/PART OF THE PIN: [ ]

Legal Description: [ ]

(hereinafter called the "Lands") to survey, lay, construct, maintain, brush, clear trees and vegetation, inspect, patrol, alter, remove, replace, reconstruct, repair, move, keep, use and/or operate one pipeline for the transmission of Pipeline quality natural gas as defined in The Ontario Energy Board Act S.O. 1998 (hereinafter called the "Pipeline") including therewith all such buried attachments, equipment and appliances for cathodic protection which the Transferee may deem necessary or convenient thereto, together with the right of ingress and egress at any and all times over and upon the Lands for its servants, agents, employees, those engaged in its business, contractors and subcontractors on foot and/or with vehicles, supplies, machinery and equipment for all purposes necessary or incidental to the exercise and enjoyment of the rights, liberty, privileges and easement hereby granted. The Parties hereto mutually covenant and agree each with the other as follows:

1. In Consideration of the sum of XX/100 Dollars ($) (hereinafter called the "Consideration"), which sum is payment in full for the rights and interest hereby granted and for the rights and interest, if any, acquired by the Transferee by expropriation, including in either or both cases payment in full for all such matters as injurious affection to remaining lands and the effect, if any, of registration on title of this document and where applicable, of the expropriation documents, subject to Clause 12 hereof to be paid by the Transferee to the Transferor within 90 days from the date of these presents or prior to the exercise by the Transferee of any of its rights hereunder other than the right to survey (whichever may be the earlier date), the rights, privileges and easement hereby granted shall continue in perpetuity or until the Transferee, with the express written consent of the Transferor, shall execute and deliver a surrender thereof. Prior to such surrender, the Transferee shall remove all debris as may have resulted from the Transferee's use of the Lands from the Lands and in all respects restore the Lands to its previous productivity and fertility so far as is reasonably possible , save and except for items in respect of which compensation is due under Clause 2, hereof. As part of the Transferee’s obligation to restore the Lands upon surrender of its easement, the Transferee agrees at the option of the Transferor to remove the Pipeline from the Lands. The Transferee and the Transferor shall surrender the Easement and the Transferee shall remove the Pipeline at the Transferor’s option where the Pipeline has been abandoned. The Pipeline shall be deemed to be abandoned where: (a) corrosion protection is no longer applied to the Pipeline, or, (b) the Pipeline becomes unfit for service in accordance with Ontario standards. The Transferee shall, within 60 days of either of these events occurring, provide the Transferor with notice of the event. Upon

removal of the Pipeline and restoration of the Lands as required by this agreement, the Transferor shall release the Transferee from further obligations in respect of restoration.

2. The Transferee shall make to the Transferor (or the person or persons entitled thereto) due compensation for any damages to the Lands resulting from the exercise of any of the rights herein granted, and if the compensation is not agreed upon by the Transferee and the Transferor, it shall be determined by arbitration in the manner prescribed by the Expropriations Act, R.S.O. 1990, Chapter E-26 or any Act passed in amendment thereof or substitution therefore. Any gates, fences and tile drains curbs, gutters, asphalt paving, lockstone, patio tiles interfered with by the Transferee shall be restored by the Transferee at its expense as closely as reasonably possible to the condition and function in which they existed immediately prior to such interference by the Transferee and in the case of tile drains, such restoration shall be performed in accordance with good drainage practice and applicable government regulations.

3. The Pipeline (including attachments, equipment and appliances for cathodic protection but excluding valves, take-offs and fencing installed under Clause 9 hereof) shall be laid to such a depth that upon completion of installation it will not obstruct the natural surface run-off from the Lands nor ordinary cultivation of the Lands nor any tile drainage system existing in the Lands at the time of installation of the Pipeline nor any planned tile drainage system to be laid in the Lands in accordance with standard drainage practice, if the Transferee is given at least thirty (30) days' notice of such planned system prior to the installation of the Pipeline. The Transferee agrees to make reasonable efforts to accommodate the planning and installation of future tile drainage systems following installation of the Pipeline so as not to obstruct or interfere with such tile installation. In the event there is a change in the use of all, or a portion of the Transferor's Lands adjacent to the Lands which results in the pipeline no longer being in compliance with the pipeline design class location requirements, then the Transferee shall be responsible for any costs associated with any changes to the Pipeline required to ensure compliance with the class location requirements.

4. As soon as reasonably possible after the construction of the Pipeline, the Transferee shall level the Lands and unless otherwise agreed to by the Transferor, shall remove all debris as may have resulted from the Transferee's use of the Lands therefrom and in all respects restore the Lands to its previous productivity and fertility so far as is reasonably possible, save and except for items in respect of which compensation is due under Clause 2 hereof.

5. It is further agreed that the Transferee shall assume all liability and obligations for any and all loss, damage or injury, (including death) to persons or property that would not have happened but for this Easement or anything done or maintained by the Transferee hereunder or intended so to be and the Transferee shall at all times indemnify and save harmless the Transferor from and against all such loss, damage or injury and all actions, suits, proceedings, costs, charges, damages, expenses, claims or demands arising therefrom or connected therewith provided that the Transferee shall not be liable under the clause to the extent to which such loss, damage or injury is caused or contributed to by the negligence or wilful misconduct of the Transferor.

6. In the event that the Transferee fails to comply with any of the requirements set out in Clauses 2, 3, or 4 hereof within a reasonable time of the receipt of notice in writing from the Transferor setting forth the failure complained of, the Transferee shall compensate the Transferor (or the person or persons entitled thereto) for any damage, if any, necessarily resulting from such failure and the reasonable costs if any, incurred in the recovery of those damages.

7. Except in case of emergency, the Transferee shall not enter upon any of the Transferor's Lands, other than the Lands, without the consent of the Transferor. In case of emergency the right of entry upon the Transferor's Lands for ingress and egress to and from the Lands is hereby granted. The determination of what circumstances constitute an emergency, for purposes of this paragraph is within the absolute discretion of the Transferee, but is a situation in which the Transferee has a need to access the Pipeline in the public interest without notice to the Transferor, subject to the provisions of Clause 2 herein. The Transferee will, within 72 hours of entry upon such lands, advise the Transferor of the said emergency circumstances and thereafter provide a written report to Transferor with respect to the resolution of the emergency situation The Transferee shall restore the lands of the Transferor at its expense as closely as reasonably practicable to the condition in which they existed immediately prior to such interference by the Transferee and in the case of tile drains, such restoration shall be performed in accordance with good drainage practice.

8. The Transferor shall have the right to fully use and enjoy the Lands except for planting trees over the lesser of the Lands or a six (6) meter strip centered over the Pipeline, and except as may be necessary for any of the purposes hereby granted to the Transferee, provided that the Transferor shall not excavate, drill, install, erect or permit to be excavated, drilled, installed or erected in, on,

over or through the Lands any pit, well, foundation, building, mobile homes or other structure or installation and the Transferor shall not deposit or store any flammable material, solid or liquid spoil, refuse, waste or effluent on the Lands. Notwithstanding the foregoing the Transferee upon request shall consent to the Transferor erecting or repairing fences, hedges, pavement, lockstone constructing or repairing tile drains and domestic sewer pipes, water pipes, and utility pipes and constructing or repairing lanes, roads, driveways, pathways, and walks across, on and in the Lands or any portion or portions thereof, provided that before commencing any of the work referred to in this sentence the Transferor shall (a) give the Transferee at least (30) clear days' notice in writing describing the work desired so as to enable the Transferee to evaluate and comment on the work proposed and to have a representative inspect the site and/or be present at any time or times during the performance of the work, (b) shall follow the instructions of such representative as to the performance of such work without damage to the Pipeline, (c) shall exercise a high degree of care in carrying out any such work and, (d) shall perform any such work in such a manner as not to endanger or damage the Pipeline as may be required by the Transferee.

9. The rights, privileges and easement herein granted shall include the right to install, keep, use, operate, service, maintain, repair, remove and/or replace in, on and above the Lands any valves and/or take-offs subject to additional agreements and to fence in such valves and/or take-offs and to keep same fenced in, but for this right the Transferee shall pay to the Transferor (or the person or persons entitled thereto) such additional compensation as may be agreed upon and in default of agreement as may be settled by arbitration under the provisions of The Ontario Energy Board Act, S.O. 1998, or any Act passed in amendment thereof or substitution therefore. The Transferee shall keep down weeds on any lands removed from cultivation by reason of locating any valves and/or take-offs in the Lands.

10. Notwithstanding any rule of law or equity and even though the Pipeline and its appurtenances may become annexed or affixed to the realty, title thereto shall nevertheless remain in the Transferee.

11. Neither this Agreement nor anything herein contained nor anything done hereunder shall affect or prejudice the Transferee's rights to acquire the Lands or any other portion or portions of the Transferor's Lands under the provisions of The Ontario Energy Board Act, S.O. 1998, or any other laws, which rights the Transferee may exercise at its discretion in the event of the Transferor being unable or unwilling for any reason to perform this Agreement or give to the Transferee a clear and unencumbered title to the easement herein granted.

12. The Transferor covenants that he has the right to convey this Easement notwithstanding any act on his part, that he will execute such further assurances of this Easement as may be requisite and which the Transferee may at its expense prepare and that the Transferee, performing and observing the covenants and conditions on its part to be performed, shall have quiet possession and enjoyment of the rights, privileges and easement hereby granted. If it shall appear that at the date hereof the Transferor is not the sole owner of the Lands, this Easement shall nevertheless bind the Transferor to the full extent of his interest therein and shall also extend to any after-acquired interest, but all moneys payable hereunder shall be paid to the Transferor only in the proportion that his interest in the Lands bears to the entire interest therein.

13. In the event that the Transferee fails to pay the Consideration as hereinbefore provided, the Transferor shall have the right to declare this Easement cancelled after the expiration of 15 days from personal service upon the Manager, Land Services of the Transferee at its Executive Head Office in Chatham, Ontario, (or at such other point in Ontario as the Transferee may from time to time specify by notice in writing to the Transferor) of notice in writing of such default, unless during such 15 day period the Transferee shall pay the Consideration; upon failing to pay as aforesaid, the Transferee shall forthwith after the expiration of 15 days from the service of such notice execute and deliver to the Transferor at the expense of the Transferee, a valid and registrable release and discharge of this Easement.

14. All payments under these presents may be made either in cash or by cheque of the Transferee and may be made to the Transferor (or person or persons entitled thereto) either personally or by mail. All notices and mail sent pursuant to these presents shall be addressed to:

    the Transferor at:

    and to the Transferee at:

    Enbridge Gas Inc.
P.O. Box 2001
50 Keil Drive North
Chatham, Ontario N7M 5M1
Attention: Manager, Land Services or to such other address in either case as the Transferor or the Transferee respectively may from time to time appoint in writing.

15. The rights, privileges and easement hereby granted are and shall be of the same force and effect as a covenant running with the Transferor's Land and this Easement, including all the covenants and conditions herein contained, shall extend to, be binding upon and inure to the benefit of the heirs, executors, administrators, successors and assigns of the Parties hereto respectively; and, wherever the singular or masculine is used it shall, where necessary, be construed as if the plural, or feminine or neuter had been used, as the case may be.

16. (a) The Transferee represents that it is registered for the purposes of the Harmonized Goods and Services Tax (hereinafter called "HST") in accordance with the applicable provisions in that regard and pursuant to the Excise Tax Act, (R.S.C., 1985, c. E-15), (hereinafter called "Excise Tax Act"), as amended.

    (b) The Transferee shall undertake to self-assess the HST payable in respect of this transaction pursuant to subparagraphs 221(2) and 228(4) of the Excise Tax Act, and to remit and file a return in respect of HST owing as required under the said Act for the reporting period in which the HST in this transaction became payable.

    (c) The Transferee shall indemnify and save harmless the Transferor from and against any and all claims, liabilities, penalties, interest, costs and other legal expenses incurred, directly or indirectly, in connection with the assessment of HST payable in respect of the transaction contemplated by this Easement. The Transferee's obligations under this Clause shall survive this Easement.

17. The Transferor hereby acknowledges that this Easement will be registered electronically.

18. The Transferee hereby declares that this easement is being acquired by the Transferee for the purpose of a hydrocarbon line within the meaning of Part VI of the Ontario Energy Board Act, 1998 and/or a utility line within the meaning of the Ontario Energy Board Act, 1998.

Dated this _____ day of _______________ 20__.

[Insert name of Individuals or Corporation]

Signature (Transferor)	Signature (Transferor)
Print Name(s) (and position held if applicable)	Print Name(s) (and position held if applicable)
Choose an item.	Choose an item.
Address (Transferor)	Address (Transferor)

ENBRIDGE GAS INC.

Signature (Transferee)

, Choose an item.

Name & Title (Enbridge Gas Inc.)

I have authority to bind the Corporation.

519-436-4673

Telephone Number (Enbridge Gas Inc.)

Additional Information: (if applicable):

Property Address:

HST Registration Number:

ENBRIDGE GAS INC.

Answer to Interrogatory from
Chippewas of Kettle and Stony Point First Nation together with Southwind Corporate Development Inc. ("CKSPFN")

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, pp.1, 31
Exhibit B, Tab 1, Schedule 1, Attachment 2, Page 3 of 53

Preamble:

EGI requests leave to construct approximately 20 km of NPS 36 pipeline from the Dawn Operations Centre ("Dawn") in the Township of Dawn Euphemia to the Corunna Compressor Station in St. Clair Township (the "Project"). EGI notes in the Application that it is proposing to retire and abandon 7 reciprocating compressor units located within the Corunna Compressor Station ("CCS") site. [p.1]

EGI's conclusions regarding the purpose and need of the Project include, among others, EGI's forecasted storage requirements based on its 2021 and 2022 Annual Gas Supply Plan Updates.

EGI notes that CCS has two main modes of operation: injection and withdrawal. "Injection operating mode takes gas from the two twin 30 NPS transmission pipelines from Dawn and flows the gas through CCS to the offsite storage pools. Withdrawal operating mode takes gas from the storage pool pipelines and flows through CCS into the transmission pipelines back to the Dawn facility." [p.3]

Question:

a) Please explain what "retire and abandon" means and provide a description of the process EGI proposes to undertake in relation to same.

b) Please discuss EGI's regional planning and gas supply and demand forecasts for Southwestern Ontario and indicate how the Project supports and is aligned with EGI's service growth forecasts in the region.

c) Please indicate whether the 7 compressor units at the CCS site are to be left in place as part of the Project. If yes, please discuss the potential and/or probable environmental or health impacts associated with leaving the compressors in place. If no, please provide details regarding the removal of the compressors.

d) Has EGI considered non-pipeline alternatives, such as installing new compressors at the CCS?

e) Please discuss whether new compressors could be powered electrically.

f) Please indicate how the remaining four compressors will be powered.

g) Please provide details regarding what will happen to the two pipelines currently running from Dawn to Corunna and indicate whether they will they still transport natural gas or whether they are to be abandoned and purged with nitrogen.

h) If the two existing pipelines are no longer required, would EGI consider removing them from the right-of-way and re-purposing the right-of-way for the new Dawn to Corunna 36” pipeline?

i) Please indicate whether EGI has or will consider equity participation of First Nations, including CKSPFN, in relation to the Project. If yes, please discuss what equity participation means to EGI and how First Nations may participate. If no, please explain why not. Please provide all related policies, documents, presentations, or other written materials relating to same.

<u>Response</u>

a) & c)
The 7 compressors identified to be retired and abandoned as part of the proposed Project will be removed from the CCS site. In the evidence the term retire has been used to mean removing those assets from operations. In addition, the term abandon means that the compressors will physically be removed from the compressor station. The compressors will be lifted and moved out of the buildings. Associated piping, electrical and controls for the seven compressors will also be removed from the building. Any remaining infrastructure that cannot be removed because it would impact the remaining compressors or operation of the station will remain. The remaining infrastructure will be deenergized and left in a state that ensures it will not impact the safe operation of remaining compressor station facilities.

b) Please see Exhibit B, Tab 1, Schedule 1 for information related to Project Need. The Project is not related to regional growth in Southwestern Ontario.

Enbridge Gas's most recent annual and design day demand forecasts were presented as part of its 2022 Annual Gas Supply Plan Update.[1]

d) & e)
Yes, please see Exhibit C of the Company's pre-filed evidence for details of its assessment of facility and non-facility alternatives.

f) The remaining 4 CCS compressor units will continue to be powered by natural gas.

g) & h)
TR1 and TR2 will continued to be used as outlined in Exhibit C, Tab 1, Schedule1, p. 25.

i) Enbridge Inc.'s Indigenous Peoples' Policy includes a commitment to consider wealth sharing (equity) on suitable "greenfield" projects which typically entail development of a new site, corridor or in a new area of investment.[2]

The proposed Project seeks to replace existing assets. Given the nature of the Project, there will be no equity participation opportunities. While there are no clear mechanisms for revenue sharing under the current OEB regulatory framework, the Company remains open to discussing the priorities of Indigenous groups and to exploring opportunities to advance innovative partnerships and economic inclusion approaches, where feasible in the future.

[1] EB-2022-0072, 2022 Annual Update to 5 Year Gas Supply Plan (UPDATED), June 9, 2022, pp. 24-25.
[2] The Indigenous Peoples Policy is set out at Exhibit H, Tab 1, Schedule 1, Attachment 4.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Chippewas of Kettle and Stony Point First Nation together with Southwind Corporate Development Inc. ("CKSPFN")

INTERROGATORY

Reference:

- Dawn – Corunna Project: Environmental Report - FINAL REPORT - Prepared by: Stantec Consulting Ltd., September 21, 2021 (the "Environmental Report")
- Ontario Energy Board: Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario (the "Environmental Guidelines")
- Exhibit F, Tab 1, Schedule 1, Attachment 3, p. 6

Preamble:

The Environmental Guidelines state at Section 4.3.14 Cumulative Effects that "[i]n many situations, individual projects produce impacts that are insignificant. However, when these are combined with the impacts of other existing or approved projects, they become important." Further, the Environmental Guidelines state: "[p]articular attention should be paid to environments of known sensitivity and high eco-value (as defined by provincial policies and public input), to situations where opportunities exist to remedy past negative impacts, and to situations in which a combination of actions may result in identifiable environmental impacts that are different from the impacts of the actions by themselves". The Environmental Guidelines also indicate that, "[c]umulative impacts may result from pipeline projects which loop existing systems and should be addressed. This may include an examination of areas of known soil erosion, soil compaction or soil productivity problems. It may mean the examination of impacts associated with continued loss of hedgerows and woodlots in the same area. As well, it could mean the increased loss of enjoyment of property because of disruptions caused by the construction of successive pipelines on a landowner's property. There may also be heightened sensitivities as a result of improper or ineffective practices and mitigation measures in the past."

CKSPFN has identified the proposed project area as an area of known sensitivity and high cultural and ecological importance to the First Nation. CKSPFN has made several requests to EGI via interrogatories and written submissions in OEB proceedings including the 2022 Storage Enhancement Project (EB-2021-0078) and Coveny and Kimball Colinville Well Drilling Project (EB-2021-0248). CKSPFN has also met virtually and in person with EGI representatives, highlighting the issue of cumulative effects and a desire to better understand current and future EGI infrastructure across CKSPFN territory. The cumulative effects issue was also raised by Aamjiwnaang First Nation ("AFN") in their November 16, 2021, comments to EGI.

The Environmental Guidelines clearly outline the approach to Cumulative Effects Assessment:

"The first step in assessing cumulative effects is to define appropriate study area boundaries. It is critical not to restrict the study area to a proposed pipeline easement and temporary work areas. The applicant is required to consider four distinctive cumulative effects pathways when delineating the study area and analyzing and assessing the cumulative effects:

1. additive effects of pipeline construction occurring slowly over time (e.g. erosion of the easement due to inadequate grading);
2. interactive or magnifying effects from pipeline construction (e.g. soil fertility loss and soil drainage degradation due to compaction during construction);
3. additive effects of pipeline construction and other existing and future projects in the area (e.g. additive forest cover losses due to tree clearing for pipeline construction and subdivision development);
4. interaction of pipeline construction with other existing and future projects in the area (e.g. cold stream fish habitat degradation, as an interactive effect of increased erosion and sedimentation due to pipeline stream crossing and floodplain development downstream)." [p.47]

EGI has repeatedly held that 100m is a sufficient boundary to assess cumulative effects. CKSPFN has repeatedly rejected the idea that a 100m boundary around proposed project locations is appropriate. 100m is an arbitrary boundary of which natural ecosystems and all living relatives do not know the borders. We have raised this issue in previous OEB filings, without an appropriate remedy. CKSPFN notes that nowhere in the Environmental Guidelines does the OEB state that 100m is an appropriate boundary for cumulative effects assessment.

In EGI's reply submission to CKSPFN comments on the 2022 Storage Enhancement Project (Filed: 2022-02-25, EB-2021-0078, p.9), EGI stated, "Enbridge Gas is committed to engaging with CKSPFN regarding cumulative effects to better understand how CKSPFN's Aboriginal or Treaty rights may be impacted by EGI's ongoing development and operations in the Project area, how the Project may further contribute to this impact and what may be done to avoid, offset or minimize the impact."

In EGI's reply submission to CKSPFN interrogatories on the Coveny and Kimball-Colinville Well Drilling Project (EB-2021-0248), EGI responded to our outstanding cumulative effects concerns by once again writing, "Enbridge Gas is committed to engaging with CKSPFN regarding cumulative effects to better understand how CKSPFN's Aboriginal or Treaty rights may be impacted by Enbridge Gas's ongoing development and operations in the Project area, how the Project may further contribute to this impact and what may be done to avoid, offset or minimize the impact." EGI then added, "Enbridge Gas would like to have a discussion with CKSPFN to determine funding requirements for a study of this nature. While the Company commits to further engagement with CKSPFN regarding this matter, Enbridge Gas maintains that it has appropriately followed the Guidelines for this Project."

CKSPFN has clearly stated that it is extremely difficult for the First Nation to assess the cumulative effects of EGI activities on CKSPFN's Aboriginal or Treaty Rights when projects are filed and assessed on a piecemeal basis. To truly assess cumulative effects in our territory, CKSPFN must be able to consider the larger picture of existing and planned gas infrastructure and the residential, commercial, and industrial development that may be enabled by expanded gas services in the region.

Question:

a) Please outline what steps EGI has taken to address CKSPFN's outstanding concerns about the cumulative effects of gas infrastructure and expansion across CKSPFN territory.

   Please provide the instructions EGI provides to its environmental consultants for assessing cumulative effects for this Project; for other projects commenced or undertaken in the past three years in the Three Fires treaty territory.

b) Please discuss whether EGI has considered all past, present, and future conditions in the cumulative effects assessment, including existing projects, the current project, and any future projects. Please note that p.28 of the Environmental Guidelines states that, "[c]umulative effects that may result from the interaction between the effects of the proposed project and the effects of other developments already in place or planned within or near the study area, are expected to be addressed."

c) Does EGI agree that non-provincially significant wetlands should be included in the Environmental Report methodology alongside "Provincially Significant Wetlands" and unevaluated wetlands? If not, please explain why not considering CKSPFN's water assertion and the cultural significance of wetlands other than those deemed "Provincially Significant Wetlands".

d) Please indicate and provide details of whether EGI assessed the cumulative effects of the existing two natural gas pipelines running from the Dawn Hub to the Corunna Compressor Station and the expansion/brand new right-of-way for the Dawn to Corunna pipeline project.

e) Please indicate and discuss whether EGI assessed the state of soil erosion, soil compaction or soil productivity problems at both the existing right-of-way and the preferred route right-of-way. If yes, did EGI also assess the cumulative effects of expanding the land taken up for pipeline right-of-way?

f) Please indicate and discuss whether EGI assessed the cumulative effects associated with continued loss of hedgerows and woodlots in the Project area.

g) Please indicate whether EGI considered the cumulative effects of multiple pipeline right-of-ways crossing the waters included in CKSPFN's 2017 Water Assertion (attached at Appendix A). If yes, please provide details and all related reports, presentations or other documents. If no, please explain why not.

h) Please explain why Table 6.1: Project Inclusion List for Cumulative Effects (PDF p. 87 of the Environmental Report) does not consider any existing, currently under construction, or future projects being conducted by EGI.

i) Section 6.1 of the Environment Report outlines methodology for the cumulative effects assessment. Please explain why accidents or emergency events were not considered in the cumulative effects assessment and discuss whether EGI believes that constructing numerous pipelines in close proximity to each other amplifies the risk of accidents and emergency events.

j) Please provide all analysis performed by EGI (and all related documents) to determine that 100m is an appropriate boundary for cumulative effects assessment? If no such analysis was undertaken, please explain why not.

k) Please explain how EGI considered each of the four distinctive cumulative effects pathways listed on PDF p. 47 of the Environmental Guidelines when delineating the cumulative effects study area of 100m.

l) Please explain and provide details of how EGI considered each of the four distinctive cumulative effects pathways listed in the Environmental Guidelines when analyzing and assessing the cumulative effects of the proposed project.

m) Please explain how EGI has made progress on its commitment to "engag[e] with CKSPFN regarding cumulative effects to better understand how CKSPFN's

Aboriginal or Treaty rights may be impacted by Enbridge Gas's ongoing development and operations in the Project area, how the Project may further contribute to this impact and what may be done to avoid, offset or minimize the impact". Although this commitment was made during EB-2021-0078 and again at EB-2021-0248, please explain how CKSPFN's outstanding concern regarding cumulative effects has been considered in EGI's evaluation of the Project and in the present Application.

Response

a) & m)
Please see response b) to l) below for a discussion of how the specific concerns identified in this information request are addressed.

Enbridge Gas continues to provide CKSPFN with information regarding its projects that may potentially impact CKSPFN and to offer the opportunity to meet with Enbridge Gas representatives to discuss the impact of its projects on CKSPFN rights and interests. During such meetings, specific concerns regarding a project and the associated cumulative effects can be discussed. In addition, CKSPFN has the opportunity to comment on the related Environmental Reports, including the cumulative effects assessment. Enbridge Gas considers such comments to determine whether concerns have been appropriately addressed, through, for example, project design or the implementation of mitigation measures. Details of the communications with the CKSPFN related to this Project can be found in the Indigenous Consultation Report filed with the Company's pre-filed evidence at Exhibit H, Tab 1, Schedule 1, Attachment 6.

Enbridge Gas met with CKSPFN representatives on May 31, 2022, and the parties discussed cumulative effects within CKSFPN's traditional territory. CKSPFN expressed that cumulative effects would be a multi-party discussion and CKSPFN would be engaging with the provincial government in this regard. Enbridge Gas expressed support for the ongoing discussion on cumulative impacts within the traditional territory with government and industry.

Enbridge Gas is committed to continuing to engage with CKSPFN regarding cumulative effects.

Generally, Enbridge Gas instructs and relies upon its environmental consultants to conduct environmental studies of proposed projects, including assessments of cumulative effects, in consideration of the guidance outlined in the OEB's Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario (2016) (the "Guidelines"). The Company provides the environmental consultants relevant supporting information as necessary/appropriate in support of the completion of any assessment of cumulative effects.

b) The project inclusion list for the cumulative effects assessment is provided in Section 6.3, Project Inclusion List of the Environmental Report. Infrastructure already in place are assessed as existing conditions, which is provided in Section 4, Impact Identification, Assessment and Mitigation of the Environmental Report. Where residual effects from impacts on these existing conditions remain after mitigation, they are carried forward to the cumulative effect assessment. The current project and any known future projects within the spatial study boundary were considered in the cumulative effects assessment.

c) Section 4.4.2, Designated Natural Areas and Vegetation of the Environmental Report provides an overview of the various types of wetlands, and whether they are traversed by the Project. The Environmental Report assesses impacts of the project on all wetland types, and the mitigation for wetlands as provided in Table 5.1, Potential Impacts and Recommended Mitigation and Protective Measures apply to all wetland types.

d) Infrastructure already in place are assessed as existing conditions, which is provided in Section 4, Impact Identification, Assessment and Mitigation of the Environmental Report. Where residual effects from impacts on these existing conditions remain after mitigation, they are carried forward to the cumulative effect assessment.

e) Knowledge of historical impacts on soil of pipeline construction will be gathered and determined through conversations that Enbridge Gas will undertake with landowners prior to construction. Enbridge Gas has retained a Professional Agrologist (P. Ag.) for the Project and a full-time soils inspector will be on-site during construction, and for post-construction monitoring as appropriate to help inform the Company's conclusions regarding the impacts of construction on soils.

f) Vegetation, regardless of feature, is assessed in Section 6.4, Analysis of Cumulative Effects of the Environmental Report.

g) The cumulative effects assessment in the Environmental Report considers residual effects, as outlined in Section 6.1, Methodology. As no residual effects are anticipated on watercourses, no cumulative effects assessment occurred.

h) Infrastructure already in place are assessed as existing conditions, which is provided in Section 4, Impact Identification, Assessment and Mitigation of the Environmental Report. Known or potentially foreseeable projects are listed in Section 6.3, Project Inclusion List of the Environmental Report. As outlined in Section 6.4.2, Operations and Maintenance of the Environmental Report, potential future pipeline construction and maintenance activities are considered in the cumulative effects assessment.

i) As outlined in Section 6.1, Methodology of the Environmental Report, accidents or emergency events have not been assessed as they are extreme in nature when compared to the effects of normal construction and operational activities and require separate response plans.

Enbridge Gas has performed a Quantitative Risk Assessment (“QRA”) to assess the cumulative risk of adding the proposed TR7 pipeline to the existing pipeline corridor between the Dawn and Corunna facilities. This assessment has been filed as part of the response at Exhibit I.SEC.10. The QRA considers the risk of accidents or emergency events which could be a result of various threats including corrosion and third-party damage and evaluates the cumulative impact of these outcomes to public Health and Safety in the surrounding population, including added conservatism to account for possible population growth near the corridor. This assessment concludes that the cumulative risk of all pipelines in the corridor, with the addition of the proposed TR7 pipeline, is at an acceptable level when compared to Enbridge Gas’s risk evaluation thresholds (which are consistent with industry best practices and risk acceptance levels recommended by the proposed CSA Z662-23 Annex B - 2023 draft standard).

j) & k)

The cumulative effects assessment and the associated study area was delineated in accordance with Section 4.3.14 of the OEB's Guidelines. The 100m boundary is considered appropriate for the limited residual Project effects (i.e., those that remain after mitigation) that are anticipated to be interactive with other concurrent, unrelated projects. Section 6.2, Study Boundaries of the Environmental Report notes that the 100m is an approximate boundary, and therefore in practice, impacts and projects that are beyond that distance may be considered. The methodologies used to conduct the cumulative effects assessment are the same as those used in other Enbridge Gas projects approved by the OEB in the past.

l) The methodology employed for the cumulative effects assessment is outlined in Section 6.1 of the Environmental Report.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Chippewas of Kettle and Stony Point First Nation together with Southwind Corporate Development Inc. ("CKSPFN")

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, pp.3-4

Preamble:

EGI indicated in the Application that the Project will have negligible impacts on the environment and there are no environmental concerns that cannot be mitigated and there are no significant cumulative impacts resulting from the Project.

Question:

a) Please identify and describe all data sources available to EGI on fugitive methane emissions associated with EGI's infrastructure in southwestern Ontario.

b) Please confirm whether EGI has access to, and uses, high-resolution satellite data to identify, measure and monitor point sources methane across EGI's infrastructure in southwestern Ontario. If yes, please describe the data available and explain how it is used. If no, please explain why not.

c) Has EGI modelled the fugitive methane emissions that will be released by the proposed Project, including at the CCS, pipe connection at the CCS, along the pipeline right-of-way, and at the connection with the Dawn Hub? If yes, please describe the modelling that was undertaken and provide all related results. If not, please explain.

d) Please indicate whether EGI considered fugitive emissions and the resulting increase in ground level ozone in the cumulative effects assessment? If EGI has not considered the cumulative effects of such fugitive emissions, please explain why not.

e) Please provide information on EGI's leak detection, repair and reporting protocol for related infrastructure, including accounting for fugitive emissions.

f) Canada has committed to developing a plan to reducing oil and gas methane emissions by at least 75 percent below 2012 levels by 2030, pursuant to the Global Methane Pledge (see Appendix B).[1] Please explain EGI's understanding of Canada's commitments under the Global Methane Pledge and describe how:
    i. EGI's operations contribute to or detracts from those commitments; and
    ii. The Project contributes to or detracts from those commitments.

<u>Response</u>

a) Enbridge Gas utilizes technical reference documents as identified in the Ontario Ministry of Environment, Conservation and Parks' ("MECP") Guideline for Quantification, Reporting and Verification of GHG Emissions, including the Canadian Energy Partnership for Environmental Innovation ("CEPEI"), Methodology Manual: Estimation of Air Emissions from the Canadian Natural Gas Transmission, Storage and Distribution System, as sources of data related to fugitive emissions associated with its operations within southwestern Ontario.

b) Enbridge Gas does not use high-resolution satellite data. Instead, Enbridge Gas uses emission factors, engineering estimates, as well as direct measurement of fugitive emissions, in accordance with the MECP Guideline for Quantification, Reporting and Verification of Greenhouse Gas Emissions and the Federal Regulations Respecting Reduction in the Release of Methane and Certain Organic Volatile Organic Compounds (Upstream Oil and Gas Sector).

c) Yes, Enbridge Gas has estimated the fugitive emissions for the Project. Calculations were undertaken following the methodologies prescribed by provincial and federal GHG reporting programs, including the use of emission factors and engineering estimates, as well as Company-specific emission factors based on direct measurement of fugitive emissions.

    Considering the fugitive emissions due to operation only, the decommissioning (retirement and abandonment) of seven compressor units at the CCS, associated modifications at the CCS and Dawn Hub, and the addition of the proposed Dawn-

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[1] Government of Canada, News Release, "Canada confirms its support for the Global Methane Pledge and announces ambitious domestic actions to slash methane emissions" (October 11, 2021), available online at: https://www.canada.ca/en/environment-climate-change/news/2021/10/canada-confirms-its-support-for-the-global-methane-pledge-and-announces-ambitious-domestic-actions-to-slash-methaneemissions.html

Corunna pipeline, construction of the proposed Project is estimated to result in a decrease in Company-specific emissions of approximately 600 tCO_2e/year.

d) Ground level ozone was not included in the fugitive assessment. Only those pollutants that are required to be calculated and reported under federal and provincial regulatory requirements were included in the assessment.

e) Enbridge Gas currently manages its fugitive emissions, in accordance with industry accepted best management practices, to reduce emissions from its operations. In July 2020, Enbridge Gas implemented a harmonized leak operating standard, which includes:

(i) increased traceability and tracking of leak repairs,
(ii) increased monitoring frequencies,
(iii) harmonized repair timelines for above ground leaks, and
(iv) initiation of a station leak survey program.

With respect to compressor stations, a leak survey of the entire facility is performed three times a year with repairs being made within federal and provincial regulatory reporting timeframes. Pipelines are inspected annually by way of a foot patrol, during which a leak survey is conducted. The results of these surveys are tracked and applied to the appropriate fugitive emission calculations within Enbridge Gas's federal and provincial emissions regulatory reporting.

f) The Global Methane Pledge aims to reduce methane emissions by 30 percent below 2020 levels by 2030. Canada has committed to developing a plan to reduce methane emissions from the oil and gas by at least 75 percent below 2012 levels by 2030.

As indicated in part c) above, the proposed project would result in a decrease in emissions of approximately 600 tCO_2e/year over current emissions levels (methane accounting for approximately 595 tCO_2e/year). In support of Canada's commitments, Enbridge Gas will continue to comply with the Federal Methane Regulation, which was implemented in order to support Canada's methane reduction targets.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Chippewas of Kettle and Stony Point First Nation together with Southwind Corporate Development Inc. ("CKSPFN")

INTERROGATORY

Reference:

- Exhibit F, Tab 1, Schedule 1, Attachment 4, p. 1
- Dawn – Corunna Project: Environmental Report - FINAL REPORT - Prepared by: Stantec Consulting Ltd., September 21, 2021, p.86
- Enbridge Inc. "Net Zero by 2050: Pathways to reducing our emissions"[2] (The "Net Zero Plan"), pp. 2 and 9-11
- Ontario's "Low-Carbon Hydrogen Strategy: A Path Forward" (see Appendix E)
- Ontario "Discussion Paper: Geological Carbon Storage In Ontario"[3]

Preamble:

The Environment Report lists Operation and Maintenance of the pipeline to occur between 2024-2074, but an asterisk to those dates explains, "Fifty years of operation is used as an assumption, although the pipeline may be operational beyond fifty years".

In their December 9, 2021, comments on the Environment Report, Walpole Island First Nation ("WIFN") stated, "[t]here is currently no consideration for climate changes in terms of both adaptation and mitigation. Please include an assessment of greenhouse gas (GHG) emissions for the lifespan of the Project. Please also provide information on EGI's leak detection, repair and reporting protocol for related infrastructure, including accounting for fugitive emissions. This information will better inform WIFN of EGI's efforts to mitigate and reduce GHG emissions form its infrastructure."

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[2] 2 Enbridge Inc. "Net Zero by 2050: Pathways to reducing our emission" (March 2022), available online at: https://www.enbridge.com/~/media/Enb/Documents/About%20Us/Net_Zero_by_2050.pdf?la=en.

[3] Government of Ontario, Discussion Paper, "Geologic Carbon Storage in Ontario" (January 2022), available online at: https://prod-environmental-registry.s3.amazonaws.com/2022-01/Geologic%20Carbon%20Storage%20Discussion%20Paper%20-%20FinalENG%20-%202022-01-04_0.pdf.

In March 2022, EGI published the Net Zero Plan which includes targets of reducing the intensity of GHG emissions from their operations by 35% by 2030 and achieving net zero greenhouse gas ("GHG") emissions from their business by 2050 (the "Commitments").

Question:

a) Please indicate and provide details of how Enbridge Inc. and EGI intend to reach the Commitments as it relates to the Application and the Project. Please comment on, and file any and all analysis EGI has performed in connection with, how the shipping and burning of methane gas across CKSPFN territory into 2074 and beyond will, or is anticipated to, affect the Commitments.

b) Please discuss whether EGI considered a "no-go" alternative where the compressors presenting a danger to EGI employees are retired and abandoned and the Project does not proceed. If EGI did not consider such an alternative, please explain why not in light of the Commitments.

c) Please provide a detailed outline of EGI's consultation with First Nations and Indigenous Communities on the alternatives studied and considered to the Project.

d) Please discuss and provide details regarding any revisions to the Project by EGI resulting from the comments put forward by AFN on November 16, 2021 and WIFN on December 9, 2021.

e) Please file any and all analysis EGI has performed to assess GHG emissions over the lifespan of the Project. If EGI has not undertaken any such analysis, please explain why no such analysis has been undertaken, in light of the Commitments.

f) Ontario has identified the Dawn Hub storage facilities and the potential to blend hydrogen with natural gas to lower its carbon footprint as an important part of its Low-Carbon Hydrogen Strategy and meeting Ontario's emission reduction targets of 30 percent below 2005 levels by 2030. Please explain EGI's understanding of Ontario's Low-Carbon Hydrogen Strategy and describe how:
   i. EGI's operations support and are aligned with the strategy; and
   ii. The Project contributes to or detracts from the strategy.

g) Ontario has released a discussion paper on the geologic storage of carbon in Ontario and is currently considering amendments to the Oil, Gas and Salt Resources Act and the Mining Act to allow and support the geological storage of carbon dioxide in deep underground geologic storage projects. Please explain EGI's understanding of Ontario's discussion paper and proposed regulatory amendments and please file any and all analysis EGI has performed to assess the potential for any deep underground geological storage projects in Ontario, including in relation to the Project.

Response

a) In support of achieving the Greenhouse Gas ("GHG") targets announced by Enbridge Inc. in 2020, Enbridge Gas is developing and implementing a scope 1 and 2 GHG emission reduction strategy in order to identify and review potential GHG emission reduction opportunities and strategies in support of the targets, and to evaluate the feasibility, emission reduction potential, and cost of the opportunities identified. As referenced in the response at Exhibit I.CKSPFN.3 c), the proposed project will result in an annual reduction of 600 tCO_2e/year over current emissions levels.

b) No, Enbridge Gas did not consider this alternative as the Company would not be able to meet its firm contractual commitments. Enbridge Gas has a responsibility to serve the firm contractual needs of its customers and as such, is unable to retire the 7 compressor units without replacing their capacity and deliverability.

c) Please see Exhibit C, Tab 1, Schedule 1 for Enbridge Gas's assessment of Project alternatives.

   Enbridge Gas did not discuss alternatives with Indigenous Communities as the assessment of alternatives was completed prior to the commencement of Project-specific engagement. Since the alternatives were determined to not be viable options, they were not presented to the Indigenous communities. However, the Company remains open to discussing concerns that any potentially affected Indigenous groups might have with respect to the Project, including alternatives.

   Enbridge Gas has discussed the Project route selection, and alternative routes with interested Indigenous groups on a number of occasions. This is documented in the Indigenous Consultation Report set out at Exhibit H, Tab 1, Schedule 1, Attachment 6 (attachments 1.8, 2.10 and 5.7).

d) Based on comments received from AFN and WIFN, Enbridge Gas made revisions to the Project. For example, Enbridge Gas increased its tree replacement ratio; typically the tree replacement ratio is 2:1 and for the Project this ratio was increased to 3:1 at the request of WIFN.

Please refer to Exhibit F, Tab 1, Schedule 1, Attachments 3 and 4 for the documented comments by AFN and WIFN on the ER and Enbridge Gas's responses.

e) Please refer to the response at Exhibit I.CKSPFN.3, part c).

f) Enbridge Gas is familiar with and contributed to the development of Ontario's low-carbon hydrogen strategy: A path forward.

   i. To provide an excerpt from the paper:[4]

   > "The Dawn Hub is a series of underground depleted cavernous natural gas reservoirs that are filled each summer when demand for natural gas is low and natural gas is cheaper and discharged in the winter to serve increased heating demand. This allows optimum utilization of pipeline capacity into Ontario, lowers natural gas prices for Ontario families and businesses, and ensures the province has the energy it needs throughout the winter. Each year Ontario stores approximately 35 per cent of its total winter natural gas demand in the Dawn Hub storage facilities. In a similar manner, Ontario's geology may provide opportunities for large scale low-carbon hydrogen production or storage."

   Although not yet technically proven, there is potential that Enbridge Gas's existing assets could support the development and utilization of hydrogen storage and transportation aligned with the strategy.

   ii. This Project supports the long-term reliability of storage assets at the Dawn hub.

g) The potential for storage of carbon dioxide in underground geological formations within Ontario bears no relevance to the current Application that is before the OEB. For this reason Enbridge Gas respectfully declines to produce any further information regarding the Company's assessment of the same.

[4] https://www.ontario.ca/files/2022-04/energy-ontarios-low-carbon-hydrogen-strategy-en-2022-04-11.pdf

ENBRIDGE GAS INC.

Answer to Interrogatory from
Chippewas of Kettle and Stony Point First Nation together with Southwind Corporate Development Inc. ("CKSPFN")

INTERROGATORY

Reference:

Exhibit G, Tab 1, Schedule 1, p. 1

Preamble:

"The proposed pipeline is approximately 20 km in length requiring approximately 95.68 hectares (236.44 acres) of permanent easement. Enbridge Gas plans to acquire the land rights to 42.14 hectares (104.13 acres) of the required permanent easement. Enbridge Gas will also require approximately 53.54 hectares (132.31 acres) of temporary land use for construction and topsoil storage purposes."

Question:

a) Please indicate whether all the land required for permanent easement and temporary land use are held in fee simple? If not, please identify the location of such other lands and indicate the applicable land rights.

Response

a) All lands required for the Project will be held in fee simple ownership with the exception of waterbodies owned by the Crown.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Chippewas of Kettle and Stony Point First Nation together with Southwind Corporate Development Inc. ("CKSPFN")

INTERROGATORY

Reference:

Exhibit A, Tab 2, Schedule 1, Attachment 1, p. 1

Preamble:

Section 94 of the Act requires applicants for an order granting leave under the relevant part to file a map showing the general location of the proposed work and the municipalities, highways, railways, utility lines and navigable waters through, under, over, upon or across which the proposed work is to pass.

The map provided in the Application identifies "watercourse", but not "navigable waters".

Question:

a) Please indicate whether there are any navigable waters impacted by the proposed project. If yes, please provide details and all analysis undertaken by EGI with respect to the impacts on navigable waters by the Project.

Response

a) The Project will not cross any known navigable watercourses listed in the Transport Canada Schedule set out in the federal *Navigable Waters Act*.[1] The list of watercourse crossings can be found in Table 4.1 Watercourse Crossings on the Preferred Route of the ER.[2]

[1] https://laws-lois.justice.gc.ca/eng/acts/N-22/FullText.html#h-365179
[2] The ER for the Project can be found at Exhibit F, Tab 1, Schedule 1, Attachment 1.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Chippewas of Kettle and Stony Point First Nation together with Southwind Corporate Development Inc. ("CKSPFN")

INTERROGATORY

Reference:

Exhibit A, Tab 2, Schedule 1, p. 2

Preamble:

EGI states that parties affected by the Application include the (i) owners of lands, government agencies and municipalities over which the pipeline will be constructed and (ii) customers resident or located in the municipalities, police villages, Indigenous communities and Métis organizations served by EGI, together with those to whom EGI sells gas, or on whose behalf EGI distributes, transmits, or stores gas. [emphasis added]

Question:

a) Please file any and all analysis EGI has performed, that is not already provided in the Application, in connection with how the Application will, or is anticipated to, affect residents and members, including off-reserve members, of CKPSFN:
   i. that EGI serves;
   ii. to which EGI sells gas; and
   iii. on whose behalf EGI distributes, transmits, or stores gas.

If EGI has not undertaken any such analysis, please explain why no such analysis has been undertaken, in light of the above paragraph.

b) Please indicate whether EGI recognizes that the following groups are also affected by this application:
   i. Indigenous nations whose Aboriginal and Treaty Rights are impacted by the continued expansion of gas infrastructure across Treaty territory and directly impacted by the increased ground level ozone caused by fugitive emissions; and
   ii. current and future generations who will face the challenges of accelerated anthropogenic climate change.

Response

a) Enbridge Gas has conducted an assessment of the need for the Project on the basis of impacts to existing customers/capacity (EGD rate zone), which includes Indigenous groups. Please see the pre-filed evidence at Exhibit B, Tab 1, Schedule 1, beginning at paragraph 23 for a summary of this assessment.

b) Enbridge Gas has been engaging with the Indigenous groups identified by the MOE in relation to the Project, which includes those who may have constitutionally protected Aboriginal or Treaty rights that may be adversely affected by the Project.

   As explained in the response at Exhibit I.CKSPFN.3 c), considering the fugitive emissions due to operation of the Project only, the decommissioning (retirement and abandonment) of seven compressor units at the CCS, associated modifications at the CCS and Dawn Hub, and the construction of the proposed Dawn-Corunna pipeline is estimated to result in a decrease in Company-specific emissions of approximately 600 tCO_2e/year. Please see the response at Exhibit I.CKSPFN.3 for further information regarding the measurement and management of fugitive emissions.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Chippewas of Kettle and Stony Point First Nation together with Southwind Corporate Development Inc. (“CKSPFN”)

INTERROGATORY

Reference:

- Exhibit A, Tab 2, Schedule 1, Attachment 1
- Exhibit B, Tab 1, Schedule 1, p. 3
- Exhibit G, Tab 2, Schedule 2, p. 4
- Exhibit H, Tab 1, Schedule 1, Attachment 2, p. 1
- Exhibit H, Tab 1, Schedule 1, Attachment 4
- Exhibit H, Tab 1, Schedule 1, Attachment 5, p. 6
- Exhibit H, Tab 1, Schedule 1, Attachment 6
- Truth and Reconciliation Commission of Canada (“TRCC”) “Calls to Action”[4] (Appendix C)
- United Nations Declaration on the Rights of Indigenous Peoples (“UNDRIP”)[5](Appendix D)

Preamble:

EGI’s natural gas infrastructure and the proposed natural gas pipeline that EGI is requesting board approval to construct as part of the Application, traverses First Nation Treaty lands, including the lands described in the Huron Tract, Treaty No. 29, 1827, as well as reserve lands impacted by EGI’s natural gas infrastructure.

The then Ministry of Energy, Northern Development and Mines (“ENDM”) determined that the Project may have the potential to adversely affect the established or credible asserted Aboriginal or Treaty rights of First Nations in the vicinity of the Project.

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[4] Truth and Reconciliation Commission of Canada “Calls to Action” (29 March 2016), available online at: https://crc-canada.org/wp-content/uploads/2016/03/trc-calls-to-action-english.pdf.

[5] UN General Assembly, United Nations Declaration on the Rights of Indigenous Peoples : resolution / adopted by the General Assembly (2 October 2007), A/RES/61/295, available online at: https://www.un.org/development/desa/indigenouspeoples/wp-content/uploads/sites/19/2018/11/UNDRIP_E_web.pdf.

Enbridge Inc.'s "Enbridge Indigenous Peoples Policy" recognizes the "importance of [UNDRIP] within the context of existing Canadian and U.S. law and the commitments that governments in both countries have made to protecting the rights of Indigenous Peoples."

Section 4(a) of the United Nations Declaration on the Rights of Indigenous Peoples Act,[6] affirms UNDRIP as a universal international human rights instrument with application in Canadian law.

UNDRIP requires that Indigenous Peoples are consulted in good faith in order to obtain their free, prior and informed consent ("FPIC") (i) before measures are adopted that affect them (article 19) or (ii) when undertaking a project that affect their rights to land, territory and resources (article 32).

CKSPFN met with EGI on February 11, 2022, to discuss the Project. During that meeting, EGI expressed a commitment to the recommendations of the TRCC, specifically Call to Action #92. Call to Action #92 calls upon the corporate sector in Canada to adopt UNDRIP as a reconciliation framework and to apply its principles, norms, and standards to corporate policy and core operational activities involving Indigenous peoples and their lands and resources.

Question:

a) Please indicate whether EGI notified CKSPFN that it may contact the Crown directly, and provide CKSPFN with the relevant ministry's contact details should they have any questions or concerns? If EGI did not provide such notification, please explain.

b) Does EGI recognize CKSPFN as a rights holder and does it confirm receipt and acknowledgement of the 2017 Water Assertion attached in Appendix A?

c) Did EGI identify to CKSPFN whether the Project is on privately owned or Crown controlled land?

d) Did EGI provide information on the potential effects of the Project, including, in particular, any likely adverse impacts on established or asserted Aboriginal or Treaty rights, specifically CKSPFN's 2017 Water Assertion attached at Appendix A?

e) Did EGI inform AFN and WIFN how their concerns were taken into consideration and whether the Project proposal was altered in response to their concerns? If so, please provide this correspondence and documentation. If not, please explain why.

[6] United Nations Declaration on the Rights of Indigenous Peoples Act S.C. 2021, c. 14.

f) Does EGI believe that all Indigenous consultation requirements from the Environmental Guidelines have been followed? If yes, please explain how they have been followed? If no, please explain why not.

g) Did EGI provide a description to potentially impacted First Nations of other provincial or federal approvals that may be required for the Project to proceed?

h) What agreements, authorizations, and or approvals with and/or from First Nation government, including CKSPFN, does EGI envision needing or entering into to support the Application?

i) Please provide details of any analysis undertaken by EGI to assess and determine the impacts on Treaty lands, generally, and on the Treaty lands of CKSPFN. If no analysis was performed, please explain why not.

j) Please provide a detailed response to how CKSPFN was consulted with the objective of obtaining their FPIC. In your response, please discuss whether EGI has received CKSPFN's FPIC regarding crossing the water bodies covered by CKSPFN's Water Assertion, passed by Band Council Resolution #2851, in 2017 and as provided in Appendix A.

k) Please discuss and provide any updates, as it pertains to CKSPFN, to the "Indigenous Consultation Report; Log and Project Correspondence" in tabular format.

l) Please provide details of how EGI has taken steps to implement TRC #92 with respect to CKSPFN over the last 4 months, including as part of the Application.

<u>Response</u>

a) Please see the Project notification letter, which Enbridge Gas provided to CKSFPN on April 13, 2021 and February 7, 2022, (set out at Exhibit H, Tab 1, Schedule 1 Attachment 6, attachments 2.16 and in the response to part k) below). The letter contains the contact information for the Ministry of Energy ("MOE") in relation to the Project. Recently, the specific MOE contact assigned to the Project has changed. Enbridge Gas communicated the new contact information to the Indigenous groups identified in the MOE's delegation letter. The Ministry of Energy contact for the Project is Rosalind Ashe.

b) Enbridge Gas acknowledges CKSFPN was identified by the MOE as a First Nation that should be consulted on the basis that they have or may have constitutionally protected Aboriginal or Treaty rights that may be adversely affected by the Project and confirms the receipt of the 2017 Water Assertion on June 10, 2022.

Enbridge Gas would like to work with CKSPFN to better understand CKSPFN's rights and views on best practices in water and water-related mitigation approaches.

c) On February 11, 2021, Enbridge Gas and CKSPFN met to discuss Enbridge Gas projects and a CKSFPN representative asked about Crown land on the Project. An Enbridge Gas representative advised that the preferred proposed route was on private and Enbridge Gas owned lands, with a small portion located within a Hydro One Corridor (please see line item 2.17 set out in the response to part k) below).

d) The ER addressed the potential impacts and recommended mitigation and protective measures on environmental features, including aquatic features. This information can be found in Table 5.1 of the Environmental Report (Exhibit F, Tab 1, Schedule 1, Attachment 1, p. 68).

Enbridge Gas would like to engage further with CKSPFN to understand how CKSPFN views its established or asserted Aboriginal or treaty rights as being impacted by the Project in light of the mitigation measures and protective measures identified in the Environmental Report.

e) Enbridge Gas provided AFN with its response to their comments on the Environmental Report on January 18, 2022. This correspondence can be found in pre-filed evidence at Exhibit F, Tab 1, Schedule 1 Attachment 3, and at Exhibit H, Tab 1, Schedule 1, Attachment 6, attachment 1.15.

f) Enbridge Gas provided WIFN with its response to their comments on the Environmental Report on February 4, 2022. This correspondence can be found in the pre-filed evidence at Exhibit F, Tab 1, Schedule 1, Attachment 4, and at Exhibit H, Tab 1, Schedule 1, Attachment 6, attachment 5.21. The WIFN representative responded on April 11, 2022, to acknowledge Enbridge Gas's comments and requested that WIFN receive updates on Enbridge Gas's ESG goals moving forward and that WIFN be provided with an opportunity to review the Natural Heritage Report when complete. Enbridge Gas follows the procedural consultation guidelines set out by the MOE which are consistent with the *Environmental Guidelines for the Location, Construction, and Operation of Hydrocarbon Pipelines and Facilities in Ontario, 7th Edition (2016)*. For example, the MOE sets out the requirements for Proponents in Schedule A to the delegation letter, which Enbridge Gas follows.

g) Enbridge Gas outlined the provincial and federal approvals that may be required for the Project to proceed in the proposed Project notification letter sent to CKSPFN on

April 13, 2021 and on February 7, 2022 (set out at Exhibit H, Tab 1, Schedule 1, Attachment 6, line item 2.1 and in the response to part k) below). The Environmental Report, which was provided to Indigenous communities, contains further details of such approvals within Table 1.1 (Exhibit F, Tab 1, Schedule 1, Attachment 1).

h) Enbridge Gas has offered capacity funding to all Indigenous groups identified as being potentially impacted by the Project and has entered into a number of capacity funding agreements to support engagement on the Project.

i) Enbridge Gas completed an analysis of the potential Project impacts on physical, bio-physical and socio-economic environmental features, which would include features within lands that are the subject of Treaties. This analysis includes recommended mitigation and protective measures. This information can be found in Table 5.1 of the Environmental Report (Exhibit F, Tab 1, Schedule 1, Attachment 1, p. 59).

Enbridge Gas would like to continue to engage with the CKSPFN to further understand any specific concerns regarding potential impacts on Treaty lands.

j) Enbridge Gas commits to meaningful engagement on projects with Indigenous communities and endeavors to provide information about its projects as early as possible in the project design phase. In addition to providing relevant information, Enbridge Gas offers to conduct meetings with Indigenous groups with a view to discussing how Aboriginal or treaty rights, and any other community interests, may be impacted by its projects. Enbridge Gas acknowledges that capacity support may be required to enable Indigenous groups to engage in timely technical reviews of documents, participation in field work associated with proposed projects, and to engage in meaningful consultation. As is Enbridge Gas's approach on all projects, Enbridge Gas has offered capacity funding to support engagement. Through its engagement, Enbridge Gas aims to secure the free, prior and informed consent of Indigenous groups potentially affected by a project.

Enbridge Gas has not received a formal communication or resolution indicating that CKSPFN consents to the Project. Enbridge Gas's engagement activities with CKSPFN are detailed in its pre-filed evidence at Exhibit H, Tab 1, Schedule 1, Attachment 6 and in the response to part k) below.

Enbridge Gas understands CKSPFN is still evaluating the Application, as is evident from its participation in this proceeding. Enbridge Gas is committed to further engagement with CKSPFN to discuss and address the concerns of CKSPFN, including with respect to the crossing of water bodies.

k) As of February 7, 2022

Chippewa of Kettle and Stony Point First Nation ("CKSPFN")					
Line Item	Date	Method	Summary of Enbridge Gas Inc. ("Enbridge Gas") Engagement Activity	Summary of Community's Engagement Activities	Outstanding Issues of Concerns
2.16	February 7, 2022	Telephone and email	An Enbridge Gas representative and a CKSPFN representative spoke to discuss Project consultation. A third party will be engaged with CKSPFN going forward and Enbridge Gas is to work with them on Projects. An Enbridge Gas representative emailed the third party representing CKSPFN to advise that Enbridge Gas planned to file the Project application with the OEB that week and provided a link to the environmental report for their review. An Enbridge Gas representative also provided the CKSPFN consultation log and the notification letter for this Project		
				A CKSPFN representative responded to acknowledge the email and asked for an overview of Enbridge Gas's projects and a call to discuss future projects.	
			On February 8, 2022, an Enbridge Gas representative responded to the email providing a list of upcoming projects and availability for a meeting. The parties agreed to February 11, 2022.		
2.17	February 11, 2022	Virtual Meeting	An Enbridge Gas representative had a virtual meeting with the CKSPFN representatives regarding the Project. Topics of discussion included supply chain	During the meeting, the CKSFPN representative requested information regarding the value/estimated cost of the Project as well as a	

			management participation and the scope of the Project. The Enbridge Gas representative noted capacity funding would be available. The presentation was provided via email following the meeting.	schedule for the Project. An Enbridge Gas representative advised that they would get back to the CKSFNP representative with the project cost. A CKSPFN representative asked about the easement on the Project. An Enbridge Gas representative advised that the easement would follow existing infrastructure however, there would be one spot of micro routing. A CKSPFN representative asked about water crossings. An Enbridge Gas representative advised that Bear Creek would be a horizontal directional drill due to species at risk and critical habitat. The other water crossings would be dam and pump ensuring all permits are in place. A CKSPFN representative asked if there would be field surveys completed. An Enbridge Gas representative advised surveys would be ongoing this spring and into the fall. The first survey would be for snakes in March. A CKSPFN representative asked if Enbridge Gas was acquiring land rights from land owners. An	

				Enbridge Gas representative advised that this was being completed when necessary. A CKSPFN representative asked whether the Project traversed any Crown land. An Enbridge Gas representative advised that the only Crown land being considered was a Hydro One corridor in the proposed route. A CKSFPN representative asked which archaeology firm was being used. An Enbridge Gas representative advised that Stantec would be completing the field survey work on this project.	
2.18	February 17, 2022	Email	An Enbridge Gas representative emailed the CKSPFN representatives providing an overview of topics of discussion from their February 11, 2022 meeting. The Enbridge Gas representative advised capacity funding was available for engagement related to the Project.		
2.19	March 10, 2022	Email	An Enbridge Gas representative sent an email to the CKSFPN representatives to provide updates to action items from the February 11 meeting. The Enbridge Gas representative provided the proposed budget and timelines for the Project as well as information on the Project value. The Enbridge Gas representative requested		

			a meeting to discuss other areas of interest outside of the Project process and suggested to meet in April to discuss.		
2.20	March 30, 2021	Email	An Enbridge Gas representative emailed the CKSPFN representatives to advise that the Project Application had been filed with the OEB. The Enbridge Gas representative indicated fieldwork would commence in the spring and AFN would be contacted. The Enbridge Gas representative expressed they would be available to meet in spring 2022 to discuss the Project.		
2.21	April 8, 2022	In person Meeting	An Enbridge Gas representative met in person with a CKSPFN representative to discuss supply chain management and possible business opportunities for Indigenous Nations on the Project.		
2.22	May 6, 2022	Email	An Enbridge Gas representative emailed the CKSPFN representatives providing a monthly update on all the Leave to Construct Enbridge Gas projects and the status of these projects.		
				The CKSFPN representative, on the same day, acknowledged receipt of the email.	
2.23	May 11, 2022	Virtual Meeting	Enbridge Gas and CKSFPN representatives had a virtual meeting to discuss issues of ongoing engagement, fugitive emissions and cumulative impacts.	A CKSPFN representative referenced a water assertion within CKSFPN traditional territory.	
2.24	May 31, 2022	In person meeting	Enbridge Gas and CKSFPN representatives met to discuss ongoing engagement, which included a discussion of cumulative effects.		

2.25	June 8, 2022	Email		A CKSPFN representative emailed the Enbridge Gas representative to advise they were wrapping up comments on the Project.	
			On June 9, 2022, an Enbridge Gas representative acknowledge the email.		
2.26	June 9, 2022	Email	An Enbridge Gas representative emailed the CKSPFN representatives providing a monthly update on all the Leave to Construct Enbridge Gas projects and the status of these projects.		

Enbridge Gas has engaged in meaningful consultation and has been working toward building a respectful relationship with CKSFPN over the last four months. Multiple meetings have been held to discuss the Project, cumulative effects and issues of concern to CKSFPN. Capacity funding has been offered and conditionally accepted by CKSPFN to allow for meaningful Project engagement. Enbridge Gas continues to offer to meet with CKSFPN and is committed to ongoing engagement to address issues and concerns of CKSFPN. The next meeting between the parties will occur on July 11, 2022.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers and Exporters ("CME")

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, pp. 11 of 31

At pp. 11, EGI stated that it had "also undertaken comprehensive studies, including a site-wide quantitative risk assessment ("QRA") to determine the severity of the increasing safety risks."

Question:

a) To the extent it is not already placed on the record, please file the QRA study completed relevant to the matters at issue in this application.

b) When was the QRA completed?

Response

a) & b)
Please see Attachments 1-4 to this response:

- Attachment 1 – Enbridge Gas Corunna Compressor Station – Site Wide Quantitative Risk Assessment (January 11, 2022).
  The QRA was commenced in 2020 and completed in 2022. During the completion, an independent reviewer (DNV GL) was hired to evaluate the report (refer Attachment 2 below). DNV GL review outcomes were accordingly incorporated in this QRA report.
- Attachment 2 – DNV GL Review of the Quantitative Risk Assessment (QRA) of Enbridge Corunna Compressor Station (January 18, 2021).
- Attachment 3 – Enbridge Gas TR7 Pipeline Corridor Risk Assessment Report (May 5, 2022).

This QRA was performed to evaluate risk from the new TR7 pipeline as a replacement of the compressors which will be abandoned (K-701 to K-703 and K-705 to K-708).

- Attachment 4 – DNV Dawn-Corunna Modifications Project QRA Report (May 17, 2022). This QRA was performed to evaluate risk after the abandonment of K-701 to K-703 and K-705 to K-708 at the CCS as part of the Project.

Corunna Compressor Station – Site Wide Quantitative Risk Assessment

January 11, 2022

Report

Company: Enbridge Gas Distribution

Owned by: Asset Management

Controlled Location: TBD

Revision History

Revision	Date	Author	Remarks	Review	Approval
0A	2020-11-22	Eric van Vliet Engineer Risk, Risk Management	Draft report issued for Technical Review	Angela Wong Supervisor Risk Supervisor	Shawn Khoshaien Director, Integrity and Asset Management
0B	2021-03-29	Eric van Vliet Engineer Risk, Risk Management	Review comments incorporated	Mike Hildebrand, Manager Integrity Assessment and Risk	Shawn Khoshaien Director, Integrity and Asset Management
0C	2022-01-11	Eric van Vliet Engineer Risk, Risk Management	Corrected minor errors	Lisa Nicholas, Supervisor Risk Services	Mike Hildebrand Manager Integrity Assessment and Risk

Executive Summary

Historically, the Corunna Compressor Station (CCS) at 3595 Tecumseh Road, Mooretown ON has been risk assessed in sections, on a project by project basis, using a quantitative approach. A previous Quantitative Risk Assessment (QRA) for the Meter Area Upgrade project at CCS indicated that there could be areas of higher than anticipated risk to workers which would not be addressed by the project. In order to fully understand risk exposures to workers, a site wide QRA was conducted with the intent to provide insights on the risk drivers at the site.

This QRA study was conducted by GDS (mentioned as the "Company" from here forward) under the guidance of an external consultant DNV GL, a global firm with industry leading experience in QRA. The approach adopted in this study was considered reasonable by DNV GL. Where relevant, published and widely recognised inputs, methods and assumptions were used. The software SAFETI (Version 8.23) used in this study was developed by DNV GL for this type of study in the 1980s.

The purpose of this QRA is to evaluate the potential risk level for workers due to accidental releases of hazardous materials, mainly natural gas, from loss of containment scenarios from the CCS facility and to evaluate against the following risk tolerance criteria:

- **Individual Risk Tolerance Criteria** – Recently endorsed criteria by the Company's leadership team

	Individual Risk Tolerance Criteria	
	Risk target(s)	**Risk limit(s)**
Worker	1E-6/year	1E-3/year
Public	Public:1E-6/year	Public: 1E-4/year

- **Societal Risk Tolerance Criteria –** Proposed by Enterprise Safety & Reliability (S&R) to address risks tolerability towards group of people.

	Societal Risk Tolerance Criteria	
	Risk target(s)	**Risk limit(s)**
Worker & Public	FN-curve, starting at 1E-5/year	FN-curve, starting at 1E-3/year

The Approach

In order to assess risks from accidental releases at any installation, it is essential to get a sense of how often such rare events could occur. Although the Company has some failure rate data for the site, such data are not in a useable form for this type of study. Also, it is quite possible that the sample size of piping and equipment that the Company owns / operates is considered small relative to the population of all similar piping and equipment in operation within the industry. A small sample size means it would be reasonable to expect that extremely rare events (usually referring to larger release sizes) may not be accounted for in the sample thereby skewing the release frequencies. Subsequently, it could underestimate risks associated with such rare events.

Therefore, per guidance of DNV GL, published generic release frequencies are being used in this study. The database covers various release sizes for a comprehensive list of process equipment and piping over a wide range of causation factors throughout the lifetime of installations. Since the basis on creating the generic data are based on offshore installations, further discussion on factors affecting level of conservatism in assessing risks and background of the database are provided in section 5.3. The different types of causation factors accounted for in the database are provided in Table 5 in the same section.

Below are the findings from the QRA study:

Individual Specific Individual Risk

The maximally exposed individual at the site is Tecumseh Operations – Op. 2 Plant. The following individuals are exposed to risks above the Company's individual risk limit for workers:

- Tecumseh Operations – Op. 2 Plant (ISIR: 1.36E-3 per yr)
- Mechanics (ISIR: 1.30E-3 per yr)
- Instrumentation (ISIR: 1.14E-03 per yr)
- Electrical (ISIR: 1.14E-03 per yr)
- Chief Mechanic (ISIR: 1.05E-03 per yr)

Societal Risk

The societal risks at the site were evaluated by treating all the workers onsite as a group and compared to the societal risk tolerable criteria proposed by Enterprise Safety & Reliability (S&R). The results showed the societal risk at the site is above the proposed risk limit when N is between 1 and just over 4. The maximum fatality count is about 20 at the frequency just below 1E-07 per yr.

Potential Loss of Life

Potential Loss of Life results are used to understand key contributors to risks in terms of locations or areas. They are not used for evaluating against any risk tolerance criteria used in this study. They have indicated that risks are concentrated in compressor buildings 1, 2 and 3.

Risk Reduction Options

The greatest contributing scenarios to the result of this assessment include:

- Potential leaks from compressors and associated indoor piping finding a potential source of ignition and resulting in a potential flash fire or explosion and fatal accident.
- Potential leaks from outdoor compressor header piping finding a potential source of ignition and resulting in a fire.

Based on stakeholder discussion the following risk reduction ideas were proposed for short term mitigation:

- Reducing the reliance on compression required at Corunna by increased compressor utilization at Dawn.
    - This option may require some additional pressure control retrofits on the twin NPS 30 transmission lines at the Dawn end; however, this is out of scope for the QRA.
    - Reduction of the average number of compressors in operation at Corunna from 4 to 3; additionally, the operating strategy would be to try to limit one running compressor per building.
    - A limiting factor of the strategy of only running one compressor per building would potentially occur in late season withdrawal when suction pressures are low. LP units K709 and K710 are both in building 2 and may both be required during late season withdrawal.
- Recent changes to operator round activities are designed to reduce the time spent by operations in compressor buildings.
    - These changes are expected to reduce time Operations personnel spend in compressor buildings by 15 to 20%.
    - The difference in time is expected to be split equally between the control room in the office and other tasks in the yard.
- Creating the following maintenance policy to eliminate the exposure of personnel to risks posted by more than one compressor and to eliminate the risk of releasing natural gas from stand-by units:
    - No maintenance when more than one compressor unit is running
    - Compressor units that are not running must be isolated and depressurized

A long-term strategy to evaluate site layout and spacing of equipment should also be considered when it is time to renew assets. Limiting one compressor unit per building with adequate spacing between buildings could be considered to separate people from process equipment and reduce potential exposure to hazards.

The design of new compressor buildings should consider ventilation rates to limit the potential buildup of gas to flammable atmospheres. The design of new ESD systems should consider the placement of ESVs to limit isolatable inventories on site during an ESD, particularly to limit gas inventory in indoor areas. Industry data suggests that reciprocating compressor units have a greater leak frequency than centrifugal – this could be investigated as a potential reduction in potential leak frequency. Where possible, new designs should consider reducing the total number of pipe connections by flange, as welds are considered less likely to leak than flanges (i.e. reduce parts count). Maintaining current and up to date process safety information including engineering documentation and records.

A future extension of this study can be completed to quantify risk reduction of the proposed short-term risk treatments from stakeholders.

Since the initial release of this report (version 0A), DNV GL has provided a review document which concluded that the approach taken to complete this QRA was reasonable. The review document is included in the appendix as an addendum along with response to minor observations that do not change the outcome of the initial QRA.

Table of Contents

List of Acronyms & Abbreviations

ACPH – Air Changes Per Hour
ALARP – As Low As Reasonably Practicable
AIChE – American Institute of Chemical Engineers
API – American Petroleum Institute
Barg – Barometric gauge pressure
BS – British Standards
CCPS – Center for Chemical Process Safety
CCS – Corunna Compressor Station
CSA – Canadian Standards Association
DNV GL – Det Norske Veritas & Germanischer Loyd
EGIG – European Gas Pipeline Incident Data Group
ESD – Emergency Shutdown
ESV – Emergency Shutdown Valve
EVV – Emergency Vent Valve
FIMP – Facilities Integrity Management Program
FR – Above Ground Pipeline Run in Meter Area
FV – Flow Control Valve
GAC – Gas Aftercoolers
HAZOP – Hazard & Operability Assessment
HCRD – Hydrocarbon Release Database
HMI – Human Machine Interface
HP – High Pressure
H&S – Health & Safety
HV – Hand Valve
IOGP – International Oil & Gas Producers Association
ISIR – Individual Specific Individual Risk
JWC – Jacket Water Coolers
LFL – Lower Flammability Limit
LP – Low Pressure
MCC – Motor Control Center
MEM – Multi-Energy Method
MKC – Mid Kimball / Conlinville
MOP – Maximum Operating Pressure
MV – Mode Valve
NFPA – National Fire Protection Agency
NPS – Nominal Pipe Size
PCV – Pressure Control Valve
PFD – Process Flow Diagram
P&ID – Piping & Instrumentation Diagram
Psig – Pounds per square inch gauge
PSV – Pressure Safety Valve
QRA – Quantitative Risk Assessment
RBI – Risk Based Inspection program
SAS – Statistical Analysis Systems (software)
SKC – South Kimball / Conlinville
SCADA – Supervisory Control & Data Acquisition
SMA – Subject Matter Advisor
S&R – Safety & Reliability
SR – Societal Risk
TNO – Netherlands Organization for Applied Scientific Research
TR – Transmission Pipeline
UFL – Upper Flammability Limit
UK HSE – United Kingdom Health & Safety Executive
UKOOA – United Kingdom Offshore Operators Association
UV/IR – Ultraviolet / Infrared
XV – Yard Valve

1. Introduction

1.1 Background

Historically, the Corunna Compressor Station (CCS) at 3595 Tecumseh Road, Mooretown ON has been risk assessed in sections, on a project by project basis, using a quantitative approach. The past risk assessments for CCS were completed as part of the legacy EGD Asset Management process for securing capital funding for various replacement/renewal projects. A previous Quantitative Risk Assessment (QRA) for the Meter Area Upgrade project at CCS indicated that there could be areas of higher risks than anticipated to workers which would not be addressed by the project. In order to fully understand risk exposures to workers, a site wide QRA was conducted with the intent to provide insights on what are risk drivers at the site. This QRA study was conducted by GDS (mentioned as "Company" from here forward) under the guidance of an external consultant DNV GL who is a global firm with industry leading experience in QRA.

1.2 Objectives

The purpose of this QRA is to evaluate the potential risk level for workers due to accidental releases of hazardous materials, mainly natural gas, from loss of containment scenarios from the CCS facility and to evaluate against the following risk tolerance criteria:

- Individual Risk Tolerance Criteria – Recently endorsed criteria by the Company's leadership team
- Societal Risk Tolerance Criteria – Proposed by Enterprise Safety & Reliability (S&R) to address risks tolerability towards group of people.

This is to support the Company's risk management process and its commitment to health and safety of workers and general public. The results of this analysis can be used to established short- and long-term risk treatment strategies for CCS.

1.3 Scope

The QRA scope covers equipment and piping containing natural gas in key process areas at the CCS facility as shown within the red box in Figure 1 and operated as of the 2019 operating philosophy.

Following the presentation of initial results to the Company's stakeholders in October 2020, an adjustment in the QRA was made based on the history of compressor runs which resulted in an increase of time that the facility operates at higher pressures than originally anticipated (from 50% to 70%). Subsequently, the estimated risks have increased slightly from what were presented in October 2020. The results and their discussion are in sections 10. and 0

Proposed modifications to operating conditions and durations spent at site with the intent to lower risks at the facility will be considered in a separate study which will be treated as an extension of the current study.

Figure 1 – Corunna Compressor Station

The key process areas covered in the QRA are:

- ILI Receiving Area
- Meter Area
- Gas Aftercoolers (GAC) & Compressor Headers
- Compressor Buildings 1, 2 & 3
- Free Flow Piping
- Utility Gas System

Detailed descriptions of these areas are provided in section 2.1 . Two operating modes under normal operation; withdrawal and injection are covered by different operating conditions throughout the year as further described in later sections.

The following process areas are excluded from the QRA:

- Lube Oil System – Lubrication oil for the compressors and engines is circulated in a closed loop system by pumps. There is a spent oil drum, maintenance oil drum, and oil storage drum on site. The lube oil system is not covered in this QRA.
- Instrument Air and Starting Air – Not considered a hazardous system for evaluation in QRA.
- Glycol System – The Jacket Water Coolers contain a glycol cooling loop for the compressor engines. Fuel Gas Heater is heated by glycol. Building heat is provided by glycol. Glycol is not considered a hazardous system for evaluation in QRA.
- Blowdown System – Blowdown System release scenarios are not considered since this system is normally at ~ 0 psig as it terminates at an atmospheric blowdown silencer. Since the normal operation of this system is typically without any significant inventory of process gas, the risk is considered negligible for QRA calculations.

- Drain System – Drain System release scenarios are not considered since this small-bore piping system is normally at ~ 0 psig as it is only intermittently used to remove any accumulated liquid from the process which is typically saltwater brine with trace hydrocarbons that can be considered negligible for QRA purposes.
- Vent System – Vent System release scenarios are not considered since this small-bore piping system is normally at ~ 0 psig as it is only used intermittently to vent process gas to atmosphere or flare for maintenance or turnaround activities when the process would be taken out of operation and already at significantly reduced pressure compared to normal operation.

1.4 Selected Approach

As the major hazard at the facility is the accidental release of natural gas resulting into flammable events (such as fire and explosion), the QRA approach commonly adopted by regulators in UK and Europe as tool to assess risks posed by installations processing hazardous substances in significant quantities was used for this study. In addition, the software SAFETI developed by DNV GL back in the 1980s (it was known as Technica then) to carry out this type of analysis was used in this study under the guidance of DNV GL.

In order to assess risks from accidental releasees at any installation, it is essential to get a sense of how often such rare events could occur. Although the Company has some failure rate data for the site, such data are not in a useable form for this type of study. Also, it is quite possible that the sample size of piping and equipment that the Company owns / operates is considered small relative to the population of all similar piping and equipment in operation within the industry. A small sample size means it would be reasonable to expect that extremely rare events (usually referring to larger release sizes) may not be accounted for in the sample thereby skewing the release frequencies. Subsequently, it could underestimate risks associated with such rare events.

Therefore, per guidance of DNV GL, published generic release frequencies are being used in this study.. The database covers various release sizes for a long list of process equipment and piping over a while range of causation factors through out the lifetime of installations. Further discussion on factors affecting level of conservatism in assessing risks and background of the database are provided in section 6.3 The different types of causation factors accounted for in the database are provided in Table 5 in the same section.

Since a wide range of causation factors leading to releases are accounted for in the release frequency database, from a risk quantification standpoint, the QRA does not consider specific causation factors that would be identified in HAZOP studies or Integrity Assessments by assuming the database has adequate representation. This treatment is usually applied as it is not always straightforward or possible to quantify risks based on these other studies. One should not assume issue and concerns identified in other studies are being addressed. In fact, one should view the QRA as one of many ways to assess risks of a process facility with more emphasis on equipment density, operating conditions, occupancy and location of workers and general public relatively to the facility. Other studies focus on very specific contexts and can offer different types of information to support the risk management process.

2. System Overview

2.1 Process Description

The Corunna Compressor Station uses 11 reciprocating compressor units to transport sweet natural gas to and from offsite underground storage facilities to transmission pipelines for eventual use in the Company's downstream distribution networks. Compressors K-701 through K-705 are located within compressor building 1, K-706 through K-710 in compressor building 2, and K-711 in compressor building 3.

Flow diagrams for the CCS are provided in Figure 2. As shown in the diagram, pool pipelines connect at a meter area inside the facility. From there, each pipeline is tied into a header system. In addition to individual headers for each pool pipeline, there is a transmission pipeline header that ties into transmission pipelines (TR-A, TR-B) and the NGTL Link pipeline.

Each of the 11 compressors is also tied into the header system that allows gas to be moved to/from any combination of the following pools: Dow Moore, Mid Kimball-Colinville, South Kimball-Colinville, Wikesport, Seckerton, Corunna and Ladysmith. Each compressor is paired with a gas aftercooler (fin-fan heat exchanger) used to cool the gas exiting the compressor.

CCS has two main modes of operation: injection and withdrawal. Injection operating mode takes gas from the two twin 30 NPS transmission pipelines from Dawn (TR-1 and TR-2) and flows the gas through CCS to the offsite storage pools. Withdrawal operating mode takes gas from the storage pool pipelines and flows through CCS into the transmission pipelines back to the Dawn facility.

Based on the differential pressure in the pipeline system, gas can free flow without the use of compression or when the pressure differential is too small, compression can be used to flow gas. Within the Injection and Withdrawal operating modes, both free flow and compression operations are utilized to move gas through CCS.

The main sections of the Corunna Compressor station are:

- ILI Receiving – Includes the buried gathering lines from the storage pools, site inlet ESVs and mobile pigging connections as well as the buried Link Line, site inlet ESV, and fixed pig traps.
- Meter Area – Includes 2 meter runs for the Link Line and a header system connected to each of the storage pool pipelines; Dow-Moore, Seckerton, Corunna, Mid & South Kimball/Colinville, Wilkesport, and Ladysmith. The Covney and Black Creek pools are interconnected through Wilkesport pipeline to the Corunna Compressor Station. The header system has valves to either receive gas from storage during withdrawal mode or exports gas to storage during injection mode. The blowdown system is also tied into the meter area piping through emergency vent valves (EVVs) that would open to depressurize the process piping in the event of a site ESD. Buried pipeline at the CCS facility are typically buried with 1 to 2m depth of cover.

- Gas After Cooler (GAC) & Compressor Headers – The compressor inlet headers are outdoor, above grade piping that include valves to run the 11 compressors in series or parallel during the injection or withdrawal operating modes depending on what pool is being filled or depleted. There is an outdoor suction scrubber before each compressor unit to remove any brine (salt water) from the gas stream coming from below ground storage. The gas aftercoolers (GAC) are on the outlet of the compressors and ensure the gas temperature does not exceed the rating of downstream pipelines. There is also a discharge scrubber for each compressor to catch any potential lube oil carryover into the process gas from compression.
- Compressor Buildings 1, 2, & 3 – Contain the 11 reciprocating compressor units (5 units per building 1 and 2, building 3 has one compressor). The compressor buildings are naturally vented via holes drilled into the building wall to increase airflow. There is also forced air ventilation if gas detection is active, but flame detection is inactive (described in more detail in the ESD section). The compressor buildings are considered to be vented at a minimum of 6 ACPH by natural convection.
- Free Flow Piping – Is above grade export piping taking gas from the compressors or meter area and exporting it to the Transmission system using flow control valves and on/off mode valves (MVs and XVs). The blowdown system is also tied into the free flow piping through normally closed emergency vent valves (EVVs). The transmission piping has site outlet ESVs.
- Utility Gas System – Natural gas from the Link Line at transmission pressure is used as utility gas, e.g. fuel gas for the compressor engines, generators, and boilers, power gas for actuated valves includes a HP (around 750 psig depending on the pressure of the Link Line) and LP (around 80 psig) system.

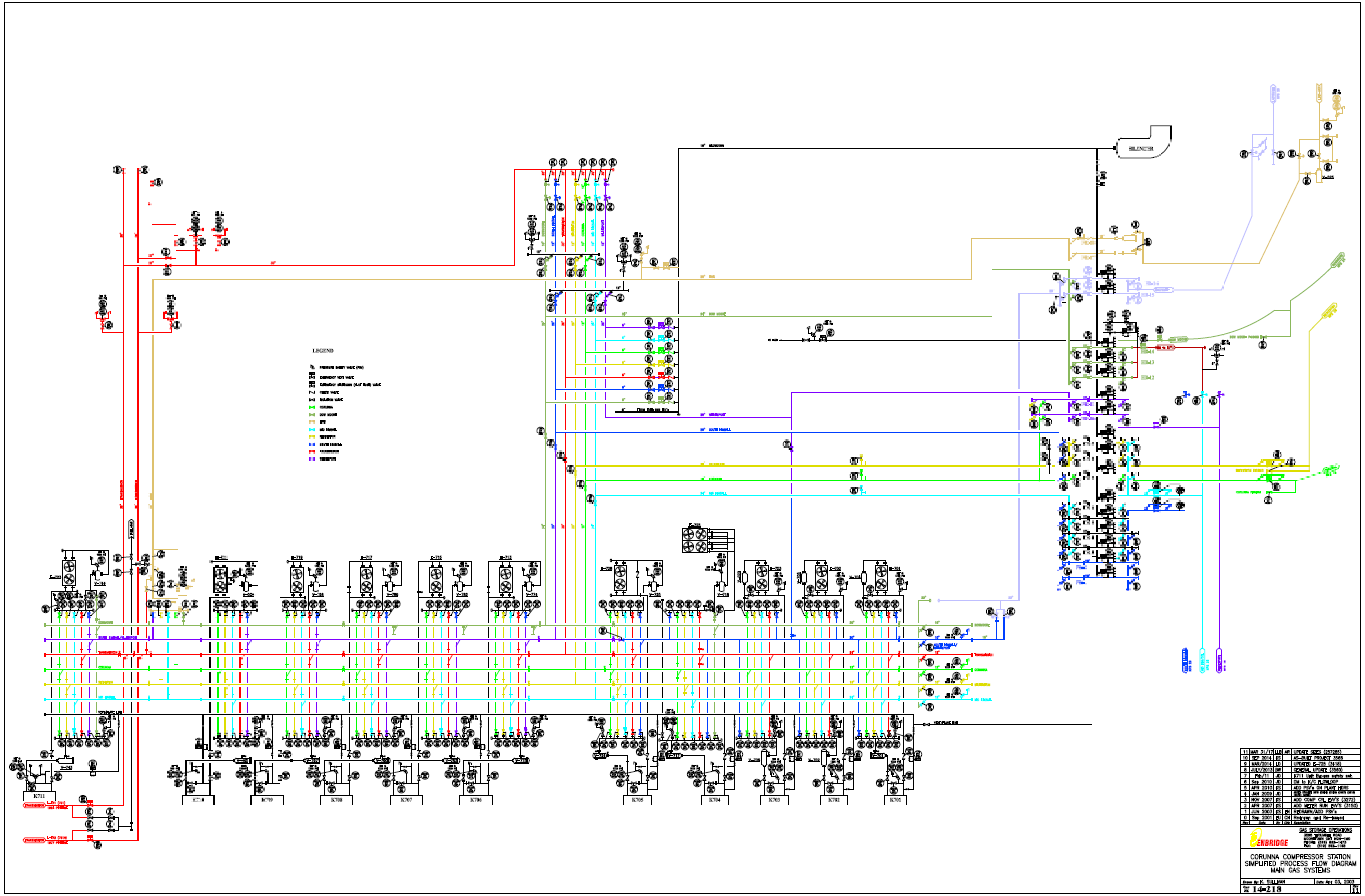

Figure 2: Corunna Compressor Station Simplified Process Flow Diagram

2.2 Process Conditions

The MOP for each pipeline system was retrieved from the “Enbridge Gas Storage Simplified Flow Diagram” drawing 14-200 Rev. 5 (See Figure 2). Typical minimum pressures were provided by stakeholder interview. Minimum pressures per pool are not always reached each year (by the end of the withdrawal season) as it depends on how much gas was needed during the heating season which changes year to year. Some pools are preferentially drawn down before others to maximize oil production. Oil production occurs offsite from the CCS facility and therefore out of scope of this QRA.

The three transmission pipelines Link, TR-1, and TR-2 do not have a typical minimum pressure. For the purposes of QRA, based on inputs from stakeholders, these pipelines operate at a fairly consistent pressure in comparison to the variation in operating pressures of the pool pipelines. The CCS facility functions throughout the year within the pressure operating limits per pipeline system included in Table 1 below.

Table 1 – Pipeline system pressures & NPS

Pipeline System	Diameter		Typical Minimum Pressure		MOP	
	[in]	[mm]	[psig]	[barg]	[psig]	[barg]
Link Transmission	24	602	N/A	N/A	935	64
Ladysmith Pool Line	20	502	300	21	1455	100
Dowmoore Pool Line	24	602	300	21	1550	107
Seckerton Pool Line	20	502	250	17	1350	93
Corunna Pool Line	16	402	250	17	1350	93
South Kimball Pool Line	20	502	300	21	1260	87
Mid Kimball Pool Line	24	602	300	21	1260	87
Wilkesport Pool Line	16	402	300	21	1335	92
TR-1	30	753	N/A	N/A	935	64
TR-2	30	753	N/A	N/A	1035	71

The temperature of natural gas at CCS is mainly at ambient conditions which is considered to be 18˚C (65˚F) for the QRA. Natural gas undergoing compression will gain heat, hence the need for the GAC at CCS. Gas on the discharge side of the compressor but upstream of the GAC is typically 29˚C (85˚F).

Natural gas composition can vary depending on its source of production and level of processing, however the variance of gas into the CCS facility must be within agreed contract limits in order to be eventually used in the distribution network. The Company’s MSDS for natural gas is included below.

Table 2 – Composition of Natural Gas

Component	Approximate Concentration
Methane	95%
Other fossil fuels	3%
Nitrogen	2%

For this QRA, natural gas is modelled as 100% methane since it is the main component. Based on previous fire and explosion consequence modelling in other QRA studies, the difference in modelling pure methane vs. natural gas is negligible on the outcome of QRA studies. According to the Company's MSDS, natural gas has an LEL of approximately 4% and a UEL of approximately 15%. The natural gas at CCS is not odourised with mercaptan like in the distribution network. The natural gas at CCS does have a slight gasoline / hydrocarbon scent after coming out of storage as trace amounts of the hydrocarbons in the storage pools would be extracted with the withdrawn natural gas.

2.3 Emergency Shutdown (ESD) System

CCS has an ESD system in place to limit the accidental release of natural gas in the event of an emergency. Based on discussions with engineering and operations stakeholders, the following description of the ESD system and its function was created to support the risk assessment.

2.3.1 ESD Components & Function

The major components in the ESD system include Emergency Shutdown Valves (ESVs), Emergency Vent Valves (EVVs), blowdown silencer and associated header piping system, indoor gas detection sensors, indoor fire/smoke detection sensors, and mechanical ventilation in compressor buildings.

ESVs are located on each pipeline into and out of the CCS facility. On site, the ESVs are commonly referred to as "plot edge valves" since they are physically located on each pipeline near the CCS property line. Under normal operation, ESVs remain open to allow the typical flow of gas through the facility. During ESD activation, the ESVs are designed to close to prevent additional gas entering the CCS facility piping.

EVVs are normally closed valves during typical operation. In an emergency, the EVVs are designed to open in order to vent process gas to the blowdown header system that terminates at the blowdown silencer. The blowdown silencer will vent any gas in the blowdown system directly to atmosphere where it is free to disperse in an open area. There are outdoor EVVs located on each line in the free flow piping area (EVVs located between XVs and FVs). There are also outdoor EVVs located on each of the pool pipeline meter area above ground piping runs (EVVs located on each of FR-1 through FR-16 meter run). There are indoor EVVs on the discharge piping of each compressor before the discharge MV. There are EVVs on the fuel gas lines as well.

The ESD impacts equipment in the main process and utility systems by turning it off (engines, motors, flare ignitor systems, etc.).

2.3.2 Activation of ESD

The ESD system can be activated manually by an operator or by automation / instrumentation inside each of the compressor buildings.

There are ESD pushbuttons located in the control room and in the plant yard available to operations. Operations can also initiate an ESD at one of the SCADA HMI screens located on site. There are also hand switches (field) for an electrical ESD that initiates a site wide ESD.

Emergency shutdown would occur in stages depending on the following control logic and operating philosophy:

- One indoor gas detector at 20% LFL
  - Alarm in control room
  - Ventilation fans in compressor buildings turn on
- Two indoor gas detectors at 40% LFL or two UV/IR positive detection or one of each fire and gas detection
  - Alarm in control room
  - Fire and Gas alarms and strobes plant wide alarm
  - Ventilation fans in compressor building turn off
  - Compressor exhaust fans turn off
  - Process equipment is turned off in the compressor building
  - EVVs in the compressor building where there is positive detection of gas or fire would open
- Operator decision to activate site wide shutdown
  - All ESVs close to prevent additional gas from pipelines into the plant
  - All EVVs open to vent gas in the plant to the blowdown silencer
  - All process equipment on site is turned off including compressor engines, fan motors, flare ignitor system, pump motors, etc.

3. SMAs and Information Used to Support the QRA

SMAs interview and gathering site information were carried out to understand how the facility is intended to operate in normal operating conditions and emergency condition.

3.1 Information Used

The information used to support the QRA include:

- P&ID Package 26882-EGD-OTR-001 (202 drawings in total)
- PFD 14-200 (2017) Layers – Simplified Flow Diagram Gas Transmission & Storage Facilities in Lambton County
- PFD 14-218 CCS Headers – Corunna Compressor Station Simplified Flow Diagram Main Gas Systems
- Draft Corunna Shutdown-Alarm Key
- Google Earth Map showing the layout of the site
- Previous QRAs being done for part of the site

3.2 SMAs Consulted

The following SMAs were consulted at different points throughout the QRA to support the establishment of basis of the QRA:

- Rick Wintjes, Technical Manager, Storage & Transmission Standards Engineering
- Andre Reif, Senior Engineer, Storage Planning
- Jeff Gallie, Manager System Operations Storage
- Chad Sutherland, Supervisor Tecumseh Operations
- Angela Scott, Manager Integrity Management
- Rob Sterling, Supervisor Facilities Integrity Management
- Bedokt Farbod, Sr FIMP Engineer

4. Risk Management Process

Risk assessment is part of the Risk Management Process as shown in Figure 3 below. This report focuses on the risk assessment step of the process. Results in this report would support other risk management activities particularly the ones in risk treatment. The risk assessment step is divided in three sub-steps: Hazard identification, Risk Analysis and Risk Evaluation. The methodologies of each step for risk assessments are described between the following sections of this report as they would apply to their specific scope.

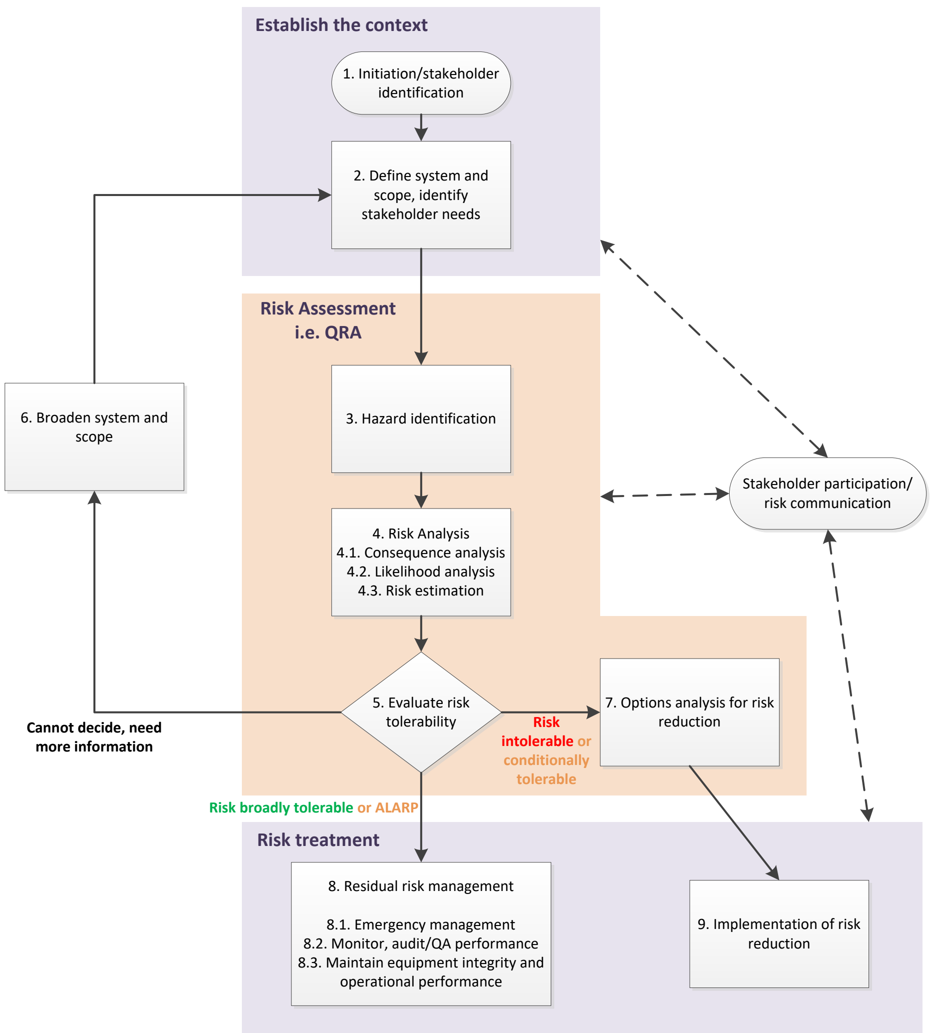

Figure 3 – Risk management process

5. Hazard Scenarios

5.1 Identification of Release Scenarios

Risk associated with major accidents caused by unintentional and uncontrolled release of natural gas are covered in this study. Since the area surrounding Corunna is farmland that is typically unoccupied by members of the public this QRA will only address risks to workers on site.

Potential fire and explosion hazardous outcomes are evaluated for the unintentional release scenarios and worker risk is assessed based on the Company's Health and Safety Risk Tolerance Criteria. In order to assess the hazards identified, the following loss of containment scenarios were developed by process area and covered in the QRA;

ILI Receiving Accidental Release Scenarios

- Ruptures and punctures of the on-site buried pool pipelines and Link Line
- Failure of pig traps (fixed equipment only)
- Leaks accounting for all smaller releases from pipework and associated valves, flanges, and instruments

Meter Run Accidental Release Scenarios

- Ruptures and punctures of the process pipework
- Ruptures and punctures of the buried transfer piping between areas
- Leaks accounting for all smaller releases from pipework and associated valves, flanges, and instruments

GAC & Compressor Header for Building 1, 2, or 3 Accidental Release Scenarios

- Ruptures and punctures of the process pipework
- Ruptures and punctures of the buried transfer piping between areas
- Releases from process equipment
- Leaks accounting for all smaller releases from equipment and pipework (including associated valves, flanges, and instruments)
- Failure of GAC tubing
- Failure of suction and discharge scrubber process vessels

Free Flow Piping Accidental Release Scenarios

- Ruptures and punctures of the process pipework

- Ruptures and punctures of the buried transfer piping between export FCVs and Transmission ESVs
- Leaks accounting for all smaller releases from equipment and pipework (including associated valves, flanges, and instruments)

Utility Gas Accidental Release Scenarios (i.e., fuel gas and power gas)

- Ruptures and punctures of the process pipework
- Ruptures and punctures of the buried transfer piping
- Leaks accounting for all smaller releases from equipment and pipework (including associated valves, flanges, and instruments)

5.2 Define Isolatable Sections for Simulation

In order to assess risks of loss of containment events, the operating facility needs to be divided into sections of similar operating conditions in order to determine release frequencies which is a major factor for calculating potential impact radius (in this study, would be focus on fire and explosion impact) and ultimately risk. The following process conditions must be defined for each isolatable section of the facility:

- Pressure
- Temperature
- Process medium & composition
- Inventory

Loss of containment that are not immediately isolated or inherently isolated under normal operating conditions, are likely to be continuously fed by upstream or downstream inventory. The total volume released from a potential leak is dependent on the accuracy of the isolatable sections. Isolatable sections are defined by the normal positioning of valves and normal operation of equipment as well as how things could potentially change during a successful ESD after a leak occurred. The impact of isolation is further discussed in the consequence section (see section 7.).

The CCS facility is operated with a range of operating pressures, however since the time spent at the extremes (i.e. at the maximum and minimum pressures for each isolated section) of the range is relatively small, it is more realistic to evaluate risks based on pressures which are representable over a majority of the operating duration. Estimating risks based on maximum or minimum pressures in each isolated area would either over or underestimate risk as risk is proportional to operating pressure.

5.3 Representative Operating Modes and Pressures Chosen

The seasonal operation dictates what flow path gas would follow through CCS and therefore impacts the isolatable sections. CCS has two main seasons of operation: withdrawal and injection causing different flow paths through the facility. Withdrawal at CCS takes gas from offsite underground storage pools and transfers it into the transmission pipelines for eventual use in the Company's distribution network. Withdrawal season depends on heating demand requirements. Injection at CCS takes gas bought on the market from transmission pipelines and injects it into the offsite underground storage pools for later use. Injection typically occurs when there is low heating demand.

Based on discussion with DNV GL, simulating all operating modes and pressures would push the simulation towards the capacity limit of SAFETI, in order to balance the efficiency of simulation and getting the best results, simplification was made by selecting representative high and low pressures for each isolated section. The representative high pressure was set at 1/3 below the average maximum pressure of the two operating modes (Withdrawal and Injection), the low pressure was set at 1/3 above the average minimum pressure of the two operating modes. The represented high and low pressures for each isolated section are given in Appendix A.

5.4 Compressor Operation

Compressors not in use can be classified in two different ways: standby mode and long-term outage. Compressors in standby mode are accounted for in the QRA and modelled as isolated from the main process via closed MVs. If one or more compressors are running while others are in standby mode, the running compressors will use the process gas from the offline compressor's cylinders drawing down the compressor in offline units and associated indoor suction and discharge piping to 150 psig (10.34 barg). When no compressors are running (i.e. free flow mode) the isolated compressors would be at transmission pressure which is considered to be 750 psig (51.71 barg) for the QRA. Each compressor in standby mode is therefore an isolatable section that is both season and operating mode dependent. Compressors are designed to trip in the event of a successful ESD. For the QRA, it was considered that a tripped compressor would prevent flow through the unit and therefore create a boundary for an isolatable section inventory.

The 11 compressors at CCS may or may not be required, at times, to flow gas during withdrawal or injection seasonal operation. The need for compression is mainly based on differential pressure in the system and limited by the MOP of pipelines and equipment. The two compressor operations considered in the QRA are "free flow" and "compression". The compression operation in this QRA is considered when one or more compressors is running. Due to the limitations of the QRA software regarding study size, it is not possible to model scenarios for every conceivable configuration of simultaneous compressor operation even though the compressor header piping allows for operational flexibility. The basis of this QRA considers that the compression operating mode is represented by the average number of compression units online at the same time and the free flow operating mode is represented by the percent of the year that zero compressor units are online.

Based on 2019 compressor run hours provided by operations, the percent of the year that multiple units were simultaneously online was tabulated as shown below.

Table 3 – Percent of the Year Compressors are Simultaneously Running

No. of Compression Units Running	% of the Year
0/11	29.0
1/11	3.3
2/11	12.6
3/11	11.5
4/11	15.9
5/11	13.7
6/11	9.3
7/11	3.6
8/11	0.8
9/11	0.0
10/11	0.3
11/11	0.0

The number of compressors online for a percent of the year can be represented as a normal distribution as shown below in Figure 4. The mean of the distribution is 4.01, therefore 4 compressors online was selected as the representative number of online units for the compression operating mode in the QRA. The portion of the year that compression operating mode occurs for is represented by the sum of the percentages that one of more compressors is online which is 71.0%.

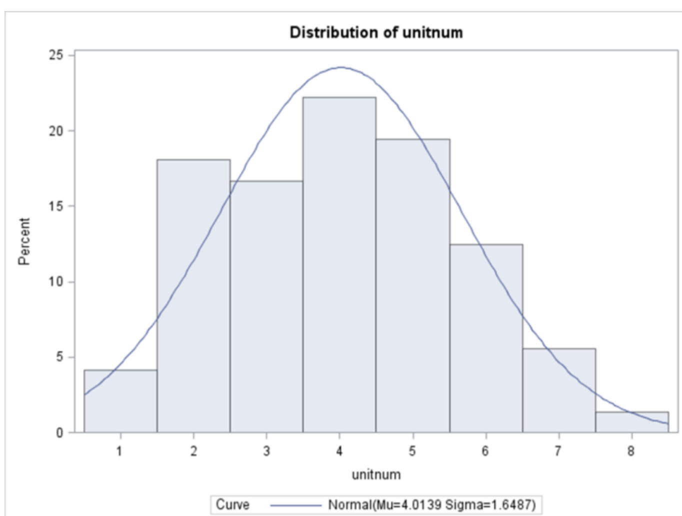

Figure 4 – Normal Distribution of Compressor Operation for 2019

The free flow operating mode where zero compressors are in operation was modelled in the QRA as 29.0% of the year as per data in Table 3 above. The distribution in Figure 4 was completed by in-house statistician using SAS software and data provided in Table 3.

5.5 Operating Temperature Chosen

The CCS facility operated mainly under ambient temperatures for the gas in pipelines and equipment. The compression process heats up the gas but there are GACs to cool the gas before going back into the pipeline system. Hence, ambient temperature of 65 °F was used.

5.6 Fraction of Time Per Operating Mode

Using the previously discussed seasons and compressor operation, operating mode can be divided into high-pressure and low-pressure mode. High pressure mode represents multiple compressors running, low pressure mode represents no compressors running. The split is given in Table 4 and used in the QRA. These two operating modes define and form the basis for further development of individual release scenarios modelled in the QRA.

Table 4 – Portion of the Year of Each Operating Mode in QRA

Operating Mode	Portion of Year
High Pressure Mode	71.0%
Low Pressure Mode	29.0%

Simplifying the QRA basis is required to prevent SAFETI from reaching its capacity limit. It is considered a reasonable basis to make this model simplification since the portion of the year where more equipment is in operation and at higher pressure is larger than the portion of the year where the system would be at lower pressure and more isolated due to no compression equipment running.

5.7 General Description of Isolatable Sections

Valve positions change depending on operating mode and compressor operation therefore impacting the isolatable sections defined in the QRA. This section will describe in a general manner, the typical position of different types of valves being assumed in the QRA for each operating mode. Marked up PFDs are included in the Appendix depicting the boundaries of each isolatable section in the QRA per operating mode.

For the Compression Injection operating mode, gas will enter the CCS facility via transmission lines TR-1 and TR-2 and flow into the transmission header portion of the compressor header piping (i.e. compressor suction piping in this mode). Four online compressors would have normally open MVs on their suction side and open MVs on the discharge side (depending on what storage pool(s) are being filled). The other MVs in the compressor header are modelled as closed so that the seven offline compressors are inherently isolated during this operation. Gas on the compressor suction side flows through a suction scrubber vessel to remove moisture from the gas before entering compression. Once compressed, gas flows through the Gas Aftercooler (GAC) to remove some of the heat gained from undergoing compression before flowing back into the compressor header system for a specific pool piping system. Gas flows through the pool

piping system (XVs in free flow piping are open and MVs in the free flow piping are closed to prevent recycling of gas back into transmission) to the meter area piping, through the normally open plot edge ESV, and eventually to the offsite underground storage pool. During a successful sitewide ESD, the ESVs on the transmission lines into CCS and pool lines out of CCS would close, the four running compressors would trip, EVVs would open to blowdown any trapped gas in the facility, and all other valves (MVs, XVs, and HVs) would remain in their normal position.
For the Free Flow Withdrawal operating mode gas enters the CCS facility via pool pipelines and flow through the normally open plot edge ESV, through the meter area piping, and through the FVs into the transmission pipelines TR-1 and TR-2. In order to create this flow path without recycling gas through compression, the XVs in the free flow header would be closed under normal operation and the MVs in the free flow piping would be normally open. During free flow all compressors are offline and modelled as isolated at transmission pressure (750 psig) via MVs in the compressor header being closed. During a successful ESD, the ESVs on the transmission lines out of CCS and pool lines into CCS would close, EVVs would open to blowdown any trapped gas in the facility, and all other valves (MVs, XVs, and HVs) would remain in their normal position forming the boundaries of isolatable sections.

There are a few systems at CCS that operate under the same or very similar conditions nearly year-round. These systems include fuel gas, power gas, Link Line, and Pig Traps.
The raw fuel gas supply can be taken from the Link pipeline or the Transmission Lines TR-1 or TR-2 via manually operated HVs. Raw fuel gas then flows through normally open ESV-139, Filter Separator V-001, Fuel Gas Heater E-77, pressure control valves PCV-129 through 132 (two runs with two PCV on each run), before going to each of the compressor buildings and MCC buildings to be used as fuel gas. The compressor buildings each have a normally open ESV on the fuel gas line before entering the building. The MCC buildings have an XV that would be unaffected by an ESD and remain in position.

Power gas is taken from the same line as the raw fuel gas but branches off the raw fuel gas upstream of ESV-139 (this is done to ensure valves would still be able to operate in an emergency). HP Power Gas goes to all ESV and XV throughout the plant to operate those valves. The HP Power Gas is at the same pressure as the source pipeline (either transmission or Link). LP Power Gas is reduced in pressure by PCV-43 before going to all EVV throughout the facility. Power gas would not be automatically isolated in the event of an ESD, operator action would be needed to close HVs in order to isolate this system.

The Link Line flows through plot edge ESV, through the meter area piping and across the yard directly to the transmission pipelines TR-1 and TR-2 via the transmission pipeline compressor header. The portion of the Link Line within CCS would be higher however still relatively close to transmission pressure year-round in order to inject from Link to transmission. For the purposes of QRA the Link line is just modelled as 750 psig.

Currently the only fixed or permanent pig trap at CCS is on the Link line and is modelled as normally isolated when pigging operations are not occurring. Based on input from the Pipeline Integrity group, pigging is considered to occur every 7 to 10 years and the pig traps are modelled as not isolated for approximately one month. Since the other pig traps are not permanent and depressurized / taken out of service for most of operation, they are excluded from risk calculations. This can be done since the time factor that non-permanent pig traps are in operation is a fraction of a percent and therefore risk is negligible.

6. Likelihood Analysis

6.1 Likelihood of Hazardous Consequences

The likelihood analysis quantifies the chance that a hazardous outcome could occur. For this QRA, hazardous outcomes include fires and explosions which are only mentioned here as they are further discussed in detail in the consequence analysis section. Figure 5 illustrates how an accidental release of natural gas (from the left) could manifest towards a hazardous outcome (at the far right). At high level, the hazardous outcome depends on the following:

- Chances (Probability) of isolating the release in time avoid buildup of flammable gases in an area
- Chances (Probability) the flammable gases could ignite and when

To get the likelihood of each hazardous outcome, the release frequency of each category would be multiplied by all event probabilities in the path to the final event outcome. This calculation is done in SAFETI. The risk analyst worked with stakeholders to develop and determine the likelihood inputs to the calculation. This section introduces the major events and their interaction during an accidental release scenario. The following sections go into the detail of quantification and basis for the likelihood values.

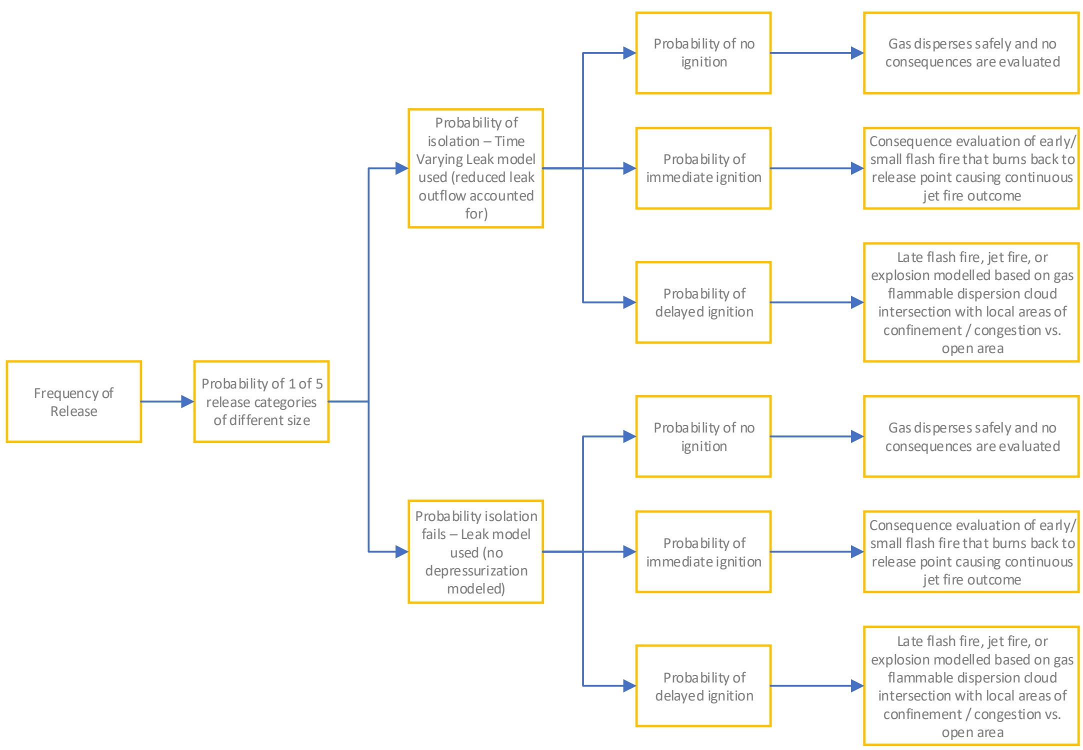

Figure 5 –Likelihood for Hazardous Consequence Outcome of Fire and Explosion

The chance that the release size is “small” or “large” would impact the magnitude of potential consequence as discussed later in the Consequence Analysis section. This study evaluates the chance of 5 different release size categories based on reported releases within industry. Generally, the smaller the release size, the less impactful the consequence outcome, which is why the distribution of potential leak sizes must be accounted for. Release sizes that tend to be the most common are very small in size and likely to result in a non-ignited event. Release sizes from catastrophic incidents are highly unlikely but if they do occur are more likely to ignite resulting in a fatal incident. To keep it simple, the diagram only shows one box representing various sizes of releases, in the QRA calculation, there are 5 different event trees evaluated for each release size as each tree would have a different magnitude of final event outcome.

The chance that a release is isolated impacts the depressurization of the system, which impacts the outflow of gas from an accidental release, and therefore impacts the magnitude of the final consequence outcome. The magnitude of leaking gas also impacts the total probability of ignition which is the next event. In general, small releases are much less likely to ignite than large releases that potentially cover a “larger” area with flammable dispersion. The larger area a flammable mass occupies, the more likely that an ignition source could be present. The effect of blowdown is accounted for in the consequence modelling and not modelled as an event probability.

The probability of ignition is split between three different events: no ignition, immediate ignition, and delayed ignition. Depending on when an accidental release is ignited impacts the consequence outcomes and their lethality potential. Unignited releases are modelled as no further consequence to workers in this QRA. Releases that are immediately ignited are considered to flash back to the release point and result in a continuous jet fire which is impacted by the available inventory feeding the fire (i.e. as previously mentioned chance of isolation would impact this available inventory feeding a fire).

Releases that are ignited at some point away from the release point are considered delayed, meaning the gas had some time to disperse into a flammable mass and potentially intersect with an ignition source away from the release point. For the delayed ignitions it is possible that the flammable dispersion is also in an area of confinement and/or congestion when it’s ignited therefore resulting in the explosion outcome instead of ignition in open areas where the outcome is modelled as a late flash fire and jet fire. The effect of an ESD trip turning off electrical equipment and minimizing potential ignition sources is accounted for in the probability of ignition events as discussed later in this section.

6.2 Likelihood of an Accidental Release

In order to estimate leak frequency using industry reported leak frequencies, the total population of piping and equipment must be defined. For a typical QRA the normal procedure would be to count all equipment types and piping length from P&IDs and other engineering drawings. Based on DNV GL guidance the parts count task using drawings would take 2 hours per P&ID to mark up, count, and review. Due to the time constraints of this project, it was determined to reuse previous QRA work for Corunna where available within reason. For this QRA the populations of piping and equipment were provided by SMA in 2017 to support replacement project specific QRAs within Asset Management. The populations were determined by SMA completing a walkthrough of the facility. Since the scope of this study includes the entire CCS facility, the SMA parts count was reviewed for completeness with some checking against the P&IDs and organized to fit the definition of isolatable sections previously described. It was discovered that instruments were not previously included in the parts count. The instrument populations were added to the parts count by reviewing an extract from MAXIMO for asset tags that were in natural gas systems.

6.3 Release Frequency Data

Accidental releases of hazardous materials can potentially occur due to many different causes. Typically, a QRA for a process facility does not go into the specific reasons as to why or how a release occurs. QRAs use industry reported release frequency statistics developed from accidents that have occurred in real life, in addition to other event statistics to quantify the overall likelihood of a risk.

A common QRA strategy is for companies to use internal data to quantify the chance of a LoC however caution needs to be applied with this approach. Given that accidents are extremely rare events it is quite possible that the sample size of piping and equipment that a company would own / operate is considered small relative to the population of all similar piping and equipment in operation within similar industry / application. A small sample size means it would be reasonable to expect that extremely rare events may not show up at all in the sample thereby skewing the rate of leak occurrences.

For this study the "Risk Assessment Data Directory – Process Release Frequencies" report 434-01 published by the IOGP in 2019 was used to quantify the chance that a leak may occur from above grade process equipment or associated piping. The data source is based on the HCRD managed by the UK HSE regulator. This data set and approach was also recommended by DNV GL. The following excerpt is from DNV GL's Failure Frequency Guidance report:

> *"DNV normally also use these data for QRA at onshore facilities. In general, the HSE data set gives higher leak frequencies than most of the onshore sources of data. There are several possible explanations for this.*
>
> *Process equipment on offshore installations might experience higher leak frequencies than on onshore plants. Possible reasons might be extra external corrosion from salt-water spray, internal erosion from entrained sand, or impacts resulting from the more compact equipment layouts. However, offshore installations have safety management systems that would be expected to counter such evident hazards. The HSE data set on leak causes shows that corrosion/erosion is a minor contributor, with operational / procedural faults and mechanical defects being the primary causes. Table 1 indicates the causes of leaks offshore between the 1st October 1992 to the 31st of March 2002.*

Table 5 – Causation factors in HSE offshore data

Category	Causation Factor	Instances (%)	Category Totals (%)
Design Fault	-	321 (9.5%)	321 (9.5%)
Equipment Fault	Corrosion/Erosion	277 (8.2%)	1362 (40.2%)
	Mechanical Defect	920 (27.2%)	
	Material Defect	76 (2.2%)	

Category	Causation Factor	Instances (%)	Category Totals (%)
	Other	89 (2.6%)	
Operational Fault	Incorrectly Fitted	267 (7.9%)	1116 (32.9%)
	Improper Operation	495 (14.6%)	
	Dropped/Impact	36 (1.1%)	
	Left Open/Opened	237 (7.0%)	
	Other	81 (2.4%)	
Procedural Fault	Noncompliance	231 (6.8%)	588 (17.4%)
	Deficient Procedure	323 (9.5%)	
	Other	34 (1.0%)	

Another possible explanation could be differences in data quality. The HSE offshore data set is a high-quality database, collected recently, covering a large population, with well-defined hole sizes, comprehensive equipment counts, and open for scrutiny by the operators and their consultants. Most of the available onshore leak frequencies come from small sample sizes. In fact, in the case of onshore pipe leak frequencies it is concluded that the most widely accepted data set is of eight leaks in U.S. nuclear plants in 19f, or earlier collections whose size and origin are now unknown.

A third factor affecting the comparison is that the HSE offshore data set includes some leaks that occurred while the equipment was depressurized, and others that were quickly isolated. The onshore frequencies are applicable to holes with process fluid at the full operating pressure. The frequencies based on HCRD data should be used with outflow models that take account of the variation in operating circumstances at the time of the leak.

A further complicating factor is that onshore and offshore management systems in the UK must address different regulatory requirements. The Offshore Safety Case requirements are more onerous than those required of onshore refineries (e.g. offshore requirements for identification of safety critical elements, performance standards and written schemes, plus the rigorous leak reporting requirements).

Overall, it is considered that the HSE offshore data provides the best available estimate of leak frequencies for both onshore and offshore process equipment. However, it does require that the outflow model should take account of the possibility of the equipment being depressurized or quickly isolated at the time of the leak."[1]

[1] *Failure Frequency Guidance – Process Equipment Leak Frequency Data for Use in QRA*. (2013). Høvik, Norway: Det Norske Veritas AS.

With the understanding that accidents, by definition, occur unintentionally meaning that despite best intentions and efforts to prevent / mitigate leaks, leaks have unfortunately still occurred within industry on accident. For this QRA it is assumed that;

- Relevant engineering codes, standards, and good engineering practices are followed,
- The facility is operated by competent and qualified operators,
- Policies and procedures are documented and enforced by management,
- Piping and equipment are part of a routine / scheduled maintenance and inspection program to ensure integrity is maintained throughout the lifecycle of the facility, and
- Routine quality assurance (QA) activities and audits take place.

As recommended by DNV GL industry release frequency base values are used from industry which may be considered conservative for the larger leak sizes but may also be an underrepresentation of the small hole sizes based on operating history. Through stakeholder engagement the following arguments were proposed against using industry data. The counterargument for using the industry data is provided afterwards each argument.

- Argument 1: The natural gas at Corunna is relatively clean from impurities compared to the offshore oil platforms used to develop 434-01. There is no need for major processes to clean the gas before compression or exporting for use in a distribution network. The Corunna site is onshore and does not experience the same harsh offshore conditions as the oil platforms used to develop 434-01.
    - Response 1: The offshore facilities contributing to industry data are required by regulations to demonstrate a rigorous and onerous safety case including management systems that are expected to control the risk associated with harsh operating conditions.
- Argument 2: Current inspection and integrity assessments have not identified any mechanical integrity issues that would cause concern for a potential major release from the process.
    - Response 2: The condition of an asset changes throughout its lifecycle. Although no issues are detected today this does not guarantee that there will be no issues in the future and does not guarantee that the inspections would be capable of detecting all potential issues before they progress to a failure. API 581 demonstrates the impact of a risk-based inspection (RBI) program, stating that risk cannot be reduced to zero solely by inspection efforts and the following residual risks could include but are not limited to;
        - Human error
        - Natural disasters
        - External events (e.g. collisions or falling objects)
        - Secondary effects from nearby units

- Consequential effects from associated equipment in the same unit
- Deliberate acts (e.g. sabotage)
- Fundamental limitations of inspection methods
- Design errors
- Unknown or unanticipated mechanisms of damage. [2]

The impact of modern integrity management programs was reflected in this QRA by using the IOGP data reported from 2006 to 2015 instead of the full data set from 1992 to 2015. The frequency of leaks in the industry data has reduced over the years partially because of the success of modern integrity programs. Therefore, the impact of integrity programs is accounted for in the industry data already.

It is also important to note that integrity program could detect some but not all root causes of accidental releases (see Table 5 for the list of potential causation factors for accidental releases), improving integrity management program should not only be driven by quantifiable risk reduction, other considerations such implementing industrial best practices to demonstrate the Company's commitment in reducing risk ALARP (as low as reasonably practicable) would be another driver.

- Argument 3: The leak repair history at Corunna from 2002 to 2016 includes 65 leaks total (between 2002 and 2016) as provided by FIMP in the excel file Classified Storage Failure Data. After interviewing Operations, Engineering, and Integrity SMA for the Corunna site, it was determined that all reported leaks going back to 2002 were considered insignificant or small (i.e. an equivalent hole diameter < 11 mm is expected based on discussion for small leaks and insignificant is considered to be < 4 mm equivalent diameter).
    - Response 3: Using the parts count and industry data to estimate leak frequency the total expected leaks from the same time period was estimated to be 0.9 leaks per year indicating the parts count may be underrepresenting the total equipment on site or the industry data may be underrepresenting the total leak frequency at Corunna. Industry reporting of leaks may not have been accurately reported for incidental or insignificant releases.

6.4 Leak Frequency of Major Equipment Items & Pipework

The QRA considers accidental releases from the following gas carrying assets:

- Above grade process piping
- Below grade transfer piping between plant sections
- Below grade pipelines e.g. on-site transmission and pool pipelines up to the pipeline ESV
- Flanges e.g. pipe connections excluding welds

[2] *Risk-based Inspection API Recommended Practice 580*. 3rd Ed. (2016). Washington, DC: American Petroleum Institute. P.13.

- Instruments
  - Pressure transducers
  - Thermocouples
  - Flow meters
- Actuated Valves
  - Flow control valves (FV)
  - Mode valves (MV)
  - Yard valves (XV)
  - Pressure Safety Valves (PSV)
  - Emergency shutdown valves (ESV)
  - Emergency vent valves (EVV)
- Manual Valves
  - Hand valves (HV)
- Process Pressure Vessels
  - Suction scrubbers
  - Discharge scrubbers
- Filters
- Reciprocating Compressors
- Air Cooled Heat Exchangers
  - Gas aftercoolers (GAC)
- Pig traps

Where available the 2006 – 2015 data published by the IOGP was selected over the 1992 to 2015 data set to reflect the modern integrity program at Corunna and subsequent expected lower leak frequency as per SMA input.

The IOGP data does not account for buried piping systems therefore the EGIG industry data is used. Since 3rd party damage is a major contributor to the chance of failure of buried piping and this QRA covers piping only on company owned property where ground disturbance activities are controlled more so than on public land, the 3rd party damage failures are removed from the EGIG data. This was done on recommendation by DNV GL and supported by the level of operational controls in place via ground disturbance policy and procedure at the CCS facility. Table 6 to Table 16 below include the unmodified base leak frequency values from industry that were used in this risk assessment.

Table 6 – IOGP Equipment Type: [1] Above Ground Steel Process Pipes, Leak Frequency [leaks per meter-year][3]

Hole Dia. Range [mm]	2" Diameter [50 mm]	6" Diameter [150 mm]	12" Diameter [300 mm]	18" Diameter [450 mm]	24" Diameter [600 mm]	36" Diameter [900 mm]
1 to 3	1.5E-05	9.5E-06	8.6E-06	8.1E-06	7.7E-06	7.7E-06
3 to 10	6.4E-06	3.9E-06	4.2E-06	4.8E-06	4.9E-06	4.9E-06
10 to 50	2.8E-06	1.6E-06	2.1E-06	3.0E-06	3.3E-06	3.3E-06
50 to 150	1.0E-06	3.2E-07	5.2E-07	9.7E-07	1.2E-06	1.2E-06
> 150	0.0E+00	2.0E-07	4.6E-07	1.3E-06	1.7E-06	1.7E-06
Total	2.5E-05	1.6E-05	1.6E-05	1.8E-05	1.9E-05	1.9E-05

Based on 2006 – 2015 data. Steel process pipes include welds

Table 7 –EGIG for Pipelines, Leak Frequency [leaks per meter-year][4]

Hole Dia. Range [mm]	Diameter < 5”	5” < Diameter < 11"	11” < Diameter < 17"	17” < Diameter < 23"	23” < Diameter < 29”	Diameter > 29”
1 to 20	7.0E-08	7.7E-08	7.5E-08	7.1E-08	7.0E-08	7.0E-08
20 to 150	3.5E-09	9.4E-09	4.6E-09	4.9E-09	4.6E-09	4.2E-09
> 150	2.9E-09	7.1E-09	6.0E-09	5.6E-09	4.0E-09	2.9E-09
Total	7.6E-08	9.4E-08	8.5E-08	8.2E-08	7.9E-08	7.7E-08

Based on 1997-2016 data. Includes welds. Does not include external impact failures based on DNV GL guidance.

Table 8 – IOGP Equipment Type [2]: Flanged Joints, Leak Frequency [leaks per flange-year]

Hole Dia. Range [mm]	2" Diameter [50 mm]	6" Diameter [150 mm]	12" Diameter [300 mm]	18" Diameter [450 mm]	24" Diameter [600 mm]	36" Diameter [900 mm]
1 to 3	4.4E-06	7.0E-06	1.3E-05	1.9E-05	2.1E-05	2.1E-05
3 to 10	2.0E-06	3.1E-06	5.0E-06	6.5E-06	6.9E-06	6.9E-06
10 to 50	9.1E-07	1.4E-06	1.9E-06	2.1E-06	2.2E-06	2.2E-06
50 to 150	3.8E-07	3.2E-07	3.7E-07	3.4E-07	3.3E-07	3.3E-07

[3] *Risk Assessment Data Directory Process Release Frequencies Report 434-01*. (2019). London, UK: International Association of Oil & Gas Producers.
[4] Gas Pipeline Incidents 10th Report of the European Gas Pipeline Incident Data Group period 1970 – 2016. (2018). Groningen, Netherlands: European Gas Pipeline Incident Data Group.

Hole Dia. Range [mm]	2" Diameter [50 mm]	6" Diameter [150 mm]	12" Diameter [300 mm]	18" Diameter [450 mm]	24" Diameter [600 mm]	36" Diameter [900 mm]
> 150	0.0E+00	5.7E-07	1.3E-06	2.0E-06	2.2E-06	2.2E-06
Total	7.7E-06	1.2E-05	2.2E-05	3.0E-05	3.3E-05	3.3E-05

Based on 2006 to 2015 data. Flanges are assumed to include other connection types such as threaded.

Table 9 – IOGP Equipment Type [3]: Manual Valves, Leak Frequency [leaks per valve-year]

Hole Dia. Range [mm]	2" Diameter [50 mm]	6" Diameter [150 mm]	12" Diameter [300 mm]	18" Diameter [450 mm]	24" Diameter [600 mm]	36" Diameter [900 mm]
1 to 3	1.5E-05	1.7E-05	2.9E-05	3.9E-05	4.1E-05	4.1E-05
3 to 10	8.0E-06	8.0E-06	1.5E-05	2.2E-05	2.5E-05	2.5E-05
10 to 50	4.6E-06	3.8E-06	8.0E-06	1.4E-05	1.6E-05	1.6E-05
50 to 150	2.7E-06	9.1E-07	2.2E-06	4.3E-06	5.3E-06	5.3E-06
> 150	0.0E+00	7.2E-07	2.2E-06	5.5E-06	7.2E-06	7.2E-06
Total	3.0E-05	3.0E-05	5.6E-05	8.5E-05	9.5E-05	9.5E-05

Based on 2006 to 2015 data. For hand valves (HVs).

Table 10 – IOGP Equipment Type [4]: Actuated Valves, Leak Frequency [leaks per valve-year]

Hole Dia. Range [mm]	2" Diameter [50 mm]	6" Diameter [150 mm]	12" Diameter [300 mm]	18" Diameter [450 mm]	24" Diameter [600 mm]	36" Diameter [900 mm]
1 to 3	1.4E-04	7.9E-05	7.5E-05	8.4E-05	8.6E-05	8.6E-05
3 to 10	5.8E-05	3.7E-05	3.3E-05	3.3E-05	3.3E-05	3.3E-05
10 to 50	2.3E-05	1.8E-05	1.5E-05	1.3E-05	1.3E-05	1.3E-05
50 to 150	7.3E-06	4.3E-06	3.3E-06	2.6E-06	2.4E-06	2.4E-06
> 150	0.0E+00	3.6E-06	2.6E-06	1.7E-06	1.4E-06	1.4E-06
Total	2.3E-04	1.4E-04	1.3E-04	1.3E-04	1.4E-04	1.4E-04

Based on 2006 to 2015 data. Actuated valves include control valves, ESV, EVV, MV, XV, PSV.

Table 11 – IOGP Equipment [5]: Instrument Connections [leaks per instrument-year]

Hole Dia. Range [mm]	1" Diameter [25 mm]	2" Diameter [50 mm]
1 to 3	1.2E-04	1.2E-04
3 to 10	5.0E-05	5.0E-05
10 to 50	2.7E-05	2.0E-05
50 to 150	0.0E+00	6.6E-06
> 150	0.0E+00	0.0E+00
Total	2.0E-04	2.0E-04

Based on 2006 to 2015 data.

Table 12 – IOGP Equipment Type [6]: Process (Pressure) Vessels, Leak Frequency [leaks per vessel-year]

Hole Dia. Range [mm]	Vessel Connections [50-150mm]	Vessel Connections [>150 mm]
1 to 3	3.3E-04	3.3E-04
3 to 10	1.7E-04	1.7E-04
10 to 50	9.3E-05	9.3E-05
50 to 150	4.9E-05	2.5E-05
> 150	0.0E+00	2.4E-05
Total	6.4E-04	6.4E-04

Based on 2006 to 2015 data. Used for the compressor suction scrubber pressure vessels.

Table 13 – IOGP Equipment Type [10]: Compressors: Reciprocating, Leak Frequency [leaks per compressor-year]

Hole Dia. Range [mm]	Compressor Inlet [>150 mm]
1 to 3	6.8E-03
3 to 10	3.1E-03
10 to 50	1.4E-03
50 to 150	3.2E-04
> 150	2.4E-04
Total	1.2E-02

Based on 2006 to 2015 data. Includes all compressor components and suction/discharge bottles.

Table 14 – IOGP Equipment Type [14]: Heat Exchangers: Air-cooled, Leak Frequency [leaks per exchanger-year]

Hole Dia. Range [mm]	Exchanger Inlet [> 150 mm]
1 to 3	8.9E-04
3 to 10	3.1E-04
10 to 50	1.1E-04
50 to 150	1.8E-05
> 150	9.3E-06
Total	1.3E-03

Based on 2006 to 2015 data. Used for the GAC – gas aftercoolers.

Table 15 – IOGP Equipment Type [15]: Filters, Leak Frequency [leaks per filter-year]

Hole Dia. Range [mm]	Filter Inlets > 150 mm
1 to 3	1.2E-03
3 to 10	4.4E-04
10 to 50	1.5E-04
50 to 150	2.6E-05
> 150	1.3E-05
Total	1.8E-03

Based on 2006 to 2015 data.

Table 16 – IOGP Equipment Type [16]: Pig Traps, Leak Frequency [leaks per pig trap-year]

Hole Dia. Range [mm]	Pig Trap Inlet > 150 mm
1 to 3	1.4E-03
3 to 10	7.4E-04
10 to 50	4.1E-04
50 to 150	1.1E-04
> 150	1.1E-04
Total	2.8E-03

6.5 Representative Hole Diameter for Release Size Range

In order to model the consequences of a leak in a QRA the size of a potential hole must be defined. The IOGP reports leaks based on the following categories in Table 17 below.

Table 17 – Release Sizes Reported by IOGP

Release Category	Leak Diameter Lower Range [mm]	Leak Diameter Upper Range [mm]
1	1	3
2	3	10
3	10	50
4	50	150
5	150	Max Diameter

A representative diameter within the reported range was selected to model leak in the QRA. The selection of hole size has a direct impact on the risk results. The IOGP provides advice on how to select representative hole sizes as follows;

> *"With the exception of the highest range, the historic probabilistic distribution and modelled correlations of hole sizes is heavily weighted towards the lower end of the range, i.e. most leaks will be smaller than the arithmetic mean. An examination of average consequence, in terms of fatalities, of holes over a given range was found to be best represented by a hole size which was close to the geometric mean for that range. Hence, the geometric mean approach is recommended for use in most risk analyses. Use of the other approaches will generally give conservative estimates of the risk."*

Consultants at DNV GL agreed with the approach to model the geometric mean instead of arithmetic mean for leaks smaller than rupture. The 5th IOGP release category was modelled as 90% of releases as 150mm diameter and 10% of releases would be modelled as ruptures.

For onshore QRAs DNV GL proposed combination of the two smallest IOGP hole size release categories to simplify the QRA calculations. This simplification reduces the calculation time for large QRA studies completed using SAFETI software. Since the majority of onshore piping and equipment is located outdoors the 1mm to 3mm leaks would be highly likely to disperse without further consequence so these small leaks are combined into one category to simplify the calculations without neglecting potential leaks.

For long pipelines, the total potential outflow area was modelled as twice the cross-sectional area of the pipeline, since outflow can occur from both the upstream and the downstream branches of the pipeline. For un-isolated ruptures, the user defined source model was used with the discharge rate from a long pipeline of similar diameter and pressure. For isolated ruptures, the time-varying leak model was used. The orifice diameter was set equal to the maximum pipe or equipment diameter. For ruptures isolated by ESD, the user defined source model was used with the discharge rate from a long pipeline of similar diameter and pressure. The discharge rate was reduced to zero by 90 seconds.

The QRA modelled the following leak sizes based on the diameter of specific equipment and piping at Corunna.

Table 18 – Leak diameter modelled in QRA per leak category

Leak Category	Leak Diameter Lower Range [mm]	Leak Diameter Upper Range [mm]	Leak Diameter Modelled in QRA [mm]
Small	1	10	5
Moderate	10	50	22
2" Rupture	-	-	50
Large	50	150	87
6" Rupture	-	-	150
12" Rupture	-	-	300
18" Rupture	-	-	450
24" Rupture	-	-	600

6.6 Probability of Isolation

For piping systems and equipment normally isolated, the probability of isolation in the QRA scenario is inherently 100%. For the modelling of free flow operations, all compressors and associated indoor piping were modelled as normally isolated. Modelling offline compressors during the compressor operating mode would still have 7 out of 11 compressors isolated.

For the 4 out of 11 compressors and associated piping normally flowing gas during compressor operation it is possible that operator leak detection and ESD could occur as well as automated gas detection/fire detection indoors initiates and ESD for all leak size categories. The probability of an indoor leak isolated due to ESD is based on the previous Meter Area QRA which determined a probability of 1.5E-1 failures per year (or an 85% chance of success).

For outdoor releases there is no automated leak detection and operations must detect leaks during operator rounds or troubleshooting/investigating related process alarms. Based on discussions with operations the time to detect a leak and isolate it could realistically take a couple minutes. Considering the time between immediate ignition and delayed ignition could be under a minute to maybe even a few seconds, the impact of isolation would not have meaningful impact on the end risk result and add unnecessary complexity to the calculation.

To illustrate that isolation does not have meaningful impact for most outdoor releases, dispersion modelling results were generated based on a natural gas piping system located outdoors with gas at 18˚C (64˚F) and 51.71 barg (750 psig) for the release sizes previously listed in Table 18 above. The releases were modelled as free to atmosphere, horizontally, from a height of 1m (3.3ft) above grade typical for accidental outdoor releases. The following results were generated for the side view of a flammable gas cloud for the different representative hole diameters and two time-steps throughout the one-hour duration model run time. The first time-step was at 1 second after initial release and the second time step was taken at the time when the flammable cloud reached its maximum size or around one minute, whichever came first. If a flammable cloud reached its maximum size, then it would be hypothetically exposed to the maximum number of potential ignition sources which may or may not be present within the flammable cloud. The presence and magnitude of potential ignition sources are accounted for in the probability of ignition in the next section.

The flammable dispersion is represented by the area between the UFL (red line) and LFL (green line). The ½ LFL is included for modelling purposes only as the user must tell the software when to stop the dispersion model and it is generally accepted that at ½ LFL there is no further accuracy gained by running the model past that concentration.

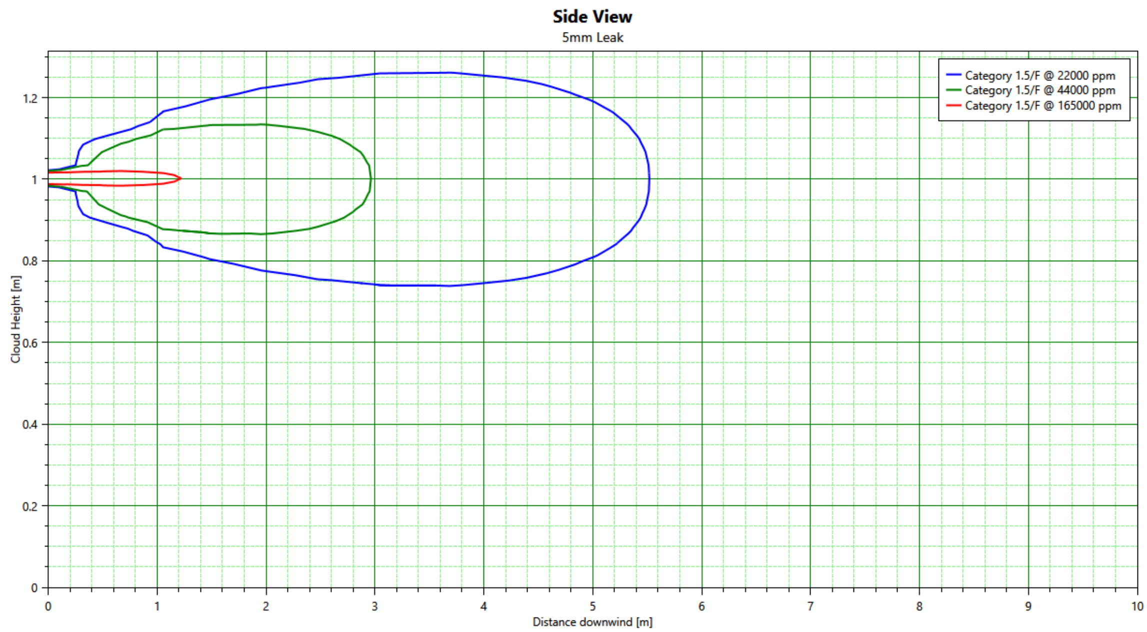

Figure 6 – Initial flammable dispersion from a 5mm leak after 1 second from release

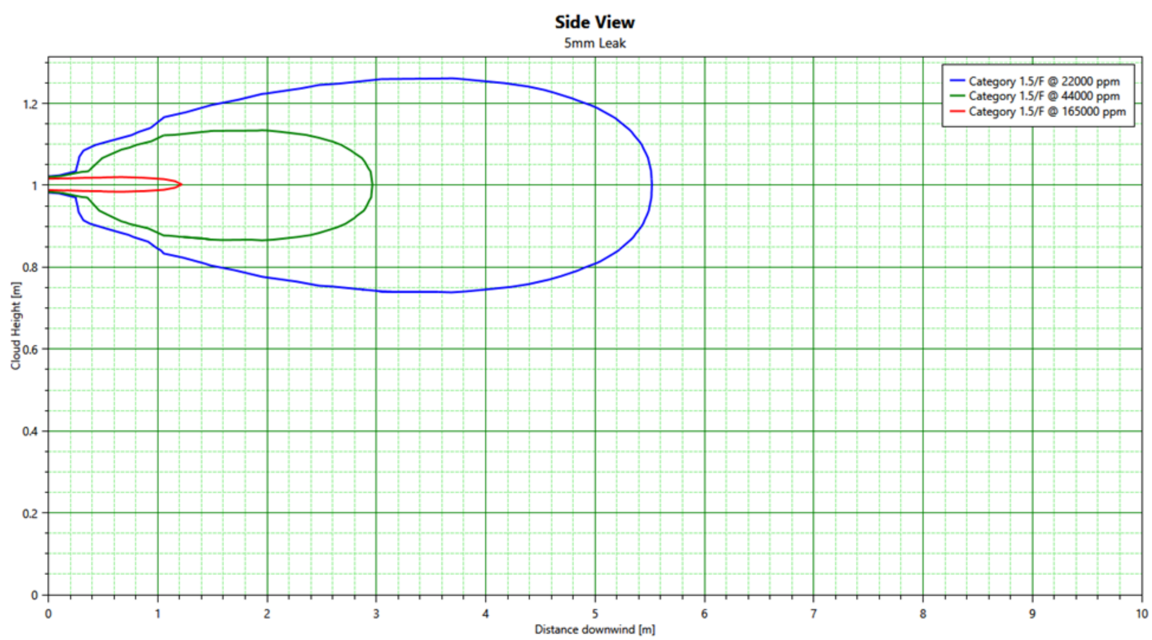

Figure 7 – Maximum flammable dispersion from a 5mm leak 37 seconds after initial release

Note that the LFL distance for the 5mm leak between 1 second and 37 seconds, which is the maximum dispersion is almost negligible between the two graphs. This means that whatever potential sources of ignition are within that flammable dispersion would have a chance to ignite the cloud. It would be unreasonable to assume that an operator could detect this leak and isolate it instantaneously of it occurring to eliminate or impact the chance of ignition the chance of ignition.

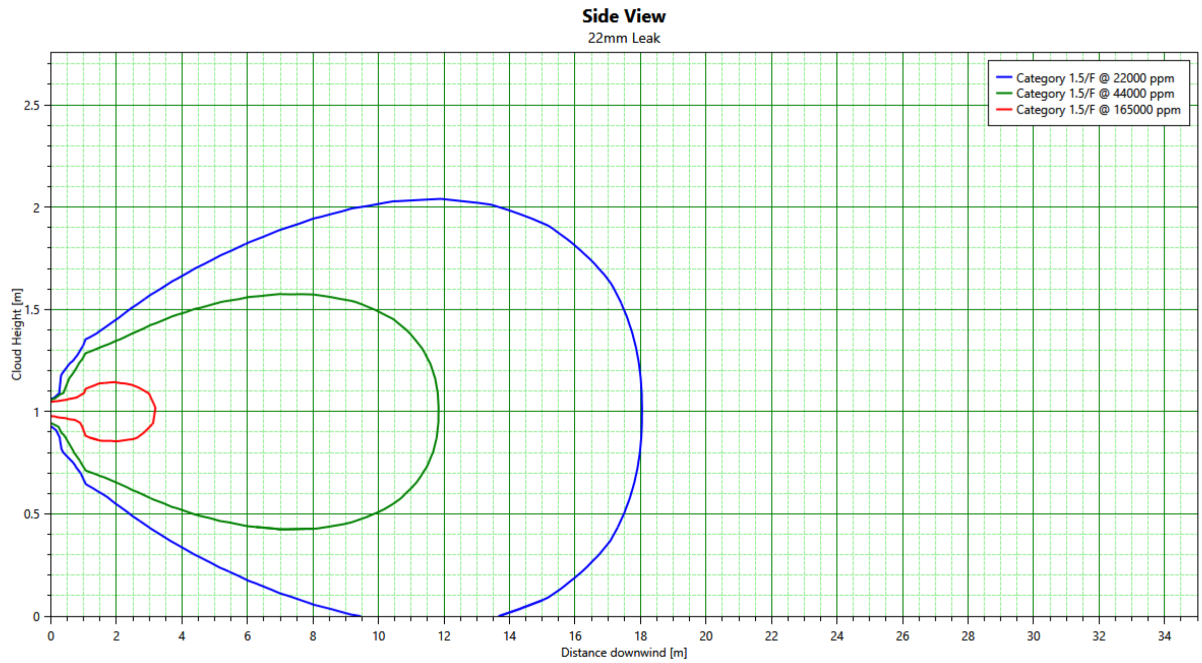

Figure 8 – Initial flammable dispersion from a 22mm leak after 1 second from release

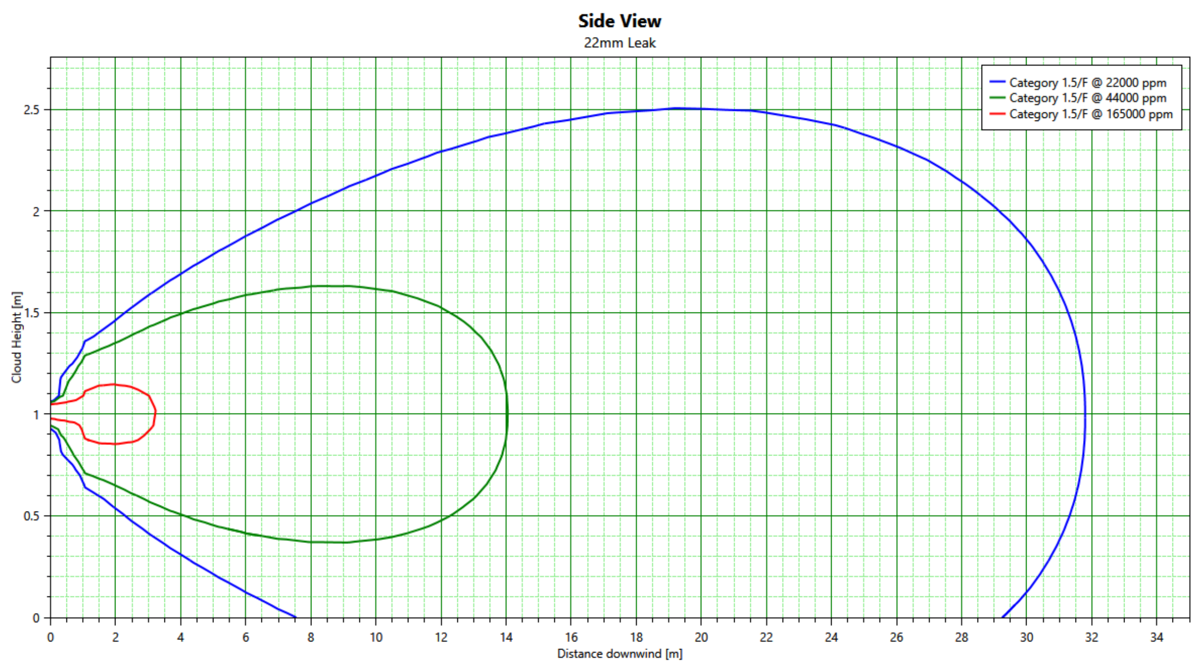

Figure 9 – Maximum flammable dispersion from a 22mm leak 37 seconds after initial release

Same conclusions for the 22mm leak as the 5mm leak due to the cloud reaching maximum size after 37 seconds.

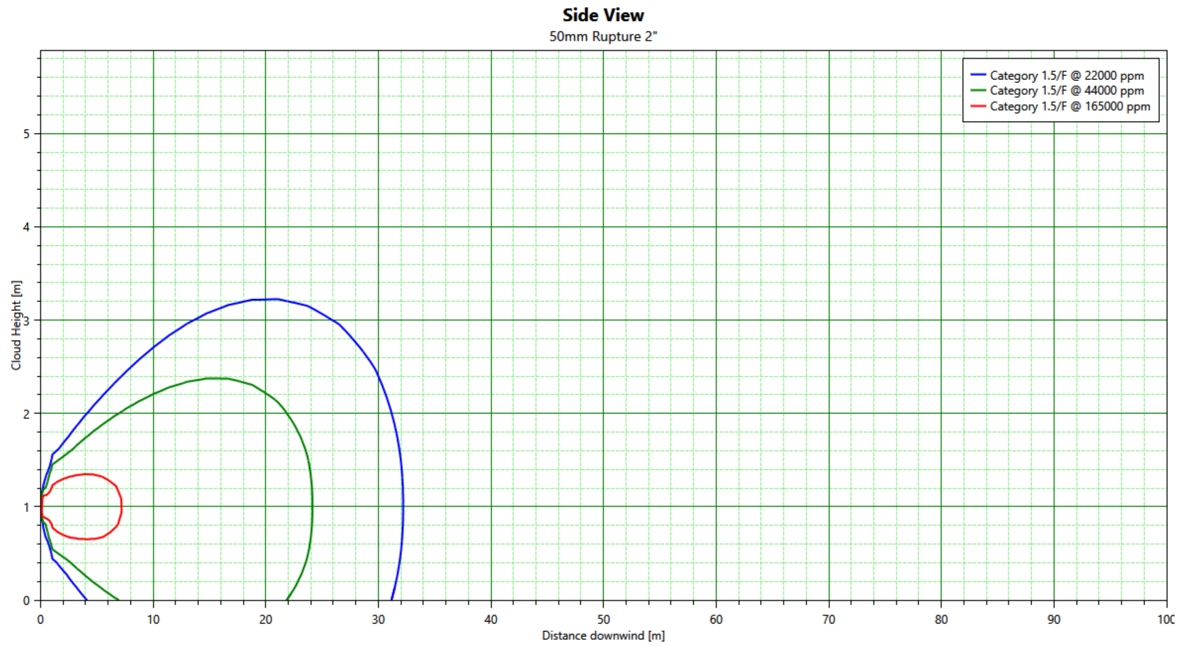

Figure 10 – Initial flammable dispersion from a 50mm leak after 1 second from release

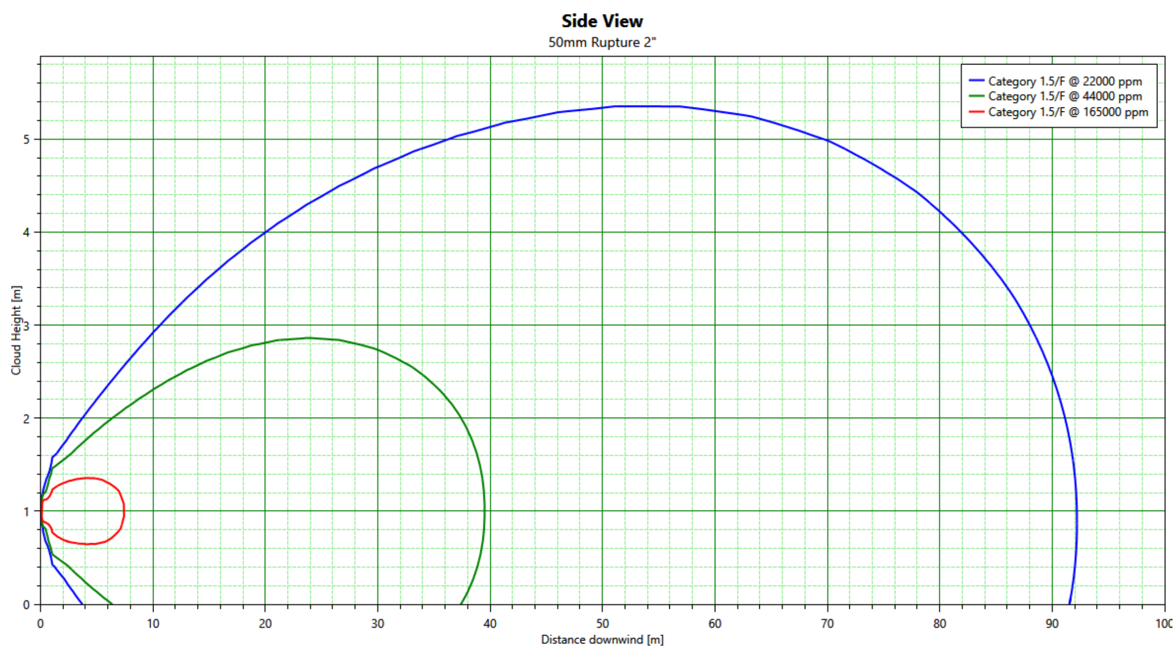

Figure 11 – Maximum flammable dispersion from a 50mm leak 73 seconds after initial release

Same conclusions for the 50mm leak as the 5mm leak due to the cloud reaching maximum size after approximately one minute.

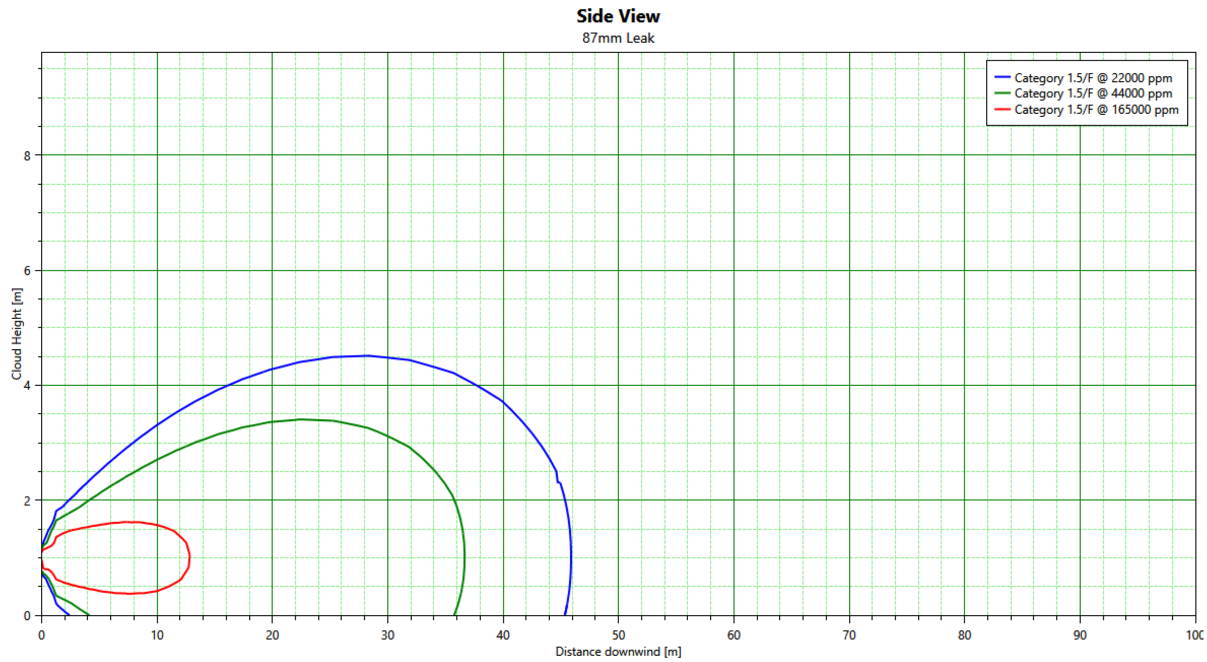

Figure 12 – Initial flammable dispersion from an 87mm leak after 1 second from release

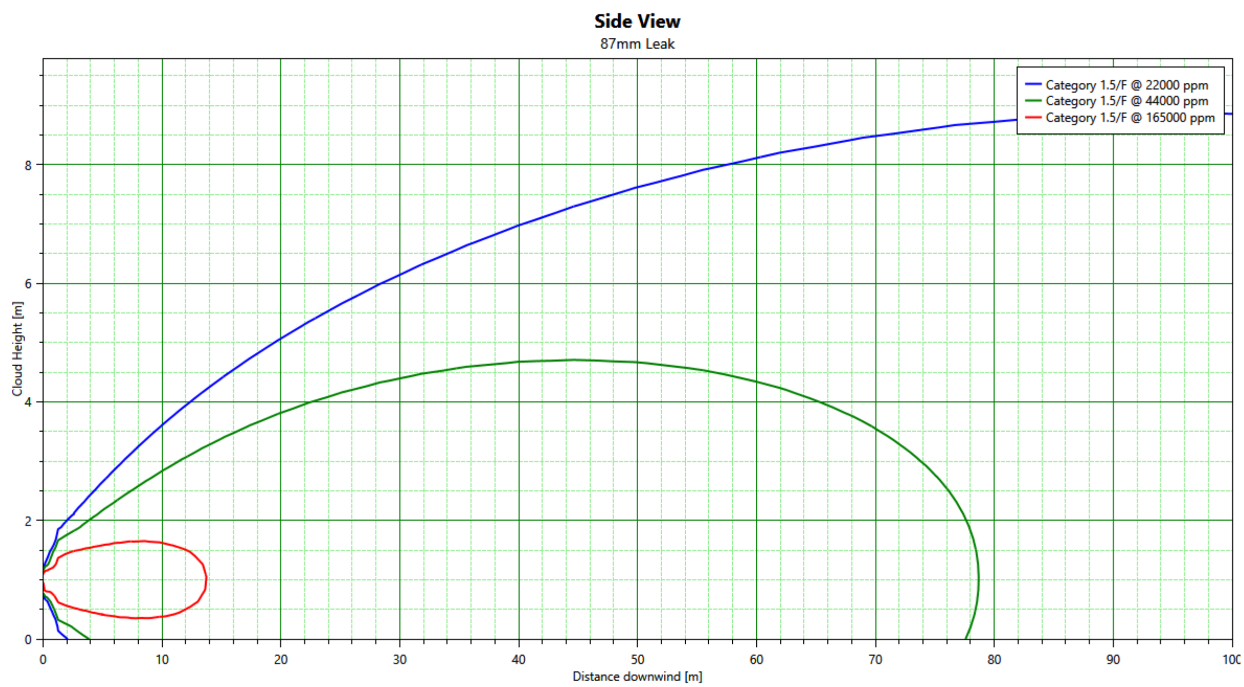

Figure 13 – Maximum flammable dispersion from an 87mm leak 73 seconds after initial release

Same conclusions for the 87mm leak as the 5mm leak due to the cloud reaching maximum size after approximately one minute.

At this point there is not much value in showing the larger release sizes as the flammable dispersion would be potentially reaching off site into typically unoccupied farmland. This means that whatever potential ignition source are present on site are the limiting factor to probability of ignition of a flammable mass instead of the impact of isolation on the maximum flammable cloud size of outdoor releases.

6.7 Probability of Ignition

6.7.1 Background on the Probability of Ignition of a Flammable Mass in a Plant Environment

The potential ignition sources at CCS can be classified into the following categories;

- Open flames, such as the onsite flare.
- Moderate temperature sources that may give rise to spontaneous ignition such as hot surfaces on an engine / exhaust (compressor or vehicle), motor, rotating equipment, other fired equipment with a hot surface such as a boiler, or tools / hot work.
- Electrical sources such as powered equipment / tools, electrostatic accumulation, stray currents, radiofrequency pick-up, and lightning.
- Physical sources such as compression energy, friction generated by gas releasing to atmosphere, or impact caused by a dropped object or caused simultaneously by the same event causing the release to occur.
- Chemical sources such as catalytic materials, pyrophoric materials and unstable species are not expected to be a factor at the CCS facility for this QRA.

The impact of an ESD cutting electricity to equipment can help reduce potential sources of electrical ignition, however if the equipment is also hot and has not cooled down by the time that the flammable gas comes into contact with it, then the hot surface of the equipment is still a potential source of ignition. In the unlikely event that the ESD fails, systems may still have a power supply which is a potential source of ignition.

As discussed previously, flammable masses can form within seconds from initial release but ESD is not instantaneously triggered with the release of flammable gases since time is required to detect the presence of flammable gas or fire following by isolation of the process and shutdown of equipment. Hence, it is possible a sizable mass of flammable gas could form before ESD trip running equipment.

Although regular maintenance is performed for equipment with electrical devices, there is remote possibility that they could fail in between maintenance cycles and becoming potential sources of ignition. This is accounted for in the probability of ignition events in QRA studies.

It is typical in QRA to assume that plants are designed and maintained according to a relevant/comparable Hazardous Area Classification (e.g. CSA, NFPA, BS, and/or API). According to guidance from the AIChE CCPS group, such standards have two inherent shortcomings for the perspective of quantifying risk:

- They are designed to address continuous or incidental (e.g. maintenance activity) releases but not major losses of containment typically covered in QRA.
- The integrity of the devices within the classified area may be compromised by the same event which initiated the release of flammable gases if it is energetic (e.g. dropped object, vehicle impact, debris projectiles from pipe or equipment that has catastrophically failed due to overpressure above burst pressure, etc.).

Therefore, while important to an ignition prevention program, according to CCPS guidance, area classification is not guaranteed to eliminate the chance of ignition in classified areas on site.

Effective work permitting systems are expected to be in place as part of an ignition prevention program to minimize the chance that hot work such as welding, or grinding could generate a potential ignition event. Work permit systems do not guarantee the chance of ignition is zero. For example, even if hot work is stopped the instant that signs of a flammable release reveal themselves, residual hot surfaces can still provide an ignition source. There is also the potential for human factors to impact the effectiveness of work permitting.

6.7.2 Probability of Ignition Basis

The QRA uses the IOGP method and Atkins method for quantifying probability of ignition. The IOGP method is a publicly available reproduction of UKOOA method for large onshore gas plants. This model is also built into the QRA software SAFETI that was used for this study as it's considered generally a good approach for conducting QRA studies of oil and gas facilities. The UKOOA model has been developed following a detailed review of earlier ignition modelling studies and it has also referred to a substantial database of releases in the UK offshore sector. The model gives variation in ignition probability based on the mass outflow; hence it is possible to represent different sizes of the releases. The Atkins method is used for assessing delayed ignition when detailed information was available to reflect site specific conditions at CCS. Using a combination of both approaches helps provide a better resolution into quantifying the probability of ignition as site specific characteristics are considered. The locations of ignition sources, relative to each release location, will automatically be factored into calculations by SAFETI software.

6.7.3 IOGP / UKOOA Model for Probability of Ignition

The UKOOA model is applicable for releases of flammable hydrocarbon gases significantly above their normal boiling point from large onshore outdoor plants. A large plant is considered to have a plant area greater than 1,200 m^2 on a site greater than 35,000 m^2. Based on approximate measurements on Google Earth the area occupied by the main compressor buildings, compressor header piping, GACs, and JWCs is 170m by 70m or 11,900m^2 and the total yard area is approximately 350m by 170m or 59,500m^2, which satisfies the UKOOA definition. This model only applies to plants that are considered to follow recognized industry good practice for controlling potential ignitions sources (i.e. hazardous area classification, work permitting policy, ESD interlocks, routine scheduled maintenance, etc.).

The data presented in the UKOOA model is considered a total probability of ignition meaning a split for immediate and delayed ignitions events must be applied. It is recommended that 30% of ignitions are modelled as “immediate” and the remaining 70% of ignitions are modelled as “delayed” events. It is important to model both immediate and delayed events since the resulting ignited event could be drastically different. Immediate events are modelled as a small flash fire that burn back to the leak source and results in a continuous jet fire until the source is isolated (if isolation is still possible during the fire). For delayed events, there is time between the initial release and ignition meaning that the flammable mass has some time to develop into a relatively large cloud compared the immediately ignited release. Given the nature of releases from pressurized systems, the time difference in immediate and delayed ignitions can be considered in seconds if the release is large and has a lot of momentum due to high source pressure, the flammable cloud can form within seconds. The UKOOA model was used to account for probability of ignition in the compressor buildings.

6.7.4 Atkins Model for Probability of Ignition

The Atkins model was used to represent delayed ignition cases as this allows point and area sources to be considered and enables differentiation between releases in different directions, releases from different locations and ignitions at different times. The model is formulated primarily for onshore sites and can take into account complex arrangements of ignition sources. The model is quite detailed and requires parameters that are often not readily available, except by judgement. This is mitigated somewhat by the provision of detailed examples in the referenced report.[5] The ignition sources that were derived for the assessment together with the required parameters to for estimating probability of ignition are shown in following tables. The ignition sources are categorized into the following types:

- Area
- Roads
- Electrical Lines
- Point Sources

Table 19 – Site specific ignition source input data (areas)

Ignition Source	Ignition Probability	In Time Period (sec)	Proportion of Time Operating	Area (W by L in m or m^2)	Location	Comments
Meter Runs	0.095	60	0.0801	35 by 55 m	Main Plant Metering Area	External Classified Area
Boiler Area	0.695	10	0.694	13 by 19 m	Main Plant	Boiler runs for 1 hour per week

[5] *Development of a method for the determination of on-site ignition probabilities*, Research Report 226. (2004). Prepared by WS Atkins Consultants Ltd for the Health and Safety Executive.

Ignition Source	Ignition Probability	In Time Period (sec)	Proportion of Time Operating	Area (W by L in m or m^2)	Location	Comments
					Northeast of CB1	
JWC/Auxiliary	1	10	1	164 by 23m	Main Plant East of CB1-3	Unclassified and with heavy equipment. Using the heavy equipment (non-hazardous) assumption from UK HSE RR226.
GAC/Header	0.095	60	0.0801	5,299 m^2	Main Plant West of CB1-3	External classified area per HSE RR226
Free Flow	0.0801	60	0.095	17 by 62m	Main Plant Free Flow Area	-
Substation	0.995	60	0.993	18 by 13m	Northeast of Main Plant	-
MKC-SKC Meter Area	0.095	60	0.0801	6,073	Main Plant	-
Outdoor Storage 1	0.305	60	0.283	86 by 52m	Main Plant Southwest of CB3	-
Outdoor Storage 2	0.305	60	0.283	2,943 m^2	Main Plant ILI Area	-

Table 20 – Site specific ignition source input data (roads)

Ignition Source	Ignition Probability	In Time Period (sec)	Traffic Density (/hr)	Average Speed (m/s)	Length (km)	Comments
Tecumseh Road	0.197	10	4.58	22.35	1.77	Ignition probability is for a single vehicle coming in contact with the

Ignition Source	Ignition Probability	In Time Period (sec)	Traffic Density (/hr)	Average Speed (m/s)	Length (km)	Comments
(Outside the Site boundary)						cloud. Traffic density assumed at 110 per day. Speed limit on road is 50 mph.
South Vehicle Route	0.0129	10	1.04	4.47	0.47	Ignition probability is for a single vehicle. Traffic density assumes 25 vehicles using this route per day and driving at speed limit of 10 mph.
North Vehicle Route	0.01	10	1.04	4.47	0.14	Ignition probability is for one vehicle. Traffic density assumes 25 vehicles use this route per day, traveling at speed limit of 10 mph.

Table 21 – Site specific ignition source input data (electrical lines)

Ignition Source	Ignition Probability	In Time Period (sec)	Traffic Density (/hr)	Per Unit Length (m)	Location	Comments
Electrical Line	1E-06	10	1E-06	0.3048	East of Main Plant Area	Removed from study based on DNV GL guidance.

Table 22 – Site specific ignition source input data (point sources)

Ignition Source	Ignition Probability	In Time Period (sec)	Proportion of Time Operating	Height of Source (m)	Comments
Flare	1	1	1	10	Flare is almost always running - no calculations modelled as POI 1

Ignition Source	Ignition Probability	In Time Period (sec)	Proportion of Time Operating	Height of Source (m)	Comments
Furnace	0.999977	10	0.5	10	Furnace on roof runs for half the year.
Transformers 1, 2, & 3	0.0997	60	0.0952	0	Transformer 1 is located to the north of Main Plant Area. Transformers 2-3 are located to the east of Main Plant Area.

6.7.5 Improvements to Ignition Source Modelling

The previous QRA for the meter area project contained much of the methodology applied in this assessment. Based on guidance from DNV GL the following improvements were proposed to the ignition source modelling;

- Not to include ignition sources with very low ignition probabilities, e.g. ‘electrical line’.
- Revisited the basis of the following inputs:
  - Height of source for flare and furnace updated to 10m above grade.
  - Proportion of time operating for point sources or area sources with high ignition probability. A judgement was made whether the particular ignition source is present for the defined proportion of time. For example, the flare is still considered operational 100% of time (which means that the source of ignition is always present).
  - Ignition probability and proportion of time operating for:
    - Meter Runs,
    - GAC/Header,
    - Free flow and
    - MKC-SKC Meter Area,
- Where values were derived using ‘external classified area, HSE RR226’ example. Source density of <u>25 per hectare</u> was used, whilst the example tables in RR226 suggest <u>10 per hectare</u> for a ‘typical’ site. There is no note to say why value 25 was chosen, however, the other source parameter calculations were based on the ‘typical’ quality of ignition controls model.

The current Corunna Shutdown-Alarm Key is a draft document and has not been kept up to date based on stakeholder feedback. The previous meter area QRA modelled ignition sources without active shut down even though the shutdown-alarm key states that certain ESD triggers would turn off certain potential ignition sources. If active shutdown modelling is selected in SAFETI, then the risk calculations will treat the source as shutting down at a time after the start of the release set by the Shut down time. After shutdown, the ignition potential for the source will decay exponentially, in such a way that the ignition potential will have halved after a time given by the Cooling time.

7. Consequence Analysis

7.1 Consequence Analysis Overview

The outcomes of events previously described in the likelihood analysis are modelled in the consequence analysis. In order to determine if an ignited event could potentially fatally injure someone who is present, the following 3 steps are completed:

1. Calculate the outflow of an accidental release based on:
    - Source pressure and temperature as previously described in the risk scenarios
    - Composition of hazardous material as previously described in the risk scenarios
    - Release size (equivalent diameter of a hole) as previously described in the risk scenarios
    - Isolation of release as previously described in the risk scenarios
    - Frictional losses in pipelines (automatically calculated in software)
2. Calculate the flammable mass of a release through dispersion modelling based on:
    - Meteorology (i.e. atmospheric stability and wind rose)
    - Jet mixing (i.e. air entrainment into a jet of gas releasing from a pipe into the atmosphere)
    - Surface roughness and terrain
    - Averaging time
    - Wake effects and impingement
3. Determine the lethal effects produced by ignited events by:
    - Calculating the size of instantaneous fires known as flash fires for flammable masses ignited in open areas
    - Calculating the thermal radiation for continuous momentum driven fires know as jet fires
    - Calculating the overpressure effects of explosions for flammable masses ignited in areas of confinement and/or congestion
    - Comparing hazardous consequence effects to lethality thresholds

Using the DNV GL software SAFETI, these calculations were completed for this QRA. The inputs to SAFETI for the first step were already discussed in previous sections of the report when the scenarios were defined. The inputs for the second and third steps are included in this section.

7.2 Dispersion Modelling

Dispersion modelling determines the flammable mass and volume that is produced by a release scenario. Flammable mass is defined by the concentration boundary of the LFL and UFL, concentrations between the two boundaries are flammable. Gas concentrations above the UFL and lower than the LFL are not possible to ignite.

7.2.1 Default Dispersion Parameters in SAFETI

The default values in SAFETI on the “Dispersion parameters” tab in the settings were used for this QRA. The SAFETI dispersion models have been verified using real world experiments where gas was released to atmosphere and concentration profiles were measured. The technical documentation in SAFETI can be provided on request. These parameters impact the jet mixing and include the averaging time setting, the surface roughness and terrain settings. Based on guidance from DNV GL there is no reason to change the default settings for this QRA.

7.2.2 Meteorology Inputs

Depending on the time of day the atmosphere will have different levels of turbulence that would aid or limit the dispersion of gas released to atmosphere. This QRA considers the following standard Pasquill Stability Classes and wind speeds to represent daytime and nighttime conditions as shown below.

Table 23 – Daytime & nighttime weather conditions

Category	Pasquill Stability Class	Wind Speed (m/s)
Daytime	D	5.0
Nighttime	F	1.5

Depending on the direction of the wind in relation to the direction of release, the dispersion of gas will be impacted. The following wind rose was input into SAFETI for annual wind direction measured at the nearby Sarnia Airport.

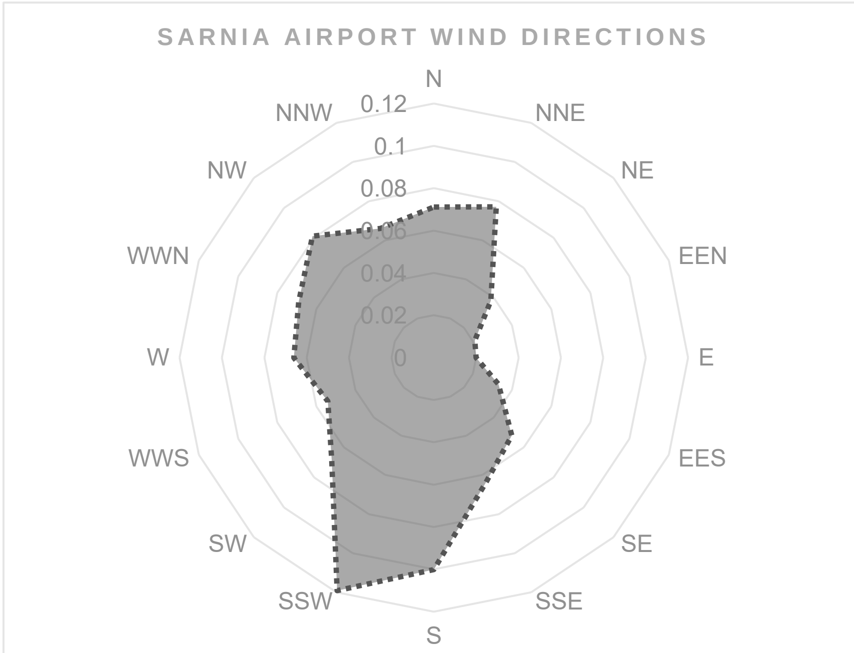

Figure 14 – Sarnia airport annual wind directions

7.2.3 Impinged Releases

Gas leaking from a pressurized system where the gas stream is obstructed by a surface is considered an impinged release. Impinged releases do not disperse as readily as releases free to atmosphere. For releases from above ground process piping and equipment leaks were modelled as free to atmosphere. For leaks indoors where the leak is likely to impinge on a wall or ceiling, the leaks were modelled as impinged.

7.2.4 Fire & Explosion Modelling & Injury Thresholds

The types of fire that could result from an ignited accidental release for this project include flash fires and jet fires. Flash fires are instantaneous events where the flame front propagates through the flammable mixture potentially back to the leak source. Jet fires are continuous where the gas leaking from a pressurized system remains on fire for the full duration of the release. A person who is engulfed in a fire for a significant portion of or their entire body, even momentarily i.e. flash fires, is considered to suffer a fatal injury for the risk assessment[6]. Therefore, for this study flash fires that are modelled to reach 1m in effect height are considered to cover a significant portion of a human if they were present and result in a fatal outcome. For continuous fires the effect of thermal radiation can reach much further than the actual fire itself. Exposure to thermal radiation can also result in fatality if certain thresholds are reached. Table 24 below describes the thermal radiation criteria used for the risk assessment based on OGP guidelines for Quantitative Risk Assessment.

Table 24 – Thermal Radiation Criteria for Jet Fires[6]

Thermal Radiation (kW/m^2)	Effect
35.0	Immediate fatality
20.0	Incapacitation, leading to fatality unless rescue is affected quickly
12.5	Extreme pain within 20 seconds; movement to shelter is instinctive; fatality if an escape route is not available
6.0	Impairment of escape routes

For a person to be impacted by thermal radiation they must have a line of site exposure. For people outdoors in the open, such as the general public area around stations, there is a higher chance of escape if they are not immediately incapacitated and can move out of the line of sight. Therefore, for this risk assessment the 20 kW/m^2 threshold is considered to be the fatal threshold since quick rescue may not be possible during an accident.

Aside from fires, explosions occur if gas disperses into a sufficient flammable mass that intersects with an area of confinement and/or congestion and is then ignited[7]. Area of confinement and congestion are location specific. The following areas at CCS were identified as areas of confinement or congestion using the TNO MEM for determining explosion strength as shown in Table 25.

According to the TNO “Yellow Book” the worst-case natural gas explosions should be modelled using a maximum blast curve 9 (out of 10) from the Multi-Energy Method – this is provided that *significant confinement and congestion are also present*[8]. Natural gas is limited to using blast curve 9 since it is on the lower end of medium reactivity fuels. Based on site evaluation of the levels of confinement and congestion the following blast curves and blockage ratios were selected. This methodology was carried over from the previous meter area QRA.

Table 25 – Defined strength obstructions for explosion modelling

Defined Strength Obstruction	Multi-Energy Curve	Blockage Ratio	Indoor or Outdoor
Compressor Buildings 1, 2, & 3	7	0.2	Indoor
Vegetation off site	5.5	0.6	Outdoor
Free Flow Area	5	0.5	Outdoor
GAC Area for Comp. Bldg. 1, 2, & 3	4	0.3	Outdoor

[6] *Vulnerability of Humans* (Risk Assessment Data Directory Report No. 434-14). (2010). London, UK: International Association of Oil & Gas Producers.

[7] American Institute of Chemical Engineers - Center for Chemical Process Safety. “Chapter 2: Management Overview”. *Guidelines for Vapor Cloud Explosion, Pressure Vessel Burst, BLEVE, and Flash Fire Hazards* 2nd Ed. Wiley, 2010, P4.

[8] W. P. M. Mercx and A. C. van den Berg. “Chapter 5 Vapour Cloud Explosions”. *Methods for the Calculation of Physical Effects “TNO Yellow Book” Publication Series on Dangerous Substances (CPR 14E) 3rd ed*, VROM, 2005, p. 5.43.

Defined Strength Obstruction	Multi-Energy Curve	Blockage Ratio	Indoor or Outdoor
Header Area for Comp. Bldg. 1, 2, & 3	5.5	0.5	Outdoor
JWC Area for Comp. Bldg. 1, 2, & 3	4	0.3	Outdoor

The effects produced by an explosion include thermal radiation similar to a flash fire and more importantly, blast overpressure that could throw debris projectiles, cause structural collapse, hemorrhage a person's lungs, or cause other bodily injury due to the force of overpressure, etc. Overpressure is the key effect from an explosion since the overpressure force can potentially reach further than the thermal effects. The lethality levels used for this risk assessment are included in Table 26 below.

Table 26 – Overpressure Criteria for Explosions[6]

Risk Receptor	Overpressure (bar)	Effect
People outdoors in the open (IOGP)	0.350	15% lethality
	0.500	50% lethality
People in buildings (IOGP as per API Recommended Practice 752)	0.069	10% lethality
	0.138	40% lethality
	0.345	100% lethality

The QRA software SAFETI calculated the effects of fires and explosions for all release scenarios previously discussed.

8. Risk Evaluation & Results

Now that the effect of hazardous consequences is defined for each potential release scenario and the likelihood of the final event outcome is quantified, risk can be evaluated. In order to evaluate risk two more inputs must be defined; the populations exposed to the risk (sometimes referred to as the risk receptors) and the Company's tolerance level to risk.

8.1 Population of Workers on Site

8.1.1 Work Groups

The populations exposed to risk from Corunna are detailed in this section. Since the area surrounding Corunna is farmland that is typically unoccupied by members of the public this QRA will only calculate the risk to workers on site. The following worker groups were covered in this assessment as shown in Table 27.

Table 27 – Workers at Corunna

Work Group	Total people in group	Notes
Reservoir	1	Normal office hours
Reservoir Supervisor	1	Normal office hours
Tecumseh Operations – Chief Operator	1	Normal office hours
Tecumseh Operations – Lead	4	One per shift
Tecumseh Operations – Plant	4	One per shift
Tecumseh Operations – Field	4	Normal office hours
Tecumseh Operations – Swing	4	One per shift
Utility Operations	2	Normal office hours
Utility Operations Supervisor	1	Normal office hours
Office Staff	15	Normal office hours
Operations Manager	1	Normal office hours
Instrumentation	3	Normal office hours
Instrumentation Supervisor	1	Normal office hours
Electrical	1	Normal office hours
Tech/SCADA	2	Normal office hours
Chief Mechanic	1	Normal office hours
Mechanics	5	Normal office hours
Safety/Training	1	Normal office hours
Warehouse	2	Normal office hours
Engineering Execution	2	Normal office hours

Work Group	Total people in group	Notes
Engineering Planning	5	Normal office hours
Engineering Manager	1	Normal office hours
Asset Management	1	Normal office hours
Inspectors	4	Normal office hours
Contractors Office Part Time	1	Normal office hours
Contractors Full Time	2	Normal office hours
Construction Contractors Plant Reliability	12	Normal office hours
Construction Contractors Engineering Execution	18	Normal office hours

8.1.2 Occupied Areas

Next, the occupied areas at the CCS facility are defined in order to tabulate where populations spend their time on site throughout the year. Indoor and outdoor areas on site are defined in Table 28 below.

Table 28 – Indoor & Outdoor Areas at CCS

Area Name	Indoor or Outdoor Population
Free flow piping area	Outdoor
Compressor headers & GACs for Compressor Bldg. 1, 2, & 3	Outdoor
ILI receiving area	Outdoor
JWC for Compressor Bldg. 1, 2, & 3	Outdoor
Meter area	Outdoor
Waste fluid & liquids storage	Outdoor
Compressor Bldg. 1, 2, & 3	Indoor
MCC Bldg. 1, 2 (old control room), & 3	Indoor
Mechanics warehouse	Indoor
Office building & current control room	Indoor

While it is true that the scope of this study only covers the piping and equipment at the CCS facility, the workers may spend their time at work partially at facilities or areas away from CCS. Since the purpose of the QRA is to calculate the risk to workers, it is considered that workers who spend part of their time at CCS and part of their time elsewhere are modelled as 100% at CCS for an area of “equivalent risk”. For example, if a worker spends time at an offsite meter area then they are considered to spend that time at the CCS meter area for this QRA. This is done to avoid “salami slicing” worker risk which could lead to incorrectly underestimating risk to a worker. If the other sites eventually have a QRA completed for them then the individual worker risk results can be updated accordingly.

Populations of workers on site change throughout the day. During typical office hours the site has more workers present than during outside office hours when only operations would be present to continue operations. It is possible that some office hours workers could be called to site for emergency work or locates. Based on SMA input, emergency calls might only occur once per month for a few hours duration and as a result would not be impactful to the final QRA result.

Table 29 shows the estimated hours worked per week per each building or area for the different worker populations during normal office hours. Table 30 shows the non-office hours. The last column in each table titled “number of people at a given time” is input to QRA software SAFETI for risk calculations. This value is calculated by dividing the total hours per week by 40 hours per work week.

Table 29 – Office Hour Populations at CCS & Other Company Owned Facilities

Work Hours Matrix **Week = 7 days** **Total Hours/Week = 24*7 = 168** **Data in Hours Worked/Week by Building or Area**	**Reservoir Ind. Contributor**	**Reservoir Supervisor**	**Tecumseh Operations - Chief Op.**	**Tecumseh Operations - Op. 1 Lead**	**Tecumseh Operations - Op. 2 Plant**	**Tecumseh Operations - Op. 3 Field**	**Tecumseh Operations - Op. 4 Swing**	**Utility Operations**	**Utility Operations - Supervisor**	**Office Staff**	**Instrumentation**	**Instrumentation - Supervisor**	**Electrical**	**Tech/Scada**	**Operations Manager**	**Chief Mechanic**	**Mechanics**	**Safety**	**Warehouse**	**Engineering - Execution**	**Engineering - Planning**	**Engineering - Manager**	**Asset Management**	**Inspectors**	**Contractors -Part Time**	**Contractors -Full Time**	**Construction Contractor - Plant Reliability**	**Construction Contractor - Engineering Execution**	**Total person-hours per week**	**Number of people at a given time**
Total people in work group	**1**	**1**	**1**	**4**	**4**	**4**	**4**	**2**	**1**	**15**	**3**	**1**	**1**	**2**	**1**	**1**	**5**	**1**	**2**	**2**	**5**	**1**	**1**	**4**	**1**	**2**	**12**	**18**		**20.24**
CCS Comp Bldg 1			0.8		7.7		3.85			0.8	8.0		8.0		1.8	8.1	9.0	1.2		0.3	0.7	0.1				4.8	5.5		**63**	**1.6**
CCS Comp Bldg 2			0.8		8.05		4.03			0.8	8.0		8.0		1.4	6.3	7.0	1.2		0.3	0.5	0.1				4.2	5.5		**59**	**1.5**
CCS Comp Bldg 3			0.4		7.7		3.85			0.4	4.0		4.0		0.8	3.6	4.0	0.7		0.2	0.4	0.1				3.0	4.1		**39**	**1.0**
CCS MCC 1					1.75		0.88																						**3**	**0.1**
CCS Old Ctrl Bldg & MCC 2					1.75		0.88							4.0															**7**	**0.2**
CCS MCC 3					1.75		0.88																						**3**	**0.1**
CCS Mechanics Warehouse							0									2.0	2.0		1.0										**5**	**0.1**
CCS Office Building	5.0	32.0	36.0	42	7	4.9	22	5.0	36.0	36.0	5.0	20.0	5.0	32.0	36.0	20.0	8.0	20.0	36.0	12.0	32.4	36.0	40.0	5.0	10.0	28.0			**571**	**14.3**
CCS AREA Waste Fluid & Liquids Storage							0											0.2									1.4		**2**	**0.1**
CCS AREA Jacket Water Coolers Bldg 1					0.7		0.35	0.3	0.2									0.5									1.4		**4**	**0.1**
CCS AREA Gas Aftercoolers Bldg 1					0.7		0.35	0.3	0.2									0.5									1.4		**4**	**0.1**
CCS AREA Jacket Water Coolers Bldg 2					0.7		0.35	0.3	0.2									0.5									1.4		**4**	**0.1**
CCS AREA Gas Aftercoolers Bldg 2					0.7		0.35	0.3	0.2									0.5									1.4		**4**	**0.1**
CCS AREA Jacket Water Coolers Bldg 3					0.7		0.35	0.3	0.2									0.2									1.4		**4**	**0.1**
CCS AREA Gas Aftercoolers Bldg 3					0.7		0.35	0.3	0.2									0.2									1.4		**4**	**0.1**
CCS AREA Meter Runs					0.7		0.35	1.0	0.2									0.7		0.2	0.4	0.1					1.4		**6**	**0.1**
CCS AREA ILI Receiving					0.7		0.35											1.0		0.4	0.7	0.1						10.0	**18**	**0.5**
CCS AREA Free Flow Piping					0.7		0.35	1.0	0.2									0.5		0.1	0.4	0.1					4.1		**9**	**0.2**
SSOM Compressor Bldg			0.8			1.0					1.0	4.3	1.0				3.0	0.3			0.1	0.1					2.1			
SSOM Glycol Bldg						0.6					0.6	0.5	0.6				2.4	0.3			0.1	0.1					1.3			
SSOM Auxiliary Bldg & MCC						0.6					0.6	0.5	0.6				0.0	0.2			0.0									
SSOM Control Bldg						0.6					1.0	2.0	1.0				0.6	0.2	1.0		0.0									
SSOM AREA Main Yard			0.8			0.6		3.0	0.4		0.3	0.2	0.3				0.0	0.3			0.1	0.1					1.7			
SSOM AREA Bypass						0.6		2.0	0.4		0.5	1.8	0.5				0.0	0.3			0.1	0.1					0.9			
SCRW Compressor Bldg																		0.4			0.0						0.9			

Work Hours Matrix **Week = 7 days** **Total Hours/Week = 24*7 = 168** **Data in Hours Worked/Week by Building or Area**	**Reservoir Ind. Contributor**	**Reservoir Supervisor**	**Tecumseh Operations - Chief Op.**	**Tecumseh Operations - Op. 1 Lead**	**Tecumseh Operations - Op. 2 Plant**	**Tecumseh Operations - Op. 3 Field**	**Tecumseh Operations - Op. 4 Swing**	**Utility Operations**	**Utility Operations - Supervisor**	**Office Staff**	**Instrumentation**	**Instrumentation - Supervisor**	**Electrical**	**Tech/Scada**	**Operations Manager**	**Chief Mechanic**	**Mechanics**	**Safety**	**Warehouse**	**Engineering - Execution**	**Engineering - Planning**	**Engineering - Manager**	**Asset Management**	**Inspectors**	**Contractors -Part Time**	**Contractors -Full Time**	**Construction Contractor - Plant Reliability**	**Construction Contractor - Engineering Execution**	**Total person-hours per week**	**Number of people at a given time**
SCRW Office & Garage																		0.2	1.0		0.0									
SCRW Meter Bldg																					0.0									
SCRW Remote Terminal Bldg																														
SCRW Odourant Bldg																														
SCRW Dehydration Bldg																		0.2			0.0						0.4			
SCRW AREA Main Yard																		0.4			0.0						0.7			
SCHT Compressor Bldg			0.4			1.0											4.0	0.5	1.0		0.1	0.2					1.0			
SCHT Electrical Bldg						0.2												0.2												
SCHT AREA Yard						0.2		3.0	0.4									0.5			0.1	0.2					1.0			
DM AREA Meter Station Yard						3.0		0.4	0.1		1.0	1.1	1.0	0.6						1.4	0.2	0.1		1.5				2.1		
MKC-SKC AREA Meter Station Yard						3.0		0.4	0.1		1.0	1.1	1.0	0.6						1.4	0.2	0.1		1.5				2.1		
SEC AREA Meter Station Yard						3.0		0.4	0.1		1.0	1.1	1.0	0.6						1.4	0.2	0.1		1.5				2.1		
COR AREA Meter Station Yard						3.0		0.4	0.1		1.0	1.1	1.0	0.6						1.4	0.2	0.1		1.5				2.1		
LDY AREA Meter Station Yard						3.0		0.4	0.1		1.0	1.1	1.0	0.6						1.4	0.2	0.1		1.5				2.1		
COV AREA Meter Station Yard						3.0		0.4	0.1		1.0	1.1	1.0	0.6						1.4	0.2	0.1		1.5				2.1		
WLK AREA Meter Station Yard						3.0		0.4	0.1		1.0	1.1	1.0	0.6						1.4	0.2	0.1		1.5				2.1		
DM Gathering System	5.7	1.4				1.0		2.2	0.1	0.4	0.5	0.3	0.5					1.8		3.5	0.3	0.2		2.2				2.8		
SEC Gathering System	3.7	0.8				1.0		2.2	0.1	0.3	0.5	0.3	0.5					1.3		2.7	0.3	0.2		2.2				2.8		
COR Gathering System	1.9	0.4				1.0		2.2	0.1	0.1	0.5	0.3	0.5					0.5		1.0	0.3	0.2		2.2				2.8		
MKC Gathering System	7.9	2.0				1.0		2.2	0.1	0.5	0.5	0.3	0.5					1.8		3.7	0.3	0.2		2.2				2.8		
SKC Gathering System	3.0	0.7				1.0		2.2	0.1	0.3	0.5	0.3	0.5					1.1		2.2	0.3	0.2		2.2				2.8		
LAD Gathering System	1.2	0.2				1.0		2.2	0.1	0.1	0.5	0.3	0.5					0.4		0.9	0.3	0.2		2.2				2.8		
WLK Gathering System	3.2	0.7				1.0		2.2	0.1	0.2	0.5	0.3	0.5					0.6		1.2	0.3	0.2		2.2				2.8		
COV Gathering System	2.1	0.4				1.0		2.2	0.1	0.1	0.5	0.3	0.5					0.3		0.6	0.3	0.2		2.2				2.8		
BC Gathering System	1.2	0.2				1.0		2.2	0.1	0.0	0.5	0.3	0.5					0.1		0.1	0.3	0.2		2.2				2.8		
PCRW Gathering System	4.6	1.1								0.0								0.0		0.0				2.2						
PCHT Gathering System	1.2	0.2								0.0								0.0		0.0				2.2						
Total	**40**	**40**	**40**	**42**	**42**	**40**	**40**	**40**	**40**	**40**	**40**	**40**	**40**	**40**	**40**	**40**	**40**	**40**	**40**	**39**	**40**	**40**	**40**	**40**	**10**	**40**	**40**	**50**		

Table 30 – Non-office Hour Populations at CCS

Work Hours Matrix (Summer) **Week = 7 days** **Total Hours/Week = 24*7 = 168** **Data in Hours Worked/Week by Building or Area**	**Tecumseh Operations - Op. 1 Lead**	**Tecumseh Operations - Op. 2 Plant**	**Tecumseh Operations - Op. 3 Field**	**Tecumseh Operations - Op. 4 Swing**	**Total person-hours per week**	**Number of people at a given time**
Total people in work group	**4**	**4**	**4**	**4**		**3.09**
CCS Comp Bldg. 1		7.7		3.9	12	**0.29**
CCS Comp Bldg. 2		8.1		4.0	12	**0.30**
CCS Comp Bldg. 3		7.7		3.9	12	**0.29**
CCS MCC 1		1.8		0.9	3	**0.07**
CCS Old Ctrl Bldg. & MCC 2		1.8		0.9	3	**0.07**
CCS MCC 3		1.8		0.9	3	**0.07**
CCS Mechanics Warehouse				0.0	0	**0.00**
CCS Office Building	42.0	7.0		22.0	71	**1.78**
CCS AREA Waste Fluid & Liquids Storage				0.0	0	**0.00**
CCS AREA Jacket Water Coolers Bldg. 1		0.7		0.4	1	**0.03**
CCS AREA Gas Aftercoolers Bldg. 1		0.7		0.4	1	**0.03**
CCS AREA Jacket Water Coolers Bldg. 2		0.7		0.4	1	**0.03**
CCS AREA Gas Aftercoolers Bldg. 2		0.7		0.4	1	**0.03**
CCS AREA Jacket Water Coolers Bldg. 3		0.7		0.4	1	**0.03**
CCS AREA Gas Aftercoolers Bldg. 3		0.7		0.4	1	**0.03**
CCS AREA Meter Runs		0.7		0.4	1	**0.03**
CCS AREA ILI Receiving		0.7		0.4	1	**0.03**
CCS AREA Free Flow Piping		0.7		0.4	1	**0.03**

9. Risk Tolerance Criteria

9.1 Introduction to Risk Tolerance Criteria for use in QRA

The concept of risk tolerability refers to a willingness by society as a whole, to live with a risk so as to secure certain benefits in the confidence that the risk is one that is worth taking and that it is being properly controlled. As per CSA Z767, facility operators shall establish risk criteria that have a value above which the risk is intolerable, and a value below which the risk is broadly tolerable and needs to be monitored but not necessarily further reduced; the remaining risks fall between these two values, referred to as the conditionally tolerable region.[9] Risks in the conditionally tolerable region are typical of the risks from activities that people are prepared to tolerate in order to secure benefits provided:

- Nature and level of risks are properly assessed, and results used properly to determine control measures.
- The residual risks are not excessively high and kept as low as reasonably practicable (ALARP); and
- The risks are periodically reviewed to ensure that they still meet the ALARP criteria.

ALARP is the concept that risk is tolerable only if it can be demonstrated that all reasonable and practicable measures have been taken commensurate with the level of accepted risk.

Currently the Company has endorsed the Individual Risk Tolerance Criteria proposed by Enterprise Safety & Reliability and is evaluating the suitability of Societal Risk Tolerance Criteria. Both criteria are discussed in the following sections.

9.2 Individual Specific Individual Risk (ISIR)

Individual risk aims to account for an individual's view on how the risk from a particular hazard affecting them and things they value personally. Individuals within society are more willing to voluntarily engage in activities, but far less willing to be exposed to risks imposed to or have little control over them, unless risks are negligible.

Individuals can be willing to live with a risk that they do not regard as negligible, if it secures them or society certain benefits, however individuals would want such risk to be managed and clearly controlled.

The Company uses Individual Risk in QRA, accounting for occupancy and vulnerability, to establish acceptability of H&S risk to maximally exposed individuals for existing sites. Use thresholds (risk limits and targets) for public and workers as shown. A higher limit for workers reflects greater risk exposure and its voluntary nature. Voluntary in this context refers to workers, in contrast to members of the public, voluntarily assuming an element of additional risk when they

[9] *Process Safety Management CSA Z767-17*. (2017). Toronto, ON: Canadian Standards Association Group.

choose their job in return for the benefits derived from employment. The risk target is the same for public and workers.

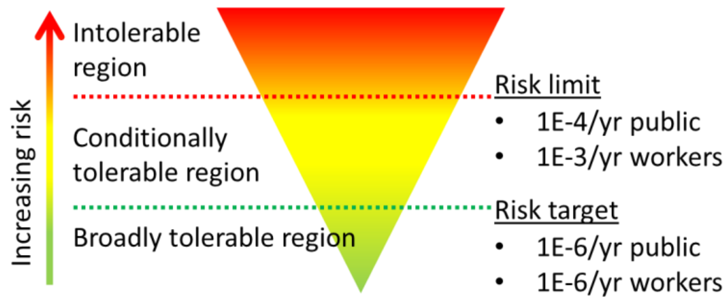

Figure 15 - Individual Risk Tolerable Criteria

9.3 Societal Risk (SR)

Societal risk is associated with risks from hazards which impact on society and which, if realized, could have adverse repercussions for the institutions responsible for putting in place the provisions and arrangements for protection people. It is often associated with hazards that give rise to risks which could provoke a socio-political response, e.g. risk of events causing widespread or large-scale detriment of the occurrence of multiple fatalities in a single event. Such events are difficult for people to estimate intuitively the level of risks and could lead to loss of trust to companies no matter how remote the chance of the event was happening in the first place. Hence, undesirable outcomes of such events are intensely political.

The SR Risk Tolerance Criteria are commonly expressed as a so-called F-N curve. An F-N curve is a plot of frequency of all events leading to N or more causalities (typically expressed as the number of fatalities). F-N curves typically use log-log plots since the frequency and number of fatalities often range over several orders of magnitude. The criteria proposed by Enterprise Safety and Reliability team (shown in Figure 16) are an adoption of the British Columbia government for their LNG regulation, which apply to all members in the society i.e. public and employees. When SR was estimated, occupancy and vulnerability were accounted for to establish acceptability of H&S risk to a group of people.

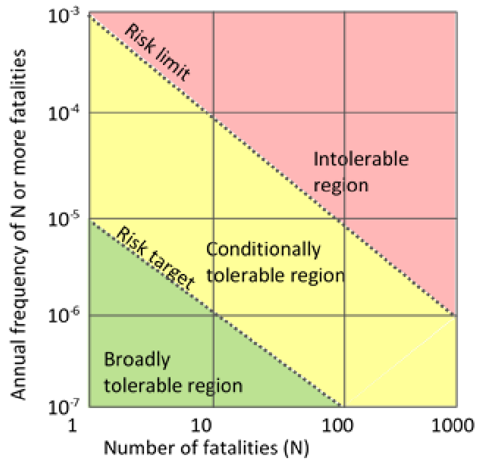

Figure 16 – Societal Risk Criteria

10. Results

10.1 Results R0 – Current Risk per 2019 operating conditions

10.1.1 Individual Specific Individual Risk Results R0

Based on ISIR (see table below), the maximally exposed individual is Tecumseh Operations – Op. 2 Plant. The following individuals are exposed to risks above the Company's individual risk tolerance criteria:

- Tecumseh Operations – Op. 2 Plant
- Mechanics
- Instrumentation
- Electrical
- Chief Mechanic

All individuals in this section spend more time in the plant area and more specially in the compressor buildings than that other on-site individuals.

Table 31 – Individual specific individual risk results for workers at Corunna

Individual	ISIR
Reservoir Ind. Contributor	8.84E-05
Reservoir Supervisor	2.17E-05
Tecumseh Operations - Chief Op.	1.35E-04
Tecumseh Operations - Op. 1 Lead	1.78E-06
Tecumseh Operations - Op. 2 Plant	1.36E-03
Tecumseh Operations - Op. 3 Field	1.32E-04
Tecumseh Operations - Op. 4 Swing	6.81E-04
Utility Operations	9.73E-05
Utility Operations - Supervisor	1.62E-05
Office Staff	1.15E-04
Instrumentation	1.14E-03
Instrumentation - Supervisor	1.25E-04
Electrical	1.14E-03
Tech/Scada	1.29E-04
Operations Manager	2.21E-04
Chief Mechanic	1.05E-03
Mechanics	1.30E-03

Individual	ISIR
Safety	2.49E-04
Warehouse	5.09E-05
Engineering - Execution	1.09E-04
Engineering - Planning	1.08E-04
Engineering - Manager	3.53E-05
Asset Management	1.79E-06
Inspectors	8.67E-05
Contractors -Part Time	4.48E-07
Contractors -Full Time	6.29E-04
Const. Contractor - Plant Reliability	9.46E-04
Const. Contractor - Engineering Execution	1.17E-04

10.1.2 Societal Risk Results R0

The societal risks at the site were evaluated by treating all the workers onsite as a group and compared to the societal risk tolerance criteria proposed by Enterprise S&R. The estimated societal risk is shown as the cumulative frequencies of N fatalities (green curve). N represents number of fatalities at N or more. The results showed the societal risk at the site is above the proposed risk limit (red line) when N is between 1 and just over 4.

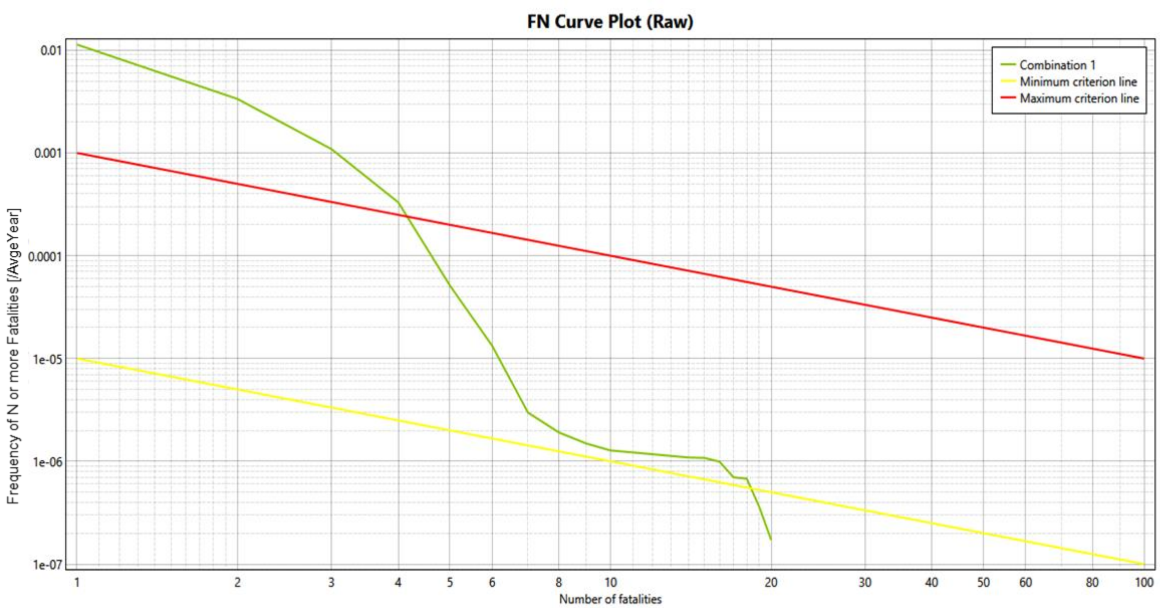

Figure 17 – Societal risk results for workers at Corunna

10.2 Potential Loss of Life (PLL)

The Potential Loss of Life (PLL) risk measure corresponds to the average number of fatalities per year. It is used to understand the key contributors to risks in terms of the locations or areas. It is NOT used for comparison with the Company's individual risk criteria and Enterprise S&R proposed societal risk criteria. The PLL is summarized in the following table, which shows risk are mainly concentrated in compressor buildings.

Table 32: Potential Loss of Life at buildings and areas in CCS

Building Name	PLL
Comp Bldg 1	7.85E-03
Comp Bldg 2	5.41E-03
Comp Bldg 3	1.48E-03
MCC 1	1.99E-04
Old Ctrl Bldg & MCC 2	4.60E-04
MCC 3	1.80E-04
Mechanics Warehouse	1.51E-04
Office Building	3.48E-05
Outdoor Yard Area	4.20E-04

11. Conclusions

11.1 Results Discussion

The current risk due to the potential accidental release of natural gas at Corunna is breaching the Company's tolerance criteria for both individual and societal risk. The greatest contributing scenarios to the result of this assessment include:

- Potential leaks from compressors and associated indoor piping finding a potential source of ignition and resulting in a potential flash fire or explosion fatal accident.
- Potential leaks from outdoor compressor header piping finding a potential source of ignition and resulting in a fire.

11.2 Risk Reduction Options

Based on stakeholder discussion the following risk reduction ideas were proposed for short term mitigation:

- Reducing the reliance on compression required at Corunna by increased compressor utilization at Dawn.
    - This option may require some additional pressure control retrofits on the twin NPS 30 transmission lines at the Dawn end however this is out of scope for the QRA.
    - This change is assumed to reduce the average compressors in operation at Corunna from 4 to 3 and the operating strategy would be to try to limit one running compressor per building.
    - A limiting factor of the strategy of only running one compressor per building would potentially occur in late season withdrawal when suction pressures are low. LP units K709 and K710 are both in building 2 and may both be required during late season withdrawal.
- Recent changes to operator round activities are designed to reduce the time spent by operations in compressor buildings.
    - These changes are expected to reduce time operations spends in compressor buildings by 15 to 20%.
    - The difference in time is expected to be split equally between the control room in the office and other tasks in the yard.
- Creating the following maintenance policy to eliminate the exposure of personnel to risks posted by more than one compressor and to eliminate the risk of releasing natural gas from stand-by units:
    - No maintenance when more than one compressor unit is running
    - Compressor units that are not running must be isolated and depressurized

A long-term strategy to evaluate site layout and spacing of equipment should also be considered when it's time to renew assets. Limiting one compressor unit per building with adequate spacing between buildings could be considered to separate people from process equipment and reduce potential exposure to hazards.

The design of new compressor buildings should consider ventilation rates to limit the potential buildup of gas to flammable atmospheres. The design of new ESD systems should consider the placement of ESVs to limit isolatable inventories on site during an ESD, particularly to limit gas inventory in indoor areas. Industry data suggests that reciprocating compressors units have a greater leak frequency than centrifugal – this could be investigated as a potential reduction in potential leak frequency. Where possible, new designs should consider reducing the total number of pipe connections by flange, as welds are considered less likely to leak than flanges (i.e., reduce parts count). Maintaining current and up to date process safety information including engineering documentation and records.

COMPRESSOR STATION QRA ASSISTANCE AND REVIEW

Review of the Quantitative Risk Assessment (QRA) of Enbridge Corunna Compressor Station

Enbridge Gas Distribution Inc.

Report No.: 10249852-1, Rev 0
Date: 18/01/2021

Project name:	Compressor Station QRA Assistance and Review	DNV GL Oil & Gas
Report title:	Review of the Quantitative Risk Assessment (QRA) of Enbridge Corunna Compressor Station	Safety Risk Holywell Park
Customer:	Enbridge Gas Distribution Inc.	Loughborough
Contact person:	Lisa Nicholas	Leicestershire, LE11 3GR
Date of issue:	18/01/2021	United Kingdom
Project No.:	10249852	
Organisation unit:	Safety Risk	Akvilina Valaityte
Report No.:	10249852-1, Rev A	Tel: +44 (0)203 8165865

Objective:

This report provides a technical review of the Quantitative Risk Assessment (QRA) report completed by Enbridge of its Corunna Compressor Station.

Prepared by:	Verified by:	Approved by:
Jamie Elliott Principal Consultant	Akvilina Valaityte Senior Engineer	Michael Simms Head of Section, Safety Risk Excellence

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Keywords:
QRA

Rev. No.	Date	Reason for Issue	Prepared by	Verified by	Approved by
0	18/01/2021	For Client Comment	J Elliott	A Valaityte	M Simms

EXECUTIVE SUMMARY

Enbridge Gas Distribution Inc. (Enbridge hereafter) has conducted a Quantitative Risk Assessment (QRA) of its Corunna Compressor Station in order to evaluate the potential risk level and support risk treatment strategies.

This report presents an external, expert verification of Enbridge's QRA by DNV GL.

This report aims to verify that:

- Appropriate inputs and data sources have been used
- Where there is uncertainty, choices have been made on a "conservative best estimate" basis. This should mean that the actual risk is no higher than the predicted risk.
- An appropriate level of detail has been included. The key factors that affect the risk should be included. Results should have sufficient granularity to allow meaningful risk treatment strategies to be devised.
- Appropriate models have been used, in line with latest best practice.

Conclusion

It is concluded that the QRA approach taken is a reasonable one. Where relevant, published and widely recognised inputs, methods and assumptions have been used. Conservative choices of inputs and assumptions have been made throughout.

Therefore, the QRA results should be considered a reliable estimate of the risks at the Corunna Compressor Station.

In reviewing the QRA, DNV GL has made the following minor observations:

Observation 1: The QRA results could be examined to see if: a) scenarios that represent cases where the ESD system fails to isolate the release make a significant contribution to the risk; and b) the scenarios that were successfully isolated by ESD produce substantially lower consequences. If so, then a potential risk reduction measure would be to establish higher levels of reliability for the ESD system. This can be achieved by compliance to the functional safety standards IEC 61508 / 61511. Probability of failure on demand as low as 0.005 (SIL 2) is not unusual for such systems. This could be done in conjunction with the risk reduction option already suggested in the QRA report of providing additional Emergency Shutoff Valves (ESVs) to limit the isolatable inventories.

Observation 2: More detailed results could be provided including risk contour plots. Breakdown of the results could be provided by scenario, hole size, effect type etc. although this may require some post-processing outside of the Safeti software.

Observation 3: DNV GL has made some minor comments on the QRA report to improve its quality and readability. These are provided on the Microsoft Word version of the QRA report.

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1 INTRODUCTION

Enbridge has conducted a Quantitative Risk Assessment (QRA) of its Corunna Compressor Station in order to evaluate the potential risk level and support risk treatment strategies (Reference [1]).

This report presents an external, expert verification of Enbridge's QRA by DNV GL.

DNV GL also supported Enbridge during the QRA processes including with methodology development and QRA software input.

The QRA is a model of the risks at the Corunna station. Any model, by definition, is a simplification of the real world. A QRA is also forward looking – it predicts the potential for future accidents. The inputs, as with any data or measurement, are subject to uncertainty. In some cases, desired inputs are not known and therefore assumptions need to made.

There is no definitive, detailed standard or guideline to verify the QRA against as inputs and methods must be adapted to suit the risks. For example, different approaches are needed on-shore and off-shore, for gas vs liquids and depending on the software tools being used. Therefore, the aim is to verify that the QRA has taken a reasonable approach, and used recognised good practice and guidance drawn from appropriate sources where available.

Therefore, this report aims to verify that:

- Appropriate inputs and data sources have been used
- Where there is uncertainty, choices have been made on a "conservative best estimate" basis. This should mean that the actual risk is no higher than the predicted risk.
- An appropriate level of detail has been included. The key factors that affect the risk should be included. Results should have sufficient granularity to allow meaningful risk treatment strategies to be devised.
- Appropriate models have been used, in line with latest best practice.

2 REVIEW OF QUANTITATIVE RISK ASSESSMENT

2.1 Approach

The QRA was carried out by Enbridge with support from DNV GL in defining the methodology and setting up the Safeti model. Subject matter advisors were consulted at various stages to ensure a sound basis for the study. The approach, inputs and assumptions are described in the QRA report (Reference [1]).

2.1.1 Software

The QRA was carried out in the DNV GL Safeti software package. The latest version available at the time (8.23) was used. Safeti is widely used and accepted and the models within it are validated against experimental data (Reference [2]).

2.1.2 Process Conditions and Operating Modes

Detailed consideration was given to the wide variability of pressures and equipment isolation throughout the year. This variability was simplified into two cases to make the model size and study complexity manageable. These were "Low Pressure" and "High Pressure" with scenarios representing less variable equipment covered in a "Year Round" case.

This is a reasonable approach which balances simplicity and granularity and includes some conservatism whilst avoiding over-conservatism.

2.1.3 Scenario Selection

A relatively high level of detail was used to define the scenarios based on factors including pressure, location, variability of isolation throughout the year, indoor or outdoor location and isolatable sections. It is considered that this will provide a good level of granularity i.e. it will be possible to drill down into the results and identify the scenarios which dominate the risk at a level of detail that will allow meaningful risk reduction measures to be devised.

2.2 Frequency analysis

2.2.1 Parts count

Parts counts from a previous study, based on plant walkdown, were reused for this QRA. These were sense checked against P&IDs and partitioned into the sections applied to the QRA. Incorrect partitioning could lead to more equipment in one section, but this would be balanced out by lower equipment counts in another neighbouring section. Enbridge discovered that instruments had not been included in the count and so these were added based on asset tags in MAXIMO. The parts count is correct for major equipment items e.g. compressors, vessels and main valves. The piping lengths have been sense checked based on the layout.

Overall, this should give a reasonable level of accuracy.

2.2.2 Release frequencies and hole sizes

Generic release frequencies for above ground equipment are from the "Risk Assessment Data Directory – Process Release Frequencies" report 434-01 published by the IOGP (Reference [3]).

This is a widely used and accepted source for generic release frequencies, including for on-shore plants.

For below ground pipework, a variety of approaches are commonly used when carrying out QRAs from discounting below ground pipework entirely to using the same frequencies as for above ground pipework. Release frequencies are taken from the EGIG database (Reference [4]) of leaks from cross country pipelines. Leaks due to third party interference were removed as the pipework is within a fenced site. The resulting leak frequencies are approximately 200 times lower than the frequencies estimated for the above ground pipework. This result would be expected as below ground pipework is not subject to many of the failure causes that above ground pipework is subject to.

2.2.3 Ignition probability

Ignition probability modelling has used a combination of the IOGP / UKOOA model (Reference [5]) and the Atkins method (Reference [6]).

- The UKOOA model is based on the material, the release rate and the type of a plant e.g. small gas plant, large gas plant etc.
- The Atkins method is only used for the delayed ignition modelling. Ignition sources are placed on the map and assigned an ignition probability. As Safeti models the dispersing flammable cloud, it calculates the probability of ignition at each point in time. This allows the QRA to take into account the location of ignition sources.

Both these methods, and their use in combination, are widely used and accepted. This approach was reviewed by DNV GL during the QRA development and comments given resulting in some adjustment to the geographic ignition source values used.

2.2.4 Explosion probability

The explosion probability given delayed ignition is the Safeti default value of 0.4, which is appropriate.

2.2.5 Isolation and blowdown probability

An isolation and blowdown probability of failure on demand of 0.152 has been used within the compressor buildings, consistent with a previous Enbridge QRA study. This is consistent with a non-Safety Integrity Level (SIL) rated system and is therefore a conservative value.

Observation 1: The QRA results could be examined to see if: a) scenarios of that represent cases where the ESD system fails to isolate the release make a significant contribution to the risk; and b) the scenarios that were successfully isolated by ESD produce substantially lower consequences. If so, then a potential risk reduction measure would be to establish higher levels of reliability for the ESD system. This can be achieved by compliance to the functional safety standards IEC 6108 / 61511. Probability of failure on demand as low as 0.005 (SIL 2) is not unusual for such systems. This could be done in conjunction with the risk reduction option already suggested in the QRA report of providing additional Emergency Shutoff Valves (ESVs) to limit the isolatable inventories.

2.3 Consequence Analysis

2.3.1 Discharge

The discharge modelling used a range of approaches to model different types of releases.

For holes in above ground pipework, the simple leak model was used. In this case, the pressure is sustained at the release pressure. This is conservative, but not overly so for gas leaks with a large inventory supplied by cross-country pipelines and storage pools.

This is confirmed by examination of the Safeti results which show that:

- For Scenario 62, 65 barg very large (150mm) hole release from the 24" Mid-Kimball line, the pressure is maintained at the orifice by gas flowing through the pipeline and the flowrate does not decrease.
- For Scenario 22, 47 barg very large (150mm) hole release from the 16" Corunna line, the pressure is maintained for nearly 10 minutes before it starts to fall along with the discharge flow rate.

For the longer sections of buried pipework, the long pipeline model within Safeti was used. This does take into account the reduction in pressure as the equipment unpacks. The total potential outflow area was modelled as twice the cross-sectional area of the pipeline, as outflow can occur from both the upstream and the downstream branches of the pipeline.

For unisolated ruptures, the user defined source model was used with the discharge rate from a long pipeline of similar diameter and pressure.

For isolated ruptures, the time-varying leak model was used. The orifice diameter was set equal to the maximum pipe or equipment diameter.

For ruptures isolated by ESD, the user defined source model was used with the discharge rate from a long pipeline of similar diameter and pressure. The discharge rate was reduced to zero by 90 seconds.

This approach was defined with support from DNV GL and is considered an appropriate representation in Safeti of the discharge scenarios that can occur.

2.3.2 Release duration

For unisolated releases, no release duration limit was set. This is not overly conservative for a gas release as the worst-case hazard extents will be developed within a few seconds from the start of the release.

For example, examination of the Safeti results shows that:

- For Scenario 45, the 20" 78 barg Ladysmith underground pipework, rupture release with a vertically upwards release direction, the maximum extent of the flammable cloud to the Lower Flammable Limit (LFL) is reached after just 10s.
- For Scenario 82, 52 barg Transmission Header, very large (150 mm) hole with a horizontal release direction, the maximum extent of the flammable cloud to the LFL is reached after 37s.

For releases from isolated equipment the duration is limited by the size of the isolated inventory. For releases which are isolated by ESD, the duration is limited by the duration before ESD plus the size of isolated inventory

2.3.3 Release direction

Both vertical and horizontal releases have been modelled for jet fires, which reduces conservatism compared to the Safeti default of modelling only horizontal releases. Releases from holes in buried pipework have been modelled as vertically upwards releases from a puncture in the top of the pipe, which is conservative.

2.3.4 Dispersion

Dispersion calculations have been carried out using the 'Unified Dispersion Model' in Safeti. Recommended default values have been used.

2.3.5 Consequence effects

2.3.5.1 Jet fires and fireballs

Vulnerability for thermal radiation is modelled using the default probit method. The critical radiation intensity above which vulnerability is taken to be 100% is reduced from the default of 35 20 kW/m^2 to 20 kW/m^2 based on OGP guidance that this level can lead to a person being incapacitated and unable to escape (Reference [7]). This is a conservative approach. The probit values are modified slightly from the defaults to align with the TNO Green Book (Reference [8]), which is reasonable.

2.3.5.2 Flash fires

The Safeti default assumption of 100% vulnerability within the flammable cloud and 0% vulnerability outside is used. This is a reasonable and widely used approach in DNV GL's experience.

2.3.5.3 Explosions

The TNO Multi-Energy Method is used. Congested regions were defined as part of the previous Enbridge QRA study based on site evaluation of the levels of confinement and congestion.

IOGP 434-14 recommended lethality levels were used outdoors (Reference [7]).

Indoors, IOGP recommends either using API 752 (Reference [9]) or the Chemical Industries Association guidance (Reference [10]). API 752 has been used which is the more conservative of the two.

2.4 Risk Analysis

2.4.1 Weather

Appropriate weather conditions were used including wind speed, atmospheric stability and wind direction probabilities.

2.4.2 Populations

Populations were determined based on the discussion with the site personnel. For the purposes of individual risk calculation, worker groups that spend only part of their time on site but who also spend time on other hazardous installations were conservatively treated as spending all their time on Corunna site.

2.4.3 Individual Risk Criteria

Company individual risk criteria have been applied. The intolerable risk limit is 10^{-3} per year for workers and 10^{-4} per year for the public. The broadly tolerable risk target is 10^{-6} per year for workers and the public. These are in line with risk criteria widely applied globally.

2.4.4 Societal Risk Criteria

The societal risk criterion used is that of the British Columbia government for their LNG regulation (Reference [11]). This is an appropriate criterion

2.5 QRA Results and Conclusions

2.5.1 QRA Results

The results appear sensible and in line with the inputs and modelling assumptions. The highest Individual Specific Risks, Location Specific Risks and Potential Loss of Life are predicted in the compressor buildings which is to be expected. Discussion is provided of the factors and scenarios contributing the most to the results e.g. compressors and compressor header release scenarios.

Observation 2: More detailed results could be provided including risk contour plots. Breakdown of the results could be provided by scenario, hole size, effect type etc. although this may require some post-processing outside of the Safeti software.

The individual risk is estimated to be intolerable for people who spend a large proportion of their time inside the compressor buildings. Societal risk is estimated to be intolerable for events causing one to four fatalities.

2.5.2 QRA Conclusions

A key reason for conducting any risk assessment is to take action to reduce the risk if necessary.

Based on stakeholder discussion various risk reduction ideas are proposed in the QRA report. The proposed ideas are appropriate, linked to the QRA results and would be expected to be effective in reducing the risk.

2.5.3 Reporting

Observation 3: DNV GL has made some minor comments on the QRA Report to improve its quality and readability. These are provided on the Microsoft Word version of the QRA Report.

3 SUMMARY

It is concluded that the QRA approach taken is a reasonable one. Where relevant, published and widely recognised inputs, methods and assumptions have been used.

Conservative choices of inputs and assumptions have been made throughout, in particular:

- Use of geographic ignition source model.
- Isolation and blowdown probability of failure on demand.
- Critical radiation intensity.
- API 752 used for indoor vulnerability.
- Itinerant workers treated as being on-site full time.
- Choice of societal risk criteria.

Therefore, the QRA results should be considered a reliable estimate of the risks at the Corunna Compressor Station.

In reviewing the QRA, DNV GL has made the following minor observations:

Observation 1: The QRA results could be examined to see if: a) scenarios of that represent cases where the ESD system fails to isolate the release make a significant contribution to the risk; and b) the scenarios that were successfully isolated by ESD produce substantially lower consequences. If so, then a potential risk reduction measure would be to establish higher levels of reliability for the ESD system. This can be achieved by compliance to the functional safety standards IEC 6108/ 61511. Probability of failure on demand as low as 0.005 (SIL 2) is not unusual for such systems. This could be done in conjunction with the risk reduction option already suggested in the QRA report of providing additional Emergency Shutoff Valves (ESVs) to limit the isolatable inventories.

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4 REFERENCES

[1] Corunna Compressor Station – Site Wide Quantitative Risk Assessment, Enbridge, Rev 01, 2020-11-22.

[2] Witlox, H. et al, Verification and Validation of Consequence Models for Accidental Releases of Toxic or Flammable Chemicals to the Atmosphere, DNV GL, Safeti v8.23 Technical Documentation.

[3] OGP 434-01, Risk Assessment Data Directory – Process Release Frequencies, International Association of Oil & Gas Producers (IOGP), 2019.

[4] Gas Pipeline Incidents 10th Report of the European Gas Pipeline Incident Data Group period 1970 – 2016. European Gas Pipeline Incident Data Group (EGIG), 2018.

[5] Ignition Probability Review, Model Development and Look-Up Correlations, IP Research Report, Energy Institute, 2006.

[6] Development of a method for the determination of on-site ignition probabilities, Research Report 226, Prepared by WS Atkins Consultants Ltd for the Health and Safety Executive, 2004.

[7] OGP 434-14, Risk Assessment Data Directory – Vulnerability of Humans, International Association of Oil & Gas Producers (IOGP), 2010.

[8] "The Green Book" CPR 16E, Methods for the Determination of Possible Damage to People and Objects Resulting from Release of Hazardous Materials, TNO, VROM, 1st Ed, 1992.

[9] API RP 752, Management of Hazards Associated with Location of Process Plant Buildings, American Petroleum Institute (API), 2nd Ed, 2003.

[10] Guidance for the Location and Design of Occupied Buildings on Chemical Manufacturing Sites, Chemical Industries Association (CIA), (3rd Edition).

[11] Oil and Gas Activities Act, Liquefied Natural Gas Facility Regulation, BC Reg. 146/2014.

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Driven by our purpose of safeguarding life, property and the environment, DNV GL enables organizations to advance the safety and sustainability of their business. We provide classification and technical assurance along with software and independent expert advisory services to the maritime, oil and gas, and energy industries. We also provide certification services to customers across a wide range of industries. Operating in more than 100 countries, our professionals are dedicated to helping our customers make the world safer, smarter and greener.

TR7 Pipeline Corridor Risk Assessment Report

May 5, 2022

Report

Company: Enbridge

Owned by: Integrity Assessments

Controlled Location: TBD

Revision History

Revision	Date	Author	Remarks	Review	Approval
0A	2022-05-22	Kai Ji Sr. Integrity Assessments Engineer	Initial Release	Laila Nurrokhmah Advisor Risk Mike Hildebrand Manager Integrity Assessments and Asset Information	Miaad Safari Technical Manager Integrity Assessments

Executive Summary

Enbridge Gas Inc. (EGI) is planning to retire 7 out of the 11 compressors at the Corunna Compressor Station. This is intended to substantially reduce the risk on site. As part of the modifications, Enbridge is planning on installing a new 36” pipeline named Transmission 7 between the Corunna and Dawn facilities.

A risk assessment was performed to assess the public health & safety risks posed by the addition of the newly proposed Transmission 7 pipeline between the Corunna and Dawn compressor station facilities. Consideration was given to account for the cumulative risks from the existing pipelines that share the same path as the new line (the “corridor”) or are within its vicinity. The risk assessment utilizes EGI’s existing risk model for transmission pipelines and was performed in the PiMSlider software package.

The final risk results were calculated using conservative modelling assumptions and compared against Enbridge public health & safety risk acceptance criteria. It was found that a) the incremental risk posed by the addition of the new pipeline is low, and b) the total risk posed by the existing and newly proposed pipelines together is expected to be able to be maintained at broadly tolerable or conditionally tolerable levels, and is not expected to pose intolerable public health & safety risk.

This work forms part of a larger holistic risk assessment on proposed modifications at the Corunna Compressor station.

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1. Background

Enbridge Gas Inc. (EGI) is planning to retire 7 out of the 11 compressors at the Corunna Compressor Station. This is intended to substantially reduce the risk on site. As part of the modifications, Enbridge is planning on installing a new 36” pipeline named Transmission 7 (TR7) between the Corunna and Dawn facilities.

The proposed pipeline route will run parallel to several adjacent pipelines in the Corunna to Dawn corridor. These pipelines include:

- NPS 30 Transmission System A Pipeline
- NPS 30 Transmission System B Pipeline
- NPS 20 Payne Pool
- NPS 10 Waubuno
- NPS 16 Sombra Transmission Pipeline

Short sections of the TR7 pipeline also have other pipelines that either cross its path or are within its vicinity. These pipelines are:

- NPS 30 Bentpath Rosedale
- NPS 36 Bickford Dawn Loop
- NPS 42 Vector
- NPS 20 South Kimball Loop Line
- NPS 6 / 10 Mid Kimball Well Lateral – TKC 2
- NPS 16 Wilkesport Transmission Pipeline
- NPS 10 Mid Kimball – TKC 3
- NPS 20 South Mid Kimball Gathering

In order to assess the public health & safety implications of the addition of the TR7 line to the existing pipeline corridor, a risk assessment was performed that considers the risks posed by the newly proposed TR7 pipeline as well as the cumulative risks associated with all the pipelines within the vicinity of (and including) the new pipeline.

2. Model Description

EGI uses a quantitative risk model to calculate the risk of loss of containment events on its transmission pipeline system (“TIMP Risk model”). The model quantifies the risk of leaks and ruptures arising from threats which are believed to be active on EGI assets and are known to have caused failures on transmission pipelines throughout industry [1]. The threats assessed within the risk model include:

1. External Corrosion
2. Internal Corrosion
3. SCC
4. Manufacturing Defects
5. Fabrication Defects
6. Incorrect Operations
7. Third Party Damage
8. Equipment Failure
9. Weather (Lightning strikes)
10. Geohazards (Slope movement, hydrotechnical failures, earthquake)

The model produces estimations of the frequency of failure due to the above threats sub-divided into 4 representative hole sizes which characterize the spectrum of possible release magnitudes:

- Pinhole
- Small Leak (10 mm^2)
- Large Leak (2580 mm^2)
- Rupture (Full Bore)

Once the frequencies of occurrence of the above hole sizes are determined, the release rates, ignition probabilities, and health & safety effects of such failures are then calculated and quantified. This allows for the expression of health & safety risk in terms of quantitative measures such as potential loss of life, societal risk, and individual risk.

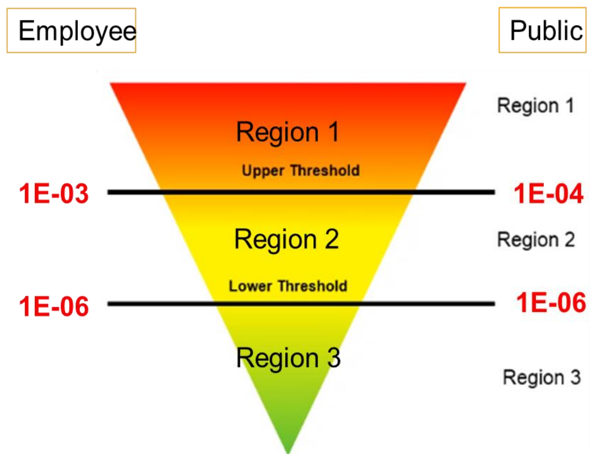
The model is calculated within the PiMSlider software platform. Modelling methodologies and assumptions are discussed in detail in the PRIM Risk Algorithm Document [2].

3. Health & Safety Criteria

Enbridge have adopted the following individual and societal risk criteria:

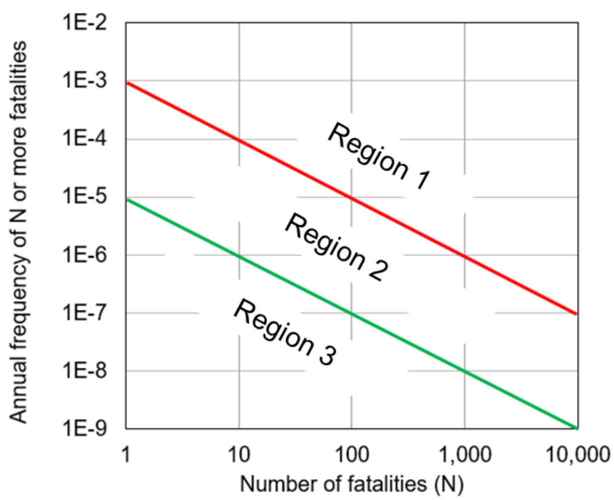
Individual Risk

Individual risk is a measure of the annual probability of fatality for an actual or hypothetical exposed individual. The boundaries below therefore indicate the limits on the annual probability of fatality a person is permitted to be exposed.



Societal Risk

Societal risk is typically represented as an F-N relationship and characterizes the potential for multiple fatalities arising from an event. Consequently, the F-N criteria shown below places limits on the frequency of events occurring which may cause fatalities to multiple individuals at the same time.



Risks are treated according to the following framework:

- If analysis indicates that the risk level is in Region 1, the risk is at or above upper threshold and the risk must be treated. This may be done through a series of short -and long-term measures to reduce the risk until it qualifies under Region 2.
- If analysis indicates the risk level is in Region 2, the risk is conditionally tolerable, provided best engineering practices have been applied and all reasonable measures have been taken to reduce it as low as reasonably practicable. These types of risks may still lead to treatment plans if the risk owner and other stakeholders determine that additional reasonable measures would lower the risk.
- If analysis indicates that the risk level is in Region 3, the risk is broadly tolerable, existing controls must be kept in place and the risk must be monitored.

In the context of treating risks from planned assets which do not yet exist, the risk reduction may be attained through design modifications that reduce risk.

More details on the definition of the regions and the risk assessment framework can be found in reference [3].

Application to TR7 QRA

Societal Risk

Because evaluating an F-N relationship requires the summation of the frequency of all events which may cause N or more fatalities, the evaluation of societal risk (in the context of transmission pipelines) is sensitive to the length of pipeline under consideration [3]. In order to equitably assess risks arising from pipelines of different lengths, therefore, the F-N criteria shown above must also be associated with a defined length of pipe for which the risk is to be evaluated.

In alignment with the CSA Z662-23, Enbridge applies the above societal risk criteria to a fixed 1 km length evaluation length at all positions along the length of a transmission pipeline. This allows for consistent and equal treatment of pipelines of different lengths, and is the method used by the TIMP risk model to report societal risk.

When assessing the societal risk of the TR7 pipeline in isolation, the societal risk is expected to be low due to the rural area which the pipeline traverses, and is not expected to differ significantly from the societal risks posed by other rural pipelines within the Enbridge system with similar size and pressure. Such pipelines are common within the Enbridge transmission system and are successfully operated within tolerable or conditionally tolerable risk levels.

When assessing the cumulative societal risk of the TR7 pipeline and other associated pipelines within the corridor, the evaluation of societal risk (and the associated criteria) would not adequately address the cumulative effects of multiple pipelines due to the requirement of a standardized 1 km evaluation length. While it would be possible to adjust the evaluation method in order to cumulatively assess all pipelines within the corridor (effectively increasing the scope of assessment to greater than 1 km), this would amount to an inequitable treatment of societal risk for this group of pipelines in relation to others in the Enbridge system, and also conflicts with the basis on which the societal risk criteria were chosen. For this reason, societal risk was not used as a measure to assess the cumulative effects of multiple pipelines.

The assessment therefore focuses on the assessment of individual risk as a measure for determining the cumulative health & safety risks of the TR7.

Individual Risk

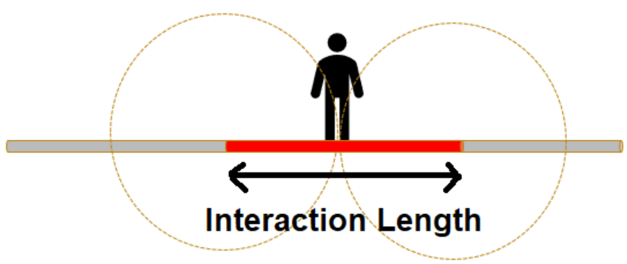
IR may be calculated in two ways [3]:

- Personal risk considers hypothetical or actual individuals at specific locations, accounting for things such as fraction of time spent at location, time to shelter, and other factors affecting actual exposure.
- Location-specific individual risk (LSIR) considers a hypothetical individual permanently present at the location where risk is being calculated, representing the notional level of risk at that location. It can be considered an upper bound on actual individual risk due to the assumption of permanent exposure.

Given populations near the TR7 line may change during the lifespan of the pipeline and giving consideration for some conservatism, the LSIR method was chosen to assess a conservative estimate on the cumulative IR of the TR7 and associated pipelines. In other words, it was assumed that hypothetical individuals would be permanently present (and therefore exposed to risk) at the location of interest.

4. Analysis Method

LSIR for pipelines may be calculated as a hypothetical individual located on top of the pipe that would be within the hazard zone of any failures occurring nearby.



Assuming permanent exposure, the length of pipe (in meters) that would expose this hypothetical individual to a rupture has an interaction length that can be calculated using [4]:

$$L_{ir}^{\mathrm{rup}} = 0.33D\sqrt{P}$$

Where D is the pipeline diameter (in) and P is the pipeline MOP (psi).

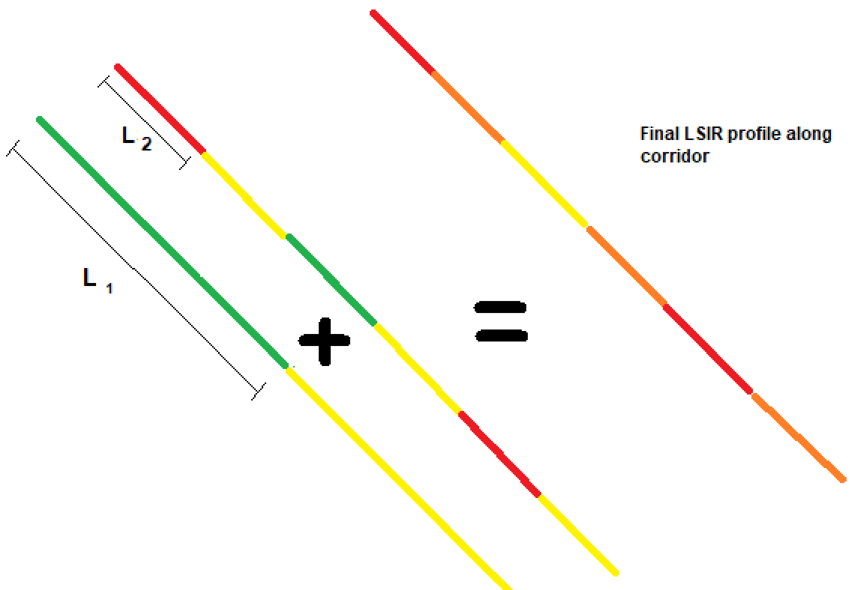
For leaks, the interaction length is:

$$L_{ir}^{L} = 0.40d_h\sqrt{P}$$

Where d_h is hole diameter (in) and P is the pipeline MOP (psi).

The LSIR at a particular location can then be calculated by summing the total frequency of ignited failures within the interaction length.

Ignoring the spacing between parallel lines, a conservative estimate of the LSIR for the corridor can be calculated by collapsing the parallel lines into a single line and summing the frequency of ignited failures along the corridor. The resulting line is a representation of the individual risk along the corridor, accounting from the exposure of all pipelines.



Interaction lengths of parallel pipelines to TR7:

Table 1

PIPELINE	P (PSIG)	D (IN)	L^{RUP}_{IR} (M)	L^{L}_{IR} (M)*
NPS 36 TR7	1300	36	428	14.4
NPS 30 Transmission System A Pipeline	935	30	303	12.2
NPS 30 Transmission System B Pipeline	935	30	303	12.2
NPS 20 Payne Pool	1000	20	209	12.6
NPS 10 Waubuno Pool	1000	10	104	12.6
NPS 16 Sombra Transmission Pipeline	1050	16	171	13.0

*In order to simplify the segmentation process, all leaks were assumed to result in a 1 in diameter hole. This errs conservatively as the majority of the leaks predicted by the model fall within the pinhole or $10mm^2$ size range.

In order to estimate the contribution of risk from pipelines crossing or within the vicinity of the TR7, the interaction zones were estimated by using the LSIR interaction lengths of each line and mapping tools to identify the length of pipe that would affect a hypothetical individual within the TR7 corridor. The frequency of ignited ruptures and leaks was extracted for these segments and are displayed below:

Table 2

PIPELINE	INTERACTION ZONE (M) - RUPTURE	FOF RUPTURE IGNITION (/YR)	INTERACTION ZONE (M) – LEAKS	FOF LEAK IGNITION (10MM^2 AND 2580MM^2) (/YR)
NPS 16 Wilkesport Transmission Pipeline	13730 m-14000m	1.13E-7	13850m-13890m	3.88E-7
NPS 30 Bentpath - Rosedale	0m - 270m	1.87E-8	-	-
NPS 36 Bickford Dawn Loop	132m – 607m	4.55E-8	450m-510m	5.98E-7
NPS 20 South Kimball Loop Pipeline	630m – 930m	2.69E-7	770m - 800	3.16E-7
NPS 20 South Mid Kimball Gathering	2160m-2440m	2.35E-5 (corrosion)	2280m - 2310m	2.22E-7
NPS 6 Mid Kimbal Well Lateral - TKC 2	0m-12m	4.9E-8	-	-
NPS 10 Mid Kimbal Well Lateral - TKC 29	240m – 320m	4.43E-8	-	-
NPS 10 Mid Kimbal Well Lateral - TKC 32A	0m – 210m	9.04E-6 (corrosion)	-	-

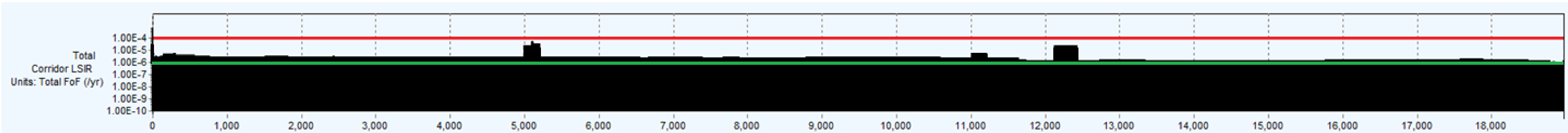
5. Results

Segmentation and reliability results were calculated for all pipelines using the EGI TIMP risk model current as of 1/20/2022 (version 4.1). Histograms representing the parallel pipelines' individual and combined LSIR profiles for leak and rupture are shown below.

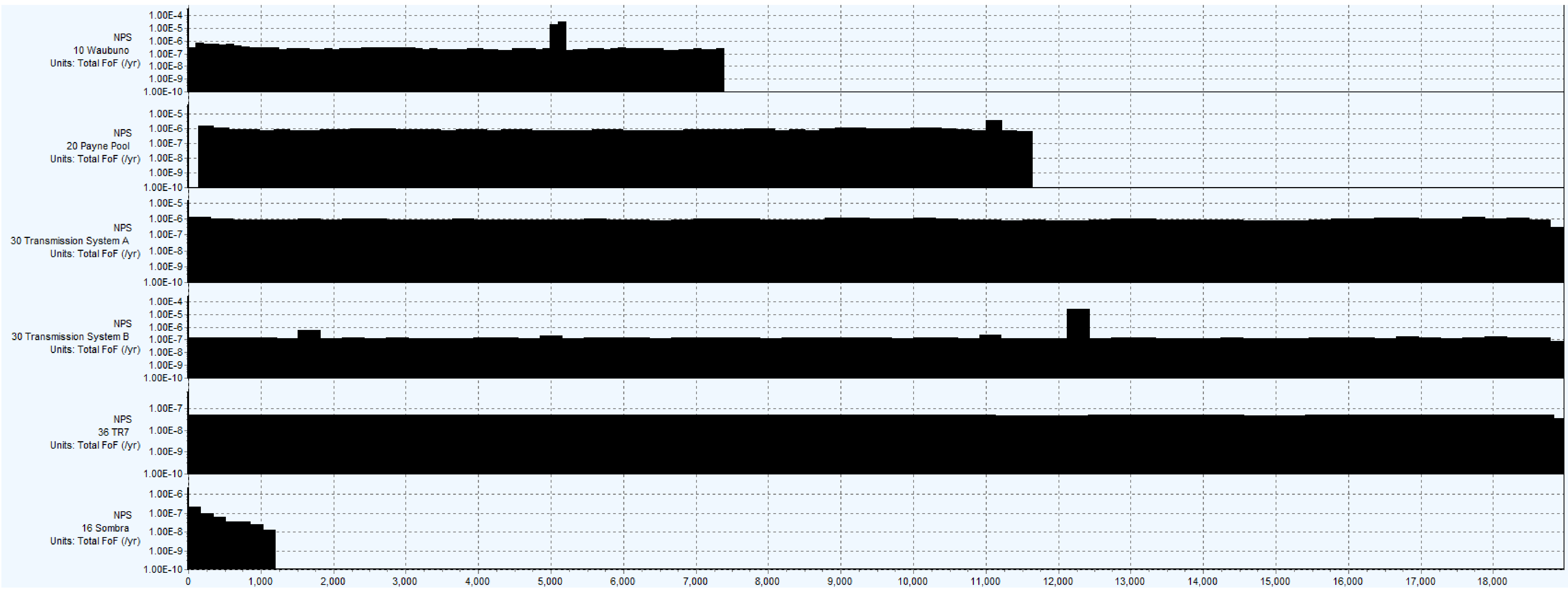
EGI Public Health & Safety Individual Risk Limit

EGI Public Health & Safety Individual Risk Target

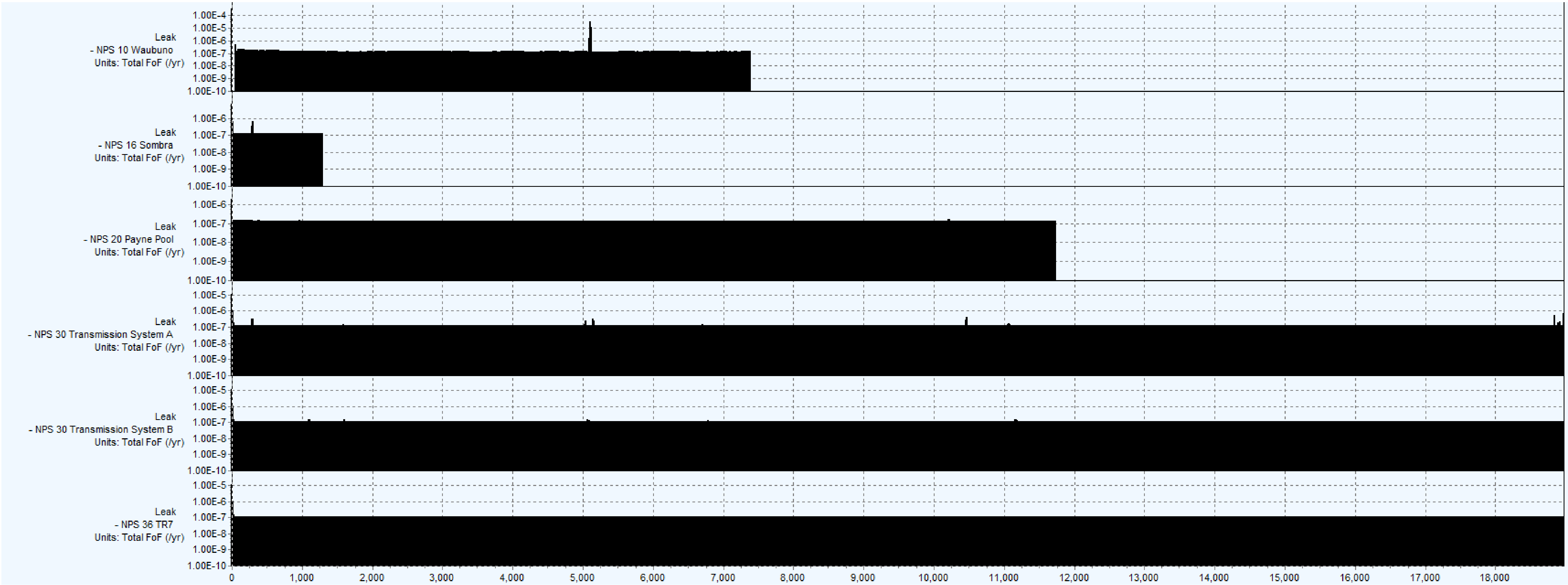
Total LSIR (parallel pipeline contribution only):



LSIR Rupture:



LSIR Leak:


Leak
- NPS 10 Waubuno
Units: Total FoF (/yr)
Leak
- NPS 16 Sombra
Units: Total FoF (/yr)
Leak
- NPS 20 Payne Pool
Units: Total FoF (/yr)
Leak
- NPS 30 Transmission System A
Units: Total FoF (/yr)
Leak
- NPS 30 Transmission System B
Units: Total FoF (/yr)
Leak
- NPS 36 TR7
Units: Total FoF (/yr)
1.00E-4
1.00E-5
1.00E-6
1.00E-7
1.00E-8
1.00E-9
1.00E-10
0
1,000
2,000
3,000
4,000
5,000
6,000
7,000
8,000
9,000
10,000
11,000
12,000
13,000
14,000
15,000
16,000
17,000
18,000

6. Conclusions

The profile of the parallel pipeline LSIR along the proposed path of TR7 is <1E-5 for the majority of the line, with a few local spikes to <1E-4 due to presence of corrosion features from the existing lines.

Since the histograms account for only the pipelines which run parallel to each other, the frequency of ignited ruptures and leaks from the pipelines within the vicinity or crossing the corridor (listed in table 2) need to be added to the total LSIR profile. It is noted that these frequencies are generally in the range of ~1E-7, and that the few areas exceeding 1E-6 are localized in areas without other interacting spikes. The LSIR contribution from these nearby lines is therefore low, and, after adding these to the parallel pipeline LSIR profile, the final profile can still be characterized as a profile <1E-5 for the majority of the line, with a few local spikes to <1E-4 due to presence of corrosion features.

It can also be seen that the expected LSIR contribution from the TR7 pipeline alone would fall in the ~1.2E-7 range, indicating that the additional contribution of risk from the TR7 is low and that the majority of the risk in the corridor is due to the existing pipelines.

Implicit in the use of LSIR as the individual risk metric is also the assumption that a hypothetical person is located at all times directly on top of the corridor. This is a highly conservative assumption given an individual is unlikely to spend 100% of their time right on top of the corridor, and it is expected that actual IR levels for real populations around the corridor (accounting for actual exposure times and realistic distances) will be significantly lower.

Given the general low risk levels above (using conservative assumptions) and assuming that localized spikes in risk that arise over time can be remediated through integrity actions if risks are not deemed to be ALARP (e.g. through targeted pipeline repairs), it is expected that the corridor will be able to be maintained at broadly tolerable or conditionally tolerable risk levels.

The total public H&S risks from the TR7 pipeline and the associated corridor are therefore not expected to result in intolerable public H&S risk.

7. Appendix

A map of the TR7 path and associated nearby pipelines is shown below.

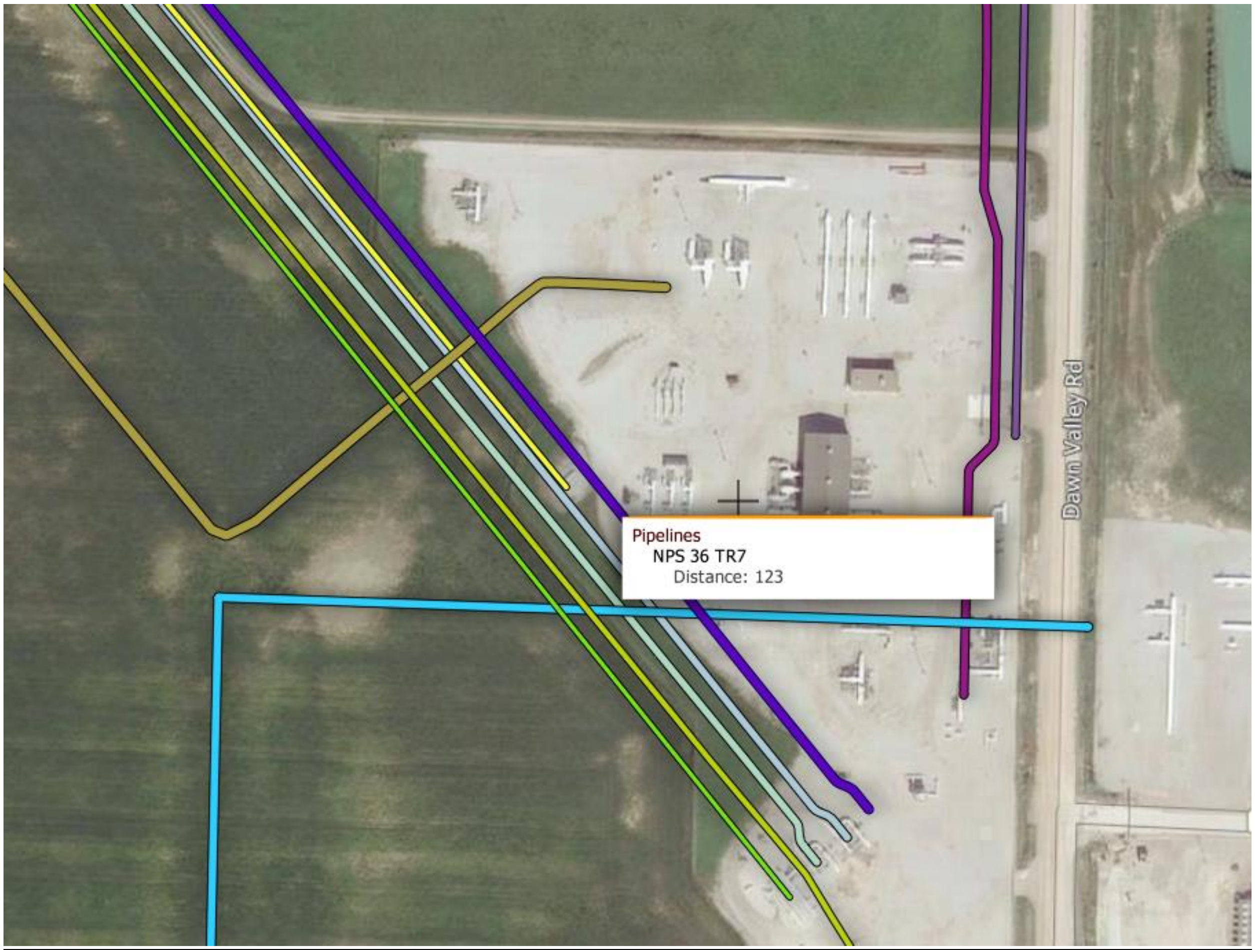
<u>Near Corunna Compressor:</u>

RUNS PARALLEL TO:	CROSSES:
NPS 30 Transmission System A Pipeline	NPS 20 South Kimball Loop Line
NPS 30 Transmission System B Pipeline	NPS 6 / 10 Mid Kimball Well Lateral – TKC 2
	NPS 16 Wilkesport Transmission Pipeline
	NPS 10 Mid Kimball – TKC 3
	NPS 20 South Mid Kimball Gathering

Middle of corridor:

RUNS PARALLEL TO:	CROSSES:
NPS 30 Transmission System A Pipeline	
NPS 30 Transmission System B Pipeline	
NPS 20 Payne Pool	
NPS 10 Waubuno	
NPS 16 Sombra Transmission Pipeline	

Near Dawn Compressor:



RUNS PARALLEL TO:	CROSSES:
NPS 30 Transmission System A Pipeline	NPS 30 Bentpath Rosedale
NPS 30 Transmission System B Pipeline	NPS 36 Bickford Dawn Loop
NPS 20 Payne Pool	NPS 42 Vector
NPS 10 Waubuno	
NPS 16 Sombra Transmission Pipeline	

8. References

1. ASME B31.8S 2018 edition
2. PRIM Risk Algorithm Document V1.2
3. Nessim, Kariyawasam "Safety Risk Acceptance Criteria for Pipelines", IPC2020-9274
4. Nessim, Zhou "Target Reliability Levels for Design and Assessment of Onshore Natural Gas Pipelines", 2009.

GENERAL CONSULTING (2021)

Dawn-Corunna Modifications Project QRA Report

Enbridge Gas, Inc.

Report No.: 10287791-PIPE-1, Rev. 2
Document No.: 10287791-PIPE-1
Date: 2022-05-17

Project name:	General Consulting (2021)	DNV Canada Ltd
Report title:	Dawn-Corunna Modifications Project QRA Report	250 6TH Avenue S.W.,
Customer:	Enbridge Gas, Inc.,	Suite 1710,
Customer contact:	Mike Hildebrand	Bow Valley Square 4,
Date of issue:	2022-05-17	T2P 3H7,
Project No.:	10287791	CALGARY, Canada
Organisation unit:	Integrity Assessment and Compliance	Tel: +1- 403-702-5679
Report No.:	10287791-PIPE-1, Rev. 2	
Document No.:	10287791-PIPE-1	

Applicable contract(s) governing the provision of this Report: MSA WITH DNV

Objective:

To assess the risks associated with the Dawn-Corunna Modifications Project.

Prepared by:	Verified by:	Approved by:
Jamie Elliott Principal Consultant	Jeff Daycock Principal Consultant	Michael Simms Head of Section – Safety Risk Excellence

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QRA

Rev. No.	Date	Reason for Issue	Prepared by	Verified by	Approved by
0	2021-12-20	First issue	J. Elliott	M. Hunter	M. Simms
1	2022-03-08	Client comments incorporated	J. Elliott	J. Daycock	M. Simms
2	2022-05-17	Further comments incorporated	J. Elliott	J. Daycock	M. Simms

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List of Abbreviations

A/G	Above Ground
CCS	Corunna Compressor Station
EGI	Enbridge Gas, Inc.
EGIG	European Gas Pipeline Incident Data Group
ESD	Emergency Shutdown
ESV	Emergency Shutoff Valve
GAC	Gas-Air Cooler
ILI	In-Line Inspection
IOGP	Institute of Oil & Gas Producers
ISIR	Individual-Specific Individual Risk
JWC	Jacket Water Coolers
LFL	Lower Flammable Limit
LNG	Liquified Natural Gas
LSIR	Location-Specific Individual Risk
MCC	Motor Control Centre
MKC	Mid Kimball / Conlinville
P&ID	Piping and Instrumentation Diagram
PFD	Process Flow Diagram
PHAST	Process Hazards Analysis Software Tool
PLL	Potential Loss of Life
POI	Probability of Ignition
QRA	Quantitative Risk Assessment
RRM	Risk Reduction Measure
SIL	Safety Integrity Level
SKC	South Kimball / Conlinville
TR7	Transmission 7
U/G	Underground
UK HSE	United Kingdom Health and Safety Executive
UKOOA	UK Offshore Operators Association

1 EXECUTIVE SUMMARY

1.1 Introduction

Enbridge Gas, Inc. (EGI) is planning to install a new 36" pipeline named Transmission 7 (TR7) between the Corunna Compressor Station (CCS) and the Dawn facility. As part of the modifications, seven out of the 11 compressors at CCS will be abandoned. This is intended to substantially reduce the risk on site.

This report presents the results of a Quantitative Risk Assessment (QRA) of the modifications at CCS.

This report presents the risk for the following cases:

- R0: CCS facility as it is today.
- Post-Abandonment.
- R1: As Post-Abandonment plus the addition of new headers to tie into the transmission pipelines. The R1 case also includes a reduction in personnel in Compressor Buildings 1 and 2, in line with the reduction in equipment.

The QRA aims to assess the risk, taking into account the proposed risk reduction measures (RRM) at the Corunna Compressor Station (CCS), which are represented by R1 scope, and evaluate against EGI's risk tolerability criteria.

This work is an update to the existing QRA for CCS which is presented in Reference /1/.

1.2 Results and Conclusions

The change from the R0 case (today) to the R1 case (after the TR7 modifications) results in the individual risk for the most exposed worker groups falling by at least 44%, as shown in Table 1-1 below. This moves the risk for these workers from Region 1, which is above the upper risk threshold, to Region 2, 'conditionally tolerable', according to the EGI risk criteria..

Table 1-1 Individual Risk Results – Most Exposed Workers

	Risk of Fatality (per year)		Risk Tolerance Criteria Region	% Change
Individual	R0 Today	R1 After Modification	R1 After Modification	R0 to R1
Mechanics	1.30E-03	7.24E-04	Region 2: Conditionally Tolerable	-44%
Tecumseh Operations - Op. 2 Plant	1.36E-03	7.18E-04	Region 2: Conditionally Tolerable	-47%
Instrumentation	1.14E-03	6.28E-04	Region 2: Conditionally Tolerable	-45%
Electrical	1.14E-03	6.28E-04	Region 2: Conditionally Tolerable	-45%
Chief Mechanic	1.05E-03	5.47E-04	Region 2: Conditionally Tolerable	-48%

Region 1, >1E-03 per year. If analysis indicates that the risk level is in Region 1, the risk is at or above upper threshold and the risk must be treated. This may be done through a series of short- and long-term measures to reduce the risk until it qualifies under Region 2.

Region 2, 1E-03 – 1E-06 per year. If analysis indicates the risk level is in Region 2, the risk is conditionally tolerable, provided best engineering practices have been applied and all reasonable measures have been taken to reduce it as low as reasonably practicable. These types of risks may still lead to treatment plans if the risk owner and other stakeholders determine that additional reasonable measures would lower the risk.

Region 3, < 1E-06 per year. If analysis indicates that the risk level is in Region 3, the risk is broadly tolerable, existing controls must be kept in place and the risk must be monitored.

2 INTRODUCTION

2.1 Background

Enbridge Gas, Inc. (EGI) is planning to install a new 36" pipeline named Transmission 7 (TR7) between the Corunna Compressor Station (CCS) and the Dawn facility. Seven compressors at CCS will be abandoned which it is expected will drive a substantial reduction in risk.

This report presents the results of a Quantitative Risk Assessment (QRA) of the modifications at CCS.

This work is an update to the existing QRA for CCS which is presented in Reference /1/. That QRA was verified by DNV, as documented in Reference /2/.

The same methodology has been used in the present analysis as in the previous report, including software (Safeti version 8.23) and software settings. The methodology is described in Appendix A and background data is listed in Appendix B.

2.2 Cases Modelled

For CCS, the QRA presents the risk for the following cases:

Table 2-1 CCS Risk Cases

Case	Description
R0	CCS facility as it is today
Post-Abandonment	Abandonment of compressors K701-K703, K705-K708.
R1	As Post-Abandonment plus the addition of the following new headers to tie into the transmission pipelines: • Header A – Extension 30" • Header B – Extension 30" • Header C – Extension 30" • Cross Flow Header E 42" • Cross Flow Header F 42" • Header E 42" • Header F 42"

In Compressor Building 1, four out of five compressors are abandoned. As per information from EGI Operations, it is estimated that this leads to an equivalent reduction in time spent in this building therefore the number of people in the building has been reduced by 80% for the R1 case. Similarly, in Compressor Building 2, three out of five compressors are abandoned and a 60% reduction in population is assumed. The populations used are listed in Appendix B.

3 RISK CRITERIA

The individual risk criteria proposed by EGI Enterprise Safety & Reliability are shown below (Ref. /3/).

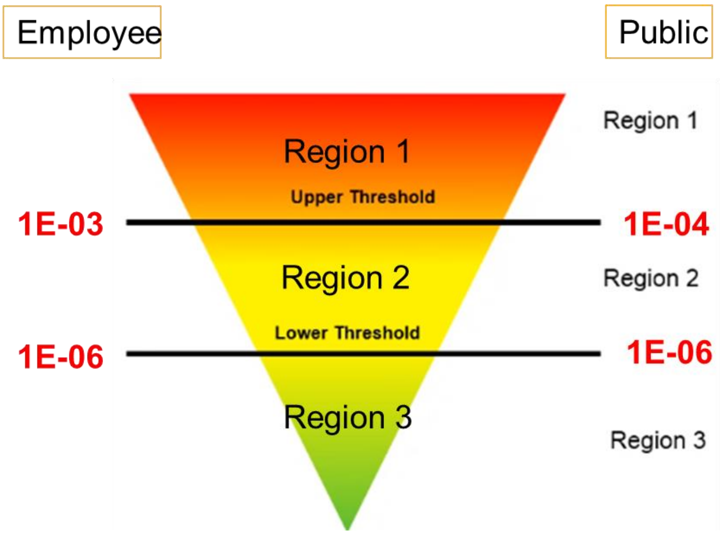

Figure 3-1 Individual Risk Criteria

- If analysis indicates that the risk level is in Region 1, the risk is at or above upper threshold and the risk must be treated. This may be done through a series of short- and long-term measures to reduce the risk until it qualifies under Region 2.
- If analysis indicates the risk level is in Region 2, the risk is conditionally tolerable, provided best engineering practices have been applied and all reasonable measures have been taken to reduce it as low as reasonably practicable. These types of risks may still lead to treatment plans if the risk owner and other stakeholders determine that additional reasonable measures would lower the risk.
- If analysis indicates that the risk level is in Region 3, the risk is broadly tolerable, existing controls must be kept in place and the risk must be monitored.

These risk criteria apply to individual-specific individual risk (ISIR) i.e. taking into account the amount of time a person spends in a particular location, They are not directly applicable to location-specific individual risk (LSIR) which is the theoretical risk at a particular location if a person was to spend all of their time there.

These risk criteria are typical of those used throughout industry. They are consistent with those set out by the British Columbia Oil & Gas Commission for LNG Facilities (Ref. /4/) and those set out by UK HSE (Ref. /5/).

4 CORUNNA COMPRESSOR STATION – RESULTS AND CONCLUSIONS

4.1 Location-Specific Individual Risk

The location-specific individual risk (LSIR) is the risk a person would experience if they were at a given location 365 days a year. It is a is useful measure to determine which are the highest risk areas. A person's vulnerability to flash fire, jet fire and explosions is different depending on whether they are indoors or outdoors, therefore separate results are given for each. People indoors are considered to not be vulnerable to flash fires but are more vulnerable to explosion overpressure from building collapse. Full details of the vulnerability assumptions are provided in Section A.5 in Appendix A.

Indoor populations include people in the three compressor buildings and three Motor Control Centre (MCC) buildings in the main plant area as well as people in the office building to the south. Outdoor populations are people spread throughout the plant areas.

The LSIR contours are shown in the following figures and discussion is provided in Section 4.1.4. Note that north is to the right on all images.

4.1.1 LSIR Results – Indoors

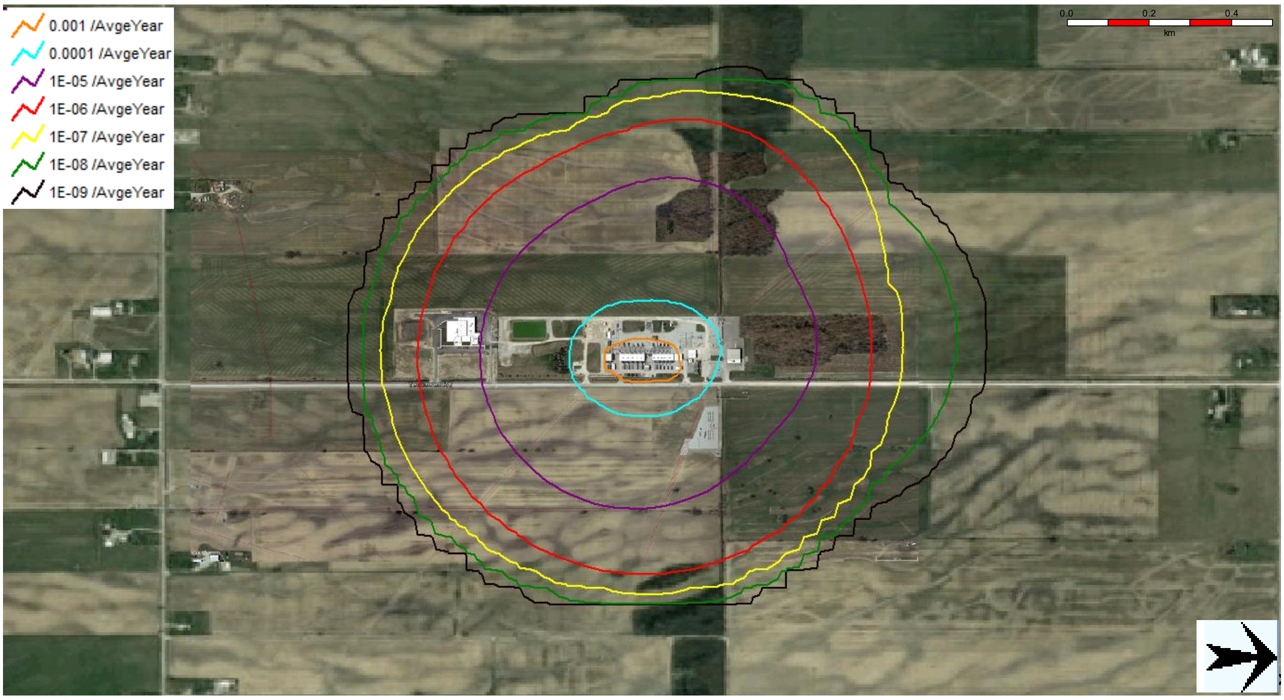

Figure 4-1 Location Specific Individual Risk – R0 Indoor Risk

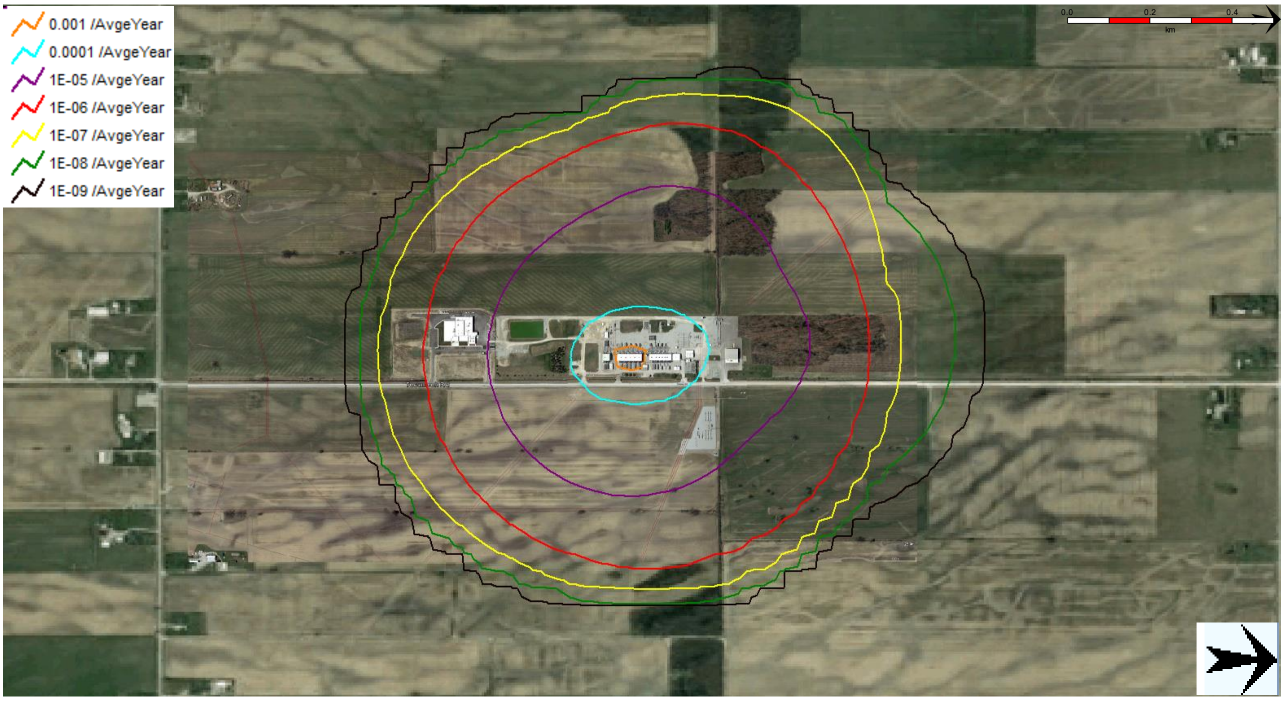

Figure 4-2 Location Specific Individual Risk – Post-Abandonment Indoor Risk

Figure 4-3 Location Specific Individual Risk – TR7 Modifications Only – Indoor Risk

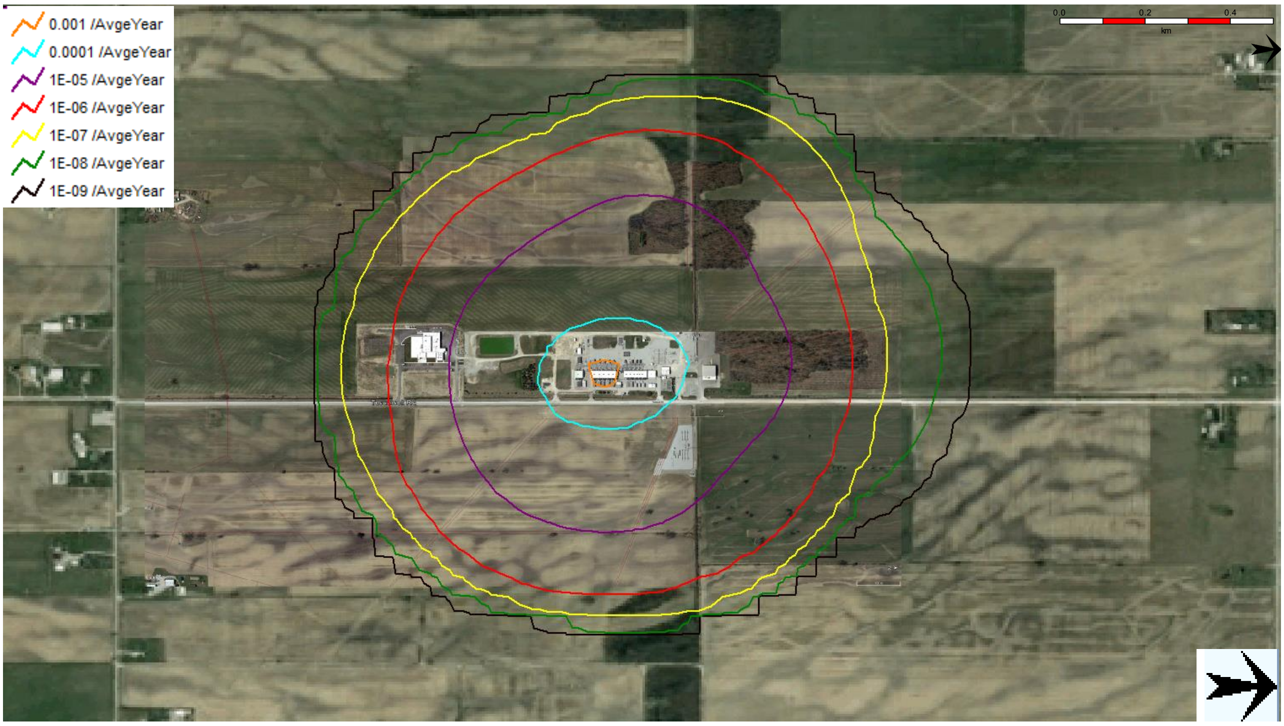

Figure 4-4 Location Specific Individual Risk – R1 Indoor Risk

4.1.2 LSIR Results - Outdoors

Figure 4-5 Location Specific Individual Risk – R0 Outdoor Risk

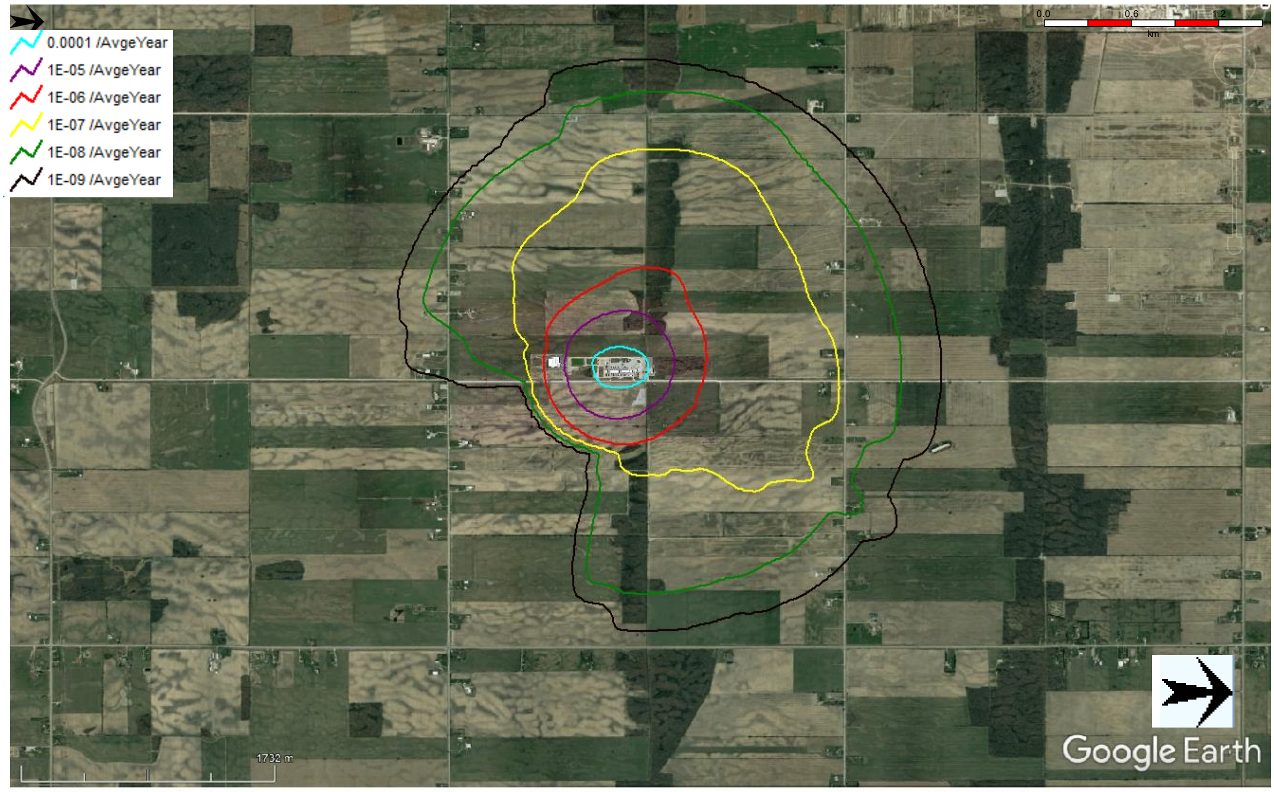

Figure 4-6 Location Specific Individual Risk – Post-Abandonment Outdoor Risk

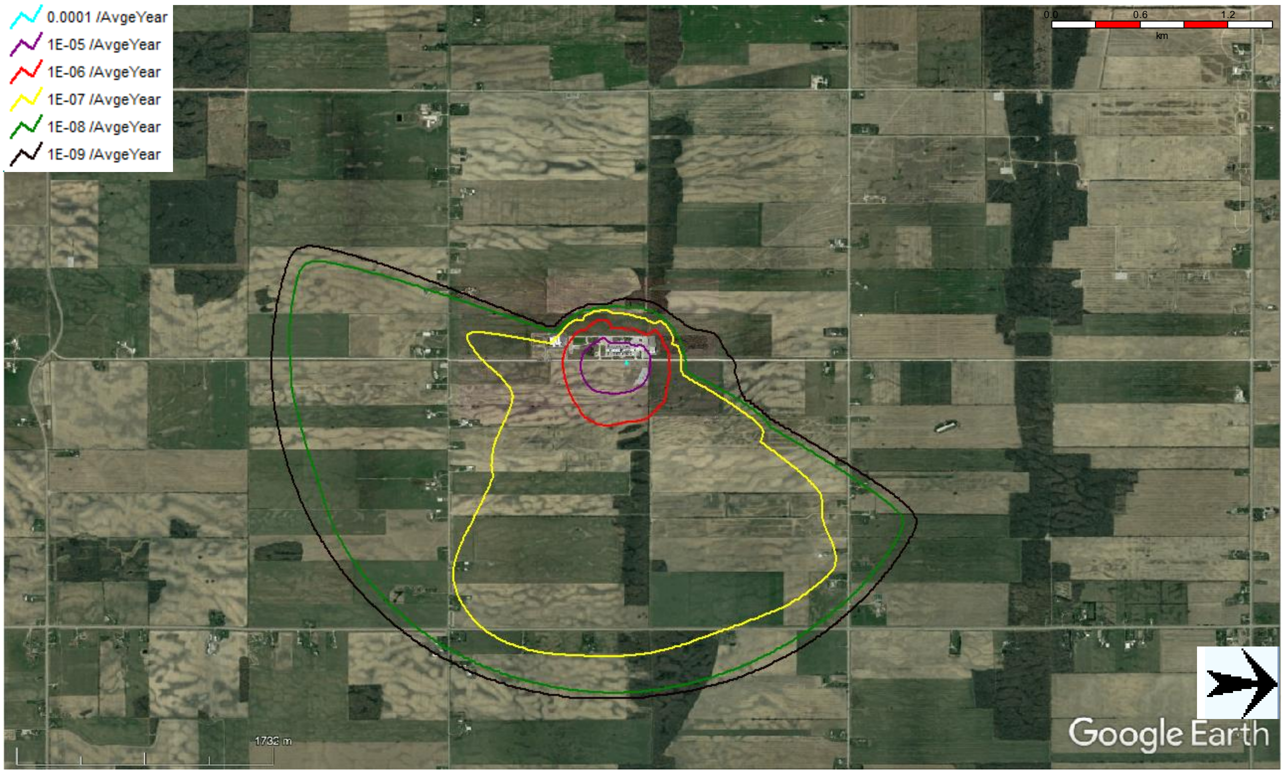

Figure 4-7 Location Specific Individual Risk – TR7 Mods Only – Outdoor Risk

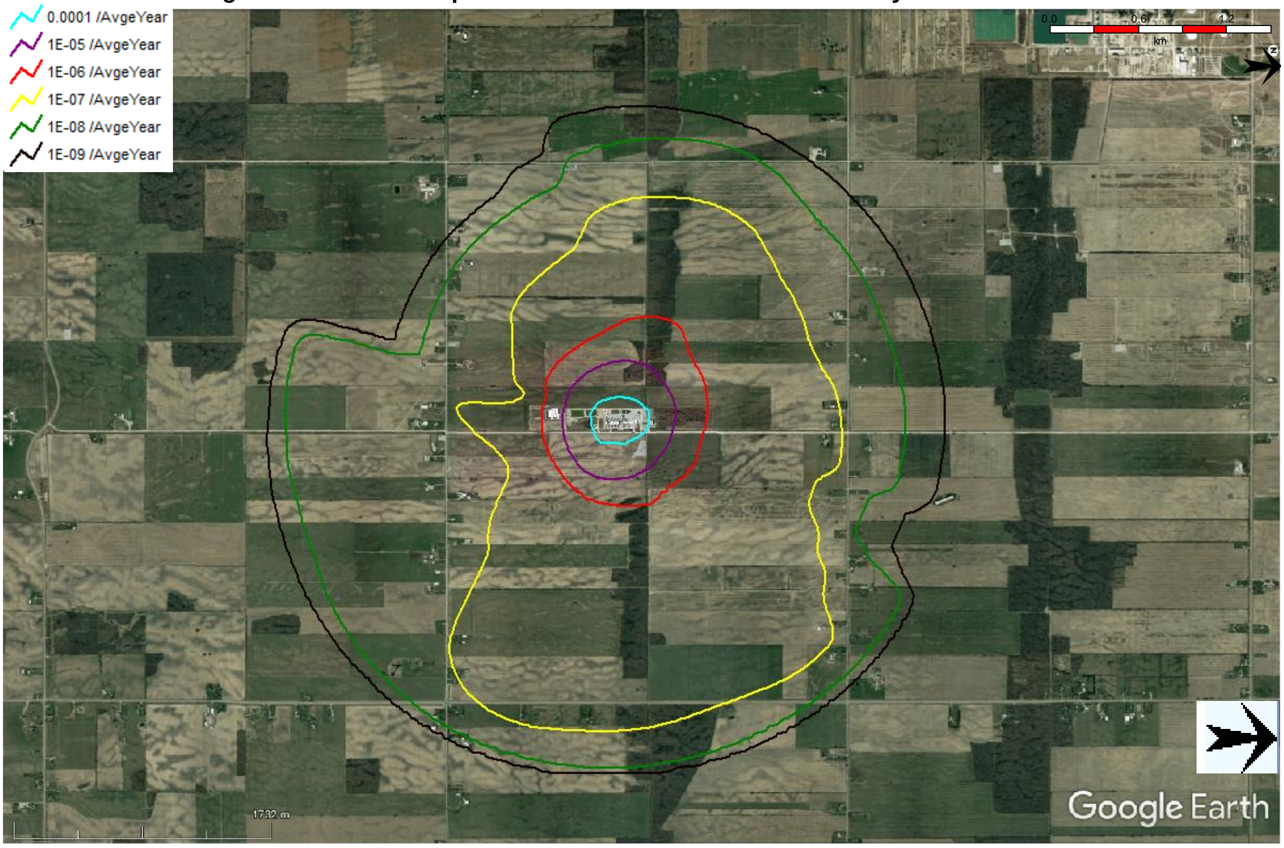

Figure 4-8 Location Specific Individual Risk – R1 Outdoor Risk

4.1.3 LSIR By Occupied Location

The following table shows the LSIR values for each occupied location where a population has been assumed. The locations are sorted from highest to lowest risk for the R1 case.

Table 4-1 Location-Specific Individual Risk by Occupied Location

Location	Type	R0 (per year)	R1 (per year)
Comp Bldg 1	Indoors	1.41E-02	5.93E-03
Comp Bldg 2	Indoors	9.66E-03	5.22E-03
Comp Bldg 3	Indoors	3.26E-03	2.74E-03
Old Ctrl Bldg & MCC 2	Indoors	5.20E-03	2.27E-03
MCC 3	Indoors	2.75E-03	2.02E-03
MCC 1	Indoors	3.03E-03	1.07E-03
Jacket Water Coolers Bldg 2	Outdoors	1.30E-03	7.70E-04
Jacket Water Coolers Bldg 1	Outdoors	1.52E-03	7.27E-04
Gas Aftercoolers Bldg 2	Outdoors	1.10E-03	6.86E-04
Gas Aftercoolers Bldg 1	Outdoors	1.17E-03	6.16E-04
Jacket Water Cooles Bldg 3	Outdoors	5.87E-04	5.50E-04
Gas Aftercoolers Bldg 3	Outdoors	7.20E-04	5.34E-04
Free Flow Piping	Outdoors	6.79E-04	5.05E-04
Mechanics Warehouse	Indoors	1.21E-03	4.66E-04
Meter Runs	Outdoors	5.62E-04	4.17E-04
ILI Receiving	Outdoors	2.99E-04	2.32E-04
Waste Fluid & Liquids Storage	Outdoors	3.95E-04	2.04E-04
Office Building	Indoors	6.90E-06	5.49E-06

4.1.4 LSIR Conclusions

The Location-Specific Individual Risk (LSIR) contour plots show that moving from today's R0 case to post-abandonment, there is significant reduction in risk in and around the compressor buildings. This is because the scenarios associated with the abandoned compressors have been removed. These scenarios were high frequency compared to the other scenarios in the QRA but had relatively short impact distances.

The explosions causing the highest overpressures are also associated with releases within the compressor buildings. In the R0 case, the indoor risk at the compressors was higher than the outdoor risk and this is driven by the explosion hazards. This includes an explosion in one compressor building leading to the collapse of another compressor building. Reducing the frequency of these severe explosions in the R1 case substantially reduces the risk for people in the compressor buildings.

Figure 4-7 shows the outdoor risk due to the TR7 modification occurring mostly to the south and east (bottom and left of the image). This is because the new equipment is to the east of the station and strong ignition sources at the station ignite drifting clouds preventing them from crossing the station and moving to the north and west.

4.2 Individual-Specific Individual Risk

The Individual-Specific Individual Risk (ISIR) - is a product of the risk for a particular location and the amount of time a person spends there. The amount of time each person is assumed to spend in each location is shown in Table B-7 in Appendix B.

ISIR is the actual risk that each person is predicted to experience and can be compared to risk criteria.

4.2.1 Individual-Specific Individual Risk Results

The ISIR result for a member of each worker group is shown below.

Table 4-2 Individual-Specific Individual Risk Results

	Risk of Fatality (per year)			Risk Tolerance Criteria Region	% Change
Individual	**R0 Today**	**Post-Abandonment**	**R1 After Modification**	**R1 After Modification**	**R0 to R1**
Mechanics	1.30E-03	7.17E-04	7.24E-04	Region 2	-44%
Tecumseh Operations - Op. 2 Plant	1.36E-03	7.11E-04	7.18E-04	Region 2	-47%
Instrumentation	1.14E-03	6.22E-04	6.28E-04	Region 2	-45%
Electrical	1.14E-03	6.22E-04	6.28E-04	Region 2	-45%
Const. Contractor - Plant Reliability	9.46E-04	5.46E-04	5.53E-04	Region 2	-41%
Chief Mechanic	1.05E-03	5.43E-04	5.47E-04	Region 2	-48%
Tecumseh Operations - Op. 4 Swing	6.81E-04	3.56E-04	3.59E-04	Region 2	-47%
Contractors -Full Time	6.29E-04	3.37E-04	3.39E-04	Region 2	-46%
Safety	2.49E-04	1.50E-04	1.52E-04	Region 2	-39%
Operations Manager	2.21E-04	1.17E-04	1.18E-04	Region 2	-47%
Tecumseh Operations - Op. 3 Field	1.32E-04	1.01E-04	1.04E-04	Region 2	-22%
Instrumentation - Supervisor	1.25E-04	9.89E-05	1.01E-04	Region 2	-19%
Const. Contractor - Engineering Execution	1.17E-04	8.86E-05	9.10E-05	Region 2	-23%
Tecumseh Operations - Chief Op.	1.35E-04	7.88E-05	7.98E-05	Region 2	-41%
Engineering - Execution	1.09E-04	7.25E-05	7.41E-05	Region 2	-32%
Utility Operations	9.73E-05	7.08E-05	7.28E-05	Region 2	-25%
Reservoir Ind. Contributer	8.84E-05	6.60E-05	6.77E-05	Region 2	-23%
Inspectors	8.67E-05	6.47E-05	6.64E-05	Region 2	-23%
Office Staff	1.15E-04	6.23E-05	6.31E-05	Region 2	-45%
Engineering - Planning	1.08E-04	6.21E-05	6.30E-05	Region 2	-42%
Tech/Scada	1.29E-04	5.88E-05	6.01E-05	Region 2	-53%
Warehouse	5.09E-05	2.82E-05	2.88E-05	Region 2	-43%
Engineering - Manager	3.53E-05	2.28E-05	2.34E-05	Region 2	-34%
Reservoir Supervisor	2.17E-05	1.61E-05	1.67E-05	Region 2	-23%
Utility Operations - Supervisor	1.62E-05	1.11E-05	1.16E-05	Region 2	-28%
Asset Management	1.79E-06	1.23E-06	1.48E-06	Region 2	-17%
Tecumseh Operations - Op. 1 Lead	1.78E-06	1.14E-06	1.44E-06	Region 2	-19%
Contractors -Part Time	4.48E-07	3.08E-07	3.71E-07	Region 2	-17%

Region 1, >1E-03 per year. If analysis indicates that the risk level is in Region 1, the risk is at or above upper threshold and the risk must be treated. This may be done through a series of short- and long-term measures to reduce the risk until it qualifies under Region 2.
Region 2, 1E-03 – 1E-06 per year. If analysis indicates the risk level is in Region 2, the risk is conditionally tolerable, provided best engineering practices have been applied and all reasonable measures have been taken to reduce it as low as reasonably practicable. These types of risks may still lead to treatment plans if the risk owner and other stakeholders determine that additional reasonable measures would lower the risk.
Region 3, < 1E-06 per year. If analysis indicates that the risk level is in Region 3, the risk is broadly tolerable, existing controls must be kept in place and the risk must be monitored.

4.2.2 Individual-Specific Individual Risk Conclusions

The change from the R0 case (today) to the R1 case (after the TR7 modifications) results in the individual risk for the most exposed worker groups falling by at least 44%, as shown in Table 1-1 below. This moves the risk for these workers from 'intolerable' to 'conditionally tolerable' according to the EGI risk criteria.

The personnel with the highest risk are those that spend the greatest proportion of their time in the highest risk locations. These are operators and technicians. The highest risk areas are the plant buildings, particularly the compressor buildings, but also MCC 1, the old control building, MCC 3 and the mechanics' warehouse. Administrative staff who spend most of their time in the office building have risk several orders of magnitude lower.

See Section 4.3 for analysis of the risk-dominating scenarios.

4.3 Potential Loss of Life (PLL)

The Potential Loss of Life (PLL) risk measure corresponds to the average number of fatalities per year. There are no established risk criteria for PLL and it is mainly used for understanding the key risk drivers. Since the risk is expressed as a single number, it is useful for making comparisons between cases, and for determining the dominating causes of risk within a given case. The results are given in the following tables and discussion is provided in Section 4.3.2.

4.3.1 PLL Results

The PLL results are shown in the following tables.

Table 4-3 Potential Loss of Life (PLL) – Change Due to Modifications

Location	PLL (fatalities per year)			R0 to R1 Change
	R0	Post-Abandonment	R1	
Compressor Building 3	1.48E-03	1.22E-03	1.23E-03	-17%
Compressor Building 2	5.41E-03	1.20E-03	1.21E-03	-78%
Compressor Building 1	7.85E-03	6.87E-04	6.90E-04	-91%
Outdoors	4.20E-04	2.65E-04	2.75E-04	-34%
Old Control Bldg & MCC 2	4.60E-04	1.97E-04	2.01E-04	-56%
MCC 3	1.80E-04	1.30E-04	1.32E-04	-26%
MCC 1	1.99E-04	6.90E-05	7.05E-05	-65%
Mechanics' Warehouse	1.51E-04	5.77E-05	5.83E-05	-61%
Office Building	3.48E-05	2.31E-05	2.84E-05	-18%
Total	**1.62E-02**	**3.85E-03**	**3.90E-03**	**-76%**

Table 4-4 Potential Loss of Life (PLL) – Percentage of R1 Total

Location	R1 PLL (fatalities per year)	% of R1 Total
Compressor Building 3	1.13E-03	31%
Compressor Building 2	1.09E-03	30%
Compressor Building 1	6.22E-04	17%
Outdoors	2.79E-04	8%
Old Control Bldg & MCC 2	1.97E-04	5%
MCC 3	1.31E-04	4%
MCC 1	7.09E-05	2%
Mechanics' Warehouse	5.01E-05	1%
Office Building	3.13E-05	1%
Total	**3.60E-03**	**100%**

Table 4-5 Top Contributing Scenarios – R0 Case

Rank	Scenario	PLL (fatalities per year)	% of Total
1	24-3L\Free Flow Piping\20" Ladysmith U/G transfer piping to compressor header	2.61E-03	9%
2	76-2M\Compressor Bldg. 2\K-706, 7 inside bldg. 2 Discharge	1.42E-03	5%
3	63-1S\Free Flow Piping\20" Ladysmith U/G transfer piping to compressor header	1.42E-03	5%
4	37-2M\Compressor Bldg. 2\Compressors K-706 to 710 & indoor piping isolated	1.06E-03	4%
5	32-1S\Compressor Bldg. 1\Compressors K-701 to 705 & indoor piping isolated	1.03E-03	4%
6	68-2M\Compressor Bldg. 1\K-702, 3 inside bldg. 1 Discharge	9.42E-04	3%
7	76-4V\Compressor Bldg. 2\K-706, 7 inside bldg. 2 Discharge	5.58E-04	2%
8	32-2M\Compressor Bldg. 1\Compressors K-701 to 705 & indoor piping isolated	5.55E-04	2%
9	76-3L\Compressor Bldg. 2\K-706, 7 inside bldg. 2 Discharge	5.37E-04	2%
10	37-4V\Compressor Bldg. 2\Compressors K-706 to 710 & indoor piping isolated	5.20E-04	2%
11	78-1S\Compressor Header outside Bldg. 2\K-706, 7 discharge outside bldg. 2	4.54E-04	2%
12	68-4V\Compressor Bldg. 1\K-702, 3 inside bldg. 1 Discharge	4.07E-04	1%
13	37-3L\Compressor Bldg. 2\Compressors K-706 to 710 & indoor piping isolated	4.07E-04	1%
14	68-3L\Compressor Bldg. 1\K-702, 3 inside bldg. 1 Discharge	3.73E-04	1%
15	92-1S\Isolated K-701\Isolated K-701 Suction outside bldg. 1	3.64E-04	1%

Table 4-6 Top Contributing Scenarios – R1 Case

Rank	Scenario	PLL (fatalities per year)	% of Total
1	24-3L\Free Flow Piping\20" Ladysmith U/G transfer piping to compressor header	1.06E-03	18%
2	38-2M\Compressor Headers outside Blgd. 3\12" & 16" Compressor Header for K-711 in front Blgd. 3 isolated	2.80E-04	5%
3	42-2M\Compressor Bldg. 3\Compressors K-711 & indoor piping isolated	2.68E-04	4%
4	115-2M\Raw Fuel Take Off\4" ESV, Filter, Heater & Pressure Control	2.14E-04	4%
5	33-4V\Compressor Headers outside Blgd. 2\12" & 16" Compressor Header for K-706 to 710 in front Blgd. 2 isolated	2.11E-04	4%
6	36-4V\Compressor/trans header outside bldg. 2\24" A/G transmission header for K-706 to 710	1.94E-04	3%
7	36-2M\Compressor/trans header outside bldg. 2\24" A/G transmission header for K-706 to 710	1.41E-04	2%
8	41-4V\Compressor/trans header outside bldg. 3\24" A/G transmission header for K-711	1.40E-04	2%
9	42-4V\Compressor Bldg. 3\Compressors K-711 & indoor piping isolated	1.29E-04	2%
10	33-3L\Compressor Headers outside Blgd. 2\12" & 16" Compressor Header for K-706 to 710 in front Blgd. 2 isolated	1.21E-04	2%
11	38-4V\Compressor Headers outside Blgd. 3\12" & 16" Compressor Header for K-711 in front Blgd. 3 isolated	1.21E-04	2%
12	38-3L\Compressor Headers outside Blgd. 3\12" & 16" Compressor Header for K-711 in front Blgd. 3 isolated	1.11E-04	2%
13	41-2M\Compressor/trans header outside bldg. 3\24" A/G transmission header for K-711	1.11E-04	2%
14	115-3L\Raw Fuel Take Off\4" ESV, Filter, Heater & Pressure Control	1.11E-04	2%
15	42-3L\Compressor Bldg. 3\Compressors K-711 & indoor piping isolated	1.02E-04	2%

Key:

1S	Small hole	A/G	Above Ground
2M	Medium hole	U/G	Underground
3L	Large hole		
4V	Very large hole		
5R	Rupture		

4.3.2 PLL Conclusions

The highest contribution to the PLL comes from the locations with the highest location-specific risk. Even though the office building has the largest population at 14 people, it has the lowest contribution to the PLL (see Section 4.1.3 for LSIR and Appendix B Section B.4 for populations).

Table 4-3 shows that the change from the R0 case (today) to the R1 case (after the TR7 modifications) results in a reduction in risk for all buildings. Overall, there is a 76% reduction in risk. The risk for Compressor Buildings 1 and 2 has reduced the most, reflecting both the reduced population and the reduced equipment in these buildings.

Looking in detail at the top contributing scenarios, Table 4-5 shows that for the R0 case many of the top contributing scenarios are from the compressors. Table 4-6 shows that many of these scenarios have dropped out of the top 15 due to the TR7 modifications in the R1 case.

As shown in Table 4-6 above, for the R1 case, 18% of the risk comes from scenario 24-3L. This is a large hole in the Ladysmith underground transfer piping going to the compressor header. Therefore, the outcomes from this scenario are considered in more detail in the following table.

Table 4-7 Outcomes for R1 Case Highest Risk Scenario
24-3L\Free Flow Piping\20" Ladysmith U/G transfer piping

Safeti Outcome	**% of Scenario PLL**
Continuous release delayed Flash fire with explosion	99.9
Continuous release delayed Flash Fire Only	0.1
Continuous release Immediate Horizontal Jet fire Only	0.0

Table 4-7 shows that the risk from this scenario is dominated by flash fire with explosion.

It is noted that the Ladysmith pipeline finishes at the congested region modelled for the building 1 header area. It is therefore possible for a release from the pipeline to lead to an explosion in the header area. The header area, in turn, is close to occupied areas so an explosion here can result in fatalities. In contrast, the other pipelines are either away from congested regions or away from occupied areas.

Going from the R0 case to the R1 case, scenario 24-3L goes from making up 9% of the total risk to 18%. However, the absolute risk from scenario 24-3L falls from 2.61E-03 to 1.06E-03 fatalities per year.

5 REFERENCES

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/3/ GD-AM-RSK-GUI-0001-D0.3 EGD Risk Tolerance, EGI, 2018-01-10.

/4/ Liquefied Natural Gas Facility - Permit Application and Operations Manual, Version 1.6, British Columbia Oil & Gas Commission, August 2018

/5/ "R2P2" Reducing Risks, Protecting People, HSE's decision-making process, ISBN 0 7176 2151 0, UK Health & Safety Executive, 2001.

/6/ 434-01 Risk Assessment Data Directory – Process Release Frequencies, IOGP, 2019.

/7/ Gas Pipeline Incidents, 10th Report (period 1970 – 2016), European Gas Pipeline Incident Data Group (EGIG), 2018.

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/11/ 434-14 Risk Assessment Data Directory – Vulnerability of Humans, IOGP, 2010.

APPENDIX A METHOD

A.1 Introduction

The following section gives a summary of the methodology used in the QRA. Further details and discussion are provided in the original QRA report (Ref. /1/).

A.2 Software

The QRA was conducted in Safeti version 8.23. Safeti is the industry-leading QRA package, incorporates the PHAST consequence modelling package and is widely used and accepted. This version of Safeti was used to provide consistency with previous QRA results.

A.3 Frequency Analysis

Leaks from process equipment are represented by failure scenarios. The frequency of each leak scenario and size identified is estimated by combining parts counts for each equipment item with generic frequencies.

A.3.1 Parts Count

A ‘parts count’ involves counting each and every equipment item in each section identified as set out in but not limited to:

- PFDs
- P&IDs
- Heat and material balances
- Equipment list; process or mechanical data sheets for equipment
- Layouts and plot plans

For equipment (pipework, flanges, valves) where the release frequency is line/connection diameter dependent, a separate count is made for each such diameter. Piping lengths are estimated from the documents listed above and layouts. Instrument populations were estimated based on an extract from MAXIMO for asset tags that were in natural gas systems.

A.3.2 Generic Release Frequency Data

For this study the IOGP report 434-01 “Risk Assessment Data Directory – Process Release Frequencies” was used to quantify the chance that a leak may occur from above-grade process equipment or associated piping (Ref. /6/). The data source is based on the Hydrocarbon Release Database managed by the UK HSE regulator.

The IOGP data does not account for buried piping systems therefore EGIG industry data was used (Ref. /7/). Since third party damage is a major contributor to the chance of failure of buried piping and this QRA covers piping only on company owned property where ground disturbance activities are controlled more so than on public land, the third party damage failures are removed from the EGIG data.

A.3.3 Release Sizes

The IOGP reports leaks based on the following categories in Table A-1 below.

Table A-1 Release Sizes Reported by IOGP

Release Category	Leak Diameter Lower Range [mm]	Leak Diameter Upper Range [mm]
1	1	3
2	3	10
3	10	50
4	50	150
5	150	Max Diameter

Categories 1 and 2 were combined to cover all leaks from 1 to 10mm. Category 5 was split into 90% 150mm leaks and 10% full bore rupture. The following representative hole sizes were modelled to represent each category.

Table A-2 Leak diameter modelled in QRA per leak category

Leak Category	Leak Diameter Lower Range [mm]	Leak Diameter Upper Range [mm]	Leak Diameter Modelled in QRA [mm]
Small	1	10	5
Moderate	10	50	22
Large	50	150	87
Very large	150	Max Diameter	150
Rupture	150	Max Diameter	Pipework Diameter

A.3.4 Ignition Probability

The Energy Institute/ UKOOA model (Ref. /8/) was used to estimate ignition probabilities. This uses correlations based on the type of plant and the release rate. The 'Large gas plant' correlation was used.

30% of ignitions are modelled as "immediate" and the remaining 70% of ignitions are modelled as "delayed" events.

In addition, the probability of delayed ignition takes into account the presence of specific geographically located ignition sources. Geographic ignition sources work in combination with the minimum probability of ignition calculated from the Energy Institute model to ensure that the overall probability of delayed ignition is at least the value calculated by the Energy Institute model. If the ignition sources are significant then the overall ignition probability will be higher.

The ignition sources were defined in terms of strength and location with ignition strengths taken from HSE Research Report 2004/226 (Ref. /9/). The ignition sources used are listed in Appendix B.

A.4 Discharge and Dispersion

Release rates were modelled in Safeti. For most equipment, no limitations were placed on release rates from holes as the equipment is connected to pipelines with large inventories of gas. Some equipment is left pressurised but isolated for some of the year. For this isolated equipment, the inventory was limited to the volume of the isolated equipment and piping. For indoor releases, emergency shutdown was modelled with separate scenarios covering successful and unsuccessful ESD, using a probability of failure on demand of 0.152. This probability was used in the existing QRA for CCS (Ref. /1/) which stated that the value was determined by EGI in the previous Meter Area QRA. This value is considered reasonable for a non-Safety Integrity Level (SIL)-rated system.

For ruptures from buried pipelines, the long pipeline model was used which calculates the time-varying discharge as the pipeline pressure drops due to the gas lost through the rupture. For ruptures from above ground piping, a 'user defined source' model was used, with the mass flow taken from the results from a long pipeline model of similar pressure and diameter.

For time-varying releases, the mass flow rate used for both the dispersion modelling and the jet fire modelling was the average over the first 20 s. Only a single value for the discharge rate can be passed to the dispersion and jet fire models and this is a reasonable balance between the initial high rate and later lower rate. It also corresponds with exposure duration assumed in the vulnerability modelling (see below). It assumes that someone will have either escaped or been killed within this time.

Releases from above ground equipment were oriented horizontally. Releases from holes in below ground pipelines were oriented vertically upwards.

Some equipment is located inside the compressor buildings. This indoor equipment had the release direction set to 'horizontal impingement'. The reduces the initial momentum of the jet, reducing the jet fire length but potentially increasing the size of the flammable cloud due to reduced air entrainment and dispersion. A separate set of obstructed regions was used for indoor releases relating to the compressor buildings. This means that explosions in the compressor buildings are modelled as only due to releases from inside the compressor buildings, and explosions in the other congested regions are modelled as only due to releases from outside equipment. The congested regions and whether they apply to indoor or outdoor releases are listed in Table B-5 in Appendix B.

A.5 Vulnerability

A.5.1 Jet Fires

For people outdoors, the probability of fatal injury is predicted using the following probit function from the TNO 'Green Book' (Ref. /10/):

$$Pr = -37.23+2.56 \ln(Q^{(4/3)} \times t)$$

Pr Probit corresponding to probability of fatal injury

Q Heat radiation (W/m^2)

t exposure time (s)

The exposure time, t, is equal to the duration of the fire, with a limit of 20 seconds.

The critical radiation intensity leading to a vulnerability of 1 was taken to be 20kW/m^2.

People indoors are assumed to be protected unless the building catches fire, therefore, the following vulnerabilities were used.

Table A-3 Jet Fire Thermal Radiation Vulnerability Criteria – Indoors

Radiation intensity level [kW/m^2]	Vulnerability
<12.5	0
12.5 – 20	0.3
>20	1

A.5.2 Fireballs

No fireball scenarios were modelled.

A.5.3 Flash fires

Flash fires can occur from ignition of a gas cloud at a concentration in air higher than the lower flammable limit (LFL). Personnel within a flash fire are assumed to be fatally injured. A flash fire outside is not considered to cause fatalities to personnel indoors due to the short duration and negligible overpressure of such an event.

A.5.4 Explosions

Combustion of a vapour/air mixture in the flammable range can result in overpressure where there is a mechanism to accelerate the flame (e.g. a region of congestion). Safeti is used to model dispersion of flammable gases and therefore determine the overlap of a flammable cloud with the congested regions. The explosion overpressures are determined from the TNO multi energy curve number defined for the congested region. See Section B.3 in Appendix B for details of the congested regions. IOGP 434-14 recommended vulnerability levels are applied for harm from explosion overpressure (Ref. /11/).

Table A-4 Overpressure Criteria for Explosions

	Overpressure (bar)	Effect
Outdoors	0.35	15% lethality
	0.50	50% lethality
Indoors	0.35	30% lethality
	0.50	100% lethality

APPENDIX B BACKGROUND DATA

B.1 Weather

This QRA considers the following standard Pasquill Stability Classes and wind speeds to represent daytime and night-time conditions as shown below.

Table B-1 Daytime & night-time weather conditions

Category	Pasquill Stability Class	Wind Speed (km/h)
Daytime	D	5.0
Night-time	F	1.5

The following wind direction probabilities were used, based on data for Sarnia airport.

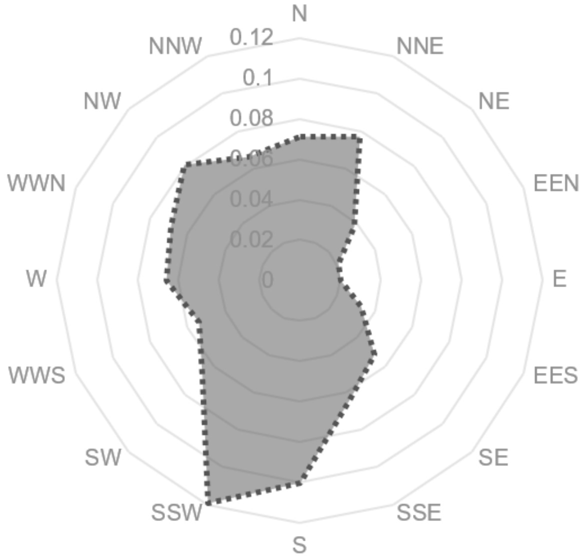

Figure B-1 Sarnia airport annual wind direction probabilities

B.2 Ignition Sources

The locations of the geographic ignition sources are identified in Figure B-2 below and their details are shown in the following tables.

Figure B-2 Ignition Source Locations

Table B-2 Site specific ignition source input data (areas)

Ref.	Ignition Source	Ignition Probability	In Time Period (sec)	Proportion of Time Operating	Area (W by L in m or m^2)	Location	Comments
1	Meter Runs	0.095	60	0.0801	35 by 55 m	Main Plant Metering Area	External Classified Area
2	Boiler Area	0.695	10	0.694	13 by 19 m	Main Plant Northeast of CB1	Boiler runs for 1 hour per week
3	JWC/Auxiliar y	1	10	1	164 by 23m	Main Plant East of CB1-3	Unclassified and with heavy equipment. Using the heavy equipment (non-hazardous) assumption from UK HSE RR226.
4	GAC/Header	0.095	60	0.0801	5,299 m^2	Main Plant West of CB1-3	External classified area per HSE RR226
5	Free Flow	0.0801	60	0.095	17 by 62m	Main Plant Free Flow Area	-
6	Substation	0.995	60	0.993	18 by 13m	Northeast of Main Plant	-
7	MKC-SKC Meter Area	0.095	60	0.0801	6,073	Main Plant	-
9	Outdoor Storage 1	0.305	60	0.283	86 by 52m	Main Plant Southwest of CB3	-
10	Outdoor Storage 2	0.305	60	0.283	2,943 m^2	Main Plant ILI Area	-

Table B-3 Site specific ignition source input data (roads)

Ref.	Ignition Source	Ignition Probability	In Time Period (sec)	Traffic Density (/hr)	Average Speed (m/s)	Length (km)	Comments
11	Tecumseh Road (Outside the Site boundary)	0.197	10	4.58	22.35	1.77	Ignition probability is for a single vehicle coming in contact with the cloud. Traffic density assumed at 110 per day. Speed limit on road is 50 mph.
12	South Vehicle Route	0.0129	10	1.04	4.47	0.47	Ignition probability is for a single vehicle. Traffic density assumes 25 vehicles using this route per day and driving at speed limit of 10 mph.
13	North Vehicle Route	0.01	10	1.04	4.47	0.14	Ignition probability is for one vehicle. Traffic density assumes 25 vehicles use this route per day, traveling at speed limit of 10 mph.

Table B-4 Site specific ignition source input data (point sources)

Ref.	Ignition Source	Ignition Probability	In Time Period (sec)	Proportion of Time Operating	Height of Source (m)	Comments
14	Flare	1	1	1	10	Flare is almost always running - no calculations modelled as POI 1
15	Furnace	0.999977	10	0.5	10	Furnace on roof runs for half the year.
16	Transformers 1, 2, & 3	0.0997	60	0.0952	0	Transformer 1 is located to the north of Main Plant Area. Transformers 2-3 are located to the east of Main Plant Area.

B.3 Congested Regions

The locations of the congested regions used for the explosion modelling are identified in Figure B-3 below and their details are shown in the following tables. These are regions where obstructions such as process equipment can cause turbulence leading to increased flame velocities and hence potential for overpressure to be generated.

Figure B-3 Congested Regions

Table B-5 Congested regions for explosion modelling

Ref.	Defined Strength Obstruction	Height (m)	Multi-Energy Curve	Blockage Ratio	Applies to [Note 1]
1	Compressor Buildings 1, 2, & 3	10	7	0.2	Indoor releases
2	Vegetation off site	7.62	5.5	0.6	Outdoor releases
3	Free Flow Area	2.44	5	0.5	Outdoor releases
4	GAC Area for Comp. Bldg. 1, 2, & 3	4.57	4	0.3	Outdoor releases
5	Header Area for Comp. Bldg. 1, 2, & 3	2.44	5.5	0.5	Outdoor releases
6	JWC Area for Comp. Bldg. 1, 2, & 3	4.57	4	0.3	Outdoor releases

Note 1: A separate set of obstructed regions was used for indoor releases relating to the compressor buildings. This means that explosions in the compressor buildings are modelled as only due to releases from inside the compressor buildings, and explosions in the other congested regions are modelled as only due to releases from outside equipment.

All congested regions were defined as independent so that Safeti does not combine them if a flammable cloud covers more than one region.

Considering the explosion vulnerabilities described in Section A.5.4, multi-energy curve 7 gives a peak overpressure of 1 bar which leads to 100% fatality for people nearby. In contrast, multi-energy curve 4 gives peak overpressures of less than 0.35 bar which has a vulnerability of 0 even for people close by.

B.4 Population

Table B-6 below shows the number of people in each occupied building and outside area. These populations are used for calculating the societal risk.

Table B-6 Populations – Number of People

Case	R0		R1	
Building	**Office Hours**	**Non-Office Hours**	**Office Hours**	**Non-Office Hours**
CCS Comp Bldg 1	1.47	0.29	0.32	0.06
CCS Comp Bldg 2	1.58	0.30	0.59	0.12
CCS Comp Bldg 3	0.98	0.29	0.98	0.29
CCS MCC 1	0.07	0.07	0.07	0.07
CCS Old Ctrl Bldg & MCC 2	0.17	0.07	0.17	0.07
CCS MCC 3	0.07	0.07	0.07	0.07
CCS Mechanics Warehouse	0.13	0.00	0.13	0.00
CCS Office Building	14.28	1.78	14.28	1.78
CCS AREA Waste Fluid & Liquids Storage	0.06	0.00	0.06	0.00
CCS AREA Jacket Water Coolers Bldg 1	0.10	0.03	0.10	0.03
CCS AREA Gas Aftercoolers Bldg 1	0.10	0.03	0.10	0.03
CCS AREA Jacket Water Coolers Bldg 2	0.10	0.03	0.10	0.03
CCS AREA Gas Aftercoolers Bldg 2	0.10	0.03	0.10	0.03
CCS AREA Jacket Water Coolers Bldg 3	0.10	0.03	0.10	0.03
CCS AREA Gas Aftercoolers Bldg 3	0.10	0.03	0.10	0.03
CCS AREA Meter Runs	0.14	0.03	0.14	0.03
CCS AREA ILI Receiving	0.46	0.03	0.46	0.03
CCS AREA Free Flow Piping	0.24	0.03	0.24	0.03
Total	**20.25**	**3.14**	**18.10**	**2.73**

The number of people at each location is not a whole number which represents that fact that people spend their working day visiting various locations.

Table B-7 below shows the percentage of time a person in each worker group is assumed to spend in each location. Workers are typically assumed to spend around 23.8% of their time at site which is equivalent to a 2085 hours per year. These figures are combined with the predicted risk at each location (Table 4-1) to calculate the individual risk for each worker group (Table 4-2).

Table B-7 Worker Group Distribution

Worker Group	Comp Bldg 1	Comp Bldg 2	Comp Bldg 3	MCC 1	Old Ctrl Bldg & MCC 2	MCC 3	Mechanics Warehouse	Office Building	Waste Fluid & Liquids Storage	Jacket Water Coolers Bldg 1	Gas Aftercoolers Bldg 1	Jacket Water Coolers Bldg 2	Gas Aftercoolers Bldg 2	Jacket Water Cooles Bldg 3	Gas Aftercoolers Bldg 3	Meter Runs	ILI Receiving	Free Flow Piping	Total
Reservoir Ind. Contributor								3.0%								10.5%	10.5%		**23.9%**
Reservoir Supervisor								19.0%								2.4%	2.4%		**23.9%**
Tecumseh Operations - Chief Op.	0.5%	0.5%	1%					21.4%								0.2%	0.2%		**23.8%**
Tecumseh Operations - Op. 1 Lead								25.0%											**25.0%**
Tecumseh Operations - Op. 2 Plant	4.6%	4.8%	4.6%	1.0%	1.0%	1.0%		4.2%		0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	**25.0%**
Tecumseh Operations - Op. 3 Field			1.2%			0.5%		3.3%						0.4%		9.3%	9.3%		**24.0%**
Tecumseh Operations - Op. 4 Swing	2.3%	2.4%	2.3%	0.5%	0.5%	0.5%		13.1%		0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	**23.5%**
Utility Operations								3.0%		0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	9.8%	9.2%	0.6%	**23.8%**
Utility Operations - Supervisor								21.4%		0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.8%	0.7%	0.1%	**23.8%**
Office Staff	0.5%	0.5%	0.2%					21.4%								0.6%	0.6%		**23.8%**
Instrumentation	4.8%	4.8%	3.0%			0.4%		3.6%						0.4%		3.6%	3.6%		**23.9%**
Instrumentation - Supervisor			2.6%			0.3%		13.1%						0.3%		3.9%	3.9%		**23.9%**
Electrical	4.8%	4.8%	3.0%			0.4%		3.6%						0.4%		3.6%	3.6%		**23.9%**
Tech/Scada					2.4%			19.0%								1.2%	1.2%		**23.8%**
Operations Manager	1.1%	0.8%	0.5%					21.4%											**23.8%**
Chief Mechanic	4.8%	3.8%	2.1%				1.2%	11.9%											**23.8%**
Mechanics	5.4%	4.2%	6.5%				1.2%	5.1%						1.4%					**23.8%**
Safety	0.7%	0.7%	1.3%			0.2%		12.1%	0.1%	0.3%	0.3%	0.3%	0.3%	0.3%	0.1%	3.3%	3.4%	0.3%	**23.8%**
Warehouse			0.6%				0.6%	22.6%											**23.8%**
Engineering - Execution	0.2%	0.2%	0.1%					7.1%								7.8%	8.0%	0.1%	**23.5%**
Engineering - Planning	0.4%	0.3%	0.4%			0.0%		19.3%						0.0%		1.4%	1.7%	0.2%	**23.8%**
Engineering - Manager	0.1%	0.1%	0.3%					21.4%						0.1%		0.9%	0.9%	0.1%	**23.8%**
Asset Management								23.8%											**23.8%**
Inspectors								3.0%								10.3%	10.3%		**23.5%**
Contractors -Full Time	2.9%	2.5%	1.8%					16.7%											**23.8%**
Const. Contractor - Plant Reliability	3.2%	3.2%	5.1%						0.8%	0.8%	0.8%	0.8%	0.8%	1.6%	0.8%	2.1%	1.3%	2.4%	**23.8%**
Const. Contractor - Engineering Execution																11.9%	17.9%		**29.8%**

About DNV

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ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers and Exporters ("CME")

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, pp. 13 of 31

At pp. 13, EGI stated "Through such assessment the Company has identified serious and increasing obsolescence and reliability risks associated with CCS compressor units K701-K703 and K705-K708. This is due to both the amount of repair downtime experienced and system shortfall that could result from their failure considering the Company's dependence upon these facilities to meet peak design conditions."

Question:

a) Please describe EGI's risk analysis process fully. For instance, does EGI use a risk assessment that employs likelihood of occurrence x impact of occurrence = risk, or another metric to evaluate risk.

b) As CME understands it, the risk represented by the compressors at issue would have increased steadily as the assets aged and through wear and tear. Please describe whether there is an objective risk level where EGI determined the risk was too high and replacement was necessary.

c) If the answer to (b) is yes, please identify the level of risk that EGI determined was needed before the project was warranted.

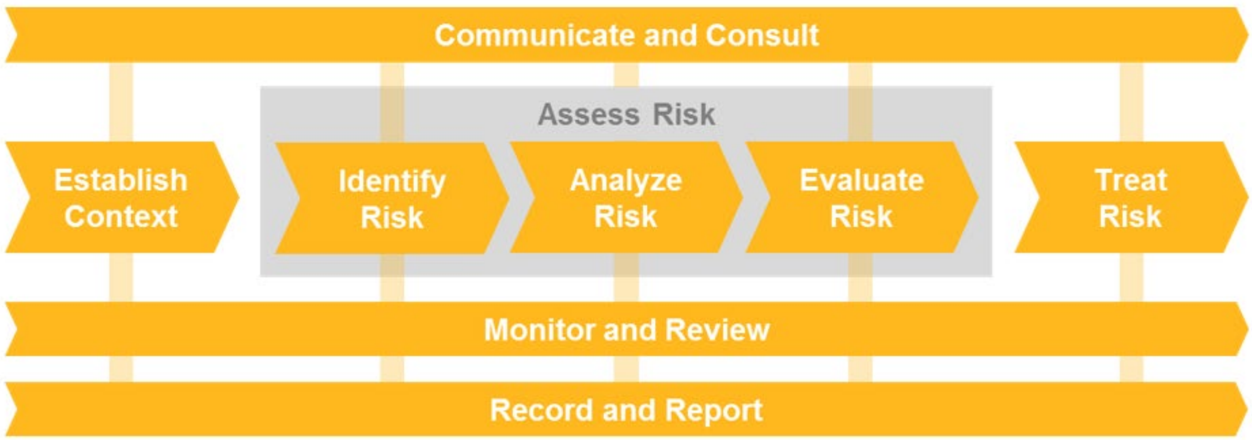
d) If the answer to (b) is no, please provide the subjective reasons why EGI determined that the risk was too high in 2022 rather than earlier or later.

Response

a) A description of Enbridge Gas's Risk Management and Risk Assessment Processes, which includes assessment in terms of likelihood and impact of occurrence, is set out below:

Enbridge Gas Risk Management and Risk Assessment Processes
Enbridge Gas follows a Risk Management process consistent with *ISO 31000* (see Figure 1), to assess, prioritize and treat risks.

Figure 1: Enbridge Risk Management Process



Establish Context
Enbridge Gas manages risks in the following categories:

- **Employee and Contractor Health and Safety**: Level of injury or illness and number of employees impacted.
- **Public Health and Safety**: Level of injury or illness and number of people in general public impacted.
- **Environmental**: Breadth and severity resulting in environmental damage/impact.
- **Financial**: Level of financial impact.
- **Operational**: Length of time and breadth of impact on utility and transportation customers and diversion of resources.
- **Reputational**: Level of media coverage, impact on customers, potential penalties, or impact on ability to operate due to compliance issues.

Identify Risk
Operational hazard and risk identification occur throughout the asset life cycle and are identified through:

- **Internal sources** such as databases, frontline processes, targeted reviews, assessments, and meetings.

- **External sources** such as published industrial incidents, industry-related publications distributed by regulatory bodies and industry associations, local governments, external crime statistics, industry standards and accepted best practices.

Analyze Risk
Risk factors in terms of likelihood and consequence of impact are analyzed and assessed. The commonly used types of risk assessments are quantitative, semi-quantitative and qualitative, each of which are described in Table 1 below. The selection of the approach to assessment is dependent on the scope of the assessment, maturity of risk assessment technique, best available data and information at the time of the assessment, and the types of assets.

Table 1: Risk Assessment Types

Type	Description	Application
Qualitative Approach	General and/or structured brainstorming with a multidisciplinary team to identify and evaluate risks. Relies mainly on qualitative inputs such as expert judgment, experience, and technical knowledge.	Used to identify and understand risk factors.
Quantitative Approach	Detailed technical assessments that leverage numerical data and mathematical methods to quantify risks.	Applied to contexts which are well understood and where numerical data and mathematical models can be used to quantify risk factors.
Semi-Quantitative Approach	Relies on qualitative inputs, such as expert judgment, experience and technical knowledge, as well as numerical data and mathematical methods to evaluate risk.	Applied to contexts which are relatively well understood but not all risk factors can be quantified.

Evaluate Risk
In order to provide clear guidance on prioritizing resources and managing risks, the Enbridge Gas Risk Evaluation Framework set out in Exhibit B, Tab 1, Schedule 1, Figure 3 is used. This framework ensures that resource allocations are prioritized to

higher risks to ensure safe and reliable operations. It also ensures the ability to demonstrate that all reasonable measures have been undertaken to reduce risk.

As Enbridge Gas evolves its risk management practices, two approaches for risk evaluation have been adopted from industry best practices:

(i) The Enbridge Gas Risk Matrix (see Figure 4 below, where the Y-axis indicates likelihood and the X-axis indicates consequence); and
(ii) risk thresholds (upper and lower thresholds) as illustrated in Exhibit B, Tab 1, Schedule 1, Figure 3.
(iii)

Figure 2: Enbridge Gas Risk Matrix

In most cases, risks are estimated in terms of likelihood and consequence and results are plotted on the Risk Matrix. The Enbridge Gas Risk Evaluation Framework and the Enbridge Risk Matrix are complementary and support risk informed decision making.

Where there is a need to understand safety risks due to potential for release of hazardous materials such as flammable and toxic material and their intersection with the public and employees,[1] risk quantification can be applied (provided there are data and analytical techniques to allow for this).

[1] Also known as catastrophic/rare events.

Safety risk evaluation criteria proposed by the Risk Management Task Force ("RMTF") formed by the CSA under the Technical Committee for the Z662 - Standard on the Oil and Gas Pipeline System[2] (the criteria were included in the 2023 version of Z662 which was out for public review early this year) and criteria adopted by BC Oil & Gas Commission[3] and UK Health & Safety Executive[4] ("UK HSE") are used for this type of assessment. This approach is also in use at a major North American energy company.[5] These criteria are represented by lower and upper thresholds as shown in the Enbridge Gas Risk Evaluation Framework.

While the Risk Evaluation Framework can support treatment prioritization and risk reduction, ultimately, the actions Enbridge Gas takes to address specific risks is informed by many factors, including but not limited to: business environment, regulatory requirements, planning horizon and strategy, financial consequences, commercial impacts, stakeholder impacts, and the quality and maturity of risk assessment data and capabilities. The risk assessment and decision to treat a risk are inputs to the Asset Investment Planning and Management process (as described in Exhibit B, Tab1, Schedule 1, Paragraph 49).

Treat Risk
Risk treatment is the modification of identified risks, ranging from day-to-day operational activities undertaken by operators and field personnel to inspect equipment, to a large capital project required to replace an existing asset.

Figure 5 below, lists the risk treatment options used at Enbridge Gas. The maintenance strategy for a facility or asset is established based on operating standards requirements, the outputs of a reliability centered maintenance study, or original equipment manufacturer ("OEM") recommendations. These risk treatment options are considered in the Asset Investment Planning and Management process.

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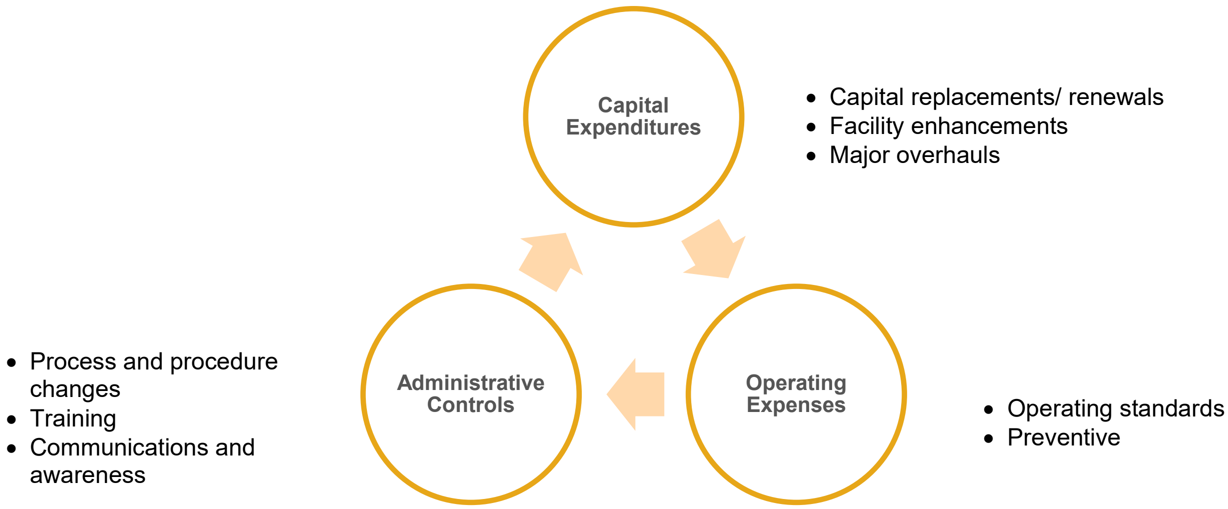
[2] Nessim, Maher, Kariyawasam, Shahani, "Safety Risk Acceptance Criteria For Pipelines", Proceeding of the 2020 13th International Pipeline Conference IPC 2020-9274, Calgary, AB, September 28-30, 2020.
[3] British Columbia Liquefied Natural Gas Facility Regulation
[4] UK Health & Safety Executive, "Reducing risks, protecting people – HSE's decision-making process", 2021.
[5] Tomic, Aleksandar, Kariyawasam, Shahani, "Critical Review of Risk Criteria for Natural Gas Pipelines", Proceeding of the 2016 11th International Pipeline Conference IPC 2016-64356, Calgary, AB, September 26-30, 2016.

Figure 3: Spectrum of Risk Treatment Options



Monitor and Review Risk
Enbridge Gas maintains a risk register to communicate and review all operational risks. Risks are regularly reported and reviewed through a risk reporting process.

b) – d)
As indicated in Exhibit B, Tab 1, Schedule 1, Paragraph 24, an Asset Health Review ("AHR") was performed in 2018 and updated in 2021, which indicates that the health and maintainability of certain compressor units at the CCS are in decline.

A RAM study was subsequently conducted by Enbridge Gas to quantify the likelihood of CCS failure to meet the operational objectives or demands placed on it and to estimate the impact of such failure in terms of resulting shortfall compared to an expected or target demand (see Exhibit B, Tab 1, Schedule 1, Attachment 2, Paragraphs 24 and 38 – 46).

The Enbridge Gas Risk Matrix was used to evaluate the risk identified through the AHR and RAM study. Enbridge Gas determined that the identified risk is ranked High in terms of financial impact, requiring Enbridge Gas to establish a treatment plan.

Additionally, based on the CCS site-wide Quantitative Risk Assessment (Exhibit B, Tab1, Schedule 1, Paragraphs 47-53),which assesses employee safety risks due to major loss of containment events by quantifying likelihood, impact and subsequent risk of loss of containment events to employees, some individuals are exposed to risks in Region 1 (above the upper risk threshold as illustrated in the Risk Evaluation Framework set out at Exhibit B, Tab 1, Schedule 1, Figure 3) and as a result a treatment plan is required to reduce this risk.

Based on the results of these assessments as well as further factors discussed in detail within Exhibits B and C, Enbridge Gas has concluded that the Project is the preferred alternative to address known risks.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers and Exporters ("CME")

INTERROGATORY

Reference:

Exhibit C, Tab 1, Schedule 1, Attachment 2, p. 6.

At p. 6, ICF indicated that "Enbridge is proposing to replace this capacity by construction of a new 36-inch diameter steel pipeline between the Corunna Compressor Station in St. Clair Township and the Dawn Operations Centre in the Township of Dawn-Euphemia."

Question:

a) Given that ICF completed its report with EGI's proposed solution in mind, did EGI complete its own internal review of options to determine that it preferred the NPS-36 pipe prior to receiving ICF's analysis?

b) If the answer to (a) is yes, please provide any internal studies or analysis completed by EGI in this regard.

c) Please provide any materials related provided to EGI's board of directors with respect to its own analysis or review of potential options.

Response

a) & b)
Early assessments were completed and information was given to ICF to permit consideration of the base facility solution. However, Enbridge Gas continued its assessment of alternatives (facility and non-facility) after engaging ICF, and subsequently drew the conclusions set out in Exhibit C which take ICF's assessment into consideration.

c) Please see the response at Exhibit I.SEC.1.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers and Exporters ("CME")

INTERROGATORY

Reference:

Exhibit C, Tab 1, Schedule 1, Attachment 2, p. 9.

At p. 9, ICF explained that EGI considers the replacement of firm delivery lost is mandatory in order to maintain the safety and reliability of the system. ICF also explained that EGI considers storage space to be optional. ICF notes that storage space however also increases flexibility and reliability.

Question:

a) If both firm delivery and storage space increase reliability, please explain why some benefits to reliability are considered mandatory and others are considered optional.

b) What impact does the deferral of significant capital spending, such as the $18.3 million underspend in 2021 due to, inter alia, delays in larger projects, have on the project prioritization process going forward?

Response

a) ICF states that replacing the deliverability of gas supply lost due to the retirement of the compressors is mandatory because the system deliverability is still needed to meet expected demand. ICF also states that storage capacity space offers more reliability than other firm delivery options like contracting with pipelines or marketers. ICF does not state that some benefits of reliability are mandatory or optional.

b) Enbridge Gas is uncertain as to the source of the $18.3 million referred to by CME.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Canadian Manufacturers and Exporters ("CME")

INTERROGATORY

Reference:

Exhibit C, Tab 1, Schedule 1, Attachment 2.

In its report, ICF included a number of calculations with respect to the cost of various alternatives.

Question:

a) Did ICF calculate the various monetary figures in its report, or was it provided with any by EGI.

b) To the extent that the answer to (a) is yes, please identify which figures were provided by EGI and which were calculated by ICF.

Response

a) & b)
ICF calculated all of the monetary figures associated with the cost of alternatives to the Project, based on information and data received from Enbridge Gas and publicly available data.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence ("ED")

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1

Question:

a) Please fully describe the assumptions and criteria for a "storage design day" referred to on page 8.

b) Please provide a table comparing the assumptions and criteria for a storage design day with the respective planning design days for the Enbridge rate zone and the Union rate zone.

c) Page 10 states: "an Asset Health Review ("AHR") was performed in 2018 and updated in 2021 (as part of the Company's comprehensive Reliability, Availability and Maintainability ("RAM") Study for the CCS, which was completed by DNV)." Please file this.

d) Per page 14: "Enbridge Gas is currently managing component availability via internally stocked critical spares, where deemed necessary and feasible." Please provide a list of this stock of critical spares. Please estimate the cost to double the stock of critical spares.

e) Per page 14: "On design day or peak storage withdrawal day, if any 1 of the 10 operating CCS units is out of service for a prolonged period of time and replaced in function by K711, no LCU unit would be available should another unit be lost." Please approximately define "prolonged time" in hours and/or minutes. Please list all the instances in which 2 of the 10 operating CSS units were out of service but exclude planned outages for maintenance.

f) Please provide a table listing the volume of gas provided at the peak and annually from each of the following units assuming they were running at full capacity: K701, K702, K703, and K711.

g) Per page 15: “In Enbridge Gas’s experience, the OEM is increasingly challenged to supply parts in a timely manner for units K705-K708.” Please estimate the cost of acquiring the same stock of critical spares as Enbridge has for K701-K703.

h) Per page 16: “For example, during withdrawal season, using the last 10 years of Dawn pricing data across January, February, and March, the loss of an additional CCS unit on a peak winter day (in addition to K705) would have ranged in cost for delivered supply between approximately $800,000 to $11 million for a single day.” Please provide the underlying calculations. Is this the total cost of the delivered supply or the incremental cost of the delivered supply in comparison to supply from storage? Please provide the incremental cost.

i) Per page 17: “Further, as CCS compressor units K705-K708 are of similar makes and models (KVR) as the remaining CCS units (K704, K709, K710 and K711)… By disassembling units K705-K708, salvaging interchangeable spare parts, and storing them within the Company’s inventory for future use, the risk of experiencing extended downtime for future repairs to those units (as well as the cost of the same) is expected to be significantly mitigated.” Has Enbridge explored purchasing a compressor of similar make and model (KVR) that is no longer in use from another utility for spare parts?

j) Are any compressors of a similar make and model (KVR) present in the Enbridge system? If yes, please provide the number and where they are located.

k) Are any compressors of a similar age as K701-K703 present in the Enbridge system? If yes, please provide the number and where they are located.

l) Are any compressors of a similar age at K705-708 present in the Enbridge system? If yes, please provide the number and where they are located.

m) Per page 19: “Results for compressor units K701-K703 and K705-K708 indicate that both engine and compressor failures are expected to occur within 2 years for all units.” Please provide a list of all the compressor failures for these units that have occurred, the date they occurred, and the time it took to fix them.

n) Per page 23: “To fully understand the risks to employee health and safety resulting from and the drivers for such events, Enbridge Gas conducted a CCS site-wide QRA that applied industry best practices (as recommended by DNV).” Please provide a copy of the report or reports generated through this assessment.

o) Per page 35: “The results also indicate that in terms of specific areas within the CCS site, risks are concentrated in compressor buildings 1 and 2, with building 1 having the highest risk.”

Please provide a list of the buildings and which compressors are housed in each building,

p) What is the safety risk of having compressor units in close proximity? Is the concern that a unit will explode while staff are working on the neighbouring unit? Can this be mitigated in part by having greater redundancy (e.g. adding a compressor), so a unit can be shut off if staff are working adjacent to it?

q) Does Enbridge have other locations that include “multiple compressor units in close proximity within a single building”? If yes, how many and where?

Response

a) & b)

The storage design day assumptions for the EGD rate zone are as follows:

1. Occurs at the end of February;
2. 43.5 PJ of gas is held in storage to provide 1.89 PJ/d of deliverability for in-franchise customers;
3. Ex-Franchise customers are at minimum inventory and maximum associated deliverability as per contract;
4. K711 used to provide LCU; and
5. TR1, TR2 and TSLE are delivering to 4,826 kPa at Dawn.

In comparison, the storage design day assumptions for the Union rate zone are as follows:

1. Occurs at the end of February;
2. In-Franchise demands are based on a 43.1 degree day with interruptibles off;
3. In-Franchise storage inventory is determined by Gas Supply;
4. Supplies are arriving at Dawn at contract pressure;
5. Ex-Franchise customers are at minimum inventory and maximum associated deliverability as per contract; and
6. G Plant used to provide LCU.

In addition to the storage design day assumptions above, Table 1 contains the delivery area degree day temperatures used to plan design days for transmission and distribution systems:

Table 1

Delivery Area	Weather Station	Design Heating Degree Days Assumption
Enbridge CDA	Toronto	41.4
Enbridge CDA	St. Catharines	38.8
Enbridge EDA	Ottawa	48.2
Union MDA	Fort Frances	54.7
Union WDA	Thunder Bay	51.6
Union SSMDA	Sault Ste. Marie	48.2
Union NDA	Sudbury	51.9
Union NCDA	Muskoka/Gravenhurst	49.3
Union EDA	Kingston	47.1
Union South	London	43.1

c) The RAM Study was filed as part of Enbridge Gas's pre-filed evidence at Exhibit B, Tab 1, Schedule 1, Attachment 2. The AHR is set out at Attachment 1 to this response.

d) & g)
Attachment 2 contains a listing of critical spare parts currently in inventory.[1]
The inventory of components provided in Attachment 2 is considered critical based on the designation provided in MAXIMO, as determined by subject matter experts (lead mechanic and reliability manager) at the time of creation of the list. The designation considered: (i) items with a lead time greater than 10 days and; (ii) all spares required to build one unit (Engine and Compressor) needed to be stocked (mainly Dresser Rand or Ingersoll Rand specific parts) less a crankshaft.

Some forged and casted components of the CCS compressor units that are the subject of this Application are no longer stocked in inventory by the Original Equipment Manufacturer. If required, these parts would need to be sourced, forged or casted, custom machined and polished to meet specifications. For example, crankshafts are not stocked in Company inventory because of the complexity of storing such parts long-term, and the fact that their size and shape is not commonly compatible across all CCS compressor units. Frames are another item not stocked

[1] Please note that Attachment 2 does not represent a comprehensive list of all spare parts that may be considered critical.

in inventory and if seriously damaged a used frame would need to be procured or the entire unit would be unusable.

Availability of component pricing is limited to the data available in MAXIMO. Where documented, the last purchase price of the component has been extracted and per unit pricing is available for 275 of the 448 items listed in inventory. The estimated value of the current inventory based on the last purchase price is $3.8 million. In the absence of pricing for a large number of components and given the recent changes in market dynamics for components, a cost estimate to double the current inventory stocked is not readily available.

Parts listed in the table are often compatible across several units. However, parts stocked for CCS compressor units K701-K703 are not necessarily compatible with CCS compressor units K705-K708.

e) Enbridge Gas designs its storage and transmission systems to include LCU to ensure that all firm demands are met in the event of an unplanned compressor outage. LCU is designed and sized to provide spare horsepower for the single biggest compressor at station. Enbridge Gas has LCU at major stations including CCS, Dawn and the Dawn to Parkway system, but does not have LCU providing backup for all storage units such as remote storage units. The importance of LCU was most recently discussed in EB-2012-0433 where the OEB found that Enbridge Gas's evidence supported the need for the Parkway West project as it provided LCU at Parkway where LCU did not previously exist.

   While the Company designs LCU based on design day and holds compression in reserve, it will operate the LCU as required across the season to support system need during times of maintenance and construction. A prolonged outage at CCS during peak period is longer than 7 days, however, the goal is to return compression to service as quickly as possible.

   Please see the gantt chart set out at Exhibit I.PP.5 Attachment 1, for the timeframe and overlap of unplanned outages since 2016.

f) The design day flow for each of the units requested is shown in Table 2 below.

   It is not possible to provide a meaningful estimate of annual flow capacity for each unit. Enbridge Gas does not forecast annual utilization of specific compressors as there are many combinations/configurations possible that can meet specific operating scenarios. Enbridge Gas plans compressor availability around operational needs to ensure storage pools can be filled and emptied.

Accordingly, Table 3 illustrates a typical flow for injection (suction pressure = 4,482 kPa, discharge pressure = 7,584 kPa) and withdrawal (suction pressure = 3,447 kPa, discharge pressure = 5,516 kPa) to provide comparative flows between the units.

Table 2

Unit	Design Day Flow (TJ/d)	Typical Flow During Injection Season (TJ/d)	Typical Flow During Withdrawal Season (TJ/d)
K701	139	89	92
K702	139	89	92
K703	139	89	92
K711	0	143	157

h) The cost range presented represents the total daily cost of the gas commodity that would be required to meet the shortfall resulting from the loss of an additional CCS unit (in addition to K705). As per the Compression – peak compression operating mode in Table 4.1 of the RAM Study (EB-2022-0086, Exhibit B, Tab 1, Schedule 1, Attachment 2, p. 16), the failure of a second CCS compressor unit would result in a shortfall ranging from 4,814 - 7,362 $10^3m^3/d$ (172,400 – 263,700 MMBtu/d) depending on the unit lost. The incremental cost of the delivered supply over the cost of the gas in storage is not relevant because in the event of an unexpected loss of a second CCS unit, Enbridge Gas would be unable to access the gas in storage to meet the immediate customer needs and would therefore need to replace the entire quantity. While the gas in storage may become available once the compressor outage has been resolved, it is likely this would be after an extended period of time.

The upper end of cost estimate was calculated by multiplying the average of the highest settlement price at Dawn over the past 10 years occurring in the months of January, February, and March by the potential shortfall from the loss of one of the larger CCS units (K709 or K710) of approximately 263,700 MMBtu/d for a result of approximately $8,678,000 USD (~$10,934,000 CAD) per day.[2]

The lower end of the cost estimate was calculated by multiplying the average settlement price at Dawn over the past 10 years occurring in the months of January, February, or March by the potential shortfall from the loss of one of the smaller CCS

[2] Average of January high price ($27.93 US/MMBtu), February high price ($29.10 US/MMBtu), and March high price ($41.69 US/MMBtu) = $32.91 US/MMBtu

units (K701, K702, K703) of approximately 172,400 MMBtu/d for a result of approximately $660,000 USD (~$832,000 CAD) per day.[3]

The actual price paid for gas commodity that would be required to meet a shortfall resulting from the loss of a CCS unit is dependent upon natural gas market supply and demand dynamics at the time of occurrence, including natural gas production levels, North American natural gas storage inventories, transportation capacity availability/outages, weather, LNG export demand, etc.

i) Enbridge Gas has not explored purchasing a "surplus" spare compressor of similar make and model ("KVR") that is no longer in use from another company for spare parts for a variety of reasons, including:
   - Any such compressor unit would be nearing the end of its useful life (would have a similar vintage) and would bring with it decades of unique operational issues that may not be easily identifiable through physical inspection or review of maintenance records.
   - In Enbridge Gas's experience, many such units available from companies across Canada and the US have operated for as many if not more hours than the CCS compressor units.
   - The potential extension of time afforded through the acquisition of such a unit would likely be limited as it could only provide a single set of additional spare parts at best (in the worst case some salvaged parts might not be suitable for continued use in Enbridge Gas compressor units).

j) There are no other KVR compressors present in the Enbridge Gas system.

k) & l)
Please see the response at Exhibit I.EP.8, for a list of Corunna Compressor Station compressors, and the response at Exhibit I.STAFF.2 c), for a list of reciprocating compressor units at other Enbridge Gas stations.

m) Please see the response at Exhibit I.PP.5 a).

n) Please see the response at Exhibit I.CME.1.

o) Please see Exhibit B, Tab 1, Schedule 1, p. 6, Para. 15.

p) Explosion is one of the safety risks that can potentially impact personnel. Other safety risks include release of fire and/or gas.

[3] Average of January average price ($3.44 US/MMBtu), February average price ($4.33 US/MMBtu), and March average price ($3.72 US/MMBtu) = $3.83 US/MMBtu

Adding a redundant compressor on its own would not in itself ensure the reduction of risk to an acceptable level. While this would in theory allow for one of the other units to be shut down to reduce risk exposure to workers in that building, the operational status of the other units in the building where the work is occurring needs to be considered. In the response at Exhibit I.ED.10 c), various permutations of unit retirements have been considered and it is shown that the retirement of 5 units (see Option 7 in that response) still exceeds the upper risk threshold for several worker groups. As discussed in the response at Exhibit I.SEC.13, there are significant economies of scale that result from replacing all 7 of the CCS units, making this the lowest cost alternative capable of eliminating the identified risks.

q) Yes. The following sites include multiple units housed within a single building:

- Hagar LNG Facility (2 units)
- Sombra Compressor Station (3 units)
- Oil Springs East Pool Site (2 units)
- Dawn F Plant (2 units)
- Tipperary Pool Site (2 units)

As a follow up to the CCS QRA, a number of other sites that share the common characteristics of high density of equipment, multiple units in a single building and higher levels of worker occupancy were identified for further study. These sites were prioritized for analysis and the Hagar LNG Facility was identified as the site with the greatest potential risk. Through a very similar analysis of process safety risk QRA it was found that the Hagar site has a risk level that is considered acceptable and as a result there are no immediate risk reduction measures requiring capital investment at this time, the same follows for the other sites listed above since they have a lower potential risk.

Asset Sub-Class	Applicable Failure Mode	Model Parameters		Comments
		β	η (hr)	
Foundation	Degradation	3.3	93034	K701-K711 failures were used
Crankshaft	Misalignment	2.3	54729	K701-K711 failures were used
Engine(K701-708 & K711, K6,K8,K9)	Critical Component Failure	1.49	10596	K704 and K711 Failures concatenated and modelled as one unit
Engine(K709 & K710)	Critical Component Failure	2.34	15338	K709 & K710 failures were used
Compressor(K701-708 & K711, K6,K8,K9)	Critical Component Failure	1.4	6042	K704 and K711 Failures concatenated and modelled as one unit
Compressor(K709&710)	Critical Component Failure	2.03	3365	K709 & K710 failures were used
AfterCooler	Component Failure	1.35	8683	K704 and K711 failures concatenated-RunHours were shifted 22628
Heating & Cooling System	Component Failure	1.1	23034	K701-K708Concatenated with K711-RunHours were shifted 19462
	Glycol Leak	1.37	5207	K704 and K711 failures concatenated-RunHours were shifted 22628
Valving System	Actuator/Leak/Failure to Operate	1.54	7520	K704 and K711 failures concatenated and modelled as one unit

Unit#	Current RunHour (1/1/2021)	Average 5-Year Run Hours	AHR - Inst. MTBF (based on units actual run hours)						
			Foundation	Crank Assembly	Engine	Compressor	Aftercooler	Heating & Cooling System	Valve System
K701	89986	788	6143	9790	1097	1135	3245	1669	1710
K702	82371	657	24971	8765	1033	1069	3263	1629	1693
K703	86022	870	22685	8402	1167	1202	3334	1737	1789
K704	123310	2680	4938	9575	3740	3061	4104	2937	2920
K705	105714	2699	56762	54729	2917	2778	4243	2992	2993
K706	94981	1860	57121	24124	2279	2057	3808	2367	2390
K707	107019	2807	56717	21202	3006	2877	4304	3079	3078
K708	115773	3631	30908	19664	3728	3657	4811	3780	3773
K709	37614	1092	52669	23596	2530	1092	4403	2272	2626
K710	40145	750	45780	29445	2184	752	4139	2036	2365
K711	80805	3140	38882	6406	4482	3594	4772	3432	3474

Asset Subsystem	Failures Considered in AHR
Foundation	- Degradation
Crankshaft	- Crankshaft misalignment - Main bearing failure (wiped out)
Engine	- Failure in critical components e.g. connecting rod, piston, cylinder, and valvetrain assemblies
Compressor	- Failure in critical components e.g. connecting rod, crosshead, piston, and cylinder assemblies
Gas AfterCooler	- Component failure
Heating & Cooling Systems	- Component failure - Glycol leak
Valving System	- fail to operate - Leak

Unit#	Current RunHour (1/1/2021)	Assumed 2000 Annual RunHour	AHR - 2021 Storage Asset Health Index (over a 2000 hr mission time)						
			Foundation	Crankshaft	Engine	Compressor	AfterCooler	Heating & Cooling System	Valving System
K701	89986	2000	SHI2 (5000-10000hrs)	SHI2 (5000-10000hrs)	SHI5 (<=2200hrs)	SHI5 (<=2200hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)	SHI4 (2200-3000hrs)
K702	82371	2000	SHI1 (>10000hrs)	SHI2 (5000-10000hrs)	SHI5 (<=2200hrs)	SHI5 (<=2200hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)	SHI4 (2200-3000hrs)
K703	86022	2000	SHI1 (>10000hrs)	SHI2 (5000-10000hrs)	SHI5 (<=2200hrs)	SHI5 (<=2200hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)	SHI4 (2200-3000hrs)
K704	123310	2000	SHI3 (3000-5000hrs)	SHI2 (5000-10000hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)	SHI4 (2200-3000hrs)
K705	105714	2000	SHI1 (>10000hrs)	SHI1 (>10000hrs)	SHI4 (2200-3000hrs)	SHI5 (<=2200hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)	SHI4 (2200-3000hrs)
K706	94981	2000	SHI1 (>10000hrs)	SHI1 (>10000hrs)	SHI4 (2200-3000hrs)	SHI5 (<=2200hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)	SHI4 (2200-3000hrs)
K707	107019	2000	SHI1 (>10000hrs)	SHI1 (>10000hrs)	SHI4 (2200-3000hrs)	SHI5 (<=2200hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)	SHI4 (2200-3000hrs)
K708	115773	2000	SHI1 (>10000hrs)	SHI1 (>10000hrs)	SHI4 (2200-3000hrs)	SHI5 (<=2200hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)	SHI4 (2200-3000hrs)
K709	37614	2000	SHI1 (>10000hrs)	SHI1 (>10000hrs)	SHI4 (2200-3000hrs)	SHI5 (<=2200hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)	SHI3 (3000-5000hrs)
K710	40145	2000	SHI1 (>10000hrs)	SHI1 (>10000hrs)	SHI4 (2200-3000hrs)	SHI5 (<=2200hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)	SHI4 (2200-3000hrs)
K711	80805	2000	SHI1 (>10000hrs)	SHI2 (5000-10000hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)	SHI3 (3000-5000hrs)	SHI4 (2200-3000hrs)	SHI4 (2200-3000hrs)

AHR Analytics and Modelling

October 1, 2021

Report

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Company: Enbridge Gas Distribution

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AHR Analytics and Modelling

Purpose/ Model Objectives

The document will outline the data used and analysis completed for each asset sub-class in the AHR to determine the population, failure history and modelling parameters for the respective asset sub-class.

Stakeholders

During the course of the development of the AHR modelling, these departments were consulted

- Operations – Model Input
- Asset Management – Model Input
- Asset Intelligence – Model Input
- Distribution System Integrity (DSI) – Sign Off
- Facilities Integrity Management Program (FIMP) - Update
- Risk Management – Model Input

Model input stakeholders were engaged at the beginning of the modelling process. The active asset population used with the AHR for failure projections and condition assessment is provided by Asset Intelligence and is derived from the Data Requirements documentation owned by Asset Intelligence. Asset Intelligence, Risk Management and Asset Management were engaged as part of the AHR modelling peer review. Sign-off of the AHR models will be completed by DSI.

Responsibilities

The following table lists the individuals and groups affected by this document and what their accountabilities are in regards to this document. For full details of the roles and responsibilities please refer to the Integrity and Asset management RACI.

Table 1: Table Title

GROUP	ACCOUNTABILITIES
Operations	• Provide input into the population, failure mechanisms and model factors
Asset Management	• Utilize the AHR models for asset management and planning
Asset Intelligence	• Provide population and failure data for use in the AHR models, maintains data Requirements documentation
DSI	• Perform AHR modelling
FIMP	• Update AHR calculations
Risk Management	• Utilize AHR modelling in risk calculation.

Terms and Definitions

The following is a list of terms found in this document and their definitions.

TERM	DEFINITION
Final Year of Analysis	Denotes that the year to be utilized should be that where final full year of failure data is available. When completing statistical modelling, utilizing the present year may add extra survival time to the assets during analysis which would skew the results.
Factors – Unclassified value	Assets with unclassified values for a particular factor were not given the scaling factor in the modelling. Example: Area 10 Stoniness Classification is "unclassified" for all assets. No Area 10 PE services is given a Rock Impingement factor value.

Model/Analysis Methods

Storage - Station Compressors

A. Population

The AHR is developed using the population and failure data of SCOR units due to the availability of failure data in Maximo, as well as their relative significance, influenced by both available power and the extent to which the compressors are employed. Although only SCOR compressors are currently included in the scope for the AHR, other stations will be considered for future inclusion in the AHR, if data becomes available.

A summary of SCOR integral engine compressors characteristics is presented in **Table** . In compressor stations, the operating hour is used as the age attribute, indicating the time each unit has been operating since installation. This specification is available within the nSoda data system for each SCOR unit and for any date after June 2009 (nSoda has been in service since June 2009). The rest of population data, such as installation dates and engine models, are extracted from historical documents.

Table 5 – SCOR Compressors Characteristics

STATION NAME	COMPRESSOR UNIT	INSTALL YEAR	ORIGINAL ENGING MODEL	CURRENT ENGINE MODEL
Corunna (SCOR)	K701	1964	KVT	KVTR
	K702	1964	KVT	KVTR
	K703	1964	KVT	KVTR
	K704	1968	KVR	KVR-Lean Burn
	K705	1970	KVR	KVR-Lean Burn
	K706	1972	KVR	KVR-Lean Burn
	K707	1973	KVR	KVR-Lean Burn
	K708	1974	KVR	KVR-Lean Burn
	K709	1980	KVR	KVR-Lean Burn
	K710	1983	KVR	KVR-Lean Burn
	K711	1995	KVR-Lean Burn	KVR-Lean Burn

All compressor asset sub-classes have the same run hours as compressor units. As the failure data is available up to May 2016, this date was established as the end date in the modeling analysis for the 2017 AHR report. The run hours for each unit are extracted from nSoda. For future year the final run time will be taken from the final year of analysis.

SCOR compressor units operate for different hours in a given year. However, to be able to compare the condition between units, an average operating hour of 2,000 run hours per year is assumed for each unit based on SMA input. The average operating hour of 2,000 run hours per year are used in asset sub-classes conditional reliability, conditional failure intensity, and Storage Health Index. However, the actual units run hours, are used in failure projections.

B. Failure Data

The Maximo data system is used to extract all work orders associated with SCOR units. This extract is limited to events or failures that occurred after Maximo came into service in 2001 and up to May 2016 for the 2017 AHR report and the final year of analysis for future modelling. It includes work orders of all preventative maintenance inspections, planned capital projects or overhauls, and unplanned failures that occurred within EGS.

The historical documents reveal that SCOR compressors have had failures and events even before Maximo, which are not recorded in Maximo. A record of historical failures of Corunna compressors is available today but it only includes major and critical repairs on engines, compressors, foundations, crankshafts, and main bearings.

A review of the Maximo extract revealed that only 9,831 of the work orders are related to Corunna station compressors. These work orders were not classified for the purpose of the AHR and required extensive post processing of the data to determine the SCOR compressor unit number, key compressor asset sub-classes and defined failure modes, as shown in **Table** .

The failures used in the modeling analysis include all unplanned failures/events, as well as the ones captured during maintenance inspections and overhauls.

Table 6 – Storage Compressor Key Asset Sub-classes and Associated Failure Modes

ASSET SUB-CLASS	COMPONENTS	FAILURE MODE	FAILURE MODE DESCRIPTION
Foundations	N/A	Degradation	Any work orders stating or indicating the foundation settling, degradation, or repair.
Crank Assemblies	Crankshaft	Misalignment	Any work orders stating or indicating the crankshaft misalignment such as bent crankshaft or bad readings in web deflection.
	Main Bearings	Component Failure	Any work orders stating or indicating main bearing component failure, such as main bearing high temperature or replacement.
Engines	Connecting Rod Assembly	Component Failure	Any work orders indicating a replacement in critical

	Piston/Cylinder Assembly	Component Failure	components, such as any components in connecting rod, piston/cylinder, and valvetrain assemblies.
	Valvetrain	Component Failure	
Compressors	Connecting Rod Assembly	Component Failure	Any work orders indicating a replacement in critical components, such as any components in connecting rod, crosshead, piston and cylinder assemblies.
	Crosshead Assembly	Component Failure	
	Piston Assembly	Component Failure	
	Compression Cylinder Assembly	Component Failure	
Gas Aftercoolers	All components	Component Failure	Any work orders indicating a component replacement
Heating and Cooling Systems	All Components	Component Failure	Any work orders indicating a component replacement.
		Glycol Leak	Any work orders indicating a glycol leak.
Valve Systems	All Components	Fail to Operate	Any work orders indicating a replacement or repair in any valve assembly components.
		Leak	Any work orders indicating an external gas leak.

The compressor failure data used in reliability modeling is comprised of pre-Maximo historical major failures and Maximo work orders data from 2001 to May 2016 for the 2017 AHR model and the final year of analysis for future modelling. As mentioned before, in order to use the available failure data in reliability analysis, additional post processing of the data is performed on the failure data including:

- Classification of the failure data to determine the failed compressor asset sub-classes and unit number, and to identify the associated failure mode.
- Identification of the failures related to key asset sub-classes that are in scope for the AHR for reliability analysis.
- Exclusion of duplicate work orders from the failure data.
- Determination of the run hours at failure for each failure datum, using available data sources such as nSoda and historical datasheets.

The final failure data used in reliability modeling analysis is outlined in **Table .**

Table 7 – Compressor Sub-classes Population and Failure Data Used in Reliability Modeling

POPULATION	FAILURE DATA

Station/Compressor Unit Number	Compressor Sub-system	Components	Failure Mode
SCOR K701-K711	Foundations	N/A	Degradation
	Crank Assemblies	Crankshaft	Misalignment
		Main Bearings	Component Failure
	Engines	Connecting Rod Assembly	Component Failure
		Piston/Cylinder Assembly	Component Failure
		Valvetrain	Component Failure
	Compressors	Connecting Rod Assembly	Component Failure
		Crosshead Assembly	Component Failure
		Piston Assembly	Component Failure
		Compression Cylinder Assembly	Component Failure
	Gas Aftercoolers	All components	Component Failure
	Heating and Cooling Systems	All Components	Component Failure
			Glycol Leak
	Valve Systems	All Components	Fail to Operate
			Leak

C. Model

All storage asset sub-classes are modeled as repairable assets, reflecting the intervention strategy. However, if an asset sub-class is replaced, the life of that asset is reset to zero. Depending on the failure data availability, the reliability modeling analysis is performed using different approaches for different asset sub-classes, as described below:

Foundations

The foundations failure data is available for all SCOR compressors since their installation. The NHPP power law function is used to model foundation failure/population data. Three failure factors, listed in Table 8, are applied to the foundation reliability model.

The foundation was replaced for some units such as K705, which resulted in a reset of the operating run hours to “0” at the time of replacement.

Crank Assemblies

For crank assembly modeling analysis, crankshaft misalignment events and main bearing component failures are analyzed together. According to the Storage Failure Mode and Effect Analysis (FMEA), main bearings failures are one of the causes of crankshaft misalignment. Therefore, these failures are modeled together, using the NHPP power law function. Three failure factors, listed in Table 8, are applied to the crank assembly reliability model.

8 – Modelling Factors

COMPRESSOR ASSET SUB-CLASS	CRITERION	FACTOR	UNITS AFFECTED	COMMENTS
Foundation	Previous frame alignment work orders	1.2	K704, K709, K710	Frame misalignment is a leading indicator of foundation degradation.
	Previous repairs	1.5	K701, K702,K703	Foundations with previous repairs are more susceptible to failure.
	Damages detected during visual Inspection	3.5	K701,K709,K710, 704	This multiplier substitutes for the unavailable condition assessment
Crank Assembly	Previous crankshaft Repairs	1.5	K702-K703, K706, K711	Bent crankshafts that have been repaired are more susceptible to failure.
	Frequent compressor starts and stops	1.5	K705-K708	Compressors with more starts and stops are more susceptible to crank failures.
		1.1	K701-K703, K709-K710	
	Compressor torque/load exceeds rating	2 (50% over rated load) 1.5 (30% over rated load) 1.1 (13% over rated load)	K711 K709 K706, K707, K708	Over-rated load/torque will apply extra stress on crankshaft and make it more susceptible to misalignment.
	Foundation Issues or Foundation Replacement	1.2 (experiencing issues) 1 (foundation and crank replaced) 0.3 (only foundation replaced)	K701 K705 K706, K707, K708	70% of crank misalignment is coming from foundation issues. misalignment wouldn't be an issue with new foundation

Engines

The engine reliability analysis is performed using failures associated with engine critical components such as connecting rods, pistons and cylinders, and valvetrain assemblies. As discussed before, the available engine failure data included the failures recorded in Maximo from 2001 and a few historical data related to major repairs performed on the compressor units prior to 2001.

As the historical data does not include critical component failures detected and repaired during inspections and overhauls, there is a gap in the failure data for compressors K701 to K708 that were operating for more than 60,000 run hours prior to the implementation of Maximo. Therefore, in order to be able to model the engine failure data, this gap issue had to be solved.

One approach to solve the data gap issue was to concatenate the K711 failures with the K704 failure data to provide a complete failure dataset for reliability modeling analysis. K704 and K711 both have similar compressor designs and were heavily operated since installation. K711 is the newest unit in Corunna station and its engine critical failure data is available from installation up to 67,482 run hours. On the other hand, K704 failure data is available from 71,948 run hours up to 112,361 run hours. Therefore, by concatenating the failure data of these two units, a complete failure dataset can be created for a typical unit (K704 or K711). This failure dataset was used to model reliability for the engine asset sub-class. This Approach is called “K704/K711 Failure Data Concatenation” and was verified by 3rd party technical review.

The engine model produced by the concatenation approach is applied to K701, K702, K703, K705, K706, K707 and K708 engines. However, due to the different makes and models of the SCOR engines, a factor is required during the development of the reliability models for each unit. Factors are added based on the actual number of each unit’s engine events compared to K704 events in a 10,000 run hour period. This actual number of engine events, in fact, represents the engine failure rate in that defined time period.

The reliability analysis for K709 and K710 engine asset sub-classes was performed using the failure data for these two units together.

Compressors

The compressor reliability analysis is performed on the failures associated with the compressor critical components such as connecting rods, crossheads, pistons and compression cylinder assemblies.

Similar to the engine asset sub-class, the “K704/K711 Failure Data Concatenation” approach is used to model reliability for K701, K702, K703, K705, K706, K707 and K708 compressors. However, due to the different designs and sizes of the compressors in SCOR units, a factor is required during the development of the reliability models for each unit. Factors are included based on the actual number of each unit’s compressor events compared to K704 or K711 events in a 10,000 run hour period. This actual number of compressor events, in fact, represents the compressor failure rate in that defined time period.

The reliability analysis for K709 and K710 compressor asset sub-classes are performed using the combined failure data for these two units. However, as the failure data was only available from 19,462 run hours in the final failure dataset, a “Run Hours Shifting” approach is used for these models, in which all failures were first shifted back for 19,462 run hours and then modeled.

Gas Aftercoolers

Similar to the engines and compressors asset sub-classes, the “K704/K711 Failure Data Concatenation” approach is used to model reliability for one typical SCOR gas aftercooler asset sub-class. Since the aftercoolers in all units have the same design, the developed reliability model is used for all aftercoolers.

Since K711 failures are only available in Maximo from 22,628 run hours, and the gas aftercooler failures that occurred prior to Maximo were not available, another additional approach is applied to handle missing early failures by shifting the failure time data before modeling it. In this approach, called “Failure Time Shift”, the first observed failure time in Maximo is assigned to a time of 0 run hours by subtracting the first failure time, (e.g. 22,628 run hours in the case of K711 failures). Subsequent failure times are also adjusted by simply subtracting 22,638 from the actual failure time. This approach was verified by 3rd party technical review.

Heating and Cooling System Glycol Leak

To model “Glycol Leaks” for the heating and cooling system, the “K704/K711 Failure Data Concatenation” approach is applied followed by the “Run Time Shift” approach.

Heating and Cooling System Component Failure:

Due to the small number of heating and cooling systems component failures associated with K704 and K711 units, a modified concatenation approach is used to model reliability for “Component Failure” in heating and cooling systems. In this approach, the K711 aftercooler failures are concatenated with the available K701 to K708 failure data to provide eight complete datasets for these units. These failure data sets are then added to K709, K710, and K711 failures. As the earliest available failure data was traced back to 19,462 run hours, the “Run Hours Shifting” approach is applied on the final failure data set before modeling it, in which all failures were first shifted for 19,462 run hours.

Valve System

The engine and compressor valve system reliability analysis is performed on leak and operational failures associated with valve systems for station units (i.e. unit and mode valves). As discussed previously, the failure data included the failures recorded in Maximo between 2001 and the final year of analysis.

Similarly, in order to minimize the impact of failure data gaps, failure data for units K711 and K704 are concatenated to provide a more comprehensive failure dataset for reliability modeling analysis. K704 and K711 both have similar valve system designs and were heavily operated since installation. K711 is the newest unit in Corunna station and its failure data is available since installation to 67,482 run hours and unit K704 failure data ranges from 71,948 run hours to 112,361 hours. The concatenated data set covers the failure history ranging from 0 to 112,361 hours. This failure dataset is used to model reliability for the valve system asset sub-class. This Approach is called “K704/K711 Failure Data Concatenation” and is verified by 3rd party technical review. The engine model produced by concatenation approach was applied to the remaining units.

Due to the limited number of available failure points to model each failure mode separately, both failure modes are combined for the analysis.

All Storage models are produced in Reliasoft using Maximum Likelihood Estimation method. The breakdown of the Station Compressors reliability analysis is listed in Error! Reference source not found..

Table 9 – Reliability Models Breakdown for Storage Station Compressors

ASSET SUB-CLASS	FAILURE MODE	RELIABILITY FUNCTION	MODEL TYPE
Foundations	Degradation	NHPP Power Law (2 Parameter)	Type II
Crank Assemblies	Misalignment	NHPP Power Law (2 Parameter)	Type II
	Component Failure	NHPP Power Law (2 Parameter)	Type II
Engines	Component Failure	NHPP Power Law (2 Parameter)	Type II
Compressors	Component Failure	NHPP Power Law (2 Parameter)	Type II
Gas Aftercoolers	Component Failure	NHPP Power Law (2 Parameter)	Type II
Heating and Cooling Systems	Component Failure	NHPP Power Law (2 Parameter)	Type II
	Glycol Leak	NHPP Power Law (2 Parameter)	Type II
Valve Systems	Fail to Operate	NHPP Power Law (2 Parameter)	Type II
	Leak		

Validation

The following methods can be utilized for the validation of AHR models. Each asset sub-class could use a single or multiple methods in the validation of the results of the modelling.

A. DSI Peer Review – Internal review by DSI to ensure learnings are incorporated from prior experience and modelling and to discover any analytical concerns.
B. Multi-department Peer Review – Review by select SMAs from several departments to ensure learnings are incorporated from prior experience and modelling and to discover any analytical concerns.
C. Stakeholder Review - Review by stakeholders to comment on modelling methodology and results.
D. Factor and/or Parameter Reasonable Checks – Review of parameters and factors to ensure they make physical sense and meet understanding of the failure mechanisms.
E. Comparison against actual failures – Comparison of projected failures against actual to ensure the model is predicting a reasonable number of leaks.
F. Comparison against industry norms –Comparison against industry norms for parameter values, known causation factors and expected material lifetimes.

History of Changes

Changes made to this document are tracked in the following table.

REVISION DATE	SUMMARY	CHANGES MADE BY

Storage Failure Classification

April 25, 2018

Bedokt Farbod, Kaveh Abhari
Distribution System Integrity

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1. Storage - Station Compressors

1.1. POPULATION

The AHR is developed using the population and failure data of SCOR units due to the availability of failure data in Maximo, as well as their relative significance, influenced by both available power and the extent to which the compressors are employed. Although only SCOR compressors are currently included in the scope for the AHR, other stations will be considered for future inclusion in the AHR, if data becomes available.

A summary of SCOR integral engine compressors characteristics is presented in **Table 1**. In compressor stations, the operating hour is used as the age attribute, indicating the time each unit has been operating since installation. This specification is available within the nSoda data system for each SCOR unit and for any date after June 2009 (nSoda has been in service since June 2009). The rest of population data, such as installation dates and engine models, are extracted from historical documents.

Table 1: SCOR Compressors Characteristics

STATION NAME	COMPRESSOR UNIT	INSTALL YEAR	ORIGINAL ENGING MODEL	CURRENT ENGINE MODEL
Corunna (SCOR)	K701	1964	KVT	KVTR
	K702	1964	KVT	KVTR
	K703	1964	KVT	KVTR
	K704	1968	KVR	KVR-Lean Burn
	K705	1970	KVR	KVR-Lean Burn
	K706	1972	KVR	KVR-Lean Burn
	K707	1973	KVR	KVR-Lean Burn
	K708	1974	KVR	KVR-Lean Burn
	K709	1980	KVR	KVR-Lean Burn
	K710	1983	KVR	KVR-Lean Burn
	K711	1995	KVR-Lean Burn	KVR-Lean Burn

All compressor asset sub-classes have the same run hours as compressor units. The current run hours for each unit are extracted from nSoda.

1.2. FAILURE DATA

The Maximo data system is used to extract all work orders associated with EGS assets. This extract is limited to events or failures that occurred after Maximo came into service in 2001 and up to May 2016 for the 2017 AHR report and the final year of analysis for future modelling. It includes work orders of all preventative maintenance inspections, planned capital projects or overhauls, and unplanned failures that occurred within EGS.

The AHR modeling analysis are based on the Storage key asset sub-classes and their associated failure modes, presented in **Table 2**, and includes all unplanned failures/events, as well as the ones captured during maintenance inspections or overhauls.

Table 2: AHR Storage Compressor Key Asset Sub-classes and Associated Failure Modes

ASSET SUB-CLASS	COMPONENTS	FAILURE MODE	FAILURE MODE DESCRIPTION
Foundations	N/A	Degradation	Any work orders stating or indicating the foundation settling, degradation, or repair.
Crank Assemblies	Crankshaft	Misalignment	Any work orders stating or indicating the crankshaft misalignment such as bent crankshaft or bad readings in web deflection.
	Main Bearings	Component Failure	Any work orders stating or indicating main bearing component failure, such as main bearing high temperature or replacement.
Engines	Connecting Rod Assembly	Component Failure	Any work orders indicating a replacement in critical components, such as any components in connecting rod, piston/cylinder, and valvetrain assemblies.
	Piston/Cylinder Assembly	Component Failure	
	Valvetrain	Component Failure	
Compressors	Connecting Rod Assembly	Component Failure	Any work orders indicating a replacement in critical components, such as any components in connecting rod, crosshead, piston and cylinder assemblies.
	Crosshead Assembly	Component Failure	
	Piston Assembly	Component Failure	
	Compression Cylinder Assembly	Component Failure	
Gas Aftercoolers	All components	Component Failure	Any work orders indicating a component replacement
Heating and Cooling Systems	All Components	Component Failure	Any work orders indicating a component replacement.
		Glycol Leak	Any work orders indicating a glycol leak.
Valve Systems	All Components	Fail to Operate	Any work orders indicating a replacement or repair in any valve assembly components.
		Leak	Any work orders indicating an external gas leak.

1.3. FAILURE DATA CLASSIFICATION

1.3.1 General Classifications

As mentioned before, in order to use the available failure data in reliability analysis, additional post processing of the data was performed on the failure data extract through the following steps:

1) Maximo Practical Attributes

- The first step in Storage failure classification was to understand the attributes available in Maximo. One of the most important attributes in the Storage work order data is “Location”, which follows the location codes defined in Storage hierarchy and identifies the characteristics of the asset involved in the work order (failure event).

Hierarchy Of MAXIMO Location-Pip | Hierarchy Of MAXIMO Location-Po | Hierarchy Of MAXIMO Location-Pro | Hierarchy Of MAXIMO Location-Sta

Usually the Location ID comes in the following format: X_ABC-***%%-Y-^^^

- The first letter in location ID, “X”, defines the Storage sub-asset classes. The letter “S” is used for Stations, “P” for Pools, “L” for Pipelines, and “B” for Production assets. For instance, **S_** defines the locations within Stations.

- The second three letters, “ABC”, identifies the name of Stations or Pools. For instance, “S_**COR**” stands for Corunna Station and “L_**DOW**” identifies the Pipeline connected to Dow Moore Pool.

- The word “***”, shown in the format, is a three digits number that shows the commodity group and commodity code of the involved asset. These commodity groups and codes are defined in Storage hierarchy. For example, any locations starting with “S_COR-**611**” is associated with “Power Cylinder and Ignition System” in Corunna Station.

- If the location is related to the Stations, there might be another two digits number in Location ID which comes right after the system code and is shown as “%%” in the format. This number shows the last two digits of compressor unit number within the known Station. For example, “S_COR611**02**” locates the power cylinder and ignition system of unit K702 in Corunna Station.

- The letter “Y” and following “^^^” number in the location ID, shows a code associated with the specific component as well as the component number within the defined system. These codes can be found in the attached document. For example, “S_COR-61102-**CYL-001**” is related to the Power Cylinder #1 in unit K702 in Corunna Station.

P&IDs-Location_Type_Codes.pdf

- Another important attribute is “Description (Material)”, which shows what material has been replaced during the work order. There is an “item number” associated with the “material” that can be searched in “Inventory” module of Maximo to identify the material specifications, such as commodity group and commodity code.

- Other important attributes used in failure classification are ”Work Order Description”, “Description”, “Failure Memo”, “Failure Description”, “Work Log”, “Log Notes”. Going forward, these six attributes will be called “Descriptive Attributes” in this document.
- The other useful attributes are “Work Type”, “Owner Group”, “Report Date”, “Work Order No.”, “Failure Code”, and “Problem Code”. These terms will be explained later in the document.

2) Corunna Failures

All failures (work orders) related to Corunna Station compressors were identified, as only the engine and compressors in Corunna Stations were in the scope for AHR. For this purpose, all locations starting with “S_COR-6” were selected using the “Location” column.

3) Corunna Unit Numbers

Using the “Location”, the work orders were classified based the unit number to differentiate the work orders related to different compressor units. Note that the classification was added to a new column called “Unit” column which was not originally included in the extract. For the locations in which the unit number is not mentioned, “work order description” can be used to determine the unit number.

4) Data Columns Modification

Storage failure data was classified to determine the asset sub-classes, components and associated failure modes, and failed sub-components. The findings were inserted in three columns which were added to the original failure extract. These columns are called “**Asset Sub-class**”, “**Components**”, and “**Failure Mode (Sub-component)**”, respectively.

5) Lean-burn and Major Overhauls

If any failures were captured during a Major Overhaul or Lean Burn Conversion, the word “Major Overhaul” or “Lean-Burn” was added to the Failure mode. For example, MajorOverhaul-CF(Head), where CF stands for “component failure”, shows the power or compressor cylinder head was replaced (or failed) during a Major Overhaul.

6) Storage Engine and Compressor Unit System Asset Sub-classes

The next important step in failure classification was to understand how Storage components function and how they relate to each other. For this purpose, an Engine and Compressor Boundary Diagram was prepared using available Storage Piping and Instrumentation Diagrams (P&IDs), as shown in Figure 1. **Figure 2** also shows a typical Engine and Compressor unit system with their associated components.

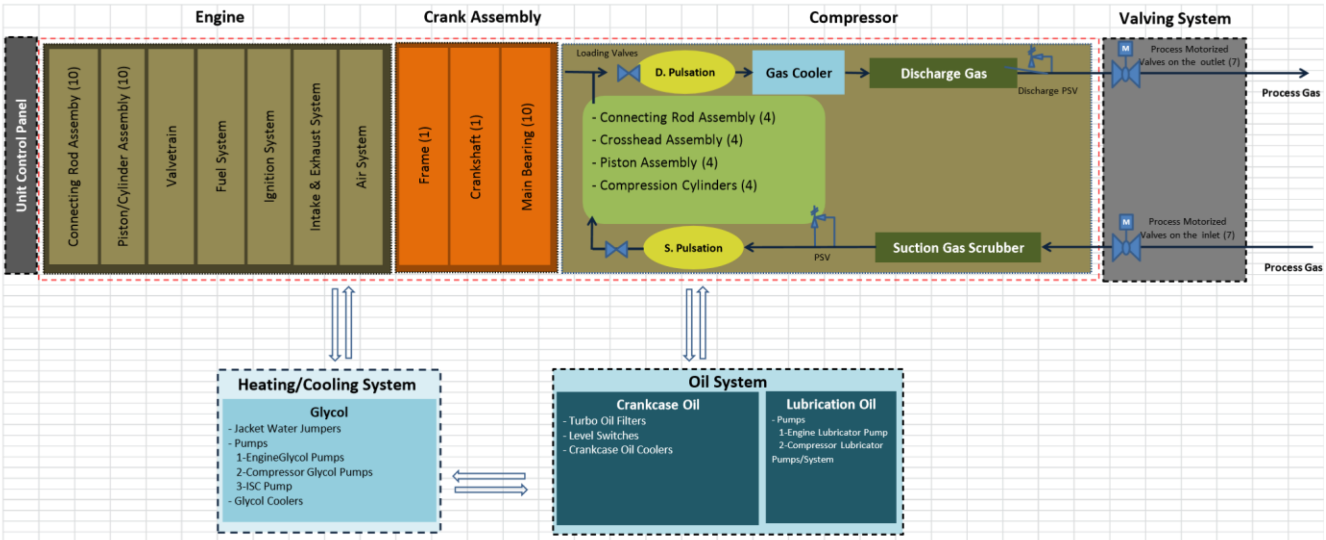

Figure 1: K704 Engine & Compressor System Boundary Diagram according to P&IDs

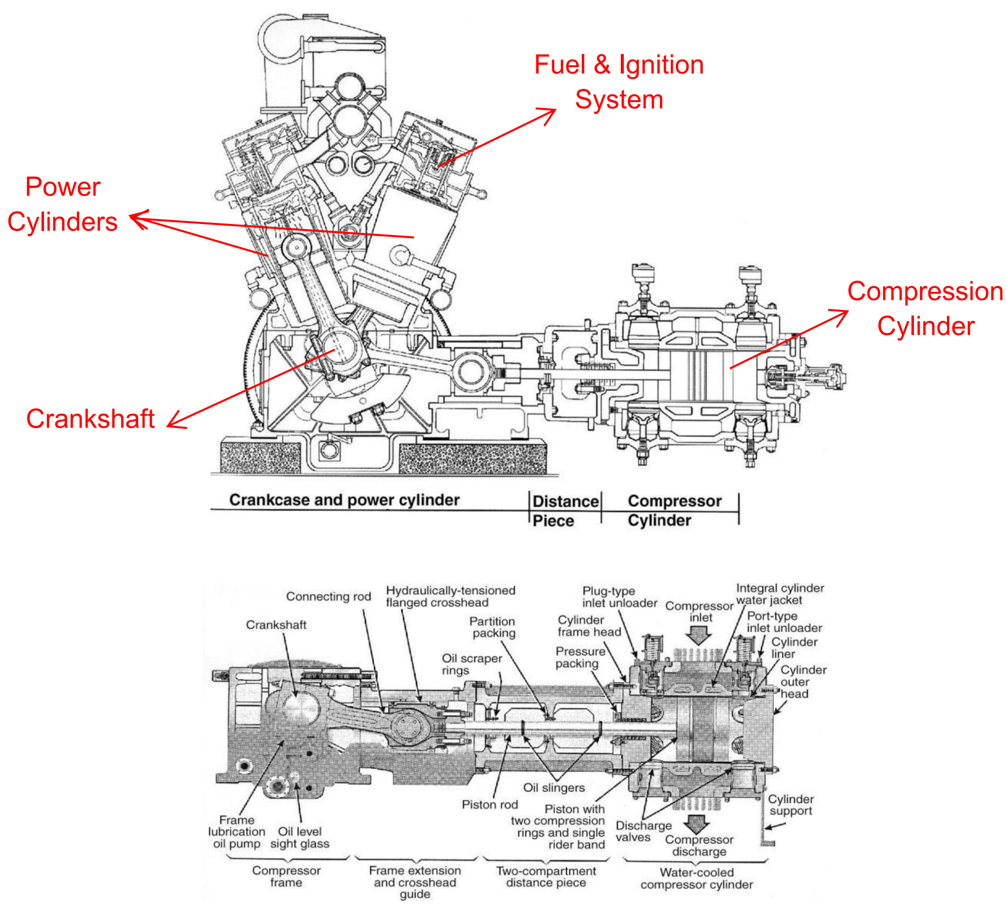

Figure 2: Engine and Compressor Unit System Breakdown

The failure data classification was performed based on the defined asset sub-classes in AHR, as shown in **Table 3.**

Table 3: Storage Engine and Compressor Unit System Asset Sub-classes, their Components and Failure Modes

ASSET SUB-CLASS	COMPONENTS (QUANTITY PER UNIT)	FAILURE MODE
Foundation	Foundation (1)	Degradation
Crank Assembly	Frame (1) Crankshaft (1) Main Bearings (10)	Misalignment/Leak Misalignment Component Failure/Leak
Engine	Connecting Rod Assembly (10) Piston/Cylinder Assembly (10) Valvetrain (10) Intake & Exhaust Assembly (1) Ignition System (10) Fuel System (1) Air System (1)	Component Failure Component Failure Component Failure Component Failure/Leak Component Failure/Leak Component Failure/Leak Component Failure/Leak
Compressor	Connecting Rod Assembly (4) Crosshead Assembly (4) Piston Assembly (4) Compression Cylinders (4) Gas Aftercooler (1) Suction & Discharge (1)	Component Failure Component Failure Component Failure/Leak Component Failure/Leak Component Failure Component Failure/Leak
Oil System	Lubrication Oil (1) Crankcase Oil (1)	Component Failure/Leak Component Failure/Leak
Heating & Cooling System	Compressor System (1) Engine System (1) Common System (1)	Component Failure/Glycol Leak Component Failure/Glycol Leak Component Failure/Glycol Leak

7) N/A Failure Mode
   - Any work orders in which no failure was captured were classified as N/A.
   - Any material replacements done as part of routine inspection was classified as N/A. For example, filter replacement during the oil change.
   - Any non-critical material replacements done as part of Capital Projects was classified as N/A. For example, piston oring replacement due to piston replacement.

8) Instrumentation Failures
   - Any failures related to instrumentation issues were classified as “Instrumentation Failure”. For instance, loose wiring, faulty thermocouple, coil issues, and etc. are instrumentation failures.
   - To classify instrumentation failures. “Description (Material) column and Descriptive Attributes were investigated by filtering the key words listed in the attached.

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Instrumentation Key W

- It is important to note that these key words may not be the only words to look for and there might be other materials/words that can be used in identifying instrumentation failures.
- The attribute “Work Owner” were also used in identifying instrumentation failures. The word “INST” in this attribute refers to Instrumentation Group.
- The instrumentation failures were later classified in detail based on defined asset sub-classes listed in **Table 3.**

9) Leak Failure Mode

- “Leak” events were identified by investigating the work orders with the words “leak” in any of Descriptive Attributes. These events were later classified in detail based on the defined asset subclasses, components and sub-components listed in the attached.

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eakdown-FinalClassific

- During the classification of leak events, the type of “leak” were determined where feasible, such as glycol leak, oil leak, air leak, exhaust leak, and gas leak. For instance, “gas leak” were determined by searching the words “gas” in all abovementioned attributes.
- The attribute “Problem Code” was also used as one of the ways to identify “leak” failures (ProblemCode P090 for leak). It is important to note that the work orders with these problem codes were later classified in detail using Descriptive Attributes and based on the defined Asset sub-classes and components.

10) Other Useful Maximo Attribute

- The ProblemCode P140 is used for physical damage events and can be useful for classification.
- The attribute “Work Type” including BR (breakdown) and CM (corrective maintenance) events were used in identifying actual failures. These failures were later classified in detail using the abovementioned attributes.
- The attribute “FailureCode” were used in identifying the asset sub-classes. For instance, the failure code “Compressor” refers to the events occurred in Compression System. However, further research showed that these failure codes may not necessarily address the actual issues. Therefore, they were used where the event could not be classified using other more reliable attributes, such as work order/failure descriptions and material.

11) Multiple Classifications within one Work Order

The failure data revealed that there might be different asset sub-classes involved in one work order or different failure modes may have occurred during one failure. For instance, one work order could be classified once for the crankshaft assembly failure and once for the engine failure. Or one work order could include both “leak” and “component failure” failure modes at the same time. Therefore, the failure classification was done as detailed as possible and for as many asset sub-classes as possible.

12) Look up in Maximo

Some work orders were directly looked up in Maximo to see if more information can be obtained.

1.3.2 Detailed Classifications

The remaining failures were classified through the following steps to identify failure modes for each asset sub-class:

1) Foundation:

Any work orders with the words “foundation”, “block”, “base”, and “deflection” in Descriptive Attributes were investigated thoroughly to find out if it was a “degradation” failure mode.

2) Crank Assembly Asset Sub-class:

Crank assembly consists of three components; crankshaft, main bearings, and frame, and each component has its sub-components, as shown in **Table 4**.

Table 4: Crank Assembly Components and Sub-components

ASSET SUB-CLASS	COMPONENTS (QUANTITY PER UNIT)	SUB-COMPONENTS	ITEM NUMBER
Crank Assembly	Frame (1)	Frame Bay Door Crankcase Components Explosion Hatch	
	Crankshaft (1)	Crankshaft Crankshaft Oil Seals	
	Main Bearings (10)	Main Bearings Main Bearing Shim	100708, 100450,100452 100454

Crankshaft: • Any work orders with the words “crankshaft”, “main bearing”, “deflection”, and “reading” in Descriptive Attributes were investigated thoroughly to find out if it was a “crankshaft misalignment” failure mode.

Main Bearings:

- Any work orders with the words “main bearing”, “main”, “deflection”, and “aluminum” in Descriptive Attributes were investigated thoroughly to find out if it was a “main bearing component failure” failure mode.

- Any work orders with the words “main bearing”, “main”, “main thrust”, and “aluminum” in “Description (Material)” column was investigated. The sub-component was added to “Failure Mode (sub-component)” column in the classification table.
- Any work orders with the item numbers related to main bearings listed in **Table 4** were classified as “main bearing component failure”.
- The failed sub-components were added to “Failure Mode (sub-component)” column in the classification table, where possible to identify.

Frame: • Any work orders with the words “frame”, “bay door”, “door”, “crankcase”, “explosion”, and “deflection” in Descriptive Attributes were investigated thoroughly to find out if it was a “frame misalignment” or “leak” failure mode.

- Any work orders with the related sub-components reported in “Description (Material)” column was classified as “frame misalignment” or “frame leak”.
- The failed sub-components were added to “Failure Mode (sub-component)” column in the classification table, where possible to identify.

3) Engine Asset Sub-class

Engine components and sub-components are shown in **Table 5**. The engine failure classification was done based on the components and sub-components identified in this table and through the following steps:

Connecting Rod Assembly:

- Any work orders with the words “connecting rod”, “power crankpin”, “power bearing”, and any combinations or abbreviations of these words in Descriptive Attributes were investigated thoroughly to find out if it was a “connecting rod component failure”.
- Any work orders with the Descriptive Attributes including any related sub-components listed in **Table 5** were investigated.
- Any work orders with the words “power crankpin” and “power connecting rod” or related subcomponents reported in “Description (Material)” column were classified as “connecting rod component failure”.
- Any work orders with the sub-components item numbers, shown in **Table 5**, were classified as “connecting rod component failure”.
- The failed sub-components were added to “Failure Mode (sub-component)” column in the classification table, where possible to identify.

Piston/Cylinder Assembly:

- Any work orders with the words “piston” and “power cylinder” and any combinations/abbreviations of these words in Descriptive Attributes needed to be investigated thoroughly to find out if it was a “connecting rod component failure” failure mode.
- Any work orders with the Descriptive Attributes including any related sub-components listed in **Table 5** were investigated.
- Any work orders with “S_COR-611” were investigated thoroughly using Descriptive Attributes to find out if the event was a “piston/cylinder component failure”.
- Any work orders with the words “power crankpin” and “power connecting rod” or related subcomponents reported in “Description (Material)” column was classified as “piston/cylinder component failure”.

- Any work orders with the sub-components item numbers, shown in **Table 5**, were classified as "piston/cylinder component failure".
- The failed sub-components were added to "Failure Mode (sub-component)" column in the classification table, where possible to identify.

Valvetrain:

- Any work orders with the words "valve" and "camshaft", "cam", "inlet valve", "exhaust valve", and any combinations or abbreviations of these words in Descriptive Attributes needed to be investigated thoroughly to find out if it was a "Valvetrain component failure" failure mode.
- Any work orders with the Descriptive Attributes including any related sub-components listed in **Table 5** were investigated.
- Any work orders with "S_COR-611" were investigated thoroughly using Descriptive Attributes to find out if the event was a "Valvetrain component failure".
- Any work orders with the related sub-components reported in "Description (Material)" column was classified as "valvetrain component failure".
- Any work orders with the sub-components item numbers, shown in **Table 5**, were classified as "piston/cylinder component failure".
- The failed sub-components were added to "Failure Mode (sub-component)" column in the classification table, where possible to identify.

Table 5: Engine Components and Sub-components

ASSET SUB-CLASS	COMPONENTS (QUANTITY PER UNIT)	SUB-COMPONENTS	ITEM NUMBER
Engine	Connecting Rod Assembly (10)	Crankpin Bearing	100453,101260
		Connecting Rod	100455
	Piston/Cylinder Assembly (10)	Piston	101002, 100489
		Piston Bushings	100796, 100978
		Piston Crown	100170, 100645, 102588
		Piston Crown Stud	
		Piston Rings, O-ring, or Nut	
		Cylinder	
		Cylinder Liner	100143,100162
		Liner Holder	100120, 100449, 101108, 101627
		Cylinder Head	100433, 100459, 101576, 102136
		Head components	
		Horse Collar	101111
	Valvetrain (10)	Camshaft	
		Cam Carrier Bearing Bushing	100301
		Cam Carrier	100122

		Cam Drive Chain	100251
		Cam Drive Gear	100148
		Pushrod	
		Lifter	100467,100998
		Rocker Arm Bushing	100718
		Rocker Arm Roller	100441
		Rocker Arm Roller Shaft	100440,100185
		Inlet Valve	100193
		Inlet Valve Components	100720
		Exhaust Valve	100709
		Exhaust Valve Components	100721
		Valve Component	100396
		Fly Wheel	
		Hall Effect	101239
		Kiene Valve	102760
		Pick Up	101239
	Intake & Exhaust Assembly (1)	Turbocharger Turbocharger Filter Aftercooler Muffler Intake Manifold Exhaust Manifold Waste gate	
	Ignition System (10)	Spark Plugs Sparkplug components (Altronic coil, gasket, etc)	
	Fuel System (1)	Injection Valve Fuel Assembly PCC Check Valve Regulator Fuel Header Fuel Bottle Filter	
	Air System (1)	Starting Air Instrument Air	

Intake and Exhaust System:

This asset sub-class was out of scope for the AHR. Therefore, more detailed failure classification may be required.

- Any work orders with "S_COR-614" were investigated thoroughly using Descriptive Attributes to find out if the event was an intake and exhaust "component failure" or "leak".
- Any work orders with the words "turbocharger", "exhaust", "manifold", "waste gate", and any combinations or abbreviations of these words in Descriptive Attributes needed to be investigated thoroughly to find out if it was a "component failure" or "leak" failure mode.
- Any work orders with the Descriptive Attributes including any related sub-components listed in **Table 5** were investigated.
- Any work orders with the related sub-components reported in "Description (Material)" column was classified as "valvetrain component failure". Please note that the sub-component was added to "Failure Mode (sub-component)" column in the classification table.
- The failed sub-components were added to "Failure Mode (sub-component)" column in the classification table, where possible to identify.
- Leaks were further classified in detail, if possible.

Ignition system:

This asset sub-class was out of scope for the AHR. Therefore, more detailed failure classification may be required.

- Any work orders with "S_COR-611" were investigated thoroughly using Descriptive Attributes to find out if the event was an ignition "component failure".
- Any work orders with the words "ignition", "sparkplug", "spark", "cold cylinder" "cold power cyl", and any combinations or abbreviations of these words in Descriptive Attributes needed to be investigated thoroughly to find out if it was an ignition "component failure".
- Any work orders with the Descriptive Attributes including any related sub-components listed in **Table 5** were investigated.
- Any work orders with the related sub-components reported in "Description (Material)" column was classified as "ignition component failure".
- The failed sub-components were added to "Failure Mode (sub-component)" column in the classification table, where possible to identify.
- Leaks were further classified in detail, if possible.

Fuel system:

This asset sub-class was out of scope for the AHR. Therefore, more detailed failure classification may be required.

- Any work orders with "S_COR-615" were investigated thoroughly using Descriptive Attributes to find out if the event was a fuel system "component failure" or "leak".
- Any work orders with the words "fuel", "PCC", "check valve", "cold cylinder", and any combinations or abbreviations of these words in Descriptive Attributes needed to be investigated thoroughly to find out if it was a "component failure" or "leak".

- Any work orders with the Descriptive Attributes including any related sub-components listed in **Table 5** were investigated.
- Any work orders with the related sub-components reported in “Description (Material)” column was classified as “ignition component failure”.
- The failed sub-components were added to “Failure Mode (sub-component)” column in the classification table, where possible to identify.
- Leaks were further classified in detail, if possible.

Air system:

Air system in the engine and compressor units has two main sub-systems, Starting Air and Air Instrument. The sub-components associated with these sub-systems are not included in **Table 5**, as this asset subclass was out of scope for the AHR. Therefore, more detailed failure classification may be required for this asset sub-class to determine the failed component in addition to the identified sub-system.

- Any work orders with “S_COR-612” and “S_COR-613” were investigated thoroughly using Descriptive Attributes to find out if the event was a “component failure” or “leak”.
- Any work orders with the words “air”, “instrument”, “starting”, “starter” and any combinations or abbreviations of these words in Descriptive Attributes needed to be investigated thoroughly to find out if it was a “component failure” or “leak”.
- Leaks were further classified in detail, if possible.
- The failed sub-components were added to “Failure Mode (sub-component)” column in the classification table, where possible to identify.

4) Compressor Asset Sub-class

Compressor components and sub-components are shown in **Table 6**. The compressor failure classification was done based on the components and sub-components identified in this table and through the following steps:

Connecting Rod Assembly:

- Any work orders with the words “connecting rod”, “compressor crankpin”, “compressor bearing”, and any combinations or abbreviations of these words in Descriptive Attributes were investigated thoroughly to find out if it was a “connecting rod component failure”.
- Any work orders with the Descriptive Attributes including any related sub-components listed in **Table 6** were investigated.
- Any work orders with the words “compressor crankpin” and “compressor connecting rod” or any related sub-components reported in “Description (Material)” column were classified as “connecting rod component failure”.
- Any work orders with the sub-components item numbers, shown in **Table 6**, were classified as “connecting rod component failure”.
- The failed sub-components were added to “Failure Mode (sub-component)” column in the classification table, where possible to identify.

Crosshead Assembly:

- Any work orders with the words “crosshead” and “cross”, “compressor” and any combinations/abbreviations of these words in Descriptive Attributes needed to be investigated thoroughly to find out if it was a “connecting rod component failure” failure mode.
- Any work orders with the Descriptive Attributes including any related sub-components listed in **Table 6** were investigated.
- Any work orders with the words “crosshead” or related sub-components reported in “Description (Material)” column was classified as “crosshead component failure”.
- Any work orders with the sub-components item numbers, shown in **Table 6**, were classified as “crosshead component failure”.
- The failed sub-components were added to “Failure Mode (sub-component)” column in the classification table, where possible to identify.

Piston Assembly:

- Leak failure mode in this asset sub-class is more likely a gas leak, which is important to classify correctly due to its safe and safety consequences. Therefore, any leaks were classified in detail, where possible, to determine the type of leak.
- Any work orders with the words “piston” and “packing”, “rod”, “compressor”, and any combinations or abbreviations of these words in Descriptive Attributes needed to be investigated thoroughly to find out if it was a “Valvetrain component failure” or “leak” failure mode.
- Any work orders with the Descriptive Attributes including any related sub-components listed in **Table 6** were investigated.
- Any work orders with “S_COR-621” were investigated thoroughly using Descriptive Attributes to find out if the event was a “piston assembly component failure” or “leak”.
- Any work orders with the related sub-components reported in “Description (Material)” column was classified as “Piston component failure”.
- Any work orders with the sub-components item numbers, shown in **Table 6**, were classified as piston failure.
- The failed sub-components were added to “Failure Mode (sub-component)” column in the classification table, where possible to identify.

Compression Cylinder:

- Leak failure mode in this asset sub-class is more likely a gas leak, which is important to classify correctly due to its safe and safety consequences. Therefore, any leaks were classified in detail, where possible, to determine the type of leak.
- Any work orders with “S_COR-621” were investigated thoroughly using Descriptive Attributes to find out if the event was a cylinder failure.
- Any work orders with the words “compressor”, “cylinder”, “unloader”, “pocket”, “poppet”, “suction valve”, “discharge valve”, “valve job”, “packing”, “comp valve” and any combinations or abbreviations of these words in Descriptive Attributes needed to be investigated thoroughly to find out if it was a compressor failure.
- Any work orders with the Descriptive Attributes including any related sub-components listed in **Table 6** were investigated.
- Any work orders with the related sub-components reported in “Description (Material)” column was classified as compressor failure.
- Any work orders with the sub-components item numbers, shown in **Table 6**, were classified as compressor failure.

- The failed sub-components were added to "Failure Mode (sub-component)" column in the classification table, where possible to identify.

Gas Aftercooler:

Gas aftercooler is a part of suction and discharge system in the Engine and Compressor Unit System. However, because this asset was in the scope of the AHR, it was classified separately.

- Any work orders with "S_COR-622" were investigated thoroughly using Descriptive Attributes to find out if the event was an aftercooler failure.
- Commodity codes were used to identify failed sub-components.
- Any work orders with the words "cooler" and "gas cooler" and any combinations or abbreviations of these words in Descriptive Attributes needed to be investigated thoroughly to find out if it was a gas aftercooler failure.
- Any work orders with the Descriptive Attributes including any related sub-components listed in **Table 6** were investigated.
- Any work orders with the related sub-components reported in "Description (Material)" column was classified as gas aftercooler failure.
- The failed sub-components were added to "Failure Mode (sub-component)" column in the classification table, where possible to identify.

Table 6: Compressor Components and Sub-components

ASSET SUBCLASS	COMPONENTS (QUANTITY PER UNIT)	SUB-COMPONENTS	ITEM NUMBER
Compress	Connecting Rod Assembly (4)	Crankpin Bearing Connecting Rod shim Connecting Rod	100458,100177 **or** 100370
	Crosshead Assembly (4)	Crosshead Pin + Bushing	100705
		Crosshead Rod	100151
		Crosshead	
		Crosshead Rod Lock	100806
		Crosshead components (supernut, door gasket, etc)	100728,102228,102665,102651,100197
		Crosshead Stud	100766
		Crosshead Spacer	100764
	Piston Assembly (4)	Piston	100064,100790,100666
		Piston Rod	100173,100587,100642,101093,101131
		Pressure packing	100544,100543,100527,100539,100936,100937, 101735,102773
		Oil scrape rings / Partition packing	100055
		Piston Rings	100047,100060,100134,100130,101972
		Rider Band Ring	100058,100070,100046,101121
		Piston Supernut	100199,100969,101130

Compression Cylinders (4)	Cylinder head	102136
	Cylinder Outer Head	
	Cylinder Frame Head	
	Cylinder End Head	
	Head Ring	100294,100292,100291
	Liner	100640
	Suction Valves	100549,101252,101010,100548,101470,101467, 101469,101415,101413
	Discharge Valves	100867,100663,101253,100002,101010,100932, 101468
	Discharge Valve components (plate, retainer, spring/channel)	
	Cooling Jacket	
	Clearance Pocket components	
	Unloader and unloader components	
	Poppet/Channel Valve	100687,100730,101471
Gas Aftercooler (1)	Motor	
	Fan & Fan Belt	
	Bearing	
	Bushing	
Suction & Discharge (1)	Inlet Strainer	
	Suction Dampener	
	Discharge Dampener	
	Suction Scrubber	
	Discharge Scrubber	

Suction & Discharge:

This asset sub-class was out of scope for the AHR. Therefore, more detailed failure classification may be required to determine the failed components.

- Any work orders with “S_COR-622” were investigated thoroughly using Descriptive Attributes to find out if the event was a “component failure” or “leak”.
- Any work orders with the words “suction”, “discharge”, “scrubber”, and any combinations or abbreviations of these words in Descriptive Attributes needed to be investigated thoroughly to find out if it was a suction & discharge failure.
- Any work orders with the Descriptive Attributes including any related sub-components listed in **Table 6** were investigated.
- Any work orders with the related sub-components reported in “Description (Material)” column was classified as compressor failure.
- The failed sub-components were added to “Failure Mode (sub-component)” column in the classification table, where possible to identify.
- Leaks were further classified in detail, if possible.

5) Heating and Cooling System

There are two failure modes defined for this asset sub-class, “component failure” and “leak”. The leak in this system is more likely “glycol leak”, which was included in the scope of AHR. Therefore, it was important to identify glycol leaks. The “component failure” failure mode was defined as failure in any components within heating and cooling system. Therefore, identifying the components, as shown in **Table 7**, was not required for the modeling analysis. However, the failed sub-components were identified where the data had enough resolution.

- Any work orders with “S_COR-640” were investigated thoroughly using Descriptive Attributes to find out if the event was a “component failure” or a “glycol leak”.
- Any work orders with the words “glycol”, “jacket water cooler”, “JWC”, “surge tank”, “cooler”, “cooling”, “water”, “jumper” and any combinations or abbreviations of these words in Descriptive Attributes needed to be investigated thoroughly to find out if it was a suction & discharge failure.
- Any work orders with the Descriptive Attributes including any related sub-components listed in **Table 7** were investigated.
- Any work orders with the related sub-components reported in “Description (Material)” column was classified as compressor failure.
- The failed sub-components were added to “Failure Mode (sub-component)” column in the classification table, where possible to identify.
- Leaks were further classified in detail, if possible.

Table 7: Heating & Cooling System Components and Sub-components

ASSET SUB-CLASS	COMPONENTS (QUANTITY PER UNIT)	SUB-COMPONENTS
Heating & Cooling System	Compressor System (1)	Compressor Glycol Pump Pump components Compressor Glycol Surge Vessel
	Engine System (1)	Engine Glycol Pump Pump components Engine Glycol Surge Vessel
	Common System (1)	Glycol Cooler (Jacket Water Cooler) Cooler components (Motor, Bearing, Fan, Belt, Bushing, and etc.) Auxiliary Glycol Pump Jumper

6) Oil System

Oil system in the engine and compressor units has two main components, Lubrication Oil (with location S_COR-651) and Crankcase Oil (with location S_COR-652), as shown in **Table 8**. The sub-components associated with these sub-systems are not included in **Table 8**, as this asset sub-class was out of scope for the AHR. Therefore, more detailed failure classification may be required for this asset sub-class to determine the failed component in addition to the identified sub-system.

- Any work orders with “S_COR-651” and “S_COR-652” were investigated thoroughly using Descriptive Attributes to find out if the event was an oil system failure.

- Any work orders with the words “oil”, “lubrication”, “crankcase”, “lubricator”, and any combinations or abbreviations of these words in Descriptive Attributes needed to be investigated thoroughly to find out if it was a suction & discharge failure.
- Any work orders with the Descriptive Attributes including any related sub-components listed in **Table 8** were investigated.
- Any work orders with the related sub-components reported in “Description (Material)” column was classified as compressor failure.
- The failed sub-components were added to “Failure Mode (sub-component)” column in the classification table, where possible to identify.
- Leaks were further classified in detail, if possible.

Table 8: Oil System Components and Sub-components

ASSET SUB-CLASS	COMPONENTS (QUANTITY PER UNIT)	SUB-COMPONENTS
Oil System	Lubrication Oil (1)	Auxiliary Oil Pump Oil Cooler Oil Filter Oil headers Lubricator
	Crankcase Oil (1)	Oil sump strainer Main Oil Pump

1.3.3 Post Classification Process

1) Determination of Time (Run Hours) at Failure

As the purpose of this failure classification was to use the failure data in the modeling analysis, it was important to know the time of those failures. As mentioned earlier, the operating hour is used as the age attribute in compressor stations, indicating the time each unit has been operating since installation. All compressor asset sub-classes have the same run hours as compressor units.

- Therefore, the operating run hours of each unit at the time of failure (work order) was used as time at failure for each failure data. However, run hours of the units at the time of work orders were not available in Maximo for all failures. Therefore, other sources such as nSoda was used to determine the run hours at failures. The issue with nSoda data is that this database has been available after June 2009, therefore the run hours prior to this date are not found in nSoda.
- A historical unit run hour sheets, as attached, were used for the failures occurred prior to nSoda (June 2009). The issue with this historical database is that the run hours are available on monthly basis.

Compressor Run Hours by month 1975

- The “report date” attribute in work order extract was used to determine the unit run hour at the time of failure.
- The identified run hours were recorded in “Unit Run Hour” column in the failure extract.

2) Work Order Duplicates Exclusion

A review of work order extract illustrated that any work orders with multiple material replacements were duplicated as many as all replaced materials were included in the extract. For instance, if a cylinder head and a head gasket and a piston ring was replaced during one work order, that work order was repeated three times with three different materials in Description (Material) attribute.

- Therefore, the work order duplicates were required to be excluded from the modeling analysis. For this purpose, all duplicates with the same classified component were identifies as “No” in the “Good for Analysis” column. In other words, if more than one failure occurred on a **component** within one asset sub-class, it would be considered as one failure on that specific component. For example, if there were 2 piston failures and 4 connecting rod failures within the engine asset subclass, it would be counted as one piston failure and one connecting rod failure.
- It is important to note that the **components** were counted for the exclusion not sub-components.
- For Heating and cooling systems and gas after coolers, each work order with at least one component failure was considered as one failure (all duplicates were excluded).
- For leak failures, all duplicated were excluded.

1.3.4 Classified Data

Attached is the classified work orders. It is important to mention that only the asset sub-classes included in AHR were classified in detail. The rest of classifications are old work and is not meant to be used in analysis. In addition, the duplicate exclusion is partially done for some asset sub-classes in this file.

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2. Storage – Station Valves

2.1. POPULATION

The AHR valves scope covers all valves that are larger than 4 inches. For the analysis and reporting purposes these valves are broken up into two main categories. The first category consists of valves in the valving system (660xx), namely Unit and Mode valves, under the Engine and Compressor Unit in the SCOR units. And the second class of valves includes all other valves across all storage units. This represents all valves within Stations, Pipelines, Production, and Pool assets that meet the defined size criteria.

A full list of all valves in scope for each category is summarized in the following excel sheet. The population is extracted from Maximo. All asset ids, description, and location attributes are available in the extract. Moreover, all installation date data gaps are addressed through historical documents, assumption (refer to AHR report), SMAs consultation, and field surveys.

Valve_Data.xlsx

2.2. FAILURE DATA

The Maximo data system is used to extract all work orders associated with the valves in scope. This can be done by cross referencing Asset ID and Location Address of the assets in the work orders. It should be noted that the extract is limited to events or failures that occurred after Maximo came into service in 2001 and up to May 2016 for the 2017 AHR report and the final year of analysis for future modelling. It includes work orders of all preventative maintenance inspections, planned capital projects or overhauls, and unplanned failures that occurred within EGS.

Valves AHR modeling analysis are based on the valve asset sub-classes associated failure modes, presented in **Table 9**, and includes all unplanned failures/events, as well as the ones captured during maintenance inspections or overhauls.

Table 9: Valve Failure Modes

ASSET SUB-CLASS	COMPONENTS	FAILURE MODE	FAILURE MODE DESCRIPTION
Valve Systems	All Components	Fail to Operate	Any work orders indicating a replacement or repair in any valve assembly components.
		Leak	Any work orders indicating an external gas leak.
		Physical Damage	Any work orders stating or indicating damage to valves physical damage to valve components such as handles, bolts, tags, and more.

2.3. VALVE FAILURE DATA CLASSIFICATION

Please refer to section 3.1 for detailed failure classification instructions. It should be noted that for Unit and Mode valves in the stations, the operating hour is used as the age attribute, indicating the time each unit has been operating since installation and for all other valves the event/failure date is used.

3. Next Steps

3.1. SOMBRA FAILURE DATA CLASSIFICATION

Following a request from the Asset Manager for Storage, Sombra units will be included in the 2018 AHR update. Therefore, failures associated with Sombra units (K801, K802, and K803) need to be classified.

3.2. CHATHAM D AND CROWLAND FAILURE DATA CLASSIFICATION

As per the Storage Asset Manager request, Chatham D (K901) and Crowland (K601) units will be included in the 2018 AHR update. Therefore, there will be a need for these units' failure data. However, there is not too many data associated with these units available in Maximo and according to the SMAs, all works performed on these units are stored in logbooks in these Stations.

3.3. CONDITION ASSESSMENT INCORPORATION

Condition assessments are required to be incorporated into the AHR for Storage Asset sub-classes to improve the models. For this purpose, the results of related inspections and maintenance programs and visual inspections will be translated into condition assessment. Some of these inspections are recorded in Maximo and the rest can be found in log books stored in Storage.

It is important to note that this information may not be sufficient and a full understanding of impact of preventative maintenance activities may be required for all asset sub-classes in determining the condition assessment criteria.

Table 10 presents some of the ongoing inspections and maintenance activities at Storage that can be used in AHR condition assessment.

Table 10: Storage Current Inspections/Preventative Maintenance Programs

ASSET SUB-CLASS	COMPONENT	INSPECTION/MAINTENNACE ACTIVITY
Foundation		Visual Inspection
Crank Assembly	Crankshaft	PM - Web Deflection
	Main Bearings	PM - Web Deflection PM - Test Run Engines for Bearing Lubrication PM - Oil Change
	Frame	Visual Inspection
Engine		PM - Meter-based Preventative Maintenance Inspection Minor and Major Overhauls
Engine		Engine Performance Analyzing and Emissions Testing PM - Oil Change PM - Oil Change and Engine Inspection (for Crowland)
Compressor		PM - Meter-based Preventative Maintenance Inspection Minor and Major Overhauls Poppet Valve Inspection/Replacement
Gas Aftercooler		PM - Inspect and Grease Gas & Glycol Coolers PM – Corunna Gas Cooler Fan Lubrication
Heating & Cooling System		PM - Inspect and Grease Gas & Glycol Coolers Glycol Sampling
Valve System		PM - EGS Station Valve Greasing PM - Flow Control Valve Inspection PM - Well Valve Greasing PM - Bettis Valves Inspection (Pipeline Valves) PM - Field Isolation Valve Greasing PM - Rexa Valve Inspection

Critical Spares Inventory

Item Number	Description	Current Balance
100006	Lead, Primary, 24", 2 Prong	3
100008	Cable, Lead Assy, MAG/JCT Box To Pickup, 72"	6
100009	Thermocouple, Exhaust, Type J	4
100021	Coil, Induction (Bendix), SS Magneto	2
100028	Thermostat, 170*F, Element Assembly (Amot)	18
100031	Bushing, 1 1/4"x1"x7 1/8", Brass	17
100032	Thermocouple, 36",	5
100033	Thermocouple, 18"	3
100045	ORing Kit	3
100046	Ring, Rider Band, 12.5"	4
100047	Ring, Piston, 12.5" (8 ea. = 1 set)	10
100051	Gasket, Nozzle	2
100055	Packing Set, Oil Wiper, 5", K704 K711	6
100058	Ring, Rider Band, 14"	6
100060	Ring, Piston, 14" (3 Pce Ring)	64
100062	Gasket, Steel, Fuel Injection	66
100066	Diaphragm, 511 Fuel Gas Pilot, #30	3
100067	Diaphragm, 511 Fuel Gas Pilot, #20	3
100070	Ring, Rider Band, 15 3/4", Uncut	38
100071	Orifice, Valve	4
100072	Gasket	4
100073	Pin, Steel	2
100074	Lever/Seat, Valve	2
100078	Ring, Rider Band, 18.5"	16
100079	Ring, Rider Band, 18.5", Bakelite	4
100080	Gasket, Rubber, 6" ID 6.625 OD Style 38 Stab Armored Grade 27 (Buna S)	18
100085	ORing, 151, Viton	13
100088	Joint, Expansion, 16"	1
100114	Impeller, Pump	3
100120	Cylinder, Liner Holder, 17"	15
100122	Carrier, Cam	2
100130	Ring, Piston, 15.75", 3 Piece	40
100131	Filter, Fuel, In Line, PCC	11
100135	Ring, Piston, 18.5"	16
100137	Cam, #1, Left Side, PCC, KVR	6
100140	Ring, Piston, 18.5", Bakelite	2
100141	Impeller, Pump	2
100148	Gear, Hub Driven	2
100151	Crosshead, 5" Rod	1
100154	Shoe, Crosshead	1
100160	Sprocket, Accessory Chain Drive	1
100162	Liner, Power Cylinder, 17"	22
100169	Impeller, Pump, 10.625", DIA. H39334	1

100170	Crown, Piston, 17"		6
100174	Camshaft, Dumbell		7
100177	Bearing, Bronze, Compressor Connect Rod KVT, Babbitt Lining .003"-.004"		5
100184	Shaft, Water Pump Compressor 3RVL		1
100190	Rod, Unloader Valve Piston, 5.88" UL47		3
100191	Roper, Gear Set		3
100192	Shaft, Engine Water Pump (5RVL)		4
100193	Valve, Power, Inlet, Tool Steel		5
100195	Shaft, Air Starter Stub		1
100196	Retainer, Camshaft (Halfmoon)		39
100199	Jamnut, 5", Piston End Supernut		3
100209	Ring, Backup, 372A, Buna		15
100211	ORing, 372, Viton		109
100212	Ring, Backup, 373, Buna		40
100213	Seat, (Robertshaw)		6
100215	ORing, 375, 0.375"" x 15', Viton		20
100216	Gear Set,5.66:1 Ratio Including Housing		1
100217	ORing, 376, Viton		24
100228	Gasket, Rubber, 8"		8
100247	Gasket, set, pcc (Set of 4)		6
100251	Camshaft, Dumbell Assy Drive (Long)		1
100253	Camshaft, Dumbell Assy (Short)		1
100255	Ring Set		36
100256	Ring Set		4
100273	Ring, Backup, 443, Buna		9
100275	ORing, 443, Viton		14
100279	ORing, 445, Viton		101
100281	Valve, Air Starter, Assembly		2
100291	Ring, Backup, 458, Buna		43
100292	ORing, 458 Viton		27
100294	ORing, 461, Viton		52
100297	Hub, Camshaft Drive		4
100298	ORing, 467, Viton		5
100301	Bushing, Camshaft Carrier Bearing		60
100305	ORing, Viton 466 Yellow KVR /KVTR Engine		135
100308	Disc, Rupture, Blue		75
100310	Valve, Check, (Trabon)		6
100311	Indicator, Reset		12
100312	Gasket, MR		90
100313	Gasket, MJ		135
100315	Plug, Lubricator Block		11
100321	Kit, Repair		12
100323	Kit, Repair (Trabon)		1
100324	Filter, Lube Oil, Kit (Trabon)		13
100329	Gasket, 1/8", Copper		12
100332	Bearing, (SKF-62062RS)		10

100333	Bearing, (SKF-62072RS)		9
100351	Nut, locking		10
100369	Gasket, Neoprene, Square (Pkg 15 ft)		73
100370	Shim, Connecting Rod		12
100375	Flange, Expansion, 16", 2 Piece		4
100377	Bushing, 1 1/4"x1"x1 3/4", Oilight		34
100380	Gasket, Copper,Cylinder to Head, Liner to Holder		48
100389	Diaphragm, 2" Air Starter		8
100398	Guide, Valve		12
100410	Gasket, air		14
100412	Gasket, Head to Exhaust Pipe, 316SS/Ceramic		23
100423	Seal, Oil		6
100428	Valve, Fuel Assembly		10
100443	Pin, Power Piston		1
100447	Gasket, Copper, Head to Liner		25
100448	Gasket, 16", 150#,Style 300, 23.25 x19.125x 1/8 304 Ceramic Ring Fullface		2
100449	Gasket, Copper, Holder to Liner		60
100450	Bearing, Aluminum, Set of 2 Halves Washington Iron Works Style		10
100451	Expansion Joint, 16" (SHCBPW16005005T321L)		3
100452	Bearing, Aluminum, Set of 2 Halves Washington Iron Works Style		3
100453	Bearing, Aluminum, Set of 2 Halves Washington Iron Works Style		6
100454	Shim, Bearing		69
100455	Shim Power Connecting Rod		24
100458	Bearing, Aluminum, Set of 2 Halves Washington Iron Works Style		5
100459	Head, Power, KVR Lean Burn		4
100461	Valve, Unloader Pocket		1
100467	Lifter, Hydraulic Stud		40
100468	Pump, Main Engine Oil		1
100473	Gasket, exhaust, 316SS/Ceramic		34
100474	Gasket, exhaust (Copper)		11
100483	Disc, Distributor		2
100485	Quad Ring, Square Buna, Gas Pipe (3 7/8 Outside, 3 1/2" Inside)		62
100487	Oring, Water Pipe, Seal, 6", Square		62
100506	Guide, Valve, Screw Type		53
100507	Channel/Spring Set		23
100508	Packing, Bronze, 4.5", HP, Single Ring		9
100517	ORing, 005, Viton		734
100519	Ring, Backup, 212, Buna		10
100520	ORing, 212 Viton		27
100527	Packing Set, 4.5"		5
100533	Bearing, (TORR-BH1312)		4

100539	Packing Set, Oil Wiper 5", KVR		5
100543	Packing Set, 4.5"		5
100544	Packing Set, 5", DO NOT REORDER		3
100548	Plate, Seat, Suction Valve		6
100549	Plate, Stop, Suction Valve		8
100552	ORing, 231 Viton, PCC Pot		44
100557	ORing, 237 Viton, PCC Pot		34
100588	Stop Plate, Valve		2
100608	ORing, Actual .250" Viton Roll 300 ft		449
100609	Packing, 4.5", Breaker Ring		5
100618	ORing, 0.275"Viton Roll 300ft		286
100622	Seat, air starter		10
100628	Module, CPU2000 Ignition Output		1
100637	Gasket, Dresser Rubber, 6" I.D.		6
100639	Piston, 18.5", Compressor, Head End		1
100641	Rod, 5", Compressor Piston (H252622)		1
100643	Liner, Compressor Cylinder, 15.75"		4
100663	Valve, Discharge		5
100664	Valve, Inlet, Compressor		1
100667	Valve, Poppet, Discharge		1
100669	Rod, Compressor Connecting		2
100670	Kit, PCC Valve Repair		18
100673	Meter, Slow Flow MRAD		2
100686	Spring, Valve, Unloader (UK47)		2
100687	Spring, Valve, Poppet		1237
100688	Spring, Valve, Unloader (PP417)		1
100689	Spring, Air Starter Disc		2
100690	Spring, Side Unloader Valve		25
100695	Spring, Valve, Unloader (PP874)		1
100703	Valve, Fuel Injection, PCC		20
100704	Guide, Valve		13
100705	Pin, Crosshead (2 Halves)		4
100706	Guide, Valve		37
100708	Bearing, Aluminum, Main - Special Thickness		2
100709	Valve, Exhaust, 30*		12
100712	Joint, Expansion, exhaust		2
100718	Bushing, Rocker Arm, Intake/Exhaust		41
100719	Bushing, Rocker Arm, Fuel		19
100720	Seat, Valve, inlet		4
100721	Seat, Valve, exhaust		22
100723	Seat, Valve		12
100724	Rod, Unloader Valve Piston, 5.25" UL47		1
100725	Rod, Unloader Valve Piston, 5.88" UL47		1
100727	Piston, 7", Unloader Valve		1
100729	Control Unit, Ignition		1
100730	Poppet, Valve		1182
100731	Regulator, Oil Level Control Float		2

100733	Bearing, 2 7/16" (SKF-RCJ2 7/16)	9
100741	Spark Plug, .012" Gap (Champion 559}	62
100748	Switch, Dynalco Speed (SST2400H)	1
100758	Pickup, Magnetic (Altronic)	4
100759	Pickup, Magnetic, Hall Effect (Altronic)	6
100762	Nut, xhead-yoke	1
100775	Bushing, Rocker Pushrod	30
100776	Bushing, Cam Drive	5
100779	Bushing, Con Rod, Power	6
100784	Gasket, 6" Special	4
100788	Pin, Power Piston	1
100793	Bushing, pwr con rod	9
100794	Bushing, Crosshead Pin	8
100796	Bushing, pwr piston	16
100798	Gasket Set	19
100799	Washer, Power Piston Crown	180
100800	Stud, Crown to Skirt	167
100801	Nut, piston crown	232
100802	ORing, Piston Crown, 17"	21
100803	Coupling, Flex Joint 6""""" 150#, Model 0600AMS150	1
100804	Coupling, Flex Joint, 8" 150# Model 0800AMS150	2
100805	ORing, 16"	23
100807	Gasket, Steel	23
100808	Gasket, Copper	7
100809	Gasket, Steel	44
100810	Gasket, Steel	56
100824	Ring, Unloader Piston, 5.25"	6
100825	Ring, Unloader Piston, 5.88"	9
100826	Ring, Pocket Unloader Piston	9
100856	Valve, Robertshaw, Kit	4
100859	Seal, Fuel Gas Pilot	3
100860	Orifice, Valve, Inlet, 1"	6
100861	Orifice, Valve, Outlet, 1"	6
100862	Valve, Double Seat, Assembly	3
100863	Diaphragm, Regulator	5
100864	Valve, Check, Power Stem, Lubricator	110
100867	Valve, Discharge, Magnum	3
100881	Thermostat, 115*F (Amot)	12
100887	Kit, Repair	2
100909	Seat, Plate, 7.5"	9
100910	Sleeve, Slinger Valve, PCC	4
100911	Sensor, Overspeed Trip	3
100975	Expansion Joint, Diaphragm	3
100978	Bushing, pwr piston	8
100980	Snuffer, Lifter Fuel Arm, PCC	8
100981	Ball, End	10
100996	Bullet, Magnum Valve	5677

100997	Insert/Spring, Magnum Valve	5742
100998	Adapter, Hydraulic Lifter	7
101010	Valve, Suction/Discharge, Magum	5
101011	Seat, Valve Suction	3
101012	ORing, 458 10" Viton	2
101013	Spring, Valve, Unloader (PP1009)	1
101059	Packing Case, KVR	6
101130	Supernut, Piston End, 410KVT 120	4
101139	Plate, Seat, Discharge	9
101148	Level Control Model L1200SS-SF Stainless Steel	2
101150	16" SINGLE EXPANSION JOINT	1
101152	Gasket, 30", turbo exh (38.625x30x1/16 GHR Ring FF)	3
101157	Head, PCC, Water	4
101158	Chamber, PCC	1
101161	Transmitter, Pressure Gage, c/w 2 Valve Manifold	1
101162	Board, Electronic Transmitter	2
101168	Gasket, sparkplug	712
101191	Gasket, 20' x 16 1/2" x 1/16", GHR	5
101196	SEAL, 48" ANSI 600# SUCTION SCRUBBER BANDLOCK	1
101198	Coupling, Jaw ML-100 X 11/8"	5
101228	Switch, Vibration PMC/BETA	1
101234	Gasket, Rubber, 8" (Dresser)	6
101245	RTD, Main Bearing	2
101246	Valve, divider	4
101250	Bearing, Comp Connect Rod, Bronze Back, Set of 2, Babbitt Lining (Special Undersize)	2
101252	Valve, Suction, Magnum, 410KVR167A	4
101253	Valve, Discharge, Magnum, 410KVR167A	4
101260	Bearing, Bronze, Pwr Crankpin, Set of 2	5
101270	Insert, M4 Coupling (Yellow)	6
101304	Seal, Rubber	6
101308	Gasket, Rubber, 4" (Dresser)	14
101310	Arm, Valve Rocker	3
101318	Plate, Crankshaft Oil Ring Baffle (Oil Flinger)	1
101322	Insert, M0 Flexible Coupling	3
101334	Hub, MO 1.125 ATR	9
101335	Hub, M0, 1.375 ATR	9
101347	Plugs, Spark Cat 3512 & 3516	17
101354	Gasket	1
101358	Terminals	22
101367	Filter, Aerial Compressor Oil	4
101403	Spark Plug, Stitt	21
101404	Lead, BG, Spark Plug	49
101405	Hose, OAL S.S. Braided Hose c/w C.S. Male NPT attached on each end	8
101413	Valve, Single Deck Suction	1
101414	Valve, Discharge Single Deck	1

101415	Valve, Half Deck Suction	1
101416	Cage, Single Deck Suction Valve & Cap w/ Pressure Indicator Connection	1
101417	Unloader Assembly, Valve Pocket Added Volume Unloader	1
101418	Unloader, Body	1
101419	Unloader, Seat	2
101420	Unloader Assembly, Front Head Pocket	1
101421	Spring, compression	1
101422	Unloader Assembly, Internal Head End & Crank End Body Pocket	1
101428	Bolt, center	39
101434	Board, amplifier	1
101435	Board, power supply	1
101438	ORing, Amot	38
101445	Seal, Transformer Lip	23
101467	Valve, Single Deck Suction	2
101468	Valve, Single Deck Discharge	5
101469	Valve, Single Deck Suction /w Hole for Indicator Connection	2
101470	Valve, Half Deck Suction /w Hole for Valve Pocket Unloader	2
101471	Valve, Poppet	3033
101472	Spring, Valve	3571
101525	Rod, 5", compressor, TCC	1
101530	Kit, repair, Sentry	1
101537	Plug, balance	2
101550	Gland, packing,	3
101576	Head, Power Cylinder KVTR	13
101582	CPU 2000, Altronic (291100-1	1
101587	Dowel, pin	3
101588	Dowel, camshaft, long	7
101590	Wire, Stainless Steel .064, 1 lb Spool (91')	5
101593	Gauge, 2.5""""" Type 1009, Plus Performance Option, 0-300 PSI	2
101596	Gasket, Dresser 1" ID	20
101597	Retainer Cup, Dresser 1" ID Gasket.	17
101605	Bolt, compressor con rod	2
101606	Nut,washer, Kvr con rod	2
101609	Gasket, oil pipe	25
101610	Gasket, oil pipe	50
101612	Tetraseal	2
101637	O`ring, Buna	14
101736	Gasket, Exhaust, 304	10
101740	Seal, door bleed screw	2
101743	Hose, 1"x35" AF4750 SS c/w Adaptor (#2024-16-16S)	19
101746	Shaft, water pump	1
101748	Cable, Lead Assy (36"""""), Hall Effect	1
101753	ORing, 136 Viton	28
101754	ORing, 043 Viton	30

101759	Gasket, Dresser, 2" ID		61
101817	Card, AB Model 1746-NO81		1
101881	Gasket, 4" 3123-0009-001 Dresser Stab 38		8
101883	Gasket WR-HTG 16" 150# 304/COG-APX2-COG		10
101898	Module, Interface 40PT		1
101944	Shim- Power Cylinder, K711		10
101946	Lead, Spark Plug, Stitt		28
101958	Thermostat, 165'F,Element Assembly(Amot)		10
101959	Valve, Amot Three Way Thermostatic Oil		1
101961	Kit, Repair Cash		1
101982	Gear, Drive 85 Teeth 5.66:1		2
101983	Gear/Shaft, Pinion 15 Teeth		2
101984	Valve 1/4", Quick Release		2
102005	Seal, Sentry LT Nitrile 48""""ID/50""""OD Scrubber, c/w Steel Backing Spring Encapsulated		5
102008	Shaft, Fan		4
102106	Ring, Seal, Gas, 4" Pipe Sleeve		10
102107	Ring, Seal, GlycolWater, 6" Pipe Sleeve		10
102155	Adaptor, 1" SS Male JIC X 1" Male NPT 90 deg.		62
102158	Hose, 1 1/4" x 21" Overall Length AF4750 SS Braided Hose c/w SS Male NPT Threads E/E		8
102163	Bearing, 22310CC/W33 SKF		2
102164	Seal, Oil		3
102165	Shaft, Compressor Water Pump(4140 HT/SR, Material)		1
102167	Hub, M4 RSB/ATR Jaw Coupling (1 half)		3
102168	Sleeve, Shaft, 600 Bronze		3
102171	Casing, Pump, Compressor Cylinder		2
102197	Filter, Cat Engine Oil 3512 3516		6
102204	Pillow Block, Dodge F&B CC-203-DL Fan & Blower		2
102206	Ring, Casing 5RVL		4
102207	Ring, Casing 3RVL		2
102208	Ring, Casing 3RVL		3
102214	Bearing, K711 Water Pump Drive Shaft Engine and Compressor		4
102215	Seal Oil, K711, Water Pump Drive Shaft Engine and Compressor		2
102222	Kit, Repair Quick Release Valve 1/4"		6
102223	Gasket, Cam Door Large, NC-80 Cork Rectangle 35.8125 X 16.9375 X 1/16"		6
102224	Gasket, CAM KVR Large, 35.625 X 17.032, NC80 Cork		27
102225	Gasket, KVT/KVR Compressor, 28 X 27.4375 NC80		20
102226	Gasket, KVT/KVR Power, 27.9375 X 23.375 NC80 Cork		13
102227	Gasket, Valve Cover KVR, 28.75 X 19.75 NC80 Cork		48
102228	Gasket, Cross Head Door, 28.5 X 25.9375 NC80 Cork		17
102229	Gasket, Chain, 27.75 X 18.3125 NC80 Cork		34
102230	Gasket, Cam Door Small, 16.9375 X 16.625 NC80 Cork		24
102231	Gasket, Cam KVR Small, 16.9375 X 16.75 NC80 Cork		31

102233	Shaft, Drive Engine Compressor Waterpump		1
102234	Seal Type 5611, K707 Auxilary Oil Pump		3
102235	Seal, Auxiliary Oil Pump (Roper) Upper Gear Case		2
102236	Seal, Auxiliary Oil Pump (Roper) Lower Gear Case		3
102238	Shaft, Pump		2
102305	Kit, Seal Replacement Valve Pocket Unloader ACI		32
102306	Kit, Seal Replacement Valve Pocket Unloader ACI		17
102318	ORing, 112 Viton Pocket Unloader		65
102319	U Cup, Piston Viton - Pocket Unloader		3
102320	ORing, 049 Viton Pocket Unloader		15
102324	Switch, Echotel Contact Ultrasonic		1
102327	Shaft, Pocket Unloader Valve		1
102330	Valve, Exhaust Bypass (Waste Gate)		2
102331	Kit, Gasket Locknut, Exhaust Bypass Waste Gate		2
102341	ORing, .210 X 60.50" Viton		3
102342	ORing, .122 Viton		64
102343	ORing, .275 X 53.50" Viton		3
102354	ORing, 120 Viton		33
102355	ORing, 219 Viton		27
102356	ORing, 010 Viton		55
102357	ORing, 425 Viton		14
102358	Gasket, UL 47 Unloader		11
102359	ORing, 376 Viton		51
102360	Elbow, Male, 3/4 Tube X 3/4 Pipe MNPT Brass		26
102361	Glass, Sight Tube 3/4" X 6' John C Ernst		3
102363	Gasket, Gas Packing Gland		13
102365	Filter, Air Primary Cat 3512 3516		1
102391	Nut, Retaining		2
102392	Washer, Retaining		22
102418	Body, Complete Assembly Valve Side Unloader		1
102469	Ring, Piston Side Unloader		4
102470	Gasket, Cover Side Valve Unloader		9
102471	Rod, Piston Side Valve Unloader		4
102472	Gland, Seal Side Valve Unloader		1
102473	Screw, Adjusting Side Valve Unloader		3
102474	Sleeve, Side Valve Unloader		1
102475	Valve, Plug Gate Assembly Side Valve Unloader		1
102476	Cap, Body Cylinder Side Valve Unloader		1
102477	Rod, Indicator Assembly Side Valve Unloader		1
102478	Body, Valve Head Unloader		1
102479	Coupling, Jaw ML-100 X 1 3/8"		3
102480	Insert, Buna L099/100N		2
102520	Bearing, Dodge Renewal Parts INS-F&B-ER-DL-203		2
102531	Sheave, 3/5V4.9 QD-SDS		3
102552	Gasket, 32"ODX25"ID 300 in 304 SS Ceramic Fill Full Face		3
102578	Flange, FFSO 16"""" X 150# STD ASTM 105, ASME B16.5-2003		1

102599	Hose, 1 1/2" X 10" OAL SS Braded c/w SS Hex Male E/E CSA Approved	3
102614	Pipe, Exhaust Upper	1
102620	Sheave, Pully 6/3V5.30 QD-SK	2
102622	Kit, Fan Heat Sink X4 X5 U8100R	4
102630	O'Ring, Viton, .006, (For Lubricator Blocks)	500
102631	Retainer	1
102643	Washer, Camshaft Drive	36
102650	Pin, Cotter	82
102666	Jamnut, Hydraulic Crosshead 4.5"	5
102667	Door, Power Bay IR KVT(R)	1
102690	Shaft, Connecting CW, I-R KVT / KVTR D-D 72 degree's	4
102691	Shaft, Connecting, I-R KVR / KVTR A-D 144 degree's	4
102692	Bolt, Cam Section and Connecting Shaft KVR / KVTR	192
102695	Door, Compressor Bay	1
102758	Hub KW (Lovejoy), L-110 X 1-3/8 STD 5/16 X 5/32	1
102759	Hub KW (Lovejoy), L-110 X 1-1/8 STD 1/4 X 1/8	1
102763	Cable, Lead (48"), Hall Effect	2
102768	Seal, Gland	7
102773	Packing Set, 5", Bronze, Low Emission	11
102804	Seat for PPSDL081-3#1	9
102814	Switch, Proximity SB-MPS	1
102815	SB-6T	1
102817	Shaft, Auxillary Oil Pump	2
102818	Seal, T21 BF50171 C/W D-1437-607 1.437 C/W Special Seat	2
102824	Joint, Expansion	1
102825	Joint, Expansion	2
102826	Joint, Expansion	1
102829	Sheave, Conv	1
102842	Pickup, Magnetic (Altronic)	4
102843	Pickup, Magnetic (Woodland)	1
102844	Nut, Connector, 3/4" - 16	2
102845	Arrestor, Flame, 3/4"	2
102846	Adaptor, Engine	2
102847	Valve, Indicator	2
102850	Sensor, Pressure, Kistler	2
102895	Ring, Flange	6
102934	Valve, Check pcc w/.028 orifice	24
102936	Kit, repair	19
103010	Shaft, Roper Pump Auxiliary Oil Pump K708	1
103026	Spark plug, Champion 631	78
103055	Pump, 5RVL Engine Water Pump	1
103090	Shaft, Unloader	2
103099	Rubber, Dresser Coupling 1 1/2" Style 27	4
103114	Kit, Repair Robertshaw 83380 Valve	2
103115	Hydraulic, Adapter	10
103132	Coupling, Oil Pump 1050T GRID	2

103172	Thermostatic valve	1

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence ("ED")

INTERROGATORY

Reference:

Exhibit B, Tab 2, Schedule 1

Question:

a) Page 4 refers to a conclusion from ICF's natural gas market outlook. This is cited to ICFs Q4 2021 base case, which pre-dates the war in Ukraine and other factors. Please provide an updated analysis from ICF. Ideally this would be a copy of the ICF base case natural market outlook. If that is not possible due to concerns regarding proprietary information, please provide a summary and excerpt similar to that provided from the Q4 2021 version.

Response

a) The ICF Natural Gas Market Outlook is confidential and proprietary, is of significant commercial value, and has not been included in its entirety. The ICF Q4 2021 base case does not include the impacts of the Ukraine war or other factors that have influenced the market since the Q4 2021 forecast was developed. ICF's more recent Base Case forecasts have been updated to reflect ICF's expectations of the impact of the war and other factors on natural gas markets. In general, the war in Ukraine and other factors are expected to have significant short-term impacts on natural gas markets, but only moderate long-term impacts. In its most recent forecast – its Q2 2022 forecast – ICF is now projecting a decline back to $3/MMBtu at Henry Hub between 2022 and 2025 as the North American market equilibrates after recovering from the demand and production shocks from the COVID-19 pandemic and the war in Ukraine. Mixed regulatory signals from local and federal authorities, investors that want to ensure higher rates of return, and the associated lack of investment in infrastructure and labor have led to higher prices and higher price volatility that greatly increase the value of natural gas storage as a hedge against price fluctuations.

After 2025, ICF's Q2 2022 forecast is similar to the Q4 2021 forecast although ICF increased LNG exports by about 1 PJ/d in the Q2 2022 forecast relative to the Q4 2021 forecast. ICF still expects there to be a steady increase in natural gas prices between 2025 and 2040 as well as a slowdown in the growth of natural gas production and greenfield natural gas pipeline expansions. ICF's assessment of trends that will tend to increase the seasonal value of natural gas storage have not changed.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence ("ED")

INTERROGATORY

Reference:

Exhibit C, Tab 1, Schedule 1

Preamble:

Per pages 6-7:

The elimination of 20 PJ (5.6 TWh) of cost-based storage capacity and 0.67 PJ/d (7.8 GW) of design day storage withdrawal deliverability for EGD rate zone customers will have significant long-term consequences to the province.

Question:

a) Please confirm that Canada's 2030 Emissions Reduction Plan includes a target for carbon emissions associated with buildings to decline by 41% by 2030 from 2019 levels (to 53 CO_2e from 91 CO_2e) and that it targets a 22% reduction by 2026 from 2019 levels (to 71 CO_2e from 91 CO_2e).[1] If not, please explain.

b) Please confirm that Canada's 2030 Emissions Reduction Plan has formal legal status under s. 9 of the Canadian Net-Zero Emissions Accountability Act in relation to the legally binding targets under that Act.[2] If not, please explain.

c) Please complete the following table:

[1] https://www.canada.ca/en/environment-climate-change/news/2022/03/2030-emissions-reduction-plan--canadas-next-steps-for-clean-air-and-a-strong-economy.html

[2] Canadian Net-Zero Emissions Accountability Act, s. 9.

Demand Reduction Scenarios					
	2019 Levels	Reduced by 5%	Reduced by 10%	Reduced by 22%	Reduced by 41%
Annual Ontario demand at Dawn Hib (PJ)					
Design day demand at Dawn Hub (PJ/d)					

d) Please complete the table above but in m3 figures instead of joules.

e) Approximately what percent of Enbridge customer demand is used for buildings?

f) Please confirm that Canada has committed to net-zero emissions from electricity generation by 2035. If not, please explain.

g) Please confirm that Canada's 2030 Emissions Reduction Plan includes its commitment to net-zero emissions from electricity generation by 2035. If not, please explain.

h) If gas-fired generation ends by 2035, how would that impact annual demand (PJ) and design day demand (PJ/d) at the Dawn Hub.

i) Please provide the current annual demand (PJ) and design day demand (PJ/d) flowing through Dawn Hub for Ontario's gas plants.

<u>Response</u>

a) f) & g)
Please refer to the federal government's 2030 Emissions Reduction Plan for information related to any targets established by the government within the plan.[3]

[3] https://www.canada.ca/en/environment-climate-change/news/2022/03/2030-emissions-reduction-plan--canadas-next-steps-for-clean-air-and-a-strong-economy.html

b) Please refer to the *Canadian Net-Zero Emissions Accountability Act, (2021)* for information regarding the legal status of the federal government's 2030 Emissions Reduction Plan.[4]

c) & d)

Table 1

Demand	
	2019 Levels
Dawn Hub Design Day Demand (PJ/d)	6.4
Dawn Hub Design Day Demand (m^3/d) Conversion assumes heat value of 39.12 GJ/10^3m^3	166,599,182

Enbridge Gas only purchases gas commodity on behalf of system gas customers, which does not represent the entire market at Dawn. In addition to Enbridge Gas, direct purchase customers, ex-franchise marketers and utilities also purchase gas commodity at the Dawn Hub. The Company is unable to quantify the total volume of gas purchased by these parties.

Based on the current supply forecast included in the 2022 Annual Update to the 5-Year Gas Supply Plan, approximately 25% of Enbridge Gas's supply is sourced from Dawn,[5] which amounts to 133 PJ.

Enbridge Gas has no basis to accept the demand reduction scenarios presented by ED and so has not discounted 2019 Levels.

e) h) & i)
Enbridge Gas respectfully declines to respond to ED's questions as it cannot confirm the precise % of customer demand that is attributable solely to buildings and the subject of gas-fired generation is not at issue in the current proceeding.

[4] https://laws-lois.justice.gc.ca/eng/acts/c-19.3/FullText.html
[5] EB-2022-0072, Table 6 Sources of Supply, p. 28

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (“ED”)

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1

Preamble:

Per page 7:

“As far as Enbridge Gas is aware, there are no plans (either in the short or longer-term) to expand electricity infrastructure in the province at the scale required to replace the energy equivalent of natural gas storage and deliverability made accessible via Tecumseh storage and the existing CCS units. Accordingly, Enbridge Gas has assessed alternatives (both facility and non-facility) based on their ability to provide characteristics commensurate to the physical capacity made accessible and deliverability currently provided by the 7 CCS compressor units proposed to be retired and abandoned.”

Question:

a) Enbridge refers to the scale of electricity infrastructure expansion needed to replace the energy equivalent of the project. With reference to this statement, approximately how much infrastructure (GW) does Enbridge believe is necessary? For instance, is it 7.8 GW or is it closer to one-third that amount (2.6 GW) after accounting for the higher efficiencies of heat pumps (e.g. minimum 3.1 co-efficient of performance for ground source heat pumps), the ability of thermal storage to move electrical heating demand off the peak, and opportunities for cost-effective building envelope energy efficiency improvements?

b) Please estimate the scale of electricity infrastructure expansion needed to replace the energy equivalent of the project assuming electric heating achieved through fuel switching is generated at a design day COP of 3 (average over new equipment, including heat pumps, thermal storage, etc.) and all cost-effective building envelope energy efficiency measures are implemented.

c) Please estimate the scale of electricity infrastructure expansion needed to replace the energy equivalent of the project assuming all cost-effective building envelope energy efficiency is implemented and all fuel switching utilizes the most efficient heat pumps and thermal storage that is achievable.

d) If Enbridge cannot provide an answer to (b) and/or (c), please explain how it is qualified to opine on the scale of electricity infrastructure expansion needed to replace the energy equivalent of the project.

e) Chris Neme of Energy Futures Group provided the following evidence in EB-2020-0091: "the IESO for this year forecast that winter peak demands will be about 2 gigawatts below summer peak demands. That suggests that you could likely electrify something like 10 percent of gas heating without requiring any significant capital additions on the electric grid…" [3]Does Enbridge have any studies or analysis to disprove these statement? If yes, please provide all such studies and analysis and explain them in the interrogatory response.

f) Chris Neme of Energy Futures Group provided the following evidence in EB-2020-0091: "Even larger amounts of electrification may not require significant changes in electric grids. And whether full electrification would require increases in electrification rates would depend on analysis that would have to be done on the marginal cost in the long-term of new generation transmission and distribution relative to current average rates." Does Enbridge have any studies or analysis to disprove these statements? If yes, please provide all such studies and analysis and explain them in the interrogatory response.

Response

a) – f)
The questions posed by ED ask Enbridge Gas to perform detailed analysis and draw conclusions on electricity infrastructure expansion requirements to replace the energy equivalent of the Project. In Exhibit C, where the Company provided the direct energy conversion referenced by ED, Enbridge Gas explained the purpose of and qualified its observation as being provided for illustrative purposes only:

> "These figures are direct energy conversions provided for illustrative purposes only, to give a sense of scale of the amount of energy stored and delivered through the Company's facilities to EGD rate zone customers. No consideration has been made for the efficiency of end use or energy loss due to combustion etc."[4] (emphasis added)

[3] EB-2020-0091, Transcript Volume 4, March 4, 2021, p. 98.
[4] Exhibit C, Tab 1, Schedule 1, Paragraph 6 (footnote 4).

The information was provided to provide a sense of scale of the energy delivery that would be lost due to the retirement and abandonment of the 7 CCS units and as noted above, no consideration was given to efficiency or energy loss.

Given this qualification, Enbridge Gas's application for the Project does not request approval of the methodology employed to provide an illustrative energy conversion. As a result, the questions posed by ED have no relevance to the approvals sought in this proceeding and the Company respectfully declines to respond.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (“ED”)

INTERROGATORY

Reference:

Exhibit C, Tab 1, Schedule 1

Preamble:

Per page 7:

Per pages 6-7:

The elimination of 20 PJ (5.6 TWh) of cost-based storage capacity and 0.67 PJ/d (7.8 GW) of design day storage withdrawal deliverability for EGD rate zone customers will have significant long-term consequences to the province. For comparative purposes, 5.6 TWh is approximately equal to the embedded electrical generation capacity in Ontario (6 TWh). 7.8 GW is approximately equal to:

- 19% of Ontario’s total electrical generation, import and storage capacity;
- 74% of Ontario’s existing nuclear generation capacity;
- 83% of Ontario’s existing hydro generation capacity;
- 141% of Ontario’s existing wind generation capacity; or
- 287% of Ontario’s existing solar generation capacity.

As far as Enbridge Gas is aware, there are no plans (either in the short or longer-term) to expand electricity infrastructure in the province at the scale required to replace the energy equivalent of natural gas storage and deliverability made accessible via Tecumseh storage and the existing CCS units. Accordingly, Enbridge Gas has assessed alternatives (both facility and non-facility) based on their ability to provide characteristics commensurate to the physical capacity made accessible and deliverability currently provided by the 7 CCS compressor units proposed to be retired and abandoned.

Question:

a) Enbridge describes the energy provided by the project as 7.8 GW. However, fossil gas is combusted at efficiencies less than 100% and therefore it generates less than 7.8 GW of heat. Approximately how many GW of heat would be generated by 7.8 GW of gas? Please provide an answer on a best estimate basis with whatever simplifying assumptions and caveats are necessary. For example, please consider any data that Enbridge has access to on average customer equipment efficiencies for furnaces and water heaters. Please provide all calculations and explain the basis for the answer.
b) Please provide an estimate on a best efforts basis of the overall efficiency (AFUE) of space and water heating of Enbridge's single-family residential customers based on Enbridge's customer equipment survey (these survey results are typically filed in DSM proceedings).
c) Please provide an estimate on a best efforts basis of the overall efficiency (AFUE) of space and water heating of Enbridge's commercial customers based on surveys or typical efficiencies of space and water heating equipment for large buildings.
d) Please confirm that the energy required for heating can be reduced through cost-effective energy efficiency measures, which pay for themselves over time in avoided energy costs.
e) Please confirm that NRCan states that "On a seasonal basis, the heating seasonal performance factor (HSPF) of market available units can vary from 7.1 to 13.2 (Region V). It is important to note that these HSPF estimates are for an area with a climate similar to Ottawa."[4] Does Enbridge disagree with NRCan? If yes, please justify the answer.
f) Please confirm that HSPF 13.2 (region 5) is equivalent to a seasonal Co-efficient of Performance (sCOP) of 3.86. Please also confirm that the sCOP is the kWs of heat created by 1 kW of electricity input over an average heating season. Please also confirm that this is sometimes described as an efficiency of 386%. If any of this is not confirmed, please explain in detail and provide the correct answer.
g) Please confirm that cold climate air-source heat pumps can have a COP greater than 2 even at -21 degrees Celsius.
h) Please confirm that NRCan states that the range of available ground-source heat pumps goes up to a heating COP of 4.2 for closed loop applications and 5 for open loop applications.[5] Does Enbridge disagree with NRCan? If yes, please justify the answer.

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[4] https://www.nrcan.gc.ca/energy-efficiency/energy-star-canada/about/energy-star-announcements/publications/heating-and-cooling-heat-pump/6817

[5] Ibid.

i) Please confirm that NRCan states that the minimum heating COP for ground-source heat pumps goes is 3.1 for closed loop applications and 3.6 for open loop applications.[6] Does Enbridge disagree with NRCan? If yes, please justify the answer.
j) Please confirm that a $10,000 incentive is available to customers in Quebec with fossil fuel based central heating (including fossil gas) to convert to an electric thermal storage system.[7]
k) Please confirm that incentives are available in Nova Scotia for electric thermal storage systems.[8]
l) Please confirm that electric thermal storage systems are intended to reduce peak electrical heating demand.
m) Please confirm that:
    i. There are electric thermal storage units on the market now that can provide over 80,000 BTU/hr of heat during the day based on a 12-hour nighttime "charge."[9]
    ii. They are also capable of utility control if desired.
    iii. This can reduce the electricity used to heat almost any home during the peak daytime hours almost to zero.
    iv. This provides a huge shift in demand from peak to off-peak times without any loss in comfort or convenience. If Enbridge does not agree, please justify the answer.
n) Please explain how the 6 TWh and 7.8 TWh figures were derived. Please provide all calculations.
o) Please convert 20 PJ and 0.67 PJ/d to m3 and m3/day. Please provide the conversion factors.

Response

a) It is not possible to accurately calculate the efficiency factor requested by ED as it is entirely dependent upon the specific appliances utilized by and consumption patterns of the millions of customers (residents, businesses and institutions) currently served by the deliverability proposed to be replaced by the Project. Absent this information, Enbridge Gas provided a direct energy conversion for illustrative purposes to the OEB to give a sense of scale with further qualification that no

[6] Ibid.
[7] Hydro Quebec: https://www.hydroquebec.com/residential/energy-wise/windows-heating-air-conditioning/thermal-storage/.
[8] Nova Scotia Power: https://www.nspower.ca/your-home/energy-products/electric-thermal-storage.
[9] Steffes, Off-Peak Heating, https://www.steffes.com/wp-content/uploads/2020/12/Steffes-Forced-Air-Furnace.pdf.

consideration was given to efficiency or energy loss. Please also see the responses at Exhibit I.ED.4.

b) – m)

ED has requested that Enbridge Gas evaluate and produce efficiency values for several types of space and water heating equipment as well as opine on NRCan's efficiency conclusions and incentives available for conversion to electric thermal storage systems in other provinces. Enbridge Gas respectfully declines to respond to ED's questions as they exceed the scope of the current proceeding and ED has provided no basis as to their relevance. Please also see the responses at Exhibit I.ED.4.

n) In responding to this question Enbridge Gas presumes that ED meant to refer to 5.6 TWh and 7.8 GW.

Conversion to 5.6 TWh:
(20 PJ x 1e6 GJ/PJ ÷ 3600 GJ/GWh) = 5555.556 GWh -or- 5.6 TWh

Conversion to 7.8 GW:
(0.67 PJ/d x 1e6 GJ/PJ ÷ 24h/d x 1h ÷ 3600 GJ/GWh) = 7.7546 GW -or- 7.8 GW

o) 20 PJ converted to m^3:[10]
39.12 GJ/10^3 m^3 ÷ 1000 x 1000MJ/GJ = 39.12 MJ/m^3
(20 PJ x 1e9 MJ/PJ ÷ 39.12 MJ/m^3) = 511,247,443 m^3 -or- 511.2 million m^3

0.67 PJ/d converted to m^3/d:[11]
39.12 GJ/10^3 m^3 ÷ 1000 x 1000MJ/GJ = 39.12 MJ/m3
(0.67 PJ/d x 1e9 MJ/PJ ÷ 39.12MJ/m^3) = 17,126,789 m^3/d -or- 17.12 million m^3/d

[10] Heating Value of natural gas: 39.12 GJ/10^3 m^3, sourced from April 1, 2022 reference price/conversion factor notice from Finance (Cost of Gas)
[11] Heating Value of natural gas: 39.12 GJ/$10^3$$m^3$, sourced from April 1, 2022 reference price/conversion factor notice from Finance (Cost of Gas)

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (“ED”)

INTERROGATORY

Reference:

Exhibit C, Tab 1, Schedule 1

Question:

a) On page 8 Enbridge states as follows: “The CCS facility provides EGD rate zone customers up to 0.67 PJ/d of design day withdrawal deliverability…” Why is the deliverability “up to” 0.67 PJ/d?

b) What is the expected withdrawal deliverability in mid-February once the storage has been depleted by winter withdrawals up to that time? In light of that, how much deliverability can Enbridge rely on for design day system planning purposes?

Response

a) On a design day, the storage withdrawal deliverability lost if the 7 CCS compressor units proposed to be retired and abandoned (K701-K703 and K705-K708) are not replaced is 0.67 PJ/d.

b) The deliverability from storage for the EGD rate zone is shown in Exhibit C, Tab 1, Schedule 1, p. 4, Figure 1. Enbridge Gas plans to hold 43.5 PJ of gas in storage at the end of February and therefore 1.9 PJ/d of deliverability is available throughout February.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence ("ED")

INTERROGATORY

Reference:

Exhibit B & C, Tab 1, Schedule 1

Preamble:

Enbridge states as follows:

"The access to storage capacity provided by the Dawn to Corunna project will reduce the NPV of commodity purchase costs over the 40-year life of the asset by $794 million, leading to a total reduction in the NPV of the cost-of-service to in-franchise customers of about $589 million relative to the Non-Replacement option." Exhibit C, Tab 1, Schedule 1, Page 9

"For example, during withdrawal season, using the last 10 years of Dawn pricing data across January, February, and March, the loss of an additional CCS unit on a peak winter day (in addition to K705) would have ranged in cost for delivered supply between approximately $800,000 to $11 million for a single day." Exhibit B, Tab 1, Schedule 1, Page 16

Question:

a) Please reconcile the figures referenced in the two paragraphs above. Please include calculations and underlying figures.

b) Please reconcile the two figures referenced in the first paragraph above.

Response

a) & b)
In its report, ICF concludes that retiring the CCS units without replacing storage space and deliverability lost would increase the market price of natural gas commodity at the Dawn Hub. The result is increased commodity costs to all parties

that purchase gas at Dawn, including Enbridge Gas. The paragraph referenced in Exhibit C, Tab 1, Schedule 1, p. 9, explains that the Project will prevent price increases to natural gas commodity that would otherwise occur if Enbridge Gas retired and abandoned the CCS units without replacement. The NPV of the avoided commodity cost increases over a 40-year term (comparable to the depreciable life of the proposed pipeline facilities) is $794 million.[1] After considering the NPV of the incremental Dawn to Corunna infrastructure costs, the result is a NPV reduction of cost of service to in-franchise customers of $589 million. A detailed explanation and supporting calculations for these amounts can be found within section 3.1 of ICF's report at Exhibit C, Tab 1, Schedule 1, Attachment 2, pp. 26 – 31.

The figures referenced by ED in Exhibit B, Tab 1, Schedule 1, p. 16, represent an estimate of the daily cost of the gas commodity that would be required to resolve a shortfall resulting from the unplanned loss of an additional CCS unit during the downtime experienced on unit K705 in 2018 on a peak winter day ($800,000 to $11 million). Please see the response at Exhibit I.ED.1 part h), for a description of the calculation of this cost range. This amount is not related to the NPV figures calculated by ICF (as discussed above), which contemplate a different scenario (the long-term impact of a planned retirement of all CCS units without replacement over a 40-year term).

[1] This increase to the commodity cost that would result from retirement of the CCS units with no replacement is limited to the impact on Enbridge Gas's in-franchise commodity portfolio and does not account for cost increases to other market participants that transact at Dawn.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence ("ED")

INTERROGATORY

Reference:

Exhibit C, Tab 1, Schedule 1

Preamble:

Table 1: NVP of Alternatives – 40-Year Term

Alternative		NVP ($ Millions)
Project	NPS 36 Pipeline	$(200)
Alternative 1	Natural Gas Fired Compression	$(212)
Alternative 2	Electric Drive Motor Compression	$(270)

Question:

Please reproduce table one assuming a term ending in (i) 2035, (ii) 2045, and (iii) 2050.

Response

ED requested additional analysis that would only be useful if the demand served by the Project were reduced to zero in (i) 2035, (ii) 2045 or (iii) 2050. ED has asked for this information without providing any foundation as to the basis for the terms requested or why they are reasonable. The Company does not believe these represent realistic scenarios and as such, respectfully declines to perform the analysis requested by ED.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence ("ED")

INTERROGATORY

Reference:

Exhibit C, Tab 1, Schedule 1

Preamble:

"NPV analysis was not completed for the Repair + Replace alternative as it is not able to adequately satisfy the project need as described in Exhibit B. While the capital cost of this alternative is lower than the proposed Project alternative described above (NPS 36 Pipeline), the O&M cost is nearly double. The alternative's inability to adequately satisfy the project need led the Company to determine that this alternative is not preferrable."

Question:

a) As the question of whether this option could meet to project need is potentially disputed in this proceeding, and the OEB has not decided on that issue, please provide the NPV analysis. Please also provide the NPV assuming a term ending in (i) 2035, (ii) 2045, and (iii) 2050.

b) Under the alternative as defined by Enbridge, K701-K703 would be decommissioned and K705-K708 would remain in service. Seeing as the safety issues pertain to compressors located in close proximity to each other, would safety be improved in this alternative if a different set of compressors where decommissioned such that greater spacing would be allowed between units?

Response

a) The Company does not agree with ED's assertion that the Repair + Replace Alternative could potentially meet the Project need.

   As described in detail in Exhibit C, leaving the existing CCS units in operation would expose ratepayers to increasing risk of interruption to storage withdrawal and injection operations and increasing cost risk to procure supply. Further, leaving units

K705-K708 in operation does not sufficiently address the employee safety risk associated with the number of compressor units and building occupancy in CCS compressor buildings 1 and 2.

The NPV of the Repair + Replace alternative over a 40-year term is ($208 million) which is more expensive than the proposed Project.

Please see the response at Exhibit I.ED.8, for Enbridge Gas's justification for not providing NPV calculations for the various shorter terms requested by ED. Please also see the response at Exhibit I.SEC.13 for a broader discussion of the assessment of alternatives..

b) As discussed in Exhibit B, Tab1, Schedule 1, p. 9, only the 7 units proposed for retirement as part of the project can be decommissioned at this time as units K704, K709, K710 and K711 provide a specific operational fit/requirement enabling the Company to fully fill and empty storage. As explained in the response at Exhibit I.SEC.13, retiring all 7 units at one time is the most effective means of reducing/eliminating obsolescence, reliability and safety risks and there are significant economies of scale that result from and the same, due to lower total cost of capital.

   Additional risk assessment for another option (i.e., abandonment of CCS compressor units K701/2/3/7/8) has also been completed and is discussed in the response at Exhibit I.ED.10 c).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence ("ED")

INTERROGATORY

Reference:

Exhibit C, Tab 1, Schedule 1

Question:

a) Please provide a table comparing the access to storage (PJ) and deliverability (PJ/d) available via:
   i. One new Spartan e90 electric motor drive ("EMD") compressor unit;
   ii. One new Taurus 70 gas turbine compressor unit; and
   iii. Each of the existing CSS compressor units.

b) Please calculate the capital cost, operating costs, and NPV for an option involving the construction of a single new compressor unit and maintaining the existing units in service to the extent necessary to supplement the new unit and provide the necessary redundancy. Please calculate the NPV based on a 40-year term and also based on terms ending in (i) 2035 and (ii) 2050.

c) Please provide a table listing the permutations of existing compressors that could be retired if Enbridge were to purchase and install a single new compressor. For each row, please indicate the impact on facility safety. The goal is to get an idea of which compressors raise the most issues and whether better spacing between them can improve safety.

d) Please provide a diagram or map with labels for each compressor and each building.

e) Please reproduce the Table 1 in Exhibit C, Tab 1, Schedule 1, Attachment 1, adding the option discussed in this interrogatory and the NPV figures calculated in (b).

Response

a) Enbridge Gas has interpreted the phrase “access to storage (PJ)” to mean lost storage capacity (deliverability and space). Please see Table 1 below.

Table 1

Scenario	Lost Design Day Deliverability (TJ/d)	Lost Space (PJ)	Lost Horsepower (HP)	Lost Horsepower (MW)*
Replace 7 units with Spartan e90	362	0	10,225	7.6
Replace 7 units with Taurus 70	362	0	10,225	7.6
Abandon K701	41	0	2,500	1.9
Abandon K701/2	88	0	5,000	3.7
Abandon K701/2/3	140	0	7,500	5.6
Abandon K701/2/3/8	329	0	11,250	8.4
Abandon K701/2/3/7/8	427	5	15,000	11.2
Abandon K701/2/3/6/7/8	547	15	18,750	14.0
Abandon K701/2/3/5/6/7/8	666	20	22,500	16.8

*Assuming conversion factor of 1 HP = 0.000746 MW

b) Please see the response at Exhibit I.SEC.13.

The addition of a single new compressor unit is not a feasible alternative as it would leave a single point of failure and would not provide full LCU coverage for the single new compressor. In addition, this alternative does not address the Project need, as the reliability and safety risks would not be addressed.

c) Implementation of adequate spacing between the compressors would reduce equipment density at a location and decrease the safety risk. Equipment density is a key input into the safety risk calculation (QRA). The higher the equipment density at a location, the higher the safety risks. However, adequate spacing between compressors could only be achieved if compressors are not housed in the same building. Table 2 outlines options for compressor abandonment that can be offset by a new compressor:

Table 2

Option #	Scenario
1	Abandon K701
2	Abandon K701/2
3	Abandon K701/2/3
4	Abandon K701/2/3/8
5	Abandon K701/2/3/5/6
6	Abandon K701/2/3/6/7
7	Abandon K701/2/3/7/8

The compressors listed in part a) provide sufficient capacity to support any of the options listed above. Options 1 through 4 would represent a lower safety improvement than Options 5 to 7 due to the lower reduction in equipment density. Additionally, the cost to implement Options 1 through 4 would be virtually the same as the cost to implement Options 5 through 7. This is because the cost for the compressor does not change with each option, and abandonment costs would be relatively insignificant. Therefore, Options 1 through 4 would not be considered.

Of the remaining Options, Options 6 and 7 achieve the lowest equipment density reduction in Building 2. Option 7 is preferable as it maximizes separation between the remaining units in Building 2. Therefore, only Option 7 would be considered for evaluation of safety improvement in comparison to the Project as it will provide the greatest safety improvement.

The risk value associated with Option 7 shows that the site still exceeds the upper risk threshold for the following personnel (Region 1):

- Operator; and
- Mechanics.

Risk reduction from Region 1 to Region 2 (conditionally tolerable) is expected for the following personnel compared to the current risk (refer Exhibit B Tab 1 Schedule 1 Page 25, Paragraph 51):

- Instrumentation Technician;
- Electrical Technician; and
- Chief Mechanic.

Based on the risk calculation for Option 7, this alternative still results in an excessive level of process safety risk.

d) Please see Attachment 1.

e) Please see the response to part c). This alternative does not meet the imminent need of obsolescence and declining reliability and does not fully address the safety concerns. As such, it is not considered to be feasible and Enbridge Gas has not completed incremental NPV analysis at this time.

Enbridge Gas Inc. — Corunna Compressor Station, 3501 Tecumseh Rd., Mooretown, ON

June 15, 2022

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence ("ED")

INTERROGATORY

Reference:

Exhibit C, Tab 1, Schedule 1

Preamble:

These questions relate to the possibility of a cheaper incremental reliable solution that would provide more time to get a better grasp on how much gas infrastructure will be needed in, say, 2030 (Canada's 2030 Emissions Reduction Plan targets a 41% decline in emissions from buildings by 2030 from 2019 levels), 2035 (Canada's target for zero-emissions electricity), or 2050 (national net zero target).

For instance, an incremental solution could involve replacing 50% of the CSS capacity with a single new compressor for now, decommissioning one or two K700 series compressors for parts, keeping the other K700 series units around for the remaining 50% capacity and as backup, and using the additional operational flexibility to allow units to be turned off when needed to improve safety. In five or ten years from now it may be that a decision is made to buy second new compressor, or it may be that demand has dropped and that no more ratepayer investment is needed.

Question:

a) Please comment on the feasibility of the above potential solution.

b) Putting aside for now a debate regarding feasibility, please estimate the cost-effectiveness (NPV) of the above potential solution.

c) The above potential solution provides what is often called "option value" by allowing investments over time, which may allow for some of those investments to be avoided based on updated information. Putting aside for now a debate regarding feasibility, please provide an estimate of the option value.

d) Please describe how option value is considered in Enbridge's planning process. If it is not considered, please describe how it could be considered as it relates to solutions for this proceeding that may provide that value.

<u>Response</u>

a) – d)

As further explained in the response at Exhibit I.SEC.13, the Company does not consider ED's proposed partial alternative to be feasible since it does not address the imminent need to resolve the obsolescence and declining reliability risks, as only 1 or 2 of the existing CCS compressor units is suggested for replacement by ED and the remaining 6 or 7 units will continue to experience increased downtime and risk of failure. This also does not address the current configuration of the remaining 6 or 7 units, or the safety risk as a result of the increased repair and maintenance time spent on the remaining 6 or 7 units by Company personnel. Enbridge Gas has an obligation to safely meet its contractual obligations to reliably serve the firm demands of its customers and as such, can only give consideration to alternatives that address these risks.

The cost estimate for ED's proposed alternative, to install a single new Taurus 70 compressor and abandon CCS compressor units K701-K703, is $160 million. The annual O&M cost for this alternative is approximately $5.5 million/year. Thus, ED's proposed alternative, which does not address the project need to resolve the current obsolescence, reliability and safety risks and puts firm deliveries of natural gas to ratepayers at risk, has a NPV of ($208 million).

Given its inability to resolve the underlying system constraints driving the need for the Project, that it is less economic than the proposed Project, and that there is no basis for ED's predictions of future natural gas demand (and more specifically the value of cost-based physical storage capacity), Enbridge Gas respectfully declines to estimate any option value for ED's alternative.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence ("ED")

INTERROGATORY

Reference:

Exhibit C, Tab 1, Schedule 1

Question:

a) Please provide all calculations, assumptions, and spreadsheets underlying the calculation of Table 2 on Exhibit C, Tab 1, Schedule 1, Page 1 and Table 1 in Exhibit C, Tab 1, Schedule 1, Attachment 1

Response

Please see below the assumptions and calculations related to O&M in Table 2 on Exhibit C, Tab 1, Schedule 1, Page 1.

The O&M Assumptions directly below are described at Exhibit C, Tab 1, Schedule 1, Attachment 1, pp. 1-2:

- Annual O&M
- Integrity O&M
- Routine Maintenance Capital
- Annual Fuel/Electricity Usages
- Annual Emissions (Carbon Cost)
- Property Tax Estimates

Further O&M details by alternative are described below:
Pipeline Assumptions –

- Annual O&M - Based on input from Enbridge Gas Storage and Transmission Operations department for pipeline right of way maintenance, valve inspections.
- Integrity O&M – historical average from Transmission Integrity Management Program.
- Routine Maintenance Capital – 3 digs between years 20-30, 6 digs between years 30-40.

- Annual Fuel Usage – 4% reduction in fuel usage based on the average fuel consumption for existing units at CCS when using the average fuel burn rate for compressor units at Dawn. An average burn rate was used due to the various combinations of compressors that could be used at Dawn on any given day. 4% is based on Dawn Plant G published burn rates.

Gas Compression Assumptions –
- Annual O&M - Assumption based on 5 yr average historical costs for Dawn J (2x). Comparable make and model.
- Routine Maintenance Capital – assume $2.6 million per overhaul, per unit as per 2020 Original equipment manufacturer (“OEM”) costs. Service costs are expected to increase.
- Annual Fuel Usage – 8% increase in fuel consumption based on the average fuel burn rate for a Solar Taurus 70 at Dawn Plant F.

Electric Motor Driven (“EMD”) Compression Assumptions –
- Annual O&M - Assumption based on 5 yr average historical costs for Dawn J (2x). Comparable make and model.
- Routine Maintenance Capital – assume $2 million per overhaul, per unit as per discussion with subject matter experts. Service costs are expected to increase.
- Annual Electricity Usage – EMD operates at 90% efficiency. The HP for current units at Corunna converted to equivalent kw and average 5 year run time @ utility rate of 0.148 $/kwh

ETEE Alternative –
- Required reduction of 90 GJ/d.
- ETEE occurs in the CDA (Exhibit C, Tab, Schedule 1, para.26).
- Unit Cost to reduce capacity (based on Achievable Potential Study):

ETEE costs to reduce sufficient capacity	$1.923 million
Volume reduction	176,410 GJ/d
Unit cost $/GJ/d	$10,901 $/GJ/d

- Total cost to reduce 90 GJ/d:

$10,901 $/GJ/d x 90 GJ/d	$981.1 million

LNG Alternative –
- Annual O&M - Based on 20-year average from Hagar.
- Maintenance Capital - Based on past 2 years of maintenance capital at Hagar LNG facility.

- Annual Fuel Usage - Based on average fuel consumption from previous 3 years at 20% utilization. Assume 4x to meet year-round operation.

Repair + Replace Alternative –
- Annual O&M – based on historical O&M for Corunna Compressor Facility from 2015-2020 proxied by average run time per unit over the same time period.
- Integrity O&M – historical average from Transmission Integrity Management Program.
- Routine Maintenance Capital – 3 digs between years 20-30, 6 digs between years 30-40.
- Planned capital investments on units K705-K708 for years 2023-2032 (see response at Exhibit I.Staff.10 for additional details).

Common Assumptions across Alternatives –
- Annual Emissions (Carbon Cost) – fuel consumption converted to equivalent tonnes of CO_2e. Does not include Fugitive Emissions.
- Annual fuel - used Dawn Reference Price = 131.431 $\$/10^3m^3$
- Annual Emissions - Average annual cost of carbon over 40 years = 54.66 $\$/tCO_2e$
- Property Tax Estimates:
    - No reassessment increases in 2024.
    - Used 2021 tax rates for St. Clair & Dawn-Euphemia and inflated by 1.8% p/a.
    - For pipeline alternatives, ISD is November 2023, pipeline would be reported to MPAC March 1, 2024. In 2024 would be responsible for 16 months taxes in 2024. 12 months for the calendar year 2024 and 4 months for the prior year per MPAC policy. In 2025 and subsequent years pipe taxes would be based on 12 months only. Subject to any additions/deletions to the pipeline. As new pipeline would be a 3rd pipeline from Corunna to Dawn, running parallel to the 2 existing NPS 30 pipelines; the second parallel oldest line has been adjusted by 25% - an assessment reduction per MPAC policy.
    - Assumed new compressor station will occupy 14 acres of land at the commercial new construction class.
    - No changes to Section 357 of the Municipal Act and company meets eligibility requirements at time of application for property tax rebates.
    - Land, buildings and compressors will be pro-rated for 61 days for 2023. Compressor will be fully abandoned by January 2024.
    - Estimate is based on high level information as provided as at Feb 17, 2021 & December 14, 2021. Some compressor details remained unconfirmed.

Annual O&M calculations made using the assumptions described above are set out in Table 1.

Table 1

Alternative	**NPS 36**	**NG Fired Compression**	**Electric Motor Drive Compression**	**Repair + Replace**	**LNG**
Annual O&M	**$ 30,000**	**$ 578,336**	**$ 578,336**	**$ 2,352,699**	**1,057,730**
Integrity O&M	**$600,000**			**$600,000**	
	every 10 years			every 10 years	
Maintenance Capital	**$ 525,000**	**$ 5,200,000**	**$ 4,000,000**	**$ 525,000**	**$ 1,000,000**
	total between 20-30 years	every 10 years	once in lifespan	total between 20-30 years	annual
	$ 1,050,000			**$ 1,050,000**	
	total between 30-40 years			total between 30-40 years	
				$9,735,532	
				2023-2032 Planned Projects	
Annual Fuel / Electricity Usage	8,642	9,392	38,465,245	8,642	395.1
	10^3m3	10^3m3	kwh	10^3m3	10^3m3
	$ 1,135,827	**$ 1,234,400**	**$ 5,692,856**	**$ 1,135,827**	**$ 51,928**
Annual Emissions (tCO2e)	17,469	19,648	0	17469	799
Average Annual Carbon Cost	**$ 954,768**	**$ 1,073,861**	**$ -**	**$ 954,768**	**$ 43,653**
Property Tax Estimates (alterantive specific)					
2023	$ 126,533	$ 75,817	$ 75,817	$ 126,533	
2024	$ 772,866	$ 461,822	$ 461,822	$ 772,866	
2025+	$ 786,778	$ 470,135	$ 470,135	$ 786,778	$ 470,135
Annual O&M	**$ 2,991,748**	**$ 3,876,732**	**$ 6,841,327.26**	**$ 5,333,232**	**$ 2,623,446.52**

Capital cost calculations made using the assumptions described above for pipeline and compression alternatives are set out in Table 2.

Table 2

	OEB FILING								
Estimate Project Costs	NPS 36 Pipeline			Natural Gas Fired Compression			Electric Motor Drive Compression		
Decsription	**Pipeline Costs**	**Ancillary Costs**	**Total Costs**	**Station Costs**	**Ancillary Costs**	**Total Costs**	**Station Costs**	**Ancillary Costs**	**Total Costs**
Materials	11,800,354	36,643,592	48,443,946	39,017,428	36,643,592	75,661,020	43,472,345	36,643,592	80,115,937
Construction & Labour	51,310,846	28,993,020	80,303,866	34,984,494	28,993,020	63,977,514	34,984,494	28,993,020	63,977,514
External Permitting & Lands	15,322,222	-	15,322,222	961,875	-	961,875	961,875	-	961,875
Outside Services	19,230,385	15,702,325	34,932,710	20,700,772	15,702,325	36,403,097	21,313,807	15,702,325	37,016,132
Direct Overheads	1,295,000	-	1,295,000	1,226,070	-	1,226,070	1,226,070	-	1,226,070
Contingency	13,180,351	10,816,348	23,996,699	19,376,594	10,816,348	30,192,942	20,306,866	10,816,348	31,123,214
IDC	2,093,000	-	2,093,000	2,171,706	-	2,171,706	2,177,758	-	2,177,758
Project Cost	**114,232,158**	**92,155,285**	**206,387,443**	**118,438,939**	**92,155,285**	**210,594,224**	**124,443,213**	**92,155,285**	**216,598,498**

For the calculation of NPV for each alternative, please refer to the response at Exhibit I.SEC.14.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence ("ED")

INTERROGATORY

Reference:

Exhibit C, Tab 1, Schedule 1

Question:

a) If the demand for storage were to decline by 20 PJ and demand for deliverability would decline by 0.67 PJ/d, would the project still be needed and/or cost-effective?
b) Enbridge's evidence refers to 20 PJ of storage capacity and 0.67 PJ/d of deliverability. How much of this would remain if units K701-703 and K705-708 were retired without being replaced by new compressors or a new pipeline?
c) How much would demand need to decline (annual and peak) to allow:
    i. One of the compressors (K701-703 / 705-708) to be retired or reserved as an additional backup (i.e. LCU) without requiring replacement by a supply-side alternative;
    ii. Two of the compressors (K701-703 / 705-708) to be retired or reserved as additional backups (i.e. LCU) without requiring replacement by a supply-side alternative;
    iii. Three of the compressors (K701-703 / 705-708) to be retired or reserved as additional backups (i.e. LCU) without requiring replacement by a supply-side alternative;
    iv. Four of the compressors (K701-703 / 705-708) to be retired or reserved as additional backups (i.e. LCU) without requiring replacement by a supply-side alternative;
    v. Five of the compressors (K701-703 / 705-708) to be retired or reserved as additional backups (i.e. LCU) without requiring replacement by a supply-side alternative;
    vi. Six of the compressors (K701-703 / 705-708) to be retired or reserved as additional backups (i.e. LCU) without requiring replacement by a supply-side alternative; and
    vii. Seven of the compressors (K701-703 / 705-708) to be retired or reserved as additional backups (i.e. LCU) without requiring replacement by a supply-side alternative.

Response

a) Please see the response to Exhibit I.PP.9 a), for discussion of the demand reduction required for Enbridge Gas to consider reducing its reliance upon cost-based storage.

b) If units K701-703 and K705-708 were retired without being replaced by new compressors or a new pipeline 20 PJ of storage capacity and 0.67 PJ/d of deliverability would be lost.

c) Table 1 outlines the demand decline that would need to occur in order to offset the requirement to replace the capacity represented by each compressor being replaced in the Project. The decline in annual demand is the reduction in the current amount of 20 PJ space requirement, and the decline in peak demand is the reduction in the current amount of 0.67 PJ/d of deliverability.

Table 1

Scenario	Decline in Annual Demand	Decline in Peak Demand
i	21%	28%
ii	21%	30%
iii	21%	31%
iv	21%	36%
v	25%	38%
vi	33%	41%
vii	37%	44%

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence ("ED")

INTERROGATORY

Reference:

Exhibit C, Tab 1, Schedule 1

Question:

a) What is the threshold in terms of declining demand (annual and peak) at which point the NPS 36 could be downsized without requiring a supplemental supply-side alternative? Please provide the threshold for each of the next three smaller standard pipe sizes.

b) Please provide a table indicating the capital and operating savings for each of the pipe sizes referred to in (a) vis-à-vis the NPS 36.

c) What is the threshold in terms of declining demand (annual and peak) at which point the NPS 36 would no longer be needed without requiring a supplemental supply-side alternative?

Response

a) & c)
As outlined in the response at Exhibit I.PP.9 a), the level of decline in design day demand required to impact the need for the Project is approximately 27% of current design day demand. Please also see the response at Exhibit I.ED.13 for additional context.

Table 1 identifies the design day demand reductions required to reduce the size of the Project by three standard pipeline sizes.

Table 1

Pipe Size	Loss in Design Day Deliverability[4]
NPS 30	90 TJ/d
NPS 24	233 TJ/d
NPS 20	306 TJ/d

b) Table 2 below calculates annual operating and maintenance capital savings as requested. The assumptions applied to complete the calculations set out in Table 2 are described below.

[4] Enbridge Gas designs its system and completes planning based on design day to ensure it can meet the firm contractual demands of its customers under design conditions (coldest day of the year).

Table 2

Alternative	Baseline (Current State)	NPS 36	Repair + Replace
Annual O&M	**$ 2,922,152**	**$ 30,000**	**$ 2,352,699**
Integrity O&M (pipelines)		**$600,000**	**$600,000**
		every 10 years	every 10 years
Maintenance Capital	**$16,246,779**	**$ 525,000**	**$ 525,000**
	2023-2032 Planned Projects	total between 20-30 years	total between 20-30 years
		$ 1,050,000	**$ 1,050,000**
		total between 30-40 years	total between 30-40 years
			$9,735,532
			2023-2032 Planned Projects
Annual Fuel (10^3m3)	8,969	8,642	8,642
	$ 1,178,804.64	**$ 1,135,826.70**	**$ 1,135,826.70**
Annual Emissions (tCO2e)	18,131	17,469	17,469
Incremental Property Tax Estimates from Baseline			
2023		**$ 126,533**	**$ 126,533**
2024		**$ 772,866**	**$ 772,866**
2025		**$ 786,778**	**$ 786,778**
Average Annual Maintenance Costs	$ 6,716,584.34	$ 2,991,748	$ 5,333,232
Annual Savings from Baseline	**-**	**$ 3,724,836.45**	**$ 1,383,352.44**

Assumptions:

For the Repair + Replace alternative the operating and maintenance capital costs are the same for the NPS 30, 24 and 20 pipelines in conjunction with continuing to operate units K705-708. The initial upfront capital and costs associated with loss in design day deliverability are not included and will differ between pipe sizes.

Annual O&M –

- Current State - 7 units based on 2015-2020 average (proxied by run-time hours).
- NPS 36 - Based on pipeline ROW maintenance, valve inspections.
- NPS 30, 24 & 20 - Based on pipeline ROW maintenance, valve inspections + 4 remaining units proxied by run-time average from 2015-2020.

Integrity O&M –

- Pipeline inspection program every 10 years.

Maintenance Capital –

- Current State - 2023-2032 Planned capital investments.
- NPS 36 – 3 digs between years 20-30 + 6 digs between years 30-40.
- NPS 30, 24 & 20 - 3 digs between years 20-30 + 6 digs between years 30-40 + 2023-2032 Planned capital investments for units K705-K708.

Annual Fuel –

- Used Dawn Reference Price = 131.431 $\$/10^3m^3$.

Annual Emissions –

- Average annual cost of carbon over 40 years = 54.66 $\$/tCO_2e$.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence ("ED")

INTERROGATORY

Reference:

Exhibit C, Tab 1, Schedule 1, Attachment 2

Preamble:

Please ask ICF to provide responses to these questions.

Question:

a) If Dawn-Parkway demand increases, would that improve the relative cost-effectiveness of the NPS 36 pipeline option vis-à-vis the alternatives set out in ICF's report? Please explain the answer in detail.

b) If Dawn-Parkway demand decreases, would that improve the relative cost-effectiveness of the alternatives set out in ICF's report vis-à-vis the NPS 36 pipeline option (but not necessarily impact which option is ultimately the most cost-effective)? Please explain the answer in detail.

c) Please provide all of ICF's assumptions and forecasts for gas demand on the Dawn-Parkway system underlying its report. Please provide the response in PJs and m3.

d) What is the threshold in terms of declining demand at which point an alternative in the ICF report becomes more cost-effective than the NPS 36 pipeline? We leave it to ICF to determine the best way to measure declining demand. For instance, ICF may wish to re-run the analysis with demand decreased by X % and indicate the percentage decline at which a market-based alternative becomes more cost-effective.

e) Please provide the live excel spreadsheet calculating the cost-effectiveness of the most cost-effective option outlined ICF's report.

f) Please calculate the relative cost-effectiveness (NPV) of an additional option, namely (a) the compressor capacity at CSS declines by 50% due to a partial retirement of some compressors and (b) the remaining capacity is made up by the most cost-effective market-based alternative.

Response

a) & b)
The Dawn-Parkway system is supplied from a combination of Dawn storage and upstream supplies delivered at Dawn, Kirkwall and Parkway. By contrast, the proposed Project is a storage project that replaces design day capacity derived from existing CCS compressor assets (which will be retired and abandoned) with design day capacity derived from the proposed pipeline and existing Dawn compression.

Any changes to Dawn-Parkway system capacity, either an increase or decrease, would be made as an adjustment to upstream supplies delivered at Dawn, Kirkwall or Parkway. Therefore, any change in Dawn-Parkway demand will not impact the relative cost-effectiveness of the Project or its alternatives.

c) The Dawn to Parkway system primarily supplies natural gas customers in Ontario (although customers outside of Ontario in Quebec and the Northeast U.S. also rely on the system to withdrawal gas from storage). Relevant gas demand forecasts are provided in Table 1 below. The Ontario total demand column shows ICF's forecast for demand from all sectors in Ontario, which is a driver of annual throughput on the system. The Ontario residential, commercial, and industrial demand column shows annual demand for those customers. The Enbridge Gas Peak Day Forecast shows the forecasted peak day demand for Enbridge's in-franchise customers, which is the driver of maximum expected withdrawals from Dawn storage, flows on the Dawn to Parkway system, and contracting on the system.

As described in ICF's report, ICF used Enbridge Gas's natural gas load forecasts for 2024 through 2028 for in-franchise customers. After 2028, the demand forecasts are based on the growth rate from ICF's Q4 2021 Base Case demand forecast for residential, commercial, and industrial customers in Ontario. The ICF forecast for annual residential, commercial, and industrial natural gas demand growth in Ontario is based on the Canada Energy Regulator 2020 Canada's Energy Future Reference Case forecast and is projected to increase by 0.61% per year between 2028 and 2045.[4] The current projected 2024 demand for Enbridge is 4,175 TJ/day.

[4] The ICF 2021 Q4 Base Case was completed prior to the release of the CER 2021 Canada's Energy Future forecast.

Table 1

	PJ			Bcm		
	Ontario Total Demand	Ontario Res/Com/Ind Demand	Enbridge Gas Peak Day Forecast	Ontario Demand	Ontario Res/Com/Ind Demand	Enbridge Gas Peak Day Forecast
2024	1091.56	941.96	4.08	30.05	25.30	0.11
2025	1118.95	941.63	4.09	31.90	25.29	0.11
2026	1187.80	944.61	4.11	31.67	25.37	0.11
2027	1179.10	948.95	4.12	32.13	25.48	0.11
2028	1196.52	954.29	4.14	32.09	25.63	0.11
2029	1194.72	955.83	4.16	32.12	25.67	0.11
2030	1195.92	959.68	4.18	32.67	25.77	0.11
2031	1216.58	964.11	4.21	32.87	25.89	0.11
2032	1224.01	972.84	4.23	32.89	26.13	0.11
2033	1224.73	975.57	4.25	33.01	26.20	0.11
2034	1229.32	980.64	4.28	33.14	26.34	0.11
2035	1234.16	985.98	4.30	33.70	26.48	0.12
2036	1254.88	988.50	4.32	34.39	26.55	0.12
2037	1280.44	997.01	4.35	35.01	26.78	0.12
2038	1303.49	1002.85	4.37	35.66	26.93	0.12
2039	1327.71	1009.37	4.40	36.24	27.11	0.12
2040	1349.58	1012.70	4.42	36.81	27.20	0.12
2041	1370.55	1023.28	4.45	37.30	27.48	0.12
2042	1389.04	1030.14	4.47	37.88	27.67	0.12
2043	1410.39	1039.53	4.50	38.38	27.92	0.12
2044	1429.19	1045.05	4.52	39.05	28.07	0.12
2045	1453.97	1058.03	4.55	39.66	28.41	0.12

d) As discussed in the response at Exhibit I.PP.9, Enbridge Gas determined that utility customer design day demand would need to decrease by 27% (approx. 1.1 PJ) before the Company would consider reducing any amount of cost-based storage. In other words, design day demand would need to be reduced by more than 27% before the fundamental economics of the Project would begin to change in a significant way relative to other market-based alternatives.

Assessment of a reduction in demand greater than this level would be a significant undertaking. A full reproduction of the analysis, including an integrated framework that considered the impact of a lower demand case on prices and on flows through Ontario into other regions, similar to the initial analysis, would require a significantly larger effort, and would take 3-4 weeks of elapsed time to complete. Enbridge Gas has not asked ICF to complete the evaluation based on the number of unknowns and assumptions that would be required to be made to support this effort and deliver a meaningful response to the future value of market-based storage.

Given the magnitude of demand reduction required (>27% -or- 1.1 PJ), the amount of time required to complete the incremental analysis requested by ED (3-4 weeks), and that such analysis would be based on a large number of assumptions regarding forecast design day demand that are without basis in fact, Enbridge Gas respectfully declines to respond to ED's request.

e) Please see Attachment 1 to this response.

f) As discussed in the response at Exhibit I.SEC.13, Enbridge Gas has determined that such an alternative is not feasible since all 7 of the CCS compressor units in question must be retired at this time.

Further, conducting the analysis requested by ED would require the Company to re-model the impact of a reduction in compression of 50% on storage injection and withdrawal capabilities at different levels of natural gas in storage, as well as a subsequent ICF analysis of the impact of the change in storage space and deliverability available on the market-based alternatives. This work would likely take weeks to complete and ultimately would not resolve the system constraints that are driving the need for the Project.

Given that ED's proposed alternative does not resolve the underlying system constraints driving the need for the Project, and that it would require Enbridge Gas to create a customized model (reflecting the impact of a reduction in compression of 50% on storage capacity at different levels of natural gas in storage) and ICF to conduct customized analysis of the impacts of the change in storage capacity on market-based alternatives, Enbridge Gas respectfully declines to conduct this additional analysis.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence ("ED")

INTERROGATORY

Reference:

Exhibit C, Tab 1, Schedule 1

Preamble:

These questions relate to the possibility that some of the storage facilities served by the CSS could be converted to store hydrogen only, and whether that might be relevant to decision-making for this project.

Question:

a) Please discuss the possibility of converting gas-fired power generation to burn hydrogen created through electrolysers and stored nearby (e.g. in a converted gas storage facility), to be used as a peaking service for electricity.

b) Has Enbridge explored using any of its storage facilities in Ontario for a hydrogen-only system? If yes, please provide any applicable studies or slide decks.

c) Please provide a map showing the proximity of the storage facilities connected to the Corunna Compressor Station to existing gas-fired power generation facilities. Please list the design day demand of those facilities.

Response

a) The Company is generally aware of interest in such projects and is more specifically aware of a number of pilot projects across North America to burn various percentage blends of hydrogen in gas-fired power generation facilities. However, Enbridge Gas is not aware of any such firm commitments by natural gas-fired power generators in Ontario at this time, to convert their facilities in order to burn hydrogen created through electrolyzers and stored nearby in the province.

b) Enbridge Gas is planning to evaluate the compatibility of hydrogen in its storage system as part of a future study.

c) Enbridge Gas respectfully declines to provide the natural gas-fired power generation customized mapping and details sought by ED as they are not readily available and are not relevant to the current Application which seeks to maintain access to cost-based storage capacity for EGD rate zone customers.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence ("ED")

INTERROGATORY

Reference:

Exhibit C, Tab 1, Schedule 1 & Exhibit D, Tab 1, Schedule 1

Preamble:

Per Exhibit D, Tab 1, Schedule 1:

Table 1: Estimated Project Costs

Item #	Description	Pipeline Costs	Ancillary Costs	Total Costs
1.0	Materials	$11,800,354	$36,643,592	$48,443,946
2.0	Construction & Labour	$51,310,846	$28,993,020	$80,303,866
3.0	External Permitting & Lands	$15,322,222	$0	$15,322,222
4.0	Outside Services	$19,230,385	$15,702,325	$34,932,710
5.0	Direct Overheads	$1,295,000	$0	$1,295,000
6.0	Contingency	$13,180,351	$10,816,348	$23,996,699
7.0	IDC	$2,093,000	$0	2,093,000
8.0	**Project Cost**	**$114,232,158**	**$92,155,285**	**$206,387,443**
9.0	Indirect Overheads & Loadings	$26,277,051	$18,085,209	44,362,260
10.0	**Total Project Costs**	**$140,509,209**	**$110,240,494**	**$250,749,703**

NOTE:
The total costs set out in Table 1 include abandonment of the existing seven CCS compressor units K701-K703 and K705-K708 amounting to $14.5 million.

Question:

a) Please reproduce the Table 1 in Exhibit C, Tab 1, Schedule 1, Attachment 1, including indirect overheads and loadings.

b) Do indirect overheads and loadings have a differential impact on capital costs versus ongoing operating costs?

c) What line in the above table is the $14.5 million abandonment cost included in?

d) Are abandonment costs for pipelines treated differently than abandonment costs for compressors?

e) Does Enbridge earn the same rate of return on capital invested in compressors as in pipelines? Please explain.

f) Is the depreciation period the same for investments into compressors as in pipelines? Please explain.

Response

a) Please see the response to Exhibit I.STAFF.9 c).

b) Indirect overheads and loadings are capitalized and depreciated as part of property, plant and equipment. In the absence of this capitalization, the related costs would be treated as operating costs and charged to income in the year they are incurred.

c) The abandonment cost is included in the following items: 2.0 Construction & Labour; 4.0 Outside services; and 6.0 Contingency.

d) The accounting for abandonment costs are the same for all Enbridge Gas assets.

e) Both compressors and pipelines are capitalized and depreciated as part of property, plant and equipment ("PP&E"). The undepreciated PP&E is included as part of rate base. Enbridge Gas earns the same rate of return on all rate base.

f) The depreciation period for the assets is different as the depreciation is based upon the life of the assets. Since these are two different types of assets, the depreciation period will be different.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence ("ED")

INTERROGATORY

Reference:

Exhibit C, Tab 1, Schedule 1

Question:

a) What is the expected lifetime of the proposed pipeline?

b) When would the proposed pipeline be fully depreciated?

c) What will the undepreciated balance of the proposed pipeline costs be in (i) 2035, (ii) 2040, and (iii) 2050?

d) Has Enbridge conducted an analysis to assess the likelihood, if any, that the proposed pipeline will be stranded or underutilized before the end of its lifetime? If yes, please file said analysis.

e) Please estimate the probability (if any) that the proposed pipeline will be stranded or underutilized before the end of its lifetime. Please provide the response as a probability (%) or a range of probabilities. For instance, if there is no chance, please indicate the probability as 0%.

Response

a) & b)
The proposed pipeline will be fully depreciated at a 40-year time horizon. There are a number of factors that dictate the expected lifetime of a pipeline, however, the Company anticipates the expected life and the fit-for-service life to be greater than 40 years.

c) Assuming the assets are fully intact without any damages and replacements, the undepreciated capital cost of the proposed pipeline (classified as XHP ST Main pipeline) will be:

(i) In 2035: $171,399,160.
(ii) In 2040: $142,576,696.
(iii) In 2050: $84,931,768.

d) & e)
No, the proposed Project is based on current demand and the Company's 5-year Gas Supply Plan, which reflects increasing demand for storage in the future and prioritizes the same over a number of alternatives. The Company has no basis to believe that the proposed pipeline will be undersubscribed or stranded.

Please see the response to Exhibit I.PP.9 a), for discussion of the demand reduction required for Enbridge Gas to consider reducing its reliance upon cost-based storage.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit A, Tab 2, Schedule 1, Page 1

Preamble:

"Enbridge Gas Inc. ("Enbridge Gas," the "Company" or the "Applicant") has identified the need to abandon, remove and replace up to seven (7) reciprocating compressor units located at the Corunna Compressor Station ("CCS") due to identified reliability, obsolescence and safety concerns."

Question:

a) The quoted text indicates that "up to seven" units have been identified for abandonment, removal, or replacement. Does that mean that the number of units affected may be less than seven?

b) Does Enbridge need OEB approval to abandon, remove or replace compressors or for leave to construct the NPS 36 pipeline or both? Please explain your answer.

Response

a) The Company is planning to retire and abandon 7 CCS compressor units (K701-703, K705-708) as part of the Project.

b) No, Enbridge Gas does not require and is not seeking OEB approval as part of the current Application to retire and abandon the 7 CCS compressor units.

   The Company has applied to the OEB, pursuant to Section 90 (1) of the Act for an Order granting leave to construct approximately 20 km of NPS 36 pipeline from the Dawn Operations Center to the CCS (the Project).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, page 3

Preamble:

If the Project meets the criteria for rate recovery through the ICM mechanism then an ICM request for the costs of the same may form part of the Company's 2023 Rates (Phase 2) application.

Question:

a) Is the proposed NPS 36 pipeline a distribution line or does it serve another purpose?

b) Why does Enbridge believe that the cost of the proposed NPS 36 pipeline should be eligible for ICM funding from ratepayers?

Response

a) The NPS 36 from the Dawn Operations Center to the CSS ("TR 7") will be classified as a transmission asset. The TR 7 pipeline will parallel the existing TR 1 and TR 2 pipelines, which are both classified as transmission assets.[1]

b) The Company will not be seeking ICM treatment for the Project.

[1] Please also see Exhibit C, Tab 1, Schedule 1, Paragraph 49, for additional context.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, page 9, 21 and 27

Preamble:

"On injection, units K704 and K711 will continue to be required after completion of the Project to compress gas arriving from Dawn to fill the top end of the pools to their Planned Maximum Operating Pressure ("PMOP"). On withdrawal, units K709 and K710 will be required to provide a low suction pressure from the CCS to allow the storage pools to reach cushion pressure or minimum operating pressure. These compressors (or equivalent horsepower) will always be required at CCS to achieve a full cycle of the 9 storage pools connected to the CCS, including after the completion of the Project."

Question:

a) Please confirm that units K704, K709, K710 and K711 will continue in service after the completion of the project.

b) Please confirm that unit K704 has second highest downtime and is one of the oldest CCS units.

c) Please confirm that K704 is in Building 1, K709 and K710 are in Building 2, and K711 is in Building 3. Please discuss why continued operation of these units is not a safety risk.

Response

a) Confirmed.

b) Confirmed.

CCS compressor unit K704 is the fourth oldest of the existing CCS units. The RAM Study indicates that unit K704 will have the second highest total downtime over the next five years, according to operational cycles (injection and withdrawal).

c) Confirmed.

Risk to the safety of personnel associated with the operation of these units will persist following retirement and abandonment of the proposed 7 CCS compressor units K701-K703 and K705-K708. However, the remaining risks are deemed ‘conditionally tolerable” (i.e., between the lower and upper threshold of Company risk tolerability/evaluation criteria per Exhibit B, Tab 1, Schedule 1, Figure 3) compared to the current risk level, which exceeds the upper risk threshold. The “conditionally tolerable” risk level is achieved due to reduction in equipment density and occupancy levels in Compressor Building 1 and 2, which lowers the risk to personnel (please also see the response at Exhibit I.CME.01 Attachment 4) compared to the current risk at the CCS.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, page 10

Preamble:

"This access has become increasingly important due to the increased frequency and severity of extreme weather events experienced across North America in recent years."

Question:

a) Please explain what Enbridge considers "extreme weather events"?

b) In which year did "extreme weather events" start?

c) Please file a table listing all "extreme weather events" in North America since the start of operation of CCS in 1964. For each "extreme weather event" please describe its impact on CCS operation.

Response

a) In using the term "extreme weather events", Enbridge Gas is referring to cold weather events across Canada and the United States that have caused freeze offs impacting above ground facilities and their ability to produce and transport natural gas. These events have caused periods of supply shortfall at the Dawn Hub. As a result, the Company relied on Enbridge Gas's storage system to deliver the majority of the supply serving Ontario customers.

b) & c)
In Exhibit B, Tab 2, Schedule 1, pp. 2-4, Enbridge Gas referred to 4 recent events that have caused supply shortfall at the Dawn Hub. While the Company utilizes historical temperature data in Ontario to support its planning needs, it does not

utilize or maintain a record weather data (including extreme weather events) across North America nor can it point to a time when extreme weather events started.

Enbridge Gas operates an integrated natural gas storage and transmission system at the Dawn Hub and manages the storage system on an integrated basis. As such, the Company is unable to produce the impacts of an extreme weather event solely on the CCS operations. Further, the impact of extreme weather events on the Dawn Hub varies depending on many factors including but not limited to: geographic location(s), severity, duration, and impacts of cold weather that can affect either supply and/or demand.

Please also see the response at Exhibit I.SEC.5.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, page 10

Preamble:

"The Company recognizes its obligation to meet the firm demands of its customers and as a result, assets are continually evaluated to identify hazards and to assess risks in order to ensure that they remain reliable, suitable, and fit for continued service."

Question:

a) Please describe the firm demands that are mentioned in the quoted sentence.

b) Do CCS and the storage pools that were part of Tecumseh Gas Storage provide services for any firm demands from ex-franchise customers? If the answer is yes, please describe and quantify these firm demands.

c) Do CCS and the storage pools that were part of Tecumseh Gas Storage provide services for any non-firm demands from ex-franchise customers? If the answer is yes, please describe and quantify these non-firm demands.

d) What is the current Working Gas Capacity in PJ and Design Peak Withdrawal Capacity in PJ/day of CCS and the storage pools that were part of Tecumseh Gas Storage?

e) What Working Gas Capacity in PJ and Design Peak Withdrawal Capacity in PJ/day are required to meet the demands of in-franchise customers?

Response

a) The firm demand referenced in Exhibit B, Tab 1, Schedule 1, paragraph 24 is a reference to the firm demands of all of Enbridge Gas's in-franchise and ex-franchise customers. The firm demands as they relate to the Project need are the bundled in-franchise storage requirements within the EGD rate zone, which are outlined in Table 1 at Exhibit B, Tab 2, Schedule 1, p. 7.

b) Yes. Enbridge Gas designs its system to meet the firm demands of its utility and non-utility customers. Storage services are not tied to specific assets and Enbridge Gas's storage system is operated on an integrated basis to serve all customer demand. All storage contracts have a firm and fixed Maximum Storage Quantity. In addition, storage contracts can have an interruptible component for both injection and withdrawal rights depending on the type of service.

   Non-utility assets have been integrated over a long period of time with utility assets. At the time of NGEIR, Union Gas Limited ("Union") had developed approximately 18 Bcf of non-utility storage and both Enbridge Gas Distribution Inc. ("EGD") and Union continued to develop non-utility storage assets at the Dawn Hub since.

   Please find the Storage Report that provides an index of storage customers as of June 1, 2022, including Maximum Storage Quantities and Firm Daily Withdrawal/Injection Quantities at Attachment 1 to this response.

c) Yes. Depending on the type of storage service a customer contracts for, services provide different levels of firm daily rights and overrun opportunities at different times of the year. Enbridge Gas schedules non-firm or interruptible demands throughout the year depending on its system ability to offer these services

d) The EGD storage system has a working gas capacity is of 126. 8 PJ and design day withdrawal capacity of 2.4 PJ/d.

e) Please see Exhibit B, Tab 2, Schedule 1, Paragraph 12. Total underground storage capacity reserved for EGD rate zone in-franchise customers is 99.4 PJ. EGD rate zone in-franchise customers are entitled to 1.9 PJ/d of withdrawal capacity between 99.4 and 43.5 PJ of inventory. Below 43.5 PJ of inventory, withdrawal capacity decreases linearly until reaching a lower limit of 0.5 PJ/d at 0.5 PJ of inventory.

ENBRIDGE
Life Takes Energy

Enbridge Gas Inc. Storage Customers as of June 1, 2022

Customer Name	Contract Identifier	Maximum Storage Quantity(GJ)	Start Date	Expiry Date	Maximum Firm Daily Withdrawal Quantity(GJ)	Maximum Firm Daily Injection Quantity(GJ)	Receipt Point	Delivery Point	Affiliate
Goreway Station Partnership	BHDS002	600,000	Jul 1, 2008	Oct 31, 2028	128,000	128,000	Dawn	Dawn	N
DTE Electric Company	DVB002	51,698	Sep 1, 2021	May 31, 2027	21,101	58,028	Dawn	Dawn	N
Enbridge Gas Inc formerly known as Enbridge Gas Distribution	Formerly LST106	3,000,000	Apr 1, 2018	Mar 31, 2023	36,000	22,500	Dawn	Dawn	Y
Enbridge Gas Inc formerly known as Enbridge Gas Distribution	Formerly LST111	3,000,000	Apr 1, 2019	Mar 31, 2024	36,000	22,500	Dawn	Dawn	Y
Enbridge Gas Inc formerly known as Enbridge Gas Distribution	Formerly LST117	4,000,000	Apr 1, 2020	Mar 31, 2025	48,000	30,000	Dawn	Dawn	Y
Enbridge Gas Inc formerly known as Enbridge Gas Distribution	Formerly LST118	1,000,000	Apr 1, 2020	Mar 31, 2024	12,000	7,500	Dawn	Dawn	Y
Enbridge Gas Inc formerly known as Enbridge Gas Distribution	Formerly LST132	1,500,000	Apr 1, 2021	Mar 31, 2026	18,000	11,250	Dawn	Dawn	Y
York Energy Centre LP	HDS008	175,000	Apr 1, 2012	Oct 31, 2022	87,654	87,654	Dawn	Dawn	N
Greenfield South Power Corporation	HDS012	162,400	Sep 1, 2017	Feb 28, 2037	16,248	16,248	Dawn	Dawn	N
Greenfield Energy Centre LP	HDS013	211,011	Nov 1, 2018	Oct 15, 2028	42,202	42,202	Dawn	Dawn	N
Thorold CoGen L.P. by its General Partner Northland Power Thorold Cogen GP Inc.	HDS014	170,000	Apr 1, 2019	Mar 31, 2030	44,000	44,000	Dawn	Dawn	N
DTE Electric Company	HDS015	1,582,584	Sep 1, 2021	May 31, 2027	21,101	58,028	Dawn	Dawn	N
Portlands Energy Centre L.P. by its General Partner, Portlands Energy Centre Inc.	HDS016	500,000	Apr 1, 2019	Apr 21, 2029	40,000	40,000	Dawn	Dawn	N
Portlands Energy Centre L.P Napanee	HDS017	500,000	Apr 29, 2020	Mar 31, 2033	126,000	126,000	Dawn	Dawn	N
BP Canada Energy Group ULC	HUB040PS0058	1,055,056	Jul 1, 2021	Jun 30, 2022	12,661	-	Dawn	Dawn	N
Ontario Power Generation Inc.	HUB335B0014	263,764	Jan 1, 2022	Dec 31, 2022	21,101	3,165	Dawn	Dawn	N
Mercuria Commodities Canada Corporation	HUB336PS0002	211,011	Apr 1, 2022	Mar 31, 2023	2,532	-	Dawn	Dawn	N
Mercuria Commodities Canada Corporation	HUB336PS0003	105,506	Apr 1, 2022	Mar 31, 2023	1,266	-	Dawn	Dawn	N
Active Energy Inc.	HUB469PS0001	10,551	Jul 1, 2021	Jun 30, 2022	127	-	Dawn	Dawn	N
Active Energy Inc.	HUB469PS0002	105,506	May 23, 2022	May 22, 2023	1,266	-	Dawn	Dawn	N
Spotlight Energy, LLC	HUB793PS0002	527,528	Apr 1, 2022	Mar 31, 2023	6,330	-	Dawn	Dawn	N
Spire Marketing Inc.	HUB874PS0001	263,764	Apr 1, 2022	Mar 31, 2023	3,165	-	Dawn	Dawn	N
Northern Utilities, Inc.	LST086	4,220,224	Apr 1, 2018	Mar 31, 2023	43,468	31,652	Dawn	Dawn	N
J. Aron & Company	LST099	1,055,056	Sep 1, 2017	Mar 31, 2023	18,991	15,826	Dawn	Dawn	N
EPCOR Natural Gas Limited Partnership	LST115	100,000	May 15, 2020	Mar 31, 2030	1,200	750	Dawn	Dawn	N
Energir, L.P. by its General Partner Energir Inc	LST116	2,125,000	Apr 1, 2020	Mar 31, 2023	25,500	31,875	Dawn	Dawn	N
1425445 Ontario Limited o/a Utilities Kingston	LST129	50,000	May 1, 2021	Apr 30, 2024	700	375	Dawn	Dawn	N
Liberty Utilities (St. Lawrence Gas) Corp.	LST131	950,000	Apr 1, 2021	Mar 31, 2024	11,400	9,500	Dawn	Dawn	N
Energir, L.P. by its General Partner Energir Inc	LST133	1,681,500	Apr 1, 2021	Mar 31, 2024	20,178	25,223	Dawn	Dawn	N
The Southern Connecticut Gas Company	LST134	1,820,000	Apr 1, 2021	Mar 31, 2026	21,840	13,650	Dawn	Dawn	N
The Southern Connecticut Gas Company	LST135	1,700,000	Apr 1, 2022	Mar 31, 2025	20,400	12,750	Dawn	Dawn	N
Connecticut Natural Gas Corporation	LST136	980,000	Apr 1, 2021	Mar 31, 2026	11,760	7,350	Dawn	Dawn	N
Connecticut Natural Gas Corporation	LST137	1,300,000	Apr 1, 2022	Mar 31, 2025	15,600	9,750	Dawn	Dawn	N
Eversource Gas Company of Massachusetts dba Eversource Energy	LST143	1,688,090	Apr 1, 2022	Mar 31, 2024	16,881	12,661	Dawn	Dawn	N
Eversource Gas Company of Massachusetts dba Eversource Energy	LST144	1,920,202	Apr 1, 2022	Mar 31, 2024	27,958	14,402	Dawn	Dawn	N
1425445 Ontario Limited o/a Utilities Kingston	LST145	150,000	Apr 1, 2022	Mar 31, 2024	2,100	1,125	Dawn	Dawn	N
Yankee Gas Services Company dba Eversource Energy	LST147	3,165,168	Apr 1, 2022	Mar 31, 2024	52,753	26,271	Dawn	Dawn	N
Enbridge Gas Inc formerly known as Enbridge Gas Distribution	LST148	2,000,000	Apr 1, 2022	Mar 31, 2024	24,000	15,000	Dawn	Dawn	Y
Energir, L.P. by its General Partner Energir Inc	LST151	7,620,625	Apr 1, 2022	Mar 31, 2025	91,448	114,309	Dawn	Dawn	N

Enbridge Gas Inc. Storage Customers as of June 1, 2022

Customer Name	Contract Identifier	Maximum Storage Quantity(GJ)	Start Date	Expiry Date	Maximum Firm Daily Withdrawal Quantity(GJ)	Maximum Firm Daily Injection Quantity(GJ)	Receipt Point	Delivery Point	Affiliate
Enbridge Gas Inc formerly known as Enbridge Gas Distribution	LST152	3,000,000	Apr 1, 2022	Mar 31, 2025	36,000	22,500	Dawn	Dawn	Y
Vermont Gas Systems, Inc.	LST154	263,764	Apr 1, 2022	Mar 31, 2024	3,165	1,978	Dawn	Dawn	N
AltaGas Ltd.	LTP035	2,844,465	Apr 1, 2009	Mar 31, 2029	34,134	21,333	Dawn	Dawn	N
NJR Energy Services Company	LTP161	2,110,112	Mar 31, 2017	Mar 31, 2023	25,321	-	Dawn	Dawn	N
NJR Energy Services Company	LTP186	1,055,056	Apr 1, 2018	Mar 31, 2023	12,661	-	Dawn	Dawn	N
J. Aron & Company	LTP238	1,582,584	Apr 1, 2019	Mar 31, 2023	18,991	-	Dawn	Dawn	N
J. Aron & Company	LTP249	2,110,112	May 8, 2019	Mar 31, 2023	25,321	-	Dawn	Dawn	N
Tenaska Marketing Canada - a division of TMV Corp.	LTP255	3,165,168	Apr 1, 2020	Mar 31, 2023	37,982	-	Dawn	Dawn	N
Powerex Corp.	LTP260	1,055,056	Apr 1, 2020	Mar 31, 2023	12,661	-	Dawn	Dawn	N
BP Canada Energy Group ULC	LTP262	1,055,056	Apr 1, 2020	Mar 31, 2025	12,661	-	Dawn	Dawn	N
1425445 Ontario Limited o/a Utilities Kingston	LTP265	250,000	Apr 1, 2020	Mar 31, 2023	-	3,750	Dawn	Dawn	N
BP Canada Energy Group ULC	LTP275	2,110,112	Apr 1, 2020	Mar 31, 2025	25,321	-	Dawn	Dawn	N
Powerex Corp.	LTP279	1,055,056	Apr 1, 2020	Mar 31, 2023	12,661	-	Dawn	Dawn	N
Constellation Energy Generation, LLC	LTP289	1,055,056	Apr 1, 2021	Mar 31, 2023	12,661	-	Dawn	Dawn	N
Emera Energy Limited Partnership	LTP290	2,110,112	Apr 1, 2021	Mar 31, 2024	25,321	-	Dawn	Dawn	N
PetroChina International (Canada) Trading Ltd.	LTP291	1,055,056	Apr 1, 2021	Mar 31, 2024	12,661	-	Dawn	Dawn	N
Repsol Oil & Gas Canada Inc. dba Repsol Energy Canada	LTP292	2,110,112	Apr 1, 2021	Mar 31, 2023	25,321	-	Dawn	Dawn	N
Hartree Partners, LP	LTP294	3,165,168	Apr 1, 2021	Mar 31, 2024	37,982	-	Dawn	Dawn	N
Macquarie Energy Canada Ltd.	LTP295	2,110,112	Mar 31, 2021	Mar 31, 2023	25,321	-	Dawn	Dawn	N
J. Aron & Company	LTP297	1,055,056	Mar 31, 2021	Mar 31, 2024	12,661	-	Dawn	Dawn	N
Morgan Stanley Capital Group Inc.	LTP298	1,055,056	Apr 1, 2021	Mar 31, 2023	12,661	-	Dawn	Dawn	N
Castleton Commodities Merchant Trading L.P.	LTP299	1,582,584	Apr 1, 2021	Mar 31, 2024	18,991	10,551	Dawn	Dawn	N
Macquarie Energy Canada Ltd.	LTP300	2,110,112	Apr 1, 2021	Mar 31, 2024	25,321	-	Dawn	Dawn	N
Canadian RiteRate Energy Corporation	LTP301	33,762	Apr 1, 2021	Mar 31, 2023	405	-	Dawn	Dawn	N
BP Canada Energy Group ULC	LTP302	1,055,056	Apr 1, 2021	Mar 31, 2026	12,661	-	Dawn	Dawn	N
Powerex Corp.	LTP303	1,055,056	Apr 1, 2021	Mar 31, 2024	12,661	-	Dawn	Dawn	N
J. Aron & Company	LTP304	1,055,056	Apr 1, 2021	Mar 31, 2024	12,661	-	Dawn	Dawn	N
Vitol Inc.	LTP306	2,110,112	Apr 1, 2021	Mar 31, 2024	25,321	-	Dawn	Dawn	N
Koch Canada Energy Services, LP	LTP308	2,110,112	Apr 1, 2021	Mar 31, 2024	25,321	-	Dawn	Dawn	N
Castleton Commodities Merchant Trading L.P.	LTP310	2,110,112	Apr 1, 2021	Mar 31, 2024	25,321	-	Dawn	Dawn	N
Powerex Corp.	LTP311	2,110,112	Apr 1, 2021	Mar 31, 2024	25,321	-	Dawn	Dawn	N
Citadel Energy Marketing LLC	LTP312	1,055,056	Mar 31, 2021	Mar 31, 2024	12,661	-	Dawn	Dawn	N
Spotlight Energy, LLC	LTP314	527,528	Mar 31, 2021	Mar 31, 2024	6,331	-	Dawn	Dawn	N
Sequent Energy Canada LLC	LTP315	3,165,168	Apr 1, 2021	Mar 31, 2024	37,982	-	Dawn	Dawn	N
DTE Energy Trading, Inc.	LTP316	1,055,056	Apr 1, 2021	Mar 31, 2024	12,661	-	Dawn	Dawn	N
Repsol Oil & Gas Canada Inc. dba Repsol Energy Canada	LTP317	1,055,056	Mar 19, 2021	Mar 31, 2023	12,661	-	Dawn	Dawn	N
Macquarie Energy Canada Ltd.	LTP318	2,110,112	Mar 31, 2021	Mar 31, 2024	25,321	-	Dawn	Dawn	N
MIECO LLC	LTP319	527,528	Apr 1, 2021	Mar 31, 2023	6,330	-	Dawn	Dawn	N
EDF Trading North America, LLC	LTP320	1,055,056	Apr 10, 2021	Mar 31, 2024	12,661	-	Dawn	Dawn	N
EDF Trading North America, LLC	LTP321	1,055,056	May 1, 2021	Mar 31, 2024	12,661	-	Dawn	Dawn	N
Castleton Commodities Merchant Trading L.P.	LTP322	1,055,056	May 7, 2021	Mar 31, 2024	12,661	-	Dawn	Dawn	N
Tidal Energy Marketing Inc.	LTP323	1,055,056	Apr 1, 2022	Mar 31, 2024	12,661	-	Dawn	Dawn	Y
BP Canada Energy Group ULC	LTP324	1,055,056	Apr 1, 2022	Mar 31, 2027	12,661	-	Dawn	Dawn	N
EDF Trading North America, LLC	LTP329	1,055,056	Apr 1, 2022	Mar 31, 2025	12,661	-	Dawn	Dawn	N
EDF Trading North America, LLC	LTP330	2,110,112	Apr 1, 2022	Mar 31, 2025	25,321	-	Dawn	Dawn	N

Enbridge Gas Inc. Storage Customers as of June 1, 2022

Customer Name	Contract Identifier	Maximum Storage Quantity(GJ)	Start Date	Expiry Date	Maximum Firm Daily Withdrawal Quantity(GJ)	Maximum Firm Daily Injection Quantity(GJ)	Receipt Point	Delivery Point	Affiliate
Macquarie Energy Canada Ltd.	LTP331	3,165,168	Apr 1, 2022	Mar 31, 2025	37,982	-	Dawn	Dawn	N
Suncor Energy Marketing Inc.	LTP332	2,110,112	Apr 1, 2022	Mar 31, 2025	25,321	-	Dawn	Dawn	N
Castleton Commodities Merchant Trading L.P.	LTP333	1,055,056	Apr 1, 2022	Mar 31, 2025	12,661	-	Dawn	Dawn	N
Tenaska Marketing Canada - a division of TMV Corp.	LTP334	3,165,168	Apr 1, 2022	Mar 31, 2025	37,982	-	Dawn	Dawn	N
EDF Trading North America, LLC	LTP335	1,055,056	Apr 1, 2022	Mar 31, 2025	12,661	-	Dawn	Dawn	N
EDF Trading North America, LLC	LTP336	4,220,224	Apr 1, 2022	Mar 31, 2025	50,643	-	Dawn	Dawn	N
Tourmaline Oil Corp.	LTP337	1,055,056	Apr 1, 2022	Mar 31, 2024	12,661	-	Dawn	Dawn	N
Shell Energy North America (Canada) Inc.	LTP339	4,220,224	Apr 1, 2022	Mar 31, 2025	50,643	-	Dawn	Dawn	N
Castleton Commodities Merchant Trading L.P.	LTP340	2,110,112	Apr 1, 2022	Mar 31, 2025	25,321	-	Dawn	Dawn	N
1425445 Ontario Limited o/a Utilities Kingston	LTP341	150,000	May 1, 2022	Apr 30, 2025	-	-	Dawn	Dawn	N
Constellation Energy Generation, LLC	LTP343	2,110,112	Apr 1, 2022	Mar 31, 2024	25,321	-	Dawn	Dawn	N
Tenaska Marketing Canada - a division of TMV Corp.	LTP344	1,318,820	Apr 1, 2022	Mar 31, 2024	15,826	9,891	Dawn	Dawn	N
Repsol Oil & Gas Canada Inc. dba Repsol Energy Canada	LTP345	2,110,112	Apr 1, 2022	Mar 31, 2024	25,321	-	Dawn	Dawn	N
Repsol Oil & Gas Canada Inc. dba Repsol Energy Canada	LTP346	1,055,056	Apr 1, 2022	Mar 31, 2024	12,661	-	Dawn	Dawn	N
Twin Eagle Resource Management Canada, LLC	LTP348	1,055,056	May 1, 2022	Apr 30, 2025	12,661	-	Dawn	Dawn	N
Powerex Corp.	LTP349	2,110,112	Apr 1, 2022	Mar 31, 2025	25,321	-	Dawn	Dawn	N
Macquarie Energy Canada Ltd.	LTP350	2,110,112	Apr 1, 2022	Mar 31, 2025	25,321	-	Dawn	Dawn	N
EDF Trading North America, LLC	LTP353	2,110,112	Apr 1, 2022	Mar 31, 2027	25,321	-	Dawn	Dawn	N
Uniper Trading Canada Ltd.	LTP354	1,055,056	Apr 1, 2022	Mar 31, 2025	12,661	-	Dawn	Dawn	N
Castleton Commodities Merchant Trading L.P.	LTP355	2,110,112	Apr 1, 2022	Mar 31, 2025	25,321	-	Dawn	Dawn	N
Emera Energy Limited Partnership	LTP357	2,110,112	Apr 1, 2022	Mar 31, 2025	25,321	-	Dawn	Dawn	N
ENGIE Energy Marketing NA, Inc.	LTP359	105,506	Apr 1, 2022	Mar 31, 2024	1,266	-	Dawn	Dawn	N
Tenaska Marketing Canada - a division of TMV Corp.	LTP360	2,110,112	Apr 1, 2022	Mar 31, 2024	25,321	-	Dawn	Dawn	N
Koch Canada Energy Services, LP	LTP361	1,055,056	Apr 1, 2022	Mar 31, 2025	12,661	-	Dawn	Dawn	N
Koch Canada Energy Services, LP	LTP362	1,055,056	Apr 1, 2022	Mar 31, 2025	12,661	-	Dawn	Dawn	N
Freepoint Commodities LLC	LTP363	1,055,056	Apr 1, 2022	Mar 31, 2024	12,661	-	Dawn	Dawn	N
Colonial Energy, Inc.	LTP364	263,764	Apr 1, 2022	Mar 31, 2024	3,165	-	Dawn	Dawn	N
BP Canada Energy Group ULC	LTP365	1,055,056	Apr 1, 2022	Mar 31, 2027	12,661	-	Dawn	Dawn	N
Constellation Energy Generation, LLC	LTP366	1,055,056	Apr 1, 2022	Mar 31, 2024	12,661	-	Dawn	Dawn	N
EDF Trading North America, LLC	LTP367	1,055,056	Apr 1, 2022	Mar 31, 2026	12,661	-	Dawn	Dawn	N

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, page 11

Preamble:

"As a result of these assessments the Company has identified serious and increasing obsolescence and reliability risks associated with certain CCS compressor units and is experiencing a need for increased maintenance and repair work to keep the units operational going forward."

Question:

a) Is the need for the project increasing obsolescence and unreliability of certain compressor units and not any other reason such as increased frequency and severity of extreme weather events?

b) Please file a table showing maintenance hours per operating hour for each compressor unit since 1964 or as far back as there are records.

c) Is the purpose of the project the maintenance of gas storage capability after these compressor units are removed from service?

Response

a) The need for the Project is obsolescence, decreasing reliability and intolerable safety risks at the CCS. The increased frequency of cold weather events highlights the importance of reliable infrastructure that is available to serve customers when they need it the most (e.g., to heat their homes during the coldest time of year).

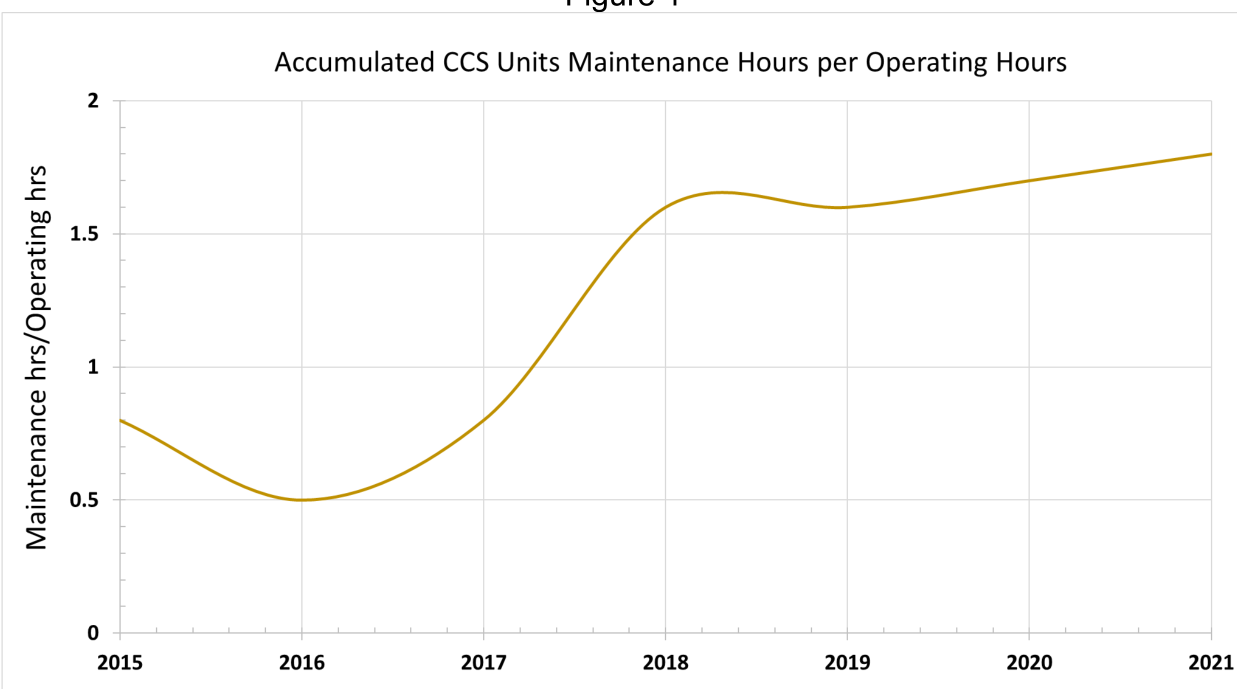
b) The electronic database that reports CCS units' outage and operating hours, nSoda Statistics Reporting, was implemented in August 2014. Therefore, the annual units' hourly data is only available from 2015. There is no accurate outage and operating hours available prior to the implementation of nSoda.

Table 1 and Figure 1 below show the accumulated maintenance hours per accumulated operating hours for all CCS compressor units.[1] Please see the responses at Exhibit I.PP.5 a) and Exhibit I.SEC.8, for a per unit breakdown of outage hours and operating hours, respectively.

Table 1

Title	2015	2016	2017	2018	2019	2020	2021
Accumulated CCS Maintenance Hours	16,868	10,201	18,575	23,544	31,805	34,559	36,090
Accumulated CCS Operating Hours	21,315	23,773	24,660	15,588	20,774	20,383	20,908
CCS Maintenance Hours/Operating Hours	0.8	0.5	0.8	1.6	1.6	1.7	1.8

Figure 1



c) Yes, Enbridge Gas is seeking to maintain storage capacity (space and deliverability) for EGD rate zone customers as described at Exhibit B, Tab 1, Schedule 1, pp. 11-12.

[1] For the purposes of completing this response Enbridge Gas defines maintenance hours as the number of hours that the unit is unavailable (outage hours) and defines operating hours as the number of hours that the unit is online and compressing gas.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, page 13

Preamble:

"For casted components, such as crankshafts, spares are not stocked in inventory by the Original Equipment."

Question:

a) Are these crankshafts castings or are they forgings as they are in most reciprocating engines?

b) How many crankshafts have failed since the units were placed in service? Please provide the year of each crankshaft failure.

Response

a) The crankshafts are forged, custom machined, and polished. There are currently no facilities in North America that are able to provide a crankshaft of this size.

   Like casted components, crankshafts are not stocked in inventory based on the long-term storage complexity, size and a single stocked component would not be compatible with all compressor units.

b) Crank assembly consists of three main components: (i) crankshaft; (ii) main bearings; and (iii) frame. The failure of any of these components will lead to crank assembly failure. Table 1 below shows the historical failures associated with CCS compressor unit crank assemblies since installation.

Table 1

Unit	Description	Year	Asset Sub-class	Component
K701	CM - K701 #11 Main Bearing Work	2018	Crank Assembly	Main Bearing
K701	CM - Crank Misalignment due to Foundation Damage	2018	Crank Assembly	Crankshaft
K702	Repaired #11 main bearing failure	1983	Crank Assembly	Main Bearing
K702	CM - Crankshaft Misalignment	2004	Crank Assembly	Crankshaft
K703	Repaired #10 main bearing failure	1987	Crank Assembly	Main Bearing
K703	Repaired #10 main bearing failure	1992	Crank Assembly	Main Bearing
K703	CM - Bent Crankshaft	2017	Crank Assembly	Crankshaft
K704	Replaced #7 main bearing	1994	Crank Assembly	Main Bearing
K704	EV -K704 frame alignment 2014	2015	Crank Assembly	Frame
K705	CM - K705 Main Bearing Replacement	2015	Crank Assembly	Main Bearing
K705	CM - K705 Main Bearing Replacement and K705 Frame Alignment 2015	2015	Crank Assembly	Main Bearing
K705	CP - Cracked Crankshaft	2018	Crank Assembly	Crankshaft
K706	CM - K706 Main bearing Replacement	2014	Crank Assembly	Main Bearing
K706	BR - K706 - Main bearing high temperature shutdown	2015	Crank Assembly	Main Bearing
K706	EV - K706 frame alignment 2014 - Completed Frame Shim Changes to Fix Web Deflections	2015	Crank Assembly	Frame
K706	BR - K706 - high main bearing temp on #5 main	2016	Crank Assembly	Main Bearing
K707	CM - K707 Main Bearing Replacement	2014	Crank Assembly	Main Bearing
K707	EV - K707 frame alignment 2014	2015	Crank Assembly	Frame
K708	CM - K708 reshim frame	2014	Crank Assembly	Frame
K709	Repaired #1 & #2 main bearing failure	1989	Crank Assembly	Main Bearing
K709	CM - K709 MAIN BEARING FAILURE 19,462 HOURS.	2003	Crank Assembly	Main Bearing
K709	EV - K709 frame alignment 2014	2015	Crank Assembly	Frame
K710	Repaired #1 & #5 main bearing failure	1985	Crank Assembly	Main Bearing
K710	Repaired #1 main bearing failure	1991	Crank Assembly	Main Bearing
K710	CM - K710 High Bearing temperature	2002	Crank Assembly	Main Bearing
K710	CM - K710 MAIN BEARING Indicator Venting Oil	2004	Crank Assembly	Main Bearing
K710	CM – Crankcase Bay door on K710 leaking at explosion hatch	2004	Crank Assembly	Frame
K710	CM - main bearing high temp. shutdown	2013	Crank Assembly	Main Bearing
K710	BR - Main Bearing Failure	2014	Crank Assembly	Main Bearing
K711	BR - Bent Crankshaft	2015	Crank Assembly	Crankshaft
K711	CM - Main Bearing Replacement	2017	Crank Assembly	Main Bearing

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, pages 13 to 17

Question:

Please file a table that lists all 11 compressors, name of original manufacturer, manufacturer's model number, and year placed in service.

Response

Please see Table 1.

Table 1

YEAR	TYPE	MANUFACTURER	MODEL
1964	K-701	Ingersoll Rand (integral unit)	KVTR
1964	K-702	Ingersoll Rand (integral unit)	KVTR
1964	K-703	Ingersoll Rand (integral unit)	KVTR
1968	K-704	Ingersoll Rand (integral unit)	KVR
1970	K-705	Ingersoll Rand (integral unit)	KVR
1972	K-706	Ingersoll Rand (integral unit)	KVR
1973	K-707	Ingersoll Rand (integral unit)	KVR
1974	K-708	Ingersoll Rand (integral unit)	KVR
1980	K-709	Ingersoll Rand (integral unit)	KVR
1983	K-710	Ingersoll Rand (integral unit)	KVR
1995	K-711	Dresser Rand (integral unit)	KVR

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, Page 21, and Table 4

Preamble:

"In total, the combined compressor downtime during Injection Mode across the 5-year period is 606 days. This means that at least one compressor is down for maintenance or repair 77% of the time during the injection season. Units K704 and K701 show the highest down times, forecasted to be down for a total of 118 and 101 days during the injection season, respectively."

Question:

a) Please expand Table 4 to show the separate maintenance column and repair column.

b) Please file a schedule that shows the regular maintenance schedule for each unit.

c) Has the regular maintenance schedule changed since the units were first placed in service? If the answer is yes, when did the schedule change and why? If the answer is no, please explain why not.

Response

a) Table 4 identifies the downtime associated with repairs.

   Downtime was calculated based on Withdrawal and Injection cycles over a typical calendar year, as noted in the RAM Study on pages 15-16 Table 4.1 Typical Operating Envelope (Exhibit B, Tab 1, Schedule 1, Attachment 2).

The assumptions for Planned Maintenance used in the RAM analysis are set out at Exhibit B, Tab 1, Schedule 1, Attachment 2, page 29 Section 4.4.1 – Planned Maintenance.

b) Table 1 below contains the regular maintenance schedule for all CCS compressor units.

Table 1[1]

Title	Frequency
PM - Inspect and Grease Gas & Glycol Coolers	Quarterly
PM - Test Run Engines for Bearing Lubrication	Monthly
PM - Sample Oil Gathering (Corunna Compressor Station)	Quarterly
PM - Air Intake Filter Inspection - Annual	Annually
PM - Oil Change - Meter Based	Meter Based
PM - Compressor Cylinder Inspection - Annual	Annually
PM - Engine Cylinder Inspection - Meter Based	Meter Based
PM - Gas Storage Shutdown Calibrations - Annual	Annually
PM - Camshaft Drive Chain and Main Water Pump Chain Inspection	Meter Based
PM - Engine Balancing - Meter Based	Meter Based
PM - Performance Analyzing - Meter Based	Meter Based
PM - Air Regulator Inspection	Annually
PM - Scrubber (Suction) Inspection -Annual	Annually
PM - Auxiliary Oil Pump Inspection -Semi-Annual	Semi-Annually
PM - Pulsation Bottle Support Inspection - Annual	Annually
PM - Gas Pressure Regulator Inspection (Pressure control for unit fuel bottles)	Annually
PM - Gas Pressure regulator rebuild - Tri-Annual	Tri-Annually
PM - EGS Stations Valve Greasing - 3 Year	Tri-Annually
PM - Electric Valve Inspection (BLDG-001) - 3 Years	Tri-Annually
PM - Electric Valve Inspection (BLDG-002) - 3 Years	Tri-Annually
PM - Electric Valve Inspection (BLDG-003) - 3 Years	Tri-Annually
PM - PSV Inspections - Annual (pop tests and rebuilds)	Annually
CP - Engine and Compressor Overhaul	Meter Based

c) Changes to the maintenance schedule since installation are set out in Table 2 below.

[1] PM = Preventative Maintenance; CP = Capital Project

Table 2[2]

Title	Reason for Change
PM - Inspect and Grease Gas & Glycol Coolers	This used to be done semi-annually and was increased to quarterly and updated to include greasing based on OEM recommended maintenance practices.
PM - Camshaft Drive Chain and Main Water Pump Chain Inspection	This inspection used to be annual and was changed to meter based. There were not many issues when inspecting some of the units annually as they all do not have the same run times. The PM now generates once the units hit run 3,000 hours from the last inspection.
PM - Engine Balancing - Meter Based	Engine Balancing used to be done annually. This was switched to performing an engine balance after completing an engine cylinder inspection. There is no reason to rebalance the engine if it is running well and no work has been done to the engine.
PM - Performance Analyzing - Meter Based	This used to be done annually and grouped with engine balancing. This work order was split up and this was also set up as meter based but on a higher run hour of 5,000 since the last inspection.
PM - Scrubber (Suction) Inspection -Annual	This used be done semi-annually. It was decided to switch to annual only after the withdrawal season as injection gas is much cleaner and issues were minimal with the scrubber during that inspection.
PM - EGS Stations Valve Greasing - 3 Year	Used to be an annual inspection that contained all station valve greasing. This was split out per station and put on a 3-year cycle. Valves do not need to be greased every year as per OEM recommendations.
PM - Electric Valve Inspection (BLDG-001) - 3 Years	Three electric valve inspections changed from a single annual inspection to three tri-annual to achieve a 3-year cycle with one building done each year. This was justified due to the implementation of IR scans in the MCC's that detect issues.
PM - Electric Valve Inspection (BLDG-002) - 3 Years	Three electric valve inspections changed from a single annual inspection to three tri-annual to achieve a 3-year cycle with one building done each year. This was justified due to the implementation of IR scans in the MCC's that detect issues.
PM - Electric Valve Inspection (BLDG-003) - 3 Years	Three electric valve inspections changed from a single annual inspection to three tri-annual to achieve a 3-year cycle with one building done each year. This was justified due to the implementation of IR scans in the MCC's that detect issues.
PM - PSV Inspections - Annual (pop tests and rebuilds)	The PSV inspection has been split into a 3-year cycle. Some of the valves may be inspected each year but some may be every 3rd year. This was all decided by the maintenance and ops engineering group based on valve performance.

[2] PM = Preventative Maintenance.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit C, Tab 1, Schedule 1, Page 1

Question:

Did Enbridge consider an alternative that would only consider the needs of in-franchise customers? Please explain your answer.

Response

Enbridge Gas did not consider Project alternatives on the basis that they only addressed the needs of in-franchise customers as the compressor units being retired serve both utility and non-utility customers. Please see the response at Exhibit I.SEC.18. As described in Exhibit C, Tab 1, Schedule 1, Enbridge Gas considered alternatives on the basis that they were able to meet the Project need (reliability, obsolescence and safety risks) and provide the equivalent deliverability and capacity as the 7 compressor units being retired at the CCS.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit C, Tab 1, Schedule 1, page 3, Table 1

Question:

a) What discount rate was used in the NPV analysis?

b) What discount rate would be required for Alternative 1, Natural Gas Fired Compression, to have a better NPV than the Project?

Response

a) The incremental after-tax weighted average cost of capital used in the NPV analysis is 4.92%.

b) If the discount rate of 4.92% is held constant for the calculation of the NPV of the Project, a discount rate of 6.29% would be required for the Natural Gas Fired Compression to have a better NPV than the Project's NPV of ($200 million).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit C, Tab 1, Schedule 1

Question:

Table 2 shows the O&M of Electric Motor Drive Compression as $6.84 million per year and Natural Gas Fired Compression as $3.88 million per year. Please provide assumptions and calculations that support these estimates.

Response

Gas Driven Compression Assumptions

- Annual O&M - Assumption based on 5 yr average historical costs for Dawn J (2x). Comparable make and model.
- Routine Maintenance Capital – assume $2.6 million per overhaul, per unit as per 2020 OEM costs. Service costs are expected to increase.
- Annual Fuel Usage – 8% increase in fuel consumption based on the average fuel burn rate for a Solar Taurus 70 at Dawn (Plant F).

Electric Motor Driven Compression Assumptions

- Annual O&M - Assumption based on 5 yr average historical costs for Dawn J (2x). Comparable make and model.
- Routine Maintenance Capital – assume $2 millionper overhaul, per unit as per discussion with SME from GTM. Service costs are expected to increase.
- Annual Electricity Usage – EMD operates at 90% efficiency. The HP for current units at Corunna converted to equivalent MW and average 5 year run time @ utility rate of $85/MWh.

Table 1

Alternative	K712/K713 (Solar T70)	K712/K713 (EMD)
Annual O&M	$ 578,336	$ 578,336
Maintenance Capital	$ 5,200,000	$ 4,000,000
	every 10 years	once in lifespan
Annual Fuel / Electricity Usage	9392 10^3m3	38,465,245 kwh
	$ 1,234,400	$ 5,692,856
Annual Emissions	19648 tCO2e	0 tCO2e
Property Tax Estimates	$ 470,135	$ 470,135
Annual O&M	**$ 3,876,732**	**$ 6,841,327**

NOTES:
Electricity Price = 0.148 $/kwh
Average annual cost of carbon over 40 Years = $54.66

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit D, Tab 1, Schedule 1, Page 1, Table 1, Note

Preamble:

"The total costs set out in Table 1 include abandonment of the existing seven CCS compressor units K701-K703 and K705-K708 amounting to $14.5 million."

Question:

a) Is the abandonment cost of $14.5 million included in Item 2.0 Construction & Labour in the Ancillary Costs column?

b) What is the estimated salvage value of the scrap steel from the abandoned units and piping?

c) What is the net salvage value of the abandonment (salvage value minus cost of removal)?

d) Will net salvage be charged to accumulated depreciation of the remaining four compressor units? Please explain your answer.

Response

a) The abandonment cost of $14.5 million is included in the following items: 2.0 Construction & Labour; 4.0 Outside services; and 6.0 Contingency.

b) Current market scrap pricing is $260-$300 /net ton. At this point it is not possible to estimate the amount of scrap steel for the Project.

c) Enbridge Gas is not able to provide the amount specific to the abandonment at issue. The costs collected through the asset depreciation rates over the life of the facility are calculated at the group (or pool) level, and not the individual asset level.

d) The net salvage that Enbridge Gas incurs will be netted against the liability account for amounts collected over time for abandonment costs.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit D, Tab 1, Schedule 1, Page 1, Table 1

Question:

a) Please confirm that Leave to Construct approval is only required for the NPS 36 pipeline and not for Ancillary work.

b) What is the exact length of the pipeline?

c) Please confirm that the pipeline will be built on agricultural land with no major water crossings.

d) What is the cost per km or per metre of the pipeline and how does it compare to the cost of similar diameter pipelines on agricultural land?

e) Please list the facilities that are included in the Ancillary Costs column.

f) Why are there no costs for Direct Overheads and IDC for Ancillary work?

g) Will Pipeline and Ancillary construction work and work be contracted out?

h) How many Enbridge employees are or will be charging time to the project? Please provide your answer in headcount and full-time equivalents (FTEs).

i) What costs are included in Direct Overheads and what costs are included in Indirect Overheads & Loadings?

j) How were the amounts for indirect overheads and loadings estimated? Please provide a schedule showing the calculations that support the numbers in the table.

k) Please provide a breakdown of the costs in External Permitting & Lands. Specifically, how much of the money will be paid to landowners and municipalities?

Response

a) Confirmed. Please see the response at Exhibit I.EP.1, part b).

b) The proposed pipeline ("TR 7") is 19,173 m in length.

c) Confirmed.

The list of watercourse crossings can be found in Table 4.1 Watercourse Crossings on the Preferred Route of the Environmental Report. The widest water crossings are Bear Creek and Black Creek, approximately 13.5m and 10.5m at the proposed crossing locations. Enbridge Gas does not consider these watercourse crossings to be "major water crossings".

d) The pipeline cost is approximately $6 million per km based on pipeline project costs of $114,232,158[1] and a pipeline length of 19.173 km. This cost is comparable to similar diameter pipelines situated on agricultural lands. However, Enbridge Gas cautions that project costs cannot be directly compared without considering all unique contributing factors at the time they are estimated or incurred.

e) The facilities included under the Ancillary Costs column are abandonment related work and all work required within the Dawn Operations Centre and the CCS.

f) For estimating purposes the costs for direct overheads and IDC were all included under the pipeline costs column. Direct overheads and IDC will be assigned to both pipeline and ancillary cost centers during construction and will be proportionate to the direct overhead allocated to the scope and cashflow as it occurs for the scope period.

g) Yes, Enbridge Gas will hire a contractor for the construction of the pipeline and ancillary facilities.

h) The direct overheads within the Project costs is for casual/contingent workers. A cost for Enbridge Gas employees time is included in Project costs through the indirect overhead allocation, not allocated by headcount or full-time equivalent (FTEs).

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[1] Exhibit D, Tab 1, Schedule 1, Table 1.

i) Direct overheads include costs associated with casual and contingent workers associated with the Project. Indirect overheads are expenses that can be linked to the creation of capital and support the production or construction of an asset but cannot be directly associated with any particular project/asset. For a description of loadings, please see the response to Exhibit I.STAFF.9 part a).

j) Please see Table 1 below. Please note that indirect overheads are not calculated on abandonment costs or IDC. Amounts are shown in $ thousands.

Table 1

	Year of Spend				
Item	**2021**	**2022**	**2023**	**2024**	**Total**
Total Capital Spend Prior to IDC	2,290	17,611	174,315	10,078	204,294
Less: Abandonment Costs	-	-	9,415	5,069	14,484
Capital Spend Subject to Indirect Overheads - A	2,290	17,611	164,900	5,009	189,810
Indirect Overhead Rate - B	20.56%	20.99%	23.58%	26.18%	
Indirect Overheads as Calculated (A x B)	471	3,697	38,883	1,311	44,362

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, p. 7-8 including Figure 2

Preamble:

Figure 2 provides a good overview of the piping network in and around the storage area of EGI.

We would like to understand and clarify the interconnections between the two central compressor stations, the storage pools and the pipelines moving gas out of the area.

Question:

Please provide the size and MAOP of all EGI-owned lines depicted in Figure 2.

a) Paragraph 18 refers the two NPS 30 pipelines that run directly between the CCS and Dawn. However, there is a pipeline that goes from Dawn to Wabuno which seems to extend to the Kimball-Colinville pool and, perhaps, the CCS. Please clarify if this pipeline connects through Wabuno to the CCS.

b) Please clarify if the pipeline depicted as the vertical line that runs through TCPL Courtright and Vector Courtright north toward Sarnia is the Sarnia Industrial Line.
   i. If so, can the CCS provide natural gas service into the Sarnia Industrial line?
      1) If yes, what is the daily demand that can theoretically be provided?
      2) How much of the daily demand of that Sarnia industrial system does the CCS provide on a peak day for the 2021/22 winter?

Response

Table 1 below lists the requested attributes of the main pipelines relevant to the CCS and the Project included in Figure 2.

Table 1

Pipeline	**NPS**	**MOP (kPa)**	**Comments**
TR1	30	6447	CCS to Dawn
TR2	30	7136	CCS to Dawn
WAUBUNO POOL LINE	10	6900	From Waubuno Pool to Dawn
PAYNE POOL LINE	20	6900	From Payne Pool to Dawn
TSLE	16	7240	Sombra Compressor Station to Dawn

a) The line shown on the map is the NPS 20 Payne pipeline that runs from the Payne pool to Dawn. In addition, the NPS 10 Waubuno pipeline runs from the Waubuno pool to Dawn. Neither of pipelines connect to the CCS.

b) Confirmed, the referenced pipeline is the Sarnia Industrial Line.

    i. No, the CCS cannot directly provide natural gas service into the Sarnia Industrial Line

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, p. 7-8 including Figure 2

Preamble:

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We would like to understand and clarify the interconnections between the two central compressor stations, the storage pools and the pipelines moving gas out of the area.

Question:

Please provide the study that EGI or Enbridge Inc. undertook to evaluate the synergy and integration opportunities of the two previously separate storage operations of the CCS and Dawn. We understand that EGI/EI may be concerned about confidentiality. Therefore, we respect if the submission of this study may require confidentiality treatment for which we will comply with the Board’s practice directions in handling.

a) If no such study exists, please explain why a newly-integrated utility would not undertake a study to determine if two physically linked operations which perform the same type of functionality would not be studied to determine how the integrated operations may be refined to create additional capacity.

Response

a) Enbridge Gas has not undertaken a study to evaluate the synergy and integration opportunities of the storage operations at Dawn and the CCS. However, Enbridge Gas analyzes its storage system on an integrated basis. The two storage systems are currently only connected at Dawn. The integrated system is primarily evaluated based on storage capacity and design day deliverability. The integration of the systems does not have any impact on the storage capacity of the individual storage pools. When evaluating design day deliverability, it is important to understand that the two storage systems were designed around similar design day principles to meet design day conditions. In addition, the pipeline and compression facilities are, for the most part, fully utilized. Therefore, any opportunities would require the construction of new facilities or the modification of existing facilities.

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, p. 7-8 including Figure 2

Preamble:

Figure 2 provides a good overview of the piping network in and around the storage area of EGI.

We would like to understand and clarify the interconnections between the two central compressor stations, the storage pools and the pipelines moving gas out of the area.

Question:

Please confirm that the CCS compressors provide compression operations that serve both the utility and non-utility storage services.

Response

Please see the response to Exhibit I.SEC.18 b).

ENBRIDGE GAS INC.

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

INTERROGATORY

Preamble:

In the following interrogatory and in some interrogatories later in our questions, we use the terms working storage space, peak injection capability and peak withdrawal capabilities. While we believe the specific definition of these parameters should be provided by EGI, we want to ensure that there is a common frame of reference.

So, for example, with certain infrastructure in place, the working storage space available would be: what is specific storage capacity available between the design minimum expected at the end of the withdrawal season and the maximum amount that could be injected at the end of the injection season.

Question:

Using the above example as a reference for a consistent definition from which various alternatives can be compared, please provide EGI's working definition of:

a) Working storage space (we have requested the space for both injection and withdrawal in respect of hysteresis or other limitations which would differentiate injection and withdrawal)

b) Peak injection capability (TJ/day at some consistent reference parameters)

c) Peak withdrawal capability (TJ/day at some consistent reference parameters)

Response

a) Working Storage Space (Working Capacity) – The amount of capacity available to be filled and emptied (i.e., the inventory at maximum pressure – the inventory at cushion pressure).

   Hysteresis does not affect a storage pools' working capacity. The working capacity of a pool is the same for injection and withdrawal.

b) & c)
Peak deliverability both for injection and withdrawal is the maximum capable deliverability from the system at a given condition. The deliverability is proportional to a multitude of factors, including but not limited to: the amount of gas in storage, operating setup, delivery pressure, storage pool hysteresis, well deliverability, facilities (pipeline, compressor, well, dehydration unit) availability, ambient temperature.

Enbridge Gas has interpreted the term peak withdrawal capability used in the question to mean design day deliverability. Design day deliverability refers to the maximum withdraw capability defined as the end of February of each year. The design day analysis ensures Enridge Gas's storage system has facilities in place to meet design day deliverability throughout the winter up to the end of February. Specific Design Day assumptions can be found in Exhibit.I.ED.1.

For Union rate zones, peak injection capability is defined by the maximum injection capability on October 31st of each year. For EGD rate zone, peak injection capacity is defined by the amount of injectability available when the system is 75% full. This ensures Enbridge Gas's storage system has facilities in place to meet peak injection capability throughout the injection season.

Peak injection capability and design day deliverability are shown in Table 2 below.

Table 2: Winter 2021/22 Storage Capability

	Peak Injection Capability (TJ/d)	**Design Day Deliverability (TJ/d)**	**Working Capacity (PJ)**
EGD rate zone	1,052	2,372	126.7
Union rate zones	1,595	3,873	185.1

ENBRIDGE GAS INC.

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

INTERROGATORY

Preamble:

In the following interrogatory and in some interrogatories later in our questions, we use the terms working storage space, peak injection capability and peak withdrawal capabilities. While we believe the specific definition of these parameters should be provided by EGI, we want to ensure that there is a common frame of reference.

So, for example, with certain infrastructure in place, the working storage space available would be: what is specific storage capacity available between the design minimum expected at the end of the withdrawal season and the maximum amount that could be injected at the end of the injection season.

Question:

For each of the CCS, Dawn and for the combined operations, please provide:

a) The working storage space and peak injection capability for the existing facilities.

b) The working storage space and peak withdrawal capabilities for the existing facilities.

c) The working storage space and peak injection capability for the existing facilities if two, three or four of the existing (determined by EGI as a smaller half from a necessity and condition point of view as a first step) are removed.

d) The working storage space and peak withdrawal capabilities for the existing facilities if two, three or four of the existing (determined by EGI as a smaller half from a necessity and condition point of view as a first step) are removed.

e) The working storage space and peak injection capability for the existing facilities if all seven compressors are removed.

f) The working storage space and peak withdrawal capabilities for the existing facilities if all seven are removed.

g) The working storage space and peak injection capability for the proposed facilities.

h) The working storage space and peak withdrawal capabilities for the proposed facilities.

Response

a) b) g) & h)
Please see Table 1.

Table 1

Rate Zone	Peak Injection Capability (TJ/d)	Design Day Deliverability (TJ/d)	Working Capacity (PJ)
EGD	1,052	2,372	126.7
Union	1,595	3,873	185.1

c) & e)
Enbridge Gas has interpreted FRPO's question to be in reference to the peak injection capacity impacts assuming the retirement and abandonment of certain of the existing CCS compressor units occurs. Please see Table 2 for the requested impacts.

Table 2

	Available Space (PJ)		Peak Injectability (TJ/d)	
	EGD	Union	EGD (1)	Union
K701	126.7	185.1	1,052	1,595
K701/2	126.7	185.1	1,052	1,595
K701/2/3	126.7	185.1	1,052	1,595
K701/2/3/5	126.7	185.1	1,052	1,595
K701/2/3/5/6/7/8	106.4	185.1	1,052	1,595

NOTES:
(1) The peak injectability for EGD is not impacted by this project. At the beginning of the injection season gas will be compressed at Dawn to provide a higher pressure to CCS and therefore there is no requirement to run compression at CCS for the first 25 PJ of injection. Thus, removing compression at CCS does not have any impact at the beginning of the injection season and subsequently does not impact the peak injectability.

d) & f)
Enbridge Gas has interpreted FRPO's question to be in reference to the peak withdrawal capacity impacts assuming the retirement and abandonment of certain of the existing CCS compressor units occurs. Please see Table 3 for the requested impacts.

Table 3

	Available Space (PJ)		**Design Day Deliverability (TJ/d)**	
	EGD	**Union**	**EGD**	**Union**
K701	126.7	185.1	2,331	3,873
K701/2	126.7	185.1	2,284	3,873
K701/2/3	126.7	185.1	2,232	3,873
K701/2/3/5	126.7	185.1	1,943	3,873
K701/2/3/5/6/7/8	106.4	185.1	1,706	3,873

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, p. 9-16 including Table 1

Preamble:

Footnote 6 states: It is anticipated that when these units reach their end of life they will be replaced with new compressor facilities at the CCS.

We are interested in the relative age and current condition of the compressors and the impact of individual compressor failures on storage operations.

Question:

For each compressor listed in Table 1, please provide:

a) the year of installation of each of the respective compressors

b) the year of and the specific compressor for any significant overhaul of the compressor internals since their date of installation

c) The amount spent on O&M or betterment capital spent on each compressor in the last 5 years

Response

a) Please see Table 1.

Table 1

Year of Installation	Unit
1964	K-701
1964	K-702
1964	K-703
1968	K-704
1970	K-705
1972	K-706
1973	K-707
1974	K-708
1980	K-709
1983	K-710
1995	K-711

b) Electronic maintenance records for overhauls were established in 2010. Table 2 below lists the CCS compressor units and year of overhauls since that time. Table 2 includes compressor, top end and bottom end engine overhauls.

Table 2

Unit of Overhaul	Year of Overhaul
K704	2011
	2013
	2018
	2021
K705	2014
	2017
K706	2014
	2015
	2019
K707	2013
	2015
	2018
K708	2014
	2016
	2020
K711	2010
	2019

c) Table 3 below sets out the O&M spent on CCS compressor units over the past 5 years. Due to cost assignments in the financial system being allocated by compressor station, the per unit breakdown by compressor has been proxied by run hours.

Table 3

Corunna Units	Annual O&M Proxied by Run Hours				
	2017	2018	2019	2020	2021
K701	$ 93,480	$ 295,294	$ 27,270	$ -	$ -
K702	$ 297,585	$ 292,772	$ 156,977	$ 208,377	$ 295,610
K703	$ 38,994	$ 491,629	$ 290,058	$ 527,752	$ 445,797
K704	$ 630,326	$ 732,366	$ 484,452	$ 709,845	$ 610,083
K705	$ 853,339	$ 401,951	$ 25,967	$ 807,525	$ 981,597
K706	$ 345,823	$ 380,380	$ 1,197,470	$ 509,303	$ 797,120
K707	$ 1,236,952	$ 1,094,506	$ 1,003,561	$ -	$ 214,683
K708	$ 998,924	$ 1,192,334	$ 852,437	$ 380,057	$ 751,584
K709	$ 298,313	$ 203,288	$ 368,905	$ 170,113	$ 411,702
K710	$ 210,323	$ 469,832	$ 400,954	$ 365,322	$ 259,019
K711	$ 815,521	$ 1,037,362	$ 535,568	$ 695,566	$ 727,309
Total	**$ 5,819,582**	**$ 6,591,711**	**$ 5,343,621**	**$ 4,373,860**	**$ 5,494,504**

Table 4 below sets out the Capital spent on CCS compressor units over the past 5 years.

Table 4

Corunna Unit	2017	2018	2019	2020	2021
Common Aux	$ 1,058,432	$ 1,065,429	$ 1,726,492	$ 2,584,417	$ 2,096,685
K701		$ 496,628	$ 465,564	$ 3,682	
K701/2/3					$ 421,510
K704		$ 17,062	$ 208,335	$ 488	$ 1,745,628
K705		$ 637,828	$ 5,337,522	$ 916,269	$ 170,175
K706	$ 4,468,219	$ 3,128,853	$ 13,382	$ 291,741	$ (96,325)
K707		$ 123,348	$ 13,326	$ 2,057,329	$ 2,653,526
K708		$ 1,085	$ 1,858,295	$ 1,928,577	$ 371,735
K709				$ 154,219	$ 402,239
K710					$ 579,667
K711			$ 153,644	$ 144,576	$ 453,243
Total	**$ 5,526,651**	**$ 5,470,233**	**$ 9,776,560**	**$ 8,081,298**	**$ 8,798,083**

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, p. 9-16 including Table 1

Preamble:

Footnote 6 states: It is anticipated that when these units reach their end of life they will be replaced with new compressor facilities at the CCS.

We are interested in the relative age and current condition of the compressors and the impact of individual compressor failures on storage operations.

Question:

In the last 10 years, please provide the following for any compressor failures that created a short notice limitation to storage services for in-franchise or ex-franchise service:

a) The compressor affected

b) The date of the incident

c) The amount of notice provided to ex-franchise customers for curtailment

d) The amount of time from the notice of outage to:
   i. Restoration of full service (i.e., no further curtailment)
   ii. Complete repair of the compressor to allow return to service

Response

a) & b)
Please see the response at Exhibit I.PP.5 part a) and Attachment 1 for a description of the compressor unit downtime for each unit over the last 6 years including duration (which is the time period for which the Company had relevant records of such data readily available).[1]

c) & d)
As shown in Exhibit B, Tab 1, Schedule 1, Figure 2, the Dawn Hub is an integrated storage system including the Dawn Operations Centre and Corunna Compressor Station. In Exhibit B, Enbridge Gas explains:

> "Currently, there are two NPS 30 pipelines (TR1 and TR2), approximately 20 km in length, that connect the CCS to Dawn for Injection and Withdrawal Modes. In addition, there is approximately 7 km of NPS 16 pipeline, known as TSLE, that connects the Sombra Compressor Station to Dawn and is utilized to fill an empty all or a portion of the Wilkesport, Coveny and Black Creek storage pools. The Sombra Compressor Station is also connected to the CCS through a series of NPS 16 pipelines."[2]

Enbridge Gas provides storage services at the integrated Dawn Hub based on the capacity available and provided by the integrated system. The available daily capacity for storage injections or withdrawals is a function of available wells, gathering systems, storage pipelines, headers and compressors as well as compressor or pipeline downtime for reasons such as maintenance activities or repairs.

Enbridge Gas evaluates available storage capacity based on the entire integrated system at the Dawn Hub and compares the capacity against the forecasted customer demand. The Company provides curtailment notices for interruptible storage services at the Dawn Hub at the integrated system level and does not maintain or categorize records of curtailment notices by failure type (i.e, specific to failures of the compressors at CCS or any other specific asset impairment at Dawn). As such, the Company cannot provide the amount of notice provided to ex-franchise customers for curtailment specific to compressor failures.

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[1] Exhibit I.PP.5 part a) and Attachment 1 includes compressor unit downtime data from 2016-2021. This list is not confirmed to have resulted in short notice limitation to storage services, but may assist in identifying when short notice limitation has occurred.
[2] Exhibit B, Tab 1, Schedule 1, P. 8.

Enbridge Gas has historically curtailed interruptible storage scheduled quantities following its Priority of Service policy and provides notice to customers through a traffic light change and an operational notice posted on the Company's website.

The Company has never had to curtail Firm in-franchise storage and distribution services or firm ex-franchise services at the Dawn Hub. This underpins the importance for the Company to have safe and reliable infrastructure available to provide these vital services.

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, p. 9-16 including Table 1

Preamble:

Footnote 6 states: It is anticipated that when these units reach their end of life they will be replaced with new compressor facilities at the CCS.

We are interested in the relative age and current condition of the compressors and the impact of individual compressor failures on storage operations.

Question:

In addition to the answers above on compressor failures that caused service limitations, if a compressor failed and Compressor K711 was activated as backup, please provide:

a) The compressor affected

b) The date of the incident

c) The amount of time to complete the repair of the compressor to allow return to service

Response

a) – c)
The Company does not directly track instances where a compressor failed and K711 was activated as backup. Please see Attachment 1 to this response, which provides a table that includes instances in which K711 was activated at the time that another unit being made unavailable. From this we can reasonably conclude that the activation of K711 was required to meet the demand at the time to avoid service limitation.

The column entitled “nSoda Report Outage Time” represents the number of hours the unit was unavailable due to the failure and the column entitled “K711 online” represents the number of hours that K711 ran in this scenario.

Unit	Title	Description	Start date	nSoda Report Outage Time (hrs)	K711 Online (hrs)
K701	CM - Gate Valve Leak	Upon inspection we found that the packing gland is cracked and needs to be replaced or repaired	01/13/2021	3696	494.70
K702	CM - Glycol Leak	pump seal was leaking removed old pump and installed re-built water pump from the warehouse	06/22/2018	105.6	48.50
K702	BR - Water Pump Failure	K702 has a knock coming from the water pump, a bushing was wore out on the water pump drive gear shaft causing the gears to not mesh properly, removed the gear case and water pump, had TREL repair the damaged drive gear and make new bronze bushings, re-assembled the gear case using a used spare shaft from a gear case we had sitting in the warehouse, installed a new rebuilt water pump from inventory, installed hardened cotter pins in the water pump drive chain	09/22/2020	320.9	402.10
K702	BR - Engine Failure	A large knocking noise started and emergency stop was used	09/13/2021	3073.7	924.50
K703	BR - Cracked Crown	Large oil leak out of front on engine possible crown issue, repaired K703 Cracked Crowns	07/25/2016	2088	1511.10
K703	CM - Crankshaft Repair	disassembled top and bottom end of engine so that the crankshaft was bare, removed flywheel, loosened timing chain, removed all but three main bearings,-installed all new (Dresser-Rand) main bearings, found that the top half of the bearing had lots of crush and the bottom half had very little, #11 main bearing is not an elliptical bearing,-recorded web deflections, checked bearing clearances, installed end seal and baffle plate, installed flywheel and torqued to 1800ft/lbs, rechecked bearing clearances and web deflections on #10 and #11 main (good), installed compressor rods with old bearings, installed all power rods with old bearings, reassembled top end of engine and tightened timing chain, bump checked compressor and power rods (good), checked crosshead pin clearances (good), when unit was test run we heard a loud ticking sounds from the flywheel end, we found that the baffle plate for the crank end seal had been damaged when the flywheel was being torqued, we removed the flywheel again and replaced the baffle plate, test ran the unit again and the noise was gone	05/01/2017	2622.4	1108.20
K703	BR - Power Cylinder Overhaul	Disassembled #7 power cylinder and inspected all parts, found that the piston crown was cracked in two places, inspected all other parts and found no issues, deglazed power cylinder, checked piston cutout for proper alignment (good), installed new piston with new rings and installed cylinder with new o-ring, cleaned and installed used head with a new copper gasket, re-assembled all top end auxiliary parts with new gaskets, -installed rocker arm with new lifters and set tappets, cleaned out that bay of the crankcase and installed doors with new gaskets, boroscoped PCC pot after water was installed (good)	06/22/2018	117.60	48.50
K704	CM - Repair identified leak	#N/A	01/24/2019	1,353.80	212.00
K704	CM - Suction Valve Very Noisy - Replace Motor	Preoper motor arrived and installed on vlave actuator, valve tested and put back into service	06/12/2019	577.70	1853.30
K705	CP -K705 Engine Block Replacement		09/05/2016	3312	882.30
K705	BR - Cylinder Overhaul	Engine was running with pre-ignition in #7 cylinder, pressure tested cylinder and found no compression, air was leaking from combustion chamber down into the crankcase	07/21/2017	123.80	67.20
K705	CM - Bearing Replacement	Installed new WIW main bearings in unit, C35used all new main bearing shims	04/30/2018	768	257.40
K705	CM - Inspect Crankshaft	This unit has a damaged crankshaft, in the summer of 2017 we had some issues with this unit	06/01/2018	1152	727.30
K705	CM - Discharge Valve Gas Leak	Repair identified leak, the valves mentioned are on the greasing list for 2019	01/24/2019	3312	212.00
K705	CP - Crank Repair	This Project Work Order was initially created as O&M spend . It has since been risk ranked and approved for Capital Spend	07/11/2018	10435	3453.40
K705	CP - Re-assemble K705 engine		06/26/2019	1730.9	739.10
K705	CP - Repair Cam Carrier and Power Cylinder	pened filter vessel and removed filters, the 2 magnets that were in the vessel had a lot of metal filings in them, cleaned filter pot, checked clean side to make sure no filings were there (it looked good), installed new oil filters, installed magnets in every filter, re-used old door o-ring, also drained oil from the bottom leg of piping and the oil cooler	10/21/2019	1757.6	306.60
K706	CP - Engine Block Foundation Replacement		07/04/2017	4872	2381.50
K706	CM - Aux Water Pump Rebuild	Sandarin rebuilt the pump and motor, we installed the pump with new gaskets, studs and nuts	01/30/2018	696	53.20
K706	CM/CP - Cam Upgrade and Laser Alignment	PCG laser aligned cam carriers on both sides of the engine, Cam carriers were shimmed and re-dowled as needed, Checked drive gears on both sides for contact and back lash and adjusted the end cover to set correctly, Installed the upgrader cams and torqued all bolts, Wire tied the dowels on the drive ends, Installed push rods and rocker arms and set tappets, Completed the timing of the cams	03/08/2018	2664	939.60
K706	CM - Engine Water Pump Rebuild	Engine water pump is installed	03/26/2018	216.00	12.80

K707	CM - Cracked Piping	Cracked nipple where vent piping threads into bypass, work completed. As builting to be completed in the coming weeks	08/23/2016	183.6	1479.00
K707	CM - Replaced Gas Packing	replaced gas packing and oil packing on all cylinders, found that the nose cone gasket was leaking on #4 cylinder, replaced the packing case on #4 cylinder because we couldn't seat the new nose cone gasket	01/21/2019	115.6	28.20
K707	CP - Engine Block Foundation Replacement		10/13/2020	4610.3	908.30
K707	CM - Gas Cooler Motor Failure	K703 #2 gas cooler fan wont run, motor has been replaced	07/08/2020	4535.1	2,028.30
K707	BR - Liner Replacement	during chain PM's we found moisture in the crankcase that was causing a lot of rusting internally, after investigating we found that the liners were leaking glycol from around the o-ring area, oil change to remove contaminated oil was completed under a different WO, replaced water pump chain under different WO, disassembled top end , installed new DR liners into refurbished Air Correct holders using D-R O-rings that came in the liner crates, cleaned up pistons and installed new rings, checked ring clearances in liner and on piston (good), re-assembled top end, cleaned and re-used the same heads, used DR gasket kits to install new gaskets everywhere on the top end, installed water and gas piping with new o-rings, pressure tested glycol system and found no major leaks, had operations put water in the unit and turn the warm up's on, this was the first time the new plant glycol was going in K707 engine , first we noticed some glycol leaking between the head and liner externally on some of the cylinders, after letting the engine sit a few days we started noticing glycol leaking internally around the liners the same as it was before , removed #6 cylinder to investigate, took liner and holder to TREL to verify measurement and machine work, found that the bronze o-ring area wasn't square to the top head gasket surface, suspected that the liners weren't sealing properly when the head was being torqued down because faces weren't square, the original holders were taken to Goodman Brown to be reconditioned, they squared up the holders and refinished the bronze sealing area, we tore down the top end again and installed the new refinished holders with the same new DR liners, installed all new O-rings and gaskets, had operations fill unit with water, found that all liners were still leaking internally past the o-ring sealing area, removed #8 cylinder to investigate because it was leaking the worse, Jim took the liner and holder to Goodman Brown with Tony Tebo, they found that the finish on the bronze was not to spec and was too porous, suspected that glycol was able to leak past the O-rings because of an improper finish, Goodman Brown refinished the bronze area again using an older method used previously to get the finish within spec, Installed the new refinished holder back in #8 cylinder with the DR liner using all new O-rings and gasket kit, operations put water back in unit and we found that glycol was still leaking internally from the o-ring area, removed #8 cylinder again to investigate, decided that there was maybe an issue with the hardness of the DR liner o-rings, ordered 90 durometer Viton O-rings and installed them on the #8 liner, re-installed #8 cylinder and checked for leaks internally, found no glycol leaking, decided that we should do another cylinder to verify this would fix the problem, removed #6 cylinder and installed 90 durometer Viton O-rings on the liner, assembled cylinder and checked for leaks, cylinder was not leaking, disassembled the rest of the top end and installed new 90	01/15/2020	6431.1	2400.50
K708	CP - Engine Block Foundation Replacement		10/09/2019	4788.5	2381.50
K708	CM - Water Pump Chain Replacement	new water pump chain was installed due to older one being stretched and could not be adjusted to proper tension, hardened cotter pins were installed, chain tension was set	10/11/2019	4488	667.40
K709	BR - Jacket Water Fan Motor Failure	Installed new motor, installed new overload switch, change witing in starter to reflect 2 winding motor	04/18/2016	243.10	2.10
K709	CM - Compressor Rod Bearing Replacement	Replaced Compressor Rod Bearings	09/10/2018	381.30	384.00
K710	CM - Replace Bearings on #1 Gas Cooler Shaft	Installed New Bearings on Cooler Shaft	05/28/2020	312.00	58.20
K710	CM - Bearing Replacement and Adjustments	Bearing Repair Work Complete	07/12/2021	864.00	281.80

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, p. 9-16 including Table 1

Preamble:

Footnote 6 states: It is anticipated that when these units reach their end of life they will be replaced with new compressor facilities at the CCS.

We are interested in the relative age and current condition of the compressors and the impact of individual compressor failures on storage operations.

Question:

Please file the EGI Priority of Storage Service Schedule

a) Please clarify if the priority of service is different for each of the legacy utility storage contracts

Response

The Priority of Storage Service Schedule is provided at Attachment 1 to this response.

a) Enbridge Gas has one priority of service schedule for all utility storage contracts.

POLICIES & GUIDELINES

Policy #: 07-CM-POS-015

☐ North ☐ South ☒ North and South

Subject:	**Effective**:
Priority of Service (POS) Guidelines	November 1, 2017

Applies to:

Applied on a daily basis to services for both in-franchise and ex-franchise customers in Union South and Union North (the combined North West and North East Zones).

Purpose:

To prioritize scheduling reductions and service restrictions for Enbridge's services during periods when Enbridge's ability to flow interruptible gas quantities is less than the requested/forecasted quantities.

Background: *(Not to limit the applicability of the policy)*

Enbridge offers firm no-notice (allocated) services, firm nominated services and interruptible services. The priority of service listings provide information regarding the processing of interruptions or scheduling reductions when requested services exceed available capacity under normal operating conditions.

Firm no-notice services are not interruptible. Firm nominated services are only firm if requested on the North American Energy Standard Board (NAESB) Timely Nomination Cycle for the gas day in question. Nominations for increases to daily quantities for Firm Services after the NAESB Timely Nomination Cycle are treated the same as interruptible services. Because Enbridge is a non-bumping pipeline, interruptible services scheduled on the NAESB Timely Nomination Cycle will not be interrupted to make room for additional firm services nominated on later nomination cycles.

In order to place services on the priority of service list, Enbridge considered several business principles. The principles included: appropriate level of access to core services; customer commitment; encouraging appropriate contracting; materiality; price and term; and promoting and enabling in-franchise consumption.

Policy:

The priority ranking for all services utilizing Enbridge Gas' storage, transmission and distribution system as applied to both in-franchise and ex-franchise services are as follows; with number 1 having the highest priority and the last interrupted.

<u>Priority for STORAGE Services</u>

1. Firm In-franchise Storage and Distribution services and firm Ex-Franchise services[(1)]
2. In-franchise Interruptible Distribution storage services
3. Peak Storage above firm up to 5% maximum storage balance (MSB) [(2)]
4. Balancing (Hub Activity) <= 100 GJ/d; Balancing (Direct Purchase) <= 500 GJ/d [(3)]
5. Off Peak Storage (First Cycle) up to 5%; Long Term Storage up to 5% MSB [(2)]
6. Peak Storage and Off Peak (First Cycle) above 5% MSB & Loans; In-franchise storage authorized overrun
7. Peak Storage and Off Peak (Second Cycle); Long Term Storage above 5% MSB
8. Balancing (Direct Purchase) > 500 GJ/d
9. Balancing (Hub Activity) > 100 GJ/d
10. Late Nominations

Priority for TRANSPORT Services

1. Firm In-franchise Transportation and Distribution services and firm Ex-franchise services[(1)]
2. In-franchise Interruptible Distribution services
3. C1/M12 IT Transport and IT Exchanges with Take or Pay rates
4. Balancing (Hub Activity) <= 100 GJ/d; Balancing (Direct Purchase) <= 500 GJ/d; In-franchise distribution authorized overrun [(3)]
5. C1/M12 IT Transport and IT Exchanges at premium rates
6. C1/M12/M17 Overrun <= 20% of CD [(4)]
7. Balancing (Direct Purchase) > 500 GJ/d
8. Balancing (Hub Activity) > 100 GJ/d; C1/M12 IT Transport and IT Exchanges
9. C1/M12/M17 Overrun > 20% of CD
10. C1/M12 IT Transport and IT Exchanges at a discount
11. Late Nominations

Notes:
(1) Nominated services must be nominated on the NAESB Timely Nomination Cycle otherwise they are considered to be a late nomination and are therefore interruptible.
(2) Higher value or more reliable IT is contemplated in the service and contract, when purchased at market competitive prices.
(3) Captures the majority of customers that use Direct Purchase balancing transactions.
(4) Captures the majority of customers that use overrun.

Procedures

1. Enbridge Gas will use its daily gas scheduling process to forecast the impact of firm and interruptible and/ordiscretionary customer activities on its storage, transmission and distribution operations.

2. Customer requested and/or forecasted quantities are compared to Enbridge Gas' operational limitations to determine if scheduling reductions and/or service restrictions are required. Any constraints are identifiedin advance of the effective flow time.

3. The Priority of Service list applicable to the operational constraint is used to make reductions to the customer's requested and/or forecasted quantities to a level sufficient to alleviate the constraint. Pro-rata reductions are performed within each priority ranking when necessary.

4. Customers are notified of an operational constraint and the corresponding impact on their requested and/or forecasted activities. All notifications occur in advance of the effective flow time.

5. Customer must re-nominate, as necessary, to balance any scheduling reductions and/or service restrictions.

6. As interruptions of specific services have ended the processing of authorized transactions will resume. The customer will be notified by phone and/or Enerline that their authorization will resume.

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, p. 9-16 including Table 1

Preamble:

Footnote 6 states: It is anticipated that when these units reach their end of life they will be replaced with new compressor facilities at the CCS.

We are interested in the relative age and current condition of the compressors and the impact of individual compressor failures on storage operations.

Question:

Footnote 13 indicates that compressors K705-708 are interchangeable and EGI only needs three to be in operation. Therefore, in a scenario whereby two of those compressors are inoperable, can K704 or K711 provide some of the functionality of the two compressors offline?

a) Please explain what operations cannot be performed and why?

b) How were the daily impacts of $0.8-11M per day calculated?
   i. Did these calculations take into account any support from K704 or K711?
      (1) If so, how?
      (2) If not, what would be the result if K711 were used to mitigate?

Response

Footnote 13 indicates that the CCS compressor units K701-K703 represent 3 of the 4 KVT model compressors that exist in North America.

Exhibit B, Tab 1, Schedule 1, p. 9, Paragraph 21, states that "during injection mode … CCS requires three of these four compressors in service simultaneously". Units K704 and K711 have different physical continuations (i.e., small cylinder sizes) and are designed for a higher maximum discharge pressure than units K705-K708. Thus, neither unit K704 nor unit K711 can fully replace any one of units K705-K708.

a) Neither CCS compressor unit K704 nor unit K711 can fully replace any one of units K705-K708. Additionally, when units K704 and/or K711 are operating in high pressure discharge services they are typically being supplied with gas from the discharge off of units K705-K708. Therefore, when units K704 and K711 are in higher pressure discharge service they cannot at the same time replace the functions of units K705-K708.

b) Please see response at Exhibit I.ED.1 h).

   i. These calculations assumed unit K704 was running to provide HP lift as required and unit K711 was running to backstop unit K705 that was out of service.

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, p. 9-16 including Table 1

Preamble:

Footnote 6 states: It is anticipated that when these units reach their end of life they will be replaced with new compressor facilities at the CCS.

We are interested in the relative age and current condition of the compressors and the impact of individual compressor failures on storage operations.

Question:

Numerous times in the evidence, EGI states that it will replace up to seven compressors. While we respect that which compressors and in what order will likely depend on operational issues that may arise in the coming years, with the best information it has at this time, please provide EGI's opinion on:

a) What would the order of replacement be?

b) In what year would EGI forecast the replacement?

c) What compressors are very unlikely to be replaced by the proposed pipe or other mitigation steps the company may envision at this time.

Response

a) Enbridge Gas is proposing to retire 7 compressor units (K701, K702, K703, K705, K706, K707, K708) at one time as part of the Project.

b) Enbridge Gas is planning to retire the 7 compressor units once the Project is placed into service (targeted for November 1, 2023).

c) Please see the response to I.STAFF.11, part a), for an explanation of the specific operational fit that K704, K709, K710 and K711 perform. As a result, Enbridge Gas is not proposing to retire these units.

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, p. 27

Preamble:

EGI evidence states: Finally, this short-term mitigant may require that the Company make additional pressure control retrofits on the two existing NPS 30 transmission lines (TR1 and TR2) connecting the CCS to Dawn at significant expense to ratepayers.

We would like to understand more about risk mitigation that could be employed.

Question:

Please provide a cost estimate of this pressure control retrofit.

Response

As discussed in Exhibit B, Tab 1, Schedule 1, p. 27, the short term mitigations identified are considered insufficient strategies as they do not resolve the risks (obsolescence, reliability and safety) described throughout Exhibit B and the underlying system constraint driving the need for the Project. Therefore, the pressure control retrofit was considered not to be a viable/feasible alternative.

The current TR1 & TR2 connections in the Dawn yard are designed to send/receive gas at approximately 4,826 kPa. To mitigate the loss/reduction of compression at CCS, Dawn compression would be required. Dawn compression could only be employed on a consistent basis if pressure control and additional header connections were constructed. This would enable Dawn to send higher pressure gas to the CCS (up to 6,447 kPa) and to receive lower pressure gas (down to 1,379 kPa). Given the complexity of working within the Dawn yard, a rough order of magnitude estimate to install the pressure control and header connection is $4,000,000. However, while providing pressure control and connectivity at Dawn may help manage the risk associated with occupancy rate and exposure to operating equipment, in the absence of an alternative that replaces the horsepower, the system cannot maintain EGD rate zone deliverability and storage capacity.

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, p. 28

Preamble:

EGI evidence states: Further, considering the obsolescence and reliability concerns discussed above, there is a heightened probability that repairs could require extended outage windows. The RAM Study specifically estimates that on average more than 6,500 hours per year of downtime will be required for units K701-K703 and units K705-K708.

While the study produced seems to project downtime, we would like to understand the historic downtime of the compressors.

Question:

In a table, for each compressor, please provide the actual downtime of each of the units due to required maintenance or repair.

Response

Please see the response at Exhibit I.PP.5, part a).

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, p. 30-31

Preamble:

EGI evidence states: Aside from the assessments and studies discussed above, the Company's conclusions were also informed by…

• ICF's forecast calling for increased seasonal storage values and winter price volatility;

Question:

Please file the report referenced.

a) Please specify where the content of the report was used in the evidence and potentially decision-making.

Response

In its pre-filed evidence at Exhibit B, Tab 2, Schedule 1, Paragraph 9, Enbridge Gas inserted the following quote from ICF:

> Going forward, ICF is projecting a general rebound in natural gas prices, as well as a slowdown in the growth of natural gas production and greenfield natural gas pipeline expansions. Both trends will tend to increase the seasonal value of natural gas storage. The general rebound in natural gas prices will lead to gas commodity prices that are generally higher in the winter withdrawal season than in the summer injection period simply due to the rising long term commodity price trend that ICF is projecting. In addition, as production growth in the Marcellus and Utica begins to slow, the increase in natural gas production during the winter relative to the previous summer will decrease, leading to an increase in the value of natural gas storage withdrawals to meet seasonal demand requirements. As a result, ICF is projecting a decline in winter gas supply availability and a general increase in storage values over the next several years. As seasonal storage values increase, winter price volatility is also expected to increase. The shift in storage

> markets makes the current time frame important for setting storage operational policy for the next few years.

Enbridge Gas mistakenly attributed this quote solely to ICF's Q4 2021 Base Case. Instead, Enbridge Gas should have explained that the referenced quote was taken from the ICF Proposal for an assessment of Enbridge's Dawn to Corunna Storage Project, dated November 17, 2021 ("ICF Proposal"). However, the ICF Proposal relied upon projections of natural gas commodity prices and storage demand requirements derived in-part from its Q4 2021 Base Case, Gas Market Model, and Gas Storage Valuation Model, all of which are proprietary in nature.

These same sources were relied upon by ICF to complete its analysis of supply side alternatives for the Project as described at Exhibit C, Tab 1, Schedule 1, Attachment 2.

The ICF Base Case is a commercially sensitive proprietary product with significant economic value. Consistent with past practice approved by the OEB, according to ICF, ICF is prepared to license the ICF Gas Market Outlook to any party that is willing to accept its commercial terms.

For these reasons, Enbridge Gas respectfully declines to provide the ICF Base Case as requested by FRPO

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, Attachment 1, p. 4-5

Preamble:

The included report states: The higher shortfall in earlier years is caused by a higher likelihood of foundation failures of units K704 (HP duty) and K701 (MP duty) as compared to the other CCS units, with the former having a high impact in injection capability, given its low level of redundancy…

- Units K-704 and K-711 (HP units) are responsible for 99.56% of the total Gas Injection shortfall. In absolute terms, this represents 309,784.3 x103 m3 of Gas Injection Shortfall (2.25%). This is attributed to the combined ‘N’ configuration that these units exhibit for the majority of the time that they are required to operate.

- Foundations are the most significant contributor to Gas Injection Shortfall, accounting for 31.37% of total shortfall (97,605.7 x103 m3, 0.71% absolute). This is attributed to the long duration associated with the repair of this maintainable item.

From our read of the evidence, compressor K704 provides specific duty that reduces the likelihood that it would be replaced in the short term. Therefore, we would like to understand more about the foundation repair.

Question:

Please provide:

a) The forecast year of repair

b) The cost of the repair

c) The amount of downtime estimated

d) EGI's approach to minimizing the impact of this downtime on peak operations where K704 provides important service

Response

a) Enbridge Gas is planning to begin the foundation repair with the dismantlement of the foundation in 2022 and replacement of the foundation to be completed in 2023.

b) The total cost including dismantlement is estimated to be $5,300,000.

c) The downtime for the unit is estimated to be November 1, 2022 – April 2023.

d) K704 is critical during injection operations. Enbridge Gas has scheduled the repair during peak period and design day when the injection function performed by K704 is not required.

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, Attachment 1, p. 6

Preamble:

The included report states: The figure below presents a yearly breakdown of the Base Case Gas Withdrawal Shortfall over the 5-year review period. During the 5 years assessed, the mean Withdrawal Efficiency of the Corunna facilities against Demand is 98.40%; 17,872,477 x103 m3 of gas was withdrawn against a Demand of 18,162,200 x103 m3.

We would like to understand this shortfall management.

Question:

Please provide the actual shortfall over the last 5 years.

a) Please confirm that the CCS does not have contingency space like Dawn.

b) What amount of deliverability is associated with the Dawn contingency space?

c) Does Dawn provide this contingency space in support of the CCS?
   i) If not, why not?
   ii) If so, how much CCS shortfall can the Dawn contingency space provide?

d) If Dawn operations are not used, how has EGI managed this CCS shortfall?

Response

The reference to the shortfall in the preamble and cited evidence is a forecasted shortfall produced from the RAM Study. As stated in the response at Exhibit I.FRPO.7

c), Enbridge Gas has never had to curtail firm in-franchise storage and distribution services and firm ex-franchise services at the Dawn Hub.

a) System integrity (referenced in the question as contingency space) is a combination of empty space and filled space (molecules) that is utilized to manage specific operational risks associated with the storage system. Unlike the Union rate zones (Dawn), the EGD rate zone (Tecumseh) does not have an OEB-approved methodology for system integrity.

b) Union rate zones utilizes 9.5 PJ of space and molecules to satisfy system integrity requirements. There is no deliverability identified as system integrity.

c) No.

   i) Union rate zones provides system integrity to manage specific risks associated with system operations for the legacy Union Gas system. System integrity was not developed to manage risks associated with the EGD rate zone storage system.

   ii) Union rate zones system integrity was not developed to manage risks associated with the EGD rate zone storage system.

d) System integrity is not utilized to manage compressor reliability or outages. Enbridge Gas has managed compressor downtime, unplanned repair and maintenance at the Dawn Hub as part of an integrated system. As shown in the response at Exhibit I.PP.5, historically the CCS compressors have experienced a range of downtime. If a compressor failure or unplanned maintenance/repair event occurs when demand is not forecasted to exceed system capacity at Dawn, the Company will not take additional action. If such an event occurs when demand exceeds system capacity, the Company will follow its priority of service policy. Should the Company forecast that it cannot meet its firm commitments then it will evaluate a market-based purchase to backstop the impairment.

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, Attachment 1, p. 10

Preamble:

The included report states: CCS has two modes of operation: injection and withdrawal. Injection operating mode takes gas from the two twin NPS 30 transmission pipelines from Dawn and flows the gas through CCS to the offsite storage pools
We would like to understand the injection operations against the risks defined in this evidence.

Question:

Please describe how EGI develops an injection/withdrawal schedule for the CCS on an annual basis.

a) Please include how the integration with Dawn operations contributes to that schedule.

b) Please file the summary injection schedule (from the last two versions prior to injection season) which highlights expected downtime for the CCS compressors for the last two injection seasons.

Response

Enbridge Gas considers and models many factors in the development of injection/withdrawal schedules. This includes but is not limited to: maintenance and construction outages; the time required to fill individual pools; availability of compression and pipelines; the timing of specific compressor operating modes; the characteristics of individual storage pools; and the availability of supply/scheduling of demand.

a) Enbridge Gas schedules and plans the filling and emptying of storage as part of the integrated system, including availability of compression and piping at Dawn, the CCS, and remote field compression. The integration with Dawn operations has provided flexibility to the integrated storage operations (injection and withdrawal) for day-to-day maintenance and construction activities. However, there are no combined benefits on design day as both legacy operations are bounded by the facilities currently in place.

b) To the extent possible, planned compressor outages are managed around injection operations and the injection schedule requirements. In some instances when outages exceed the available time the injection schedule is planned to accommodate the outage or additional mitigations are planned. Please see Attachment 1 and 2 to this response for examples of the injection and field work schedule for 2021 and 2022.

RevB 2021-02-19

ENBRIDGE Gas Inc. – Tecumseh Gas Storage Operations

2021 Field Work Schedule

Legend:
- Integrity - Inline Inspections (ILI), Integrity Digs, Repairs, and Upgrades
- Engineering, and Capital Repair Projects
- Well Work
- Reservoir Testing
- Tentative work execution windows - to be confirmed
- Scheduled for gas injection or withdrawal
- Scheduled for oil production
- Scheduled in-service for Operations
- Shut-In for Stabilization and Pressure Audit
- X = unavailable

Monday dates of calendar week: 04 11 18 25 01 08 15 22 01 08 15 22 29 05 12 19 26 03 10 17 24 31 07 14 21 28 05 12 19 26 02 09 16 23 30 06 13 20 27 04 11 18 25 01 08 15 22 29 06

Withdrawal Season | Injection Season | Withdrawal Season

Months / Calendar Week: January 2 3 4 5; February 6 7 8 9; March 10 11 12 13 14; April 15 16 17 18; May 19 20 21 22 23; June 24 25 26 27; July 28 29 30 31; August 32 33 34 35 36; September 37 38 39 40; October 41 42 43 44; November 45 46 47 48; Dec. 49 50

Facilities / Scheduled Work	Entries printed in schedule
Dow Moore	XG INJ; PMOP @ 1440#
I/W well performance testing	3
fill Dow Moore using COR & SEC PL's	
Corunna	oil production; 26; XG INJ; PMOP @ 1510#
Ready oil facilities for oil production (P<350 psi)	1; 14
pool pipeline MOP verification - repairs - repl. road crossing	??; 26; alternate Fall time execution window
delta-pressure upgrades (I/W well head upgrades)	7; 24
Drill TC8 (new observation well) [incl. inst./remove drill pad, land restoration etc.] - 2021 drilling permit pending	6; 14
Oil Battery Tank Telemetry Upgrade	
Seckerton	oil production; 11; XG INJ; 1481#
Ready oil facilities for oil production (P<350 psi)	1; 14
SEC I/W well loop upgrades with choke valves ??? **Julian Hampson** to provide dates & details	
pool pipeline MOP verification - repairs - repl. road crossing	??; 10; alternate execution window
delta-pressure upgrades (I/W well head upgrades)	8; 3
Oil Battery Tank Telemetry Upgrade	
Mid Kimball-Colinville	XG INJ; 1240#
Gathering line repair (2018 ILI follow-up)	10; 29
MKC&SKC INJ supply from Sombra via WLK pipeline	
South Kimball-Colinville	XG INJ; 1240#
TKC67H Drill Pad Preparations (2020 work)	
drill new I/W well TKC67H	19; 7
TKC67H lateral and ESV installation, gathering line tie-in	10; 29
deconstruct drilling pad	
land restoration around TKC67H	
Payne	
drill new I/W well UP24	24
install PU24 lateral and ESV, gathering line tie-in	14; 4
deconstruct drilling pad	
land restoration around UP24	
Ladysmith	XG INJ; 1397#
TL9 – stratigraphic pressure data gathering	
Drill TL9H (convert stratigraphic well to horizontal I/W well)	31; 18
Install new 10" lateral for TL9H	21; 5
Drill TL8 (new observation well)	5; 1
Deconstruct drill pads	26; 8
land restoration around TL8 and TL9H	
Upgrade meter station and Gathering Line to NPS20	3; 30
Integrity dig/repair on 90° elbow on NPS20 LAD pipeline	??; ??
install permanent pig receiver at CCS end of LAD NPS20 PL	19; 9
Integrity digs &repairs (5x) on LAD-WLK interconnect pipeline	??; ??
install permanent pig launcher at WLK-LAD Interconnect (at Hwy 80)	3; 22
Wilkesport	XG INJ; 1281#
Deconstruct Baby Rd. connection	3; 23
complete TR3 integrity repairs	10; 4
reconnect TR3 at Dig#18 near WLK meter station	5; 19
reconnect TR3 at Burman Line	12; 19
Liquids knock-out/filtration installation at WLK meter station ??? **Julian Hampson** to provide dates & details	??; ??
Coveny	XG; 1266#
I/W well performance testing	29
install permanent pig launcher on COV pipeline. ….**Kaella Earl** to provide dates & details	??; ??
Black Creek	XG; 1416#
Chatham D	
LINK Pipeline	
Corunna Comp. Stn. – Meter Run Replcm't. Project – PHASE 1	
Daylighting of existing U/G piping, final field checks, final field set-up	
ESD & inventory gas piping - ready for cold cutting, sever DOW & LAD PL's	17
Relocate LINK Measurement runs FR18 & FR17	
WLK to Hdr.-A — provision connections to Hdr. A – install pipe and 2 new valves	
complete full excavation	
Install new NPS30 crossflow headers: Headers A, B, C	
Install new DOW, LAD & PYN crossflow piping, modified HP Loop spool, new small bore utility piping, backfill as required	
ESD & de-inventory CCS yard - ready for cold cutting, final tie-ins on DOW, LAD, Hdr-A	30
final small bore and utility piping connections; final backfill of excavation, surface dressing	
commission new DOW, LAD PL's, Hdr.-A to WLK connection	
complete all possible instrumentation connections, DCS tie-in's etc.	
Corunna Compressor Stn. — Other Major Work	
K704 & K711 HP Valve Disconnect	29
K704 - Mode Valve Replacement (Julian H)	30; 15
K704 - iBalance Upgrade (Mark McLaughlin)	30
K704 - PLC Replacement **Mark McLaughlin** to provide dates & details	
K704 - Overhaul	12; 4
K704 - PSV Upgrades	30; 15
K705 - iBalance Upgrade (Mark McLaughlin)	5; 21
K705 - PSV Upgrades	5; 14
K705 - Jacket Water Cooler replacement **Jim Finley** to provide dates & details	
K705 - Utility Jacket Water Valve Replacement (3 way valve) **Jim Finley** to provide dates & details	
K707 - foundation rehab. {started in Oct. 2020}	
K707 - Oil Filter Replacement	
K707 - Aux Pump Replacement	
K707 - Forced Lube Upgrade	
K708 - Oil Filter Replacement	
K708 - Aux Pump Replacement	
K708 - Forced Lube Upgrade	
K709 - PSV Upgrade	
K709 - Oil Filter Replacement	
K709 - Aux Pump Replacement	
K709 - Forced Lube Upgrade	
K710 - PLC Upgrade	7; 2
K710 - Oil Filter Replacement	
K710 - Aux Pump Replacement	
K710 - Forced Lube Upgrade	
K710 - PSV Upgrade	
K711 - PSV Upgrade	
Air Compressor Replacement	
Dow Freeflow Valve Rebuild	4; 3
Emission Testing (K709/10)	18
Rockwell Server Refresh	29; 9
FR17/18 and GC BLDG Commissioning	29; 9
MCC2 Transfer Switch Replacement	29; 9
Sombra Compressor Station	
K801 & K802 Silencer Replacement	21; 4
K803 Header Valve Replacements (Julian H.)	10; 18
Coveny MV-7101 - Replacement	10
Dehy to Vector MV-7147 - Replacement	13
Trans MV-7113 - Replacement	31; 11
TLSE (TR5) Trans Plot Edge ESV-6301 - Replacement	6; 14
253351 - Sombra Dehy Rehab. ??? **Julian Hampson** to provide dates & details	12; 20
Other Major Work	
Unit Discharge PSV's (to be done one unit at a time)	1; 13

Rev3 2022-04-26
Printed: 2022-04-28

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ENBRIDGE Gas Inc. – Tecumseh Gas Storage Operations

2022 Field Work Schedule

Legend:
- Integrity
- Engineering, and Capital Repair Projects
- Well Work
- Reservoir Testing
- Tentative work execution windows - to be confirmed
- Scheduled for gas injection or withdrawal
- Scheduled for oil production
- Scheduled in-service for Operations
- Shut-In for Stabilization and Pressure Audit
- X = unavailable

Monday dates of calendar week: 03 10 17 24 31 07 14 21 28 07 14 21 28 04 11 18 25 02 09 16 23 30 06 13 20 27 04 11 18 25 01 08 15 22 29 05 12 19 26 03 10 17 24 31 07 14 21 28 05 12 19 26 02 09

CMRR Ph.2 Outage

Withdrawal Season | Injection Season | Withdrawal Season

Calendar Week: January 2 3 4 5 | February 6 7 8 9 | March 10 11 12 13 14 | April 15 16 17 18 | May 19 20 21 22 23 | June 24 25 26 27 | July 28 29 30 31 | August 32 33 34 35 36 | September 37 38 39 40 | October 41 42 43 44 | November 45 46 47 48 | Dec. 49 50 51 52 | Jan. 53 2 3

Facilities / Scheduled Work	Notes in schedule
Dow Moore	XG INJ; PMOP @ 1516#
I/W well performance testing - TD27 & TD28 (in Dec. 2021?)	
Well workovers for delta-pressuring to 1516#	11
Install flow loops on wells with completed workovers	11
Install flow control valve at DOW meter station incl. DCS tie-ins	?? 11
Corunna	oil production; XG; PMOP @ 1510#
fill COR & SEC using Dow Moore PL	
Ready oil facilities for oil production (P<350 psi)	1 14
TC8 Drill Pad installation	
Drill TC8 A1 observation well (pad installed in Q4/2021)	26 8
Install new PIT, telelmetry and DCS tie-in	
deconstruct drilling pad & land restoration	
Upgrades to Bettis Operators for pool delta-pressuring	
Seckerton	oil production; XG; 1481#
Ready oil facilities for oil production (P<350 psi)	1 14
Upgrades to Bettis Operators for pool delta-pressuring	
Mid Kimball-Colinville	1; XG 1240#
TKC68 Drill Pad - preparations	
drill new I/W well TKC68 (pad installed in Q4/2021)	16
TKC68 lateral and ESV installation, gathering line tie-in	30
Install new ESV telelmetry and DCS tie-in	20
deconstruct drill pad & land restoration	
MKC&SKC INJ supply from Sombra via WLK pipeline	
South Kimball-Colinville	1; XG 1240#
TKC69 Drill Pad - preparations	
drill new I/W well TKC69 (pad installed in Q4/2021)	25
TKC69 lateral and ESV installation, gathering line tie-in	9
Install new ESV telelmetry and DCS tie-in	23
deconstruct drill pad & land restoration	
Payne	
1150# HG gas to Payne pool via CCS and new NPS24 pool PL	gas routed via NPS24 from CCS
new NPS24 pool pipeline tie-in at Corunna Comp. Stn.	
new NPS24 pool pipeline - pipeline construction	
new NPS24 pool pipeline tie-in at Payne Comp. Stn.	
commissioning of valves / complete set-up in CCS DCS	
Ladysmith-Payne Crosover station	
demoltionion/removal of decomssined line heaters	
PYN pipeline tie-ins / install new valves for crossover functions	
LAD pipeline tie-ins	5 11
commissioning of new crossover valves / complete set-up in CCS DCS	
Ladysmith	XG 1397#; WDR to 750#; Refill to 1350#
TL8 Drill Pad installation	
Drill TL8 (new obs well) **contingent** on acquiring drilling permit in 2022	4 22; 28 16
Install new PIT, telelmetry and DCS tie-in	
Deconstruct drill pad	
land restoration around TL8 and TL9H	
Pigging: LAD-WLK NPS16 interconnect pipeline	30 ??; 28 16
Install temporary NPS16 pig barrel, filter, and condensates tank	27
install new LAD 16" FCV on temporary (2022 use only) basis	
install new NPS16 piping in east side of meter station [2023]	
install new permamnet NPS16 pig barrel, filter, and Clemmer tank [2023]	
Install new FCV in new, permanent locations and complete DCS programming and tie-ins [2023]	
Install 3 new NPS20 Filters and connect to Clemmer tank [2023]	
Wilkesport	XG 1281#
install permenent pig barrel on gathering line at Baby Rd. Stn.	
install permenent pig barrel on gathering line at WLK MS	
Coveny	1267#
I/W well performance testing	29
TCV7 Drill Pad installation	
Drill TCV7 (A1 observation well)	13
Install new PIT, telelmetry and DCS tie-in	4
deconstruct drilling pad & land restoration	
Pigging: NPS16 COV pool gatheing pipeline	18 19
Pigging: COV NPS16 pool pipeline & TSLE pipeline	20 11
Black Creek	XG; XG 1416#
Sombra Compressor Station	
FR30 - remove and replace with straight section of pipe	3 22
FR31 & FR32 replace and make these dedicated msmt. for Black Creek	10 22
Chatham D	
LINK Pipeline	
Corunna Comp. Stn. – Meter Run Replcm't. Project – PHASE 2	
Sever CCS - WLK PL (requires WLK PL to be de-pressurized)	
Daylighting of existing U/G piping, final field checks, final field set-up	
ESD & de-inventory gas piping, setting spades on compression headers	16 18
remove FR01 thru FR11	
complete full excavation	
Install new NPS30 crossflow headers: Headers A, B, C	
Install new WLK, SKC, SEC, COR, MKC pool pipe segmments and associated crossover valves	all yard side, and COR & SEC pool pipe connections; WLK, MKC, SKC pool pipe connetions
Install new new small bore utility piping, backfill as required	
Install instrumentation and communication cables	
final small bore and utility piping connections; final backfill of excavation, surface dressing	
commission new WLK, SKC, SEC, COR, MKC yard pipe valves; cross-over valves	
complete all instrumentation terminations, DCS tie-in's etc.	
connect east and west sections of NPS30 cross-flow headers: Headers A, B, C; backfill	
final commissioning	
Corunna Compressor Stn. — Other Major Work	
Install TR2 temporary pig launcher barrel	14
Pigging of TR2 transmission pipeline	4 2
install WLK, MKC, SKC permement pig barrels [2023]	
K709/10 OPP & ACTUATOR UPGRADE (Rick)	
Alex Bullock's projects	
K704 - Foundation replacement	
K706 Oil Filter Replacement	
K711 Oil Filter Replacement	
Corunna Glycol heating system – Installing check valves and PITs	
Corunna Fuel gas heater – Installing new fuel gas heater for Corunna engines	
Julian Hampson's projects	
Unit Discharge PSV's (to be done one unit at a time)	?? ??
K709/K710 mode valve replacement	21
I&E & Controls Project work (Mark McLaughlin's Grp.)	
CMRR Project – PHASE 2 – I&E support work	
Sever CCS - WLK PL (requires WLK PL to be de-pressurized)	
Daylighting of existing U/G piping, final field checks, final field set-up	
ESD & de-inventory gas piping, setting spades on compression headers	15 18
remove FR01 thru FR11	
complete full excavation	
Install new NPS30 crossflow headers: Headers A, B, C	
Install new WLK, SKC, SEC, COR, MKC pool pipe segmments and associalted crossover valves	
Install new new small bore utility piping, backfill as required	
Install instrumentation and communication cables	14 4
final small bore and utility piping connections; final backfill of excavation, surface dressing	
commission new WLK, SKC, SEC, COR, MKC yard pipe valves; cross-over valves	
complete all instrumentation terminations, DCS tie-in's etc.	
connect east and west sections of NPS30 cross-flow headers: Headers A, B, C; backfill	
final commissioning	30 10
K704 IBALANCE	10 28
EMMISSIONS K702/3/9/10	14
VECTOR NEST POWER UPGRADE	1
OIL BATTERY AUTOMATION UPGRADE	14
SCADA ACTIVE DIRECTORY REFRESH	21
MCC3 TRANSFER SWITCH UPGRADE	22 30
VIDEO WALL UPGRADE	28
SCADA ICM SSCM CONNECTION	2 13
K709/10 VALVE & ACTUATOR UPGRADE	15
TRANSFORMER UPGRADE	
K704 OPP ACTUATOR INSTALL	21
LDY REXA FCV	20
ESV UPGRADE 2021	
DIGI METER STATION UPGRADES	
PASSWORD POLICY	
AIR DRYER TEC UPGRADE	1
VECTOR USM RECERTIFICATION	?? ??
PAYNE STATION UPGRADE	19
SCADA IDC THIN MANAGER INSTALL	5
USM SOM UPGRADE	10 22
DOW REXA FCV	19 7
ESV UPGRADE 2022	
LINK PLOT EDGE UPGRADE	
SCADA IDC UPGRADE	1 25
GAS DETECTOR UPGRADE	
IBALANCE K709	
IBALANCE K710	
TR7 VALVE & ACTUATOR INSTALL	?? ??
Update K704 & K711 Operating Maps	?? ??

S:_OPERATE\Pool Schedule\2022\2022 Field Work Schedule\2022 TEC Field Schedule - Rev3 2022-04-26

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, Attachment 1, p. 10

Preamble:

The included report states: CCS has two modes of operation: injection and withdrawal. Injection operating mode takes gas from the two twin NPS 30 transmission pipelines from Dawn and flows the gas through CCS to the offsite storage pools
We would like to understand the injection operations against the risks defined in this evidence.

Question:

What is the minimum pressure assumed, under design conditions, that the gas will be received from the NPS 30 lines from Dawn during the injection season?

a) Does the CCS draw gas from other pipelines during the injection season?
b) If so, please provide the pipelines and the range of delivery pressures from these pipelines at the CCS during the last two injection seasons?
c) Over those last two injection seasons, for each pipeline including the two NPS 30 pipelines from Dawn, what percentage of days does the receipt pressure drop below the minimum pressure from Dawn?
    i. Please describe the impact that incremental pressure from these pipelines including Dawn has on runtime during the injection season.
        1) For each compressor, please provide a summary of expected runtime from the injection schedule over the last 2 years and the actual runtime experienced.
    ii. Please describe the impact that the incremental pressure above minimum design pressure in the injection schedule has on risks associated with downtime during the injection season.

<u>Response</u>

It is assumed that the minimum pressure supplied from Dawn in the NPS 30 pipelines is approximately 4,826 kPa. This pressure is expected to vary based on receipt pressures from supply pipelines and the associated yard losses.

a) & b)
No.

c) Over the past two years (2020 & 2021), the receipt pressure into the NPS 30 pipelines at Dawn has been below 4,826 kPa 13% of the time. Supply delivered to the NPS 30 pipelines is received from supply pipelines (Great Lakes and Vector) and routes through Tecumseh measurement at Dawn.

   i. Incremental pressure from Dawn would reduce pressure lift required at CCS. Depending on the amount of incremental pressure received from Dawn it is possible that less run time is required on some units.

      1. Enbridge Gas does not use hydraulic simulation to forecast expected runtime for individual units as part of the injection schedule but ensures there is enough availability of compression to fill the working capacity of the reservoirs. Please see the response at Exhibit I.SEC.8 for actual run time for each compressor unit.

   ii. Depending on the amount of incremental pressure, risks associated with downtime could potentially be reduced. However, on injection the greatest risks associated with downtime are related to CCS compressor units K704 and K711 as they are required to fill the top inventory portions of the pools – K704 & K711 have always been supplied with an elevated suction pressures of ±7,500-8,650 kPa (from other compressors at the CCS in these top-end filling operations), which is above the MOP of the NPS 30 pipelines. Therefore, incremental pressure from Dawn with the current pipeline facilities between the CCS and Dawn cannot address this risk.

   The proposed NPS 36 will have a MOP of 9,308 kPa which can facilitate a similar suction pressure feeding into units K704 and K711 as the existing CCS compressor units proposed for retirement. This will consequently maintain or potentially slightly reduce some of the run time requirements for units K704 and K711. Moreover, the existing NPS 30 pipelines between the CCS and Dawn, can only provide incremental pressure up to 6,447 kPa under specific operational scenarios during the injection season, compared to the higher pressure and related operational flexibility provided by the proposed NPS 36.

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, Attachment 1, p. 15

Preamble:

The included report states: The following list details the Base Case models basis and assumptions, which are considered in more detail in the following sections:

- Period of study: This RAM study is based on a 5-year look-ahead period

We would like to understand more about the scope of the work in this study.

Question:

Please provide the RFP for the work.

a) Please provide the terms of reference or comparable that defines the scope of the work.
b) How was recent history of the compressor operations of the CCS used in developing the results of this study.
    i. Please be specific and provide any comparisons of actual vs. projected from working papers or other documents not filed.
        (1) If not available, please describe why this was not done.

Response

a) No RFP was required for this work. The scope of work is outlined in the proposal from DNV at Attachment 1 to this response.

b) Recent history of the compressor operations of CCS was used in the RAM Study by way of the Asset Health review ("AHR"). Please see Exhibit B, Tab 1, Schedule 1, Attachment 1, p. 15, which lays out the approach to incorporating appropriate reliability data from the AHR which is based on historical failure and maintenance data.

(i) The inputs for the RAM model are the reliability parameters associated with the CCS compressor units by way of the AHR, the RAM results (i.e., projected shortfall) are inherently consistent with historical data.

The AHR results have been validated by comparing the projected failure frequencies vs. actual failure frequencies. For instance, the AHR projections predicted at least 1 foundation failure per year, where foundation failure refers to foundation degradation. As presented in the response at Exhibit I.PP.5 a), Attachment 1, the CCS has experienced at least 1 foundation repair or replacement in the period from 2016-2021.

Proposal for Corunna Compressor Station – RAM Study

Enbridge Gas Inc.

DNV doc No: TC-ID-1208788
Date of first issue: 2021-06-17
Date of this revision: 2021-06-17

DNV

Customer Details

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DNV doc. No. :	TC-ID-1208788

About this document

Proposal Title:	Corunna Compressor Station – RAM Study
Date of first issue:	2021-06-17
Date of this revision:	2021-06-17
Validity of proposal:	3 months from date of issue
Terms and Conditions:	See Section 7, Contractual

Confidentiality

This proposal contains information that is business sensitive to DNV. No part of the proposal or information received during the proposal process may be used, duplicated or disclosed for any other purpose. Any such use of DNV's information is regarded as an infringement of DNV intellectual property rights.

for DNV Canada Ltd.

Prepared by:	Approved by:
Neil Wragg Senior Principal Consultant	Mark Klages Head of Section, Incident and Integrity Management
Jeremy Johnson, P.Eng. Engineer	

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Table of Contents

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1 INTRODUCTION

The Corunna Compressor Station (CCS) is located at 3595 Tecumseh Road, Mooretown ON. It uses 11 reciprocating compressor units to transport sweet natural gas to and from offsite underground storage facilities to transmission pipelines for eventual use in downstream distribution networks.

CCS has two main modes of operation: injection and withdrawal. Injection operating mode takes gas from the two twin NPS 30 transmission pipelines from Dawn and flows the gas through CCS to the offsite storage pools. Withdrawal operating mode takes gas from the storage pool pipelines and flows through CCS into the transmission pipelines back to the Dawn facility.

Enbridge Gas Inc. (Enbridge) have asked DNV to provide a proposal to undertake a RAM analysis for the Corunna Compressor Station. The primary objective of this analysis is to forecast the availability performance of the station (against project targets) and identify any potential areas of improvement.

This document contains DNV's proposal to support Enbridge, and describes the study objectives, approach, and deliverables required to complete the scope of work.

1.1 Why DNV?

DNV is a leading provider of Risk Management Solutions to the Oil & Gas industry worldwide. DNV believes they are well placed to deliver the best value in the market today for the following reasons:

- DNV has in-depth, industry-leading competence in RAM analysis having carried out many RAM studies for onshore and offshore oil and gas facilities, worldwide.
- DNV Performance Forecasting team in the UK, who will perform the RAM analysis, are highly qualified and experienced in delivering RAM studies. We are specialists in using our proprietary RAM simulation software tools, TARO, MAROS and OPTAGON.
- The DNV team has extensive experience in working with a variety of Company standard and international standards, including: ISO 20815, ISO 14224, IEC 60812, Norsok Standards, Shell Standards, Total Standards, Saudi Aramco Standards, Chevron Standards, ENI Standards, etc.
- DNV recently lead a Joint Industry Project in 2018 for the development of "Guidelines for the Execution of a RAM Analysis in the Petroleum, Petrochemical and Natural Gas Industries". This guideline is now the official methodology to perform RAM analysis used by Shell, Chevron, SBM, Centrica, Repsol Sinopec and Gasunje.

1.2 DNV Capabilities in RAM Modelling

DNV has over 30 years of experience in reliability/availability studies of oil and gas assets around the world. In this period DNV has carried out over 1500 RAM analyses of various facilities including:

- Offshore:
    - FPSOs / FLNGs / FSRUs
    - Fixed Platforms
    - Subsea Installations
- Onshore:
    - Oil and Gas production facilities
    - Refineries
    - Petrochemical Plants

- LNG Liquefaction and Regasification terminals
- Oil & Gas Distribution Networks
- Utility Systems
- Transportation / Logistics

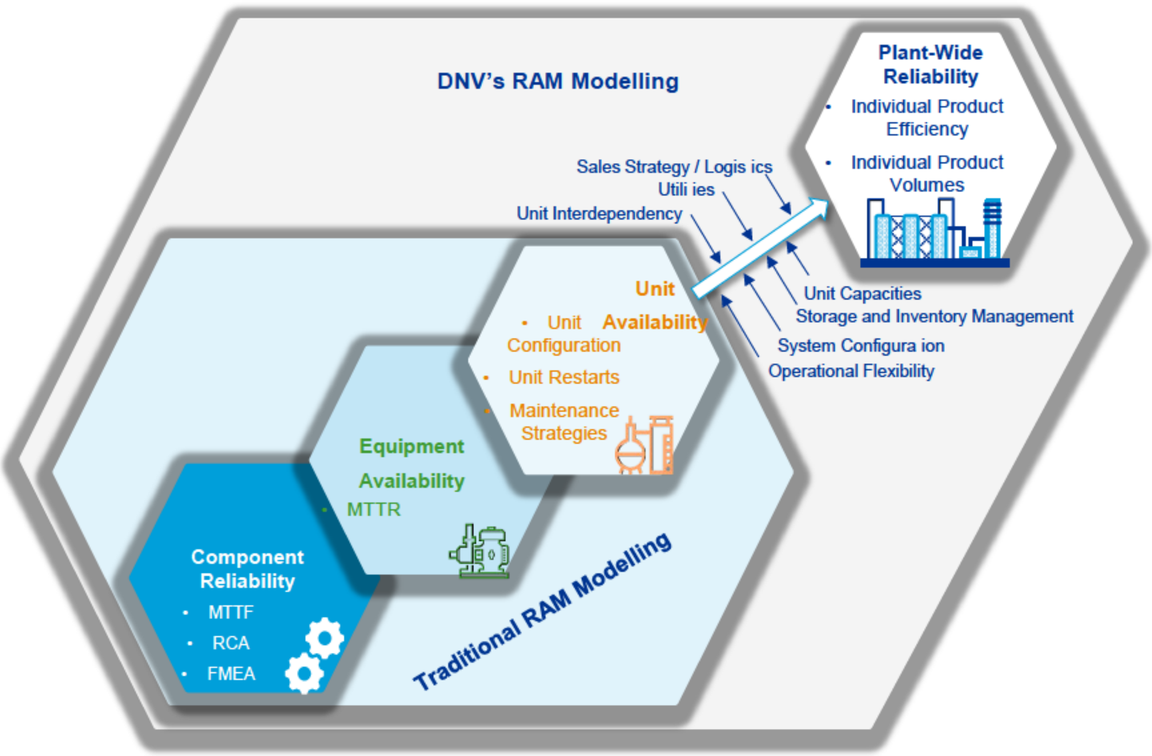
A summary of recent RAM experience is provided in Appendix A.

1.3 DNV RAM Software Tools

DNV software tools for Reliability Analysis are increasingly the industry standard for RAM analysis, utilised by most of the leading oil and gas operators. RAM analysis allows the assessment of numerous, often complex interrelated parameters:

- Product deliverability over venture life
- Network / plant configuration
- Equipment reliability
- Logistics (e.g. spares)
- Maintenance resource levels / availability
- Unit re-start times (maintenance and process related)
- Operational logic (flexibility)
- Unit costs/rates and OPEX (Operating Expenditure)
- Gas demand requirements (contractual supply obligations)

The figure below provides an overview of the methodology that is utilised by DNV to perform RAM studies:



Typical outputs from RAM studies are:

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- Average availability and production efficiency and over the life of the facilities
- Key systems, equipment and events which result in production loss
- Identification of bottlenecks from throughput changes e.g. compression, liquids handling
- Quantitatively focusing attention to those areas that will have maximum benefits on performance
- A design optimised for availability whilst working within cost constraints
- An assessment of maintenance plans and their impact to plant availability
- A prediction of future system performance, not only in terms of availability but also considering its ability to meet contractual obligations (gas sales nominations)
- Quantification of benefits of loss offsetting measures (e.g. storage, alternate routes, reconfiguration)
- Setting realistic production and efficiency targets
- Logistics optimisation
- Production recovery operations

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2 SCOPE OF WORK

2.1 Objectives

The objectives of the RAM study are as follows.

- Forecast Availability (%) and Uptime (%) of the CCS over the remaining operational life. The following operations will be assessed:
  - **Injection mode**: Gas taken from Dawn facility and transferred to offsite storage pools
  - **Withdrawal mode:** Gas taken from offsite storage pools and transferred to Dawn facility
- Identify key systems and equipment that result in Availability losses, and rank by system and equipment contributions (criticality analysis)
- Identify any potential areas of performance improvement through consideration of defined sensitivity cases (3 sensitivity cases are included in this scope). For example, these may include:
  - Compressor replacement / overhaul
  - Alternative configurations
  - Spares holding / logistic delays
  - Maintenance strategies

2.2 Study Boundaries

The RAM study will consider all process and utility equipment critical to gas injection / withdrawal, within the following boundaries:

Injection Mode

- Upstream: Inlet ESDVs from Dawn Facility (TR1/TR2)
- Downstream: Outlet ESDVs to Offsite Storage Pools (Dow Moore/Mid Kimball-Colinville/ South Kimball-Colinville, Wikesport/Seckerton/Corunna/Ladysmith)

Withdrawal Mode

- Upstream: Inlet ESDV from Offsite Storage Pools (Dow Moore/Mid Kimball-Colinville/ South Kimball-Colinville, Wikesport/Seckerton/Corunna/Ladysmith)
- Downstream: Outlet ESDV to Dawn Facility (TR1/TR2)

2.3 Design Capacities & Production Profiles

The Base Case RAM model will:

- Represent a single development scenario, as selected by Enbridge. Appropriate process plant capacities will be provided by Enbridge.
- Forecast Availability and Uptime against a single production profile (as provided by Enbridge).

2.4 Modelling Assumptions

RAM modelling work is carried out according to the principles set in ISO 20815 and DNV Joint Industry “Guideline for the Execution of RAM analysis”.

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2.4.1 Model Indenture

- RAM models will be developed at equipment level (e.g. vessel, heat exchanger) from PFDs / UFDs.
- Failure modes will be defined on an equipment (pump, vessel, etc.) level, not on a component level in line with the ISO 14224 definitions. For each production critical item, the model will include one or more failure modes dependent on the utilized data source. The data source for each failure mode will be referenced. Failure modes for all equipment critical to production will be defined and considered in the modelling. Non-production critical systems and utilities will be excluded.
- Control valves, XVs, SDVs, and BDVs associated with equipment (such as vessels, compressors, etc.), if included in the defined boundary for these equipment items, will not be considered separately in the RAM model. However, if critical valves are found outside equipment boundaries, they will be listed and modelled accordingly.

2.4.2 Reliability Data

- All reliability data used in this RAM study shall be provided to Enbridge for their review / approval, prior to inclusion the RAM model, and subsequently documented in the Final Report.
- Equipment reliability data will be taken from the following sources, in order of priority:
    1. Enbridge data (where available)
    2. OREDA – where applicable, latest version will be used (DNV may suggest alternative e.g. due to insufficient data population)
    3. DNV Reliability Database (based on previous project experience)
- DNV recommend use of exponential distributions for both MTTF and MTTR - alternatives can be discussed and agreed if preferred (e.g. fixed, rectangular, triangular).
- Early Life & Wear-out Period: In terms of process stability and equipment failures, all facilities are assumed to be in a steady state ('useful life') running condition. Start-up issues and infant mortality failures are excluded from the scope of work, as well as the wear out period of equipment life. Systematic failures (i.e. recurrent fabrication faults or design defects) are also excluded from the scope of work.
- Systematic failures, such as recurrent fabrication faults or design defects, will not be considered.
- Rare and Catastrophic Events: Some rare unplanned events are likely to cause major production losses should they occur. These events can be classified as catastrophic events, which need to be considered differently from the frequently occurring events, which are part of the daily running of the facilities. These will not be included in the RAM study as recommended in the ISO standard.
- Human Error: Most Reliability databases focus on data gathering on hardware components and systems, and unavailability of systems due to human error is generally not included. For this reason, human error is generally excluded from RAM analysis and DNV propose to exclude it from this scope of work.
- Common Mode Failure: the availability of the redundant unit in general is only marginally degraded by common mode failures and these are not normally included in a RAM analysis.

2.4.3 Maintenance

- Planned Maintenance: Planned maintenance shutdowns shall be included in the model.
- Non-intrusive planned maintenance or inspection activities, that can be carried out without a unit shut down or turndown, will be excluded from the RAM study. All turnaround maintenance activities will be grouped together and treated as a single maintenance shutdown.

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- This study will not explicitly model opportunity maintenance. If certain failures are only repaired on an opportunity basis and those failures will not have an impact on production, then the failure will be considered not critical.
- Maintenance resources will be modelled at high level (i.e. with mobilization delays). The study is not expected to quantify requirements for specific skills and maintenance resources.
- Capital Spares: The availability of selected capital spares (pumps, motors, rotors, seals, etc.) may be included in the models. Assumptions of procurement time, logistics delay and replacement time are to be confirmed (if required).
- Warehouse Sparing: It is assumed that this model will not quantify requirements for normally used spare parts (expendables), these spare parts will be assumed to be available when needed.
- Vendor Representation: The models will consider additional mobilisation times for a vendor representative to perform breakdown maintenance on specific equipment.

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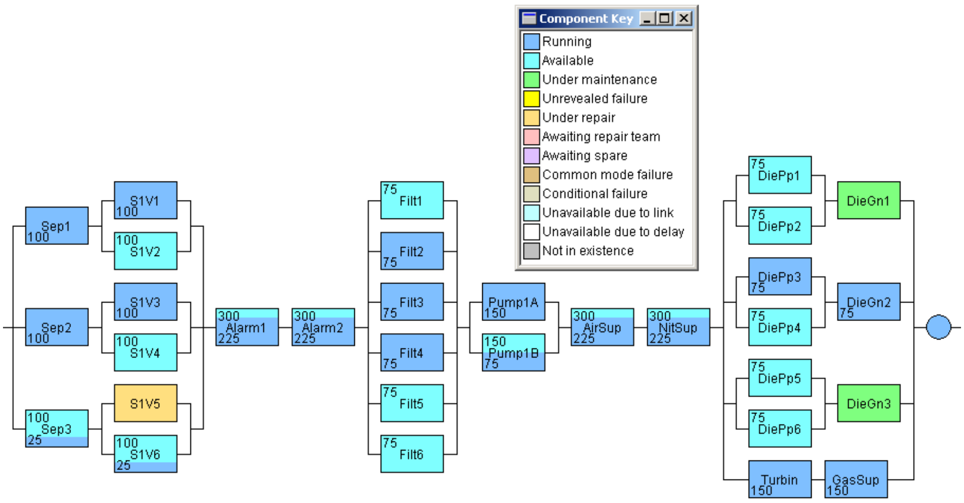
3 THE DNV SOLUTION

3.1 RAM Software

The study will be conducted using DNV's in-house OPTAGON availability modelling package. The OPTAGON product, which is owned and licensed by DNV, was co-developed with BG in the 1990's and was specifically designed with oil and gas production assets in mind. OPTAGON is a Monte Carlo simulation package that has been developed for predicting and optimising the reliability, availability and maintainability of production facilities. OPTAGON includes features that are specifically designed to model oil and gas industry operations.

When using OPTAGON, the system to be investigated is described by a reliability block diagram that shows how the operation of the system as a whole depends on its critical components. This concept is extended in OPTAGON by associating a capacity, or flow, with each component. A required production level (i.e. demand) is placed on the system, which is not necessarily the maximum capacity of the system and can vary with time. Each component in the reliability block representation can have a wide variety of attributes including failures and repair characteristics, varying process throughput, preventative maintenance schedules, spare requirements for repairs, type of redundancy and logistic delays.



Results are generated by Monte Carlo simulation, a stochastic method in which failures of components are randomly generated, based on statistical distributions specified by the user. This approach consists of explicitly modelling the system being studied, subjecting it to a typical set of events over its lifetime, and empirically observing how it performs. The nature of the model means that it is possible to include a wide variety of complex system behaviour (e.g. independent supply, capacity and demand profiles, equipment interdependencies, common mode failures, start delays, deferred effects) without having to reduce them to analytical approximations.

Due to the random nature of the events, the results of each simulation will vary. However, by collecting the results from multiple runs, statistics that describe system performance (together with confidence limits) can be generated. Results from an OPTAGON study may typically include:

- Production Efficiency (% of demand met)
- Availability (% of time 100% demand is met)
- Shortfall Contributors (systems and equipment items most critical to production, including quantifying contribution to losses)

The functionality within OPTAGON is extensive and enables complex system behaviour to be incorporated into the system model. Examples of such complexities include:

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- Bulk storage & Shipping Operations
- Deferred Effects
- Multiple revenue streams
- Resource constraints (e.g. repair team limitations, spares holding)
- Variable demand profile (e.g. seasonal) with random fluctuations
- Partial states of operation
- System configuration changes and equipment throughput variation

3.2 Approach

The tasks involved in delivering the scope of work detailed in this proposal are summarised in the table below:

List and Description of Project Tasks		
Task No	**Task**	**Description**
1	Kick-off Meeting and Information Gathering	Collate and review all data required to carry out study. This includes a kick-off meeting (by Microsoft [MS] Teams) with review of all data inputs. The following information will be required as input to the RAM study: • Overview of facilities to be modelled including criticalities • Supply/demand profiles for injection/withdrawal operating modes • Basis of Design • PFDs / UFDs / P&IDs • Equipment list (including capacities, configurations, equipment type) • Details on facility operation and logistics • Historical reliability data (where available) The following activities are expected to take place prior to the information review: • Receipt and acceptance of appropriate work order • Issuing of key input data (up-to-date/relevant revisions) In the event any clarifications are required, DNV will notify Enbridge in a timely manner.
2-1	Base Assumptions Report (BAR)	Upon completion of the information gathering exercise, DNV will detail base case modelling assumptions in a Base Assumptions Report, which will be issued to Enbridge for review and approval prior to commencement of modelling. Changes requested after approval of the BAR, requiring the models to be updated, may be considered as additional scope of work (to be agreed separately).
2-2	BAR Review Workshop (MS Teams)	BAR Review Workshop (by MS Teams) to present the BAR, discuss comments on the basis, finalize any HOLDS and agree outstanding assumptions, prior to commencing model build.
3	RAM Model (Base Case)	Based on agreed assumptions detailed in the Base Assumptions Report, DNV will develop the Base Case model

DNV

List and Description of Project Tasks		
Task No	Task	Description
4	Base Case Results Presentation (MS Teams)	DNV will perform the results analysis from the Base Case model and will present and discuss these with Enbridge via MS Teams. Sensitivity case scenarios will also be discussed and agreed.
5	Sensitivity Cases	DNV will develop the defined sensitivity cases with results compared with the Base Case outputs. For the base scope of this proposal, DNV have allowed for up to 3 sensitivity cases to be considered (to be defined/agreed). *Note: A sensitivity case is assumed to look at specific changes to the base case model such as sparing equipment, logistic delays, equipment capacity, planned maintenance alignment / durations / frequencies or reliability data. The following changes are not deemed to be a sensitivity case and should be considered separately due to increased complexity in developing models: alternative production profiles, process configurations, sub-unit level modelling.*
6	Draft Report	A Draft Report will be prepared and issued. This document will include key modelling assumptions and results for the defined base and sensitivity cases. It is intended for review and comments by Enbridge. Any re-working of the RAM models resulting from changes made to the agreed Base Assumptions after this time may be considered outside the scope of this study.
7	Final Results Presentation (MS Teams)	Final presentation (by MS Teams) to discuss all key results and findings from the assessment.
8	Final Report	Following review by Enbridge, the Draft Report will be updated and re-issued as Final, incorporating any comments. Any re-working of the models resulting from changes to the agreed Base Assumptions may be considered outside this scope.

3.3 Deliverables

This base scope for this assessment will include the following key deliverables:

1. Base Assumptions Report (BAR) for review / approval, prior to model development
2. Base Case Results Presentation (via MS Teams)
3. Final Results Presentation (via MS Teams)
4. RAM Study Report – to include:
    a. Executive Summary
    b. Introduction
    c. Study objectives and boundaries
    d. Key modelling assumptions
    e. Results
    f. Conclusions & Recommendations
    g. Appendices

All key project documentation (Base Assumptions Report, Draft Report and Final Report) will be issued in PDF format.

4 SCHEDULE

The chart below details the proposed schedule for completion of the RAM Study:

Ref	Task	Week 1	Week 2	Week 3	Week 4	Week 5	Week 6	Week 7	Week 8	Week 9	Week 10
1	Kick-off Meeting (MS Teams)										
	Supply of Input Data										
2-1	Base Assumptions Report (BAR)										
	Customer BAR Review										
2-2	BAR Review Workshop (MS Teams)										
3	RAM Model (Base Case)										
4	Initial Results Discussion (MS Teams)										
5	RAM Model (Sensitivity Cases)										
6	Draft Report										
7	Results Presentation (MS Teams)										
	Draft Report Review										
8	Final Report										

DNV and Enbridge
DNV
Enbridge

The above schedule is based on the following assumptions:

1. All appropriate data and clarifications will be made available to DNV, in order to perform this RAM analysis.
2. All data will be provided to DNV in a timely manner to ensure effective and efficient project delivery.
3. Throughout this study, DNV will have access to an appropriate technical point of contact within the project team.

5 PRICING

5.1 [redacted]

[redacted]

No	Description	Total Price (CAD)
[redacted]	[redacted]	[redacted]

5.2 [redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]

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6 PROJECT ORGANISATION

The proposed project team will be comprised of personnel with expertise in conducting RAM studies. Project roles and biographies of key personnel are listed below, and complete resumes are included in Appendix B – Resumes:

Project Team Member	Role
Jeremy Johnson, Engineer (Canada)	Project Manager
Neil Wragg, Senior Principal Consultant, Reliability (UK)	Technical Lead

Jeremy Johnson, P.Eng. – Project Manager

Mr. Johnson is an Engineer and Project Manager working in the Compliance and Risk Solutions group at DNV. He has over nine years of experience in the pipeline industry focused on areas of pipeline integrity, pipeline regulatory compliance (including audits), and pipeline management systems and program development.

As the Project Manager (PM), Mr. Johnson is responsible for the day to day contact with the Customer. The PM has the overall operational responsibility for the fulfilment of the contract and for running the project to meet the defined goals, milestones, and budget as well as ensuing the development of quality deliverables.

Neil Wragg, C.Eng. – Technical Lead

Mr. Wragg leads the DNV Performance Forecasting team in Loughborough (UK) and is responsible for managing their global project portfolio. He has twenty-five years Process Engineering and Reliability experience in the oil and gas industry and is a Chartered Engineer with IChemE since 2000.

Mr. Wragg has specialist knowledge and experience in reliability and availability modelling techniques and has presented technical papers in this field at conferences worldwide. Also experienced in Lead Engineer and Project Manager roles, working for a number of major upstream engineering design contractors on completion of proposals, conceptual studies, front-end and detailed design projects (both onshore and offshore developments).

DNV

7 CONTRACTUAL

7.1 Contract Basis - Terms and Conditions

DNV proposes to conduct the project in accordance with the existing 'Consulting Agreement' (valid until December 31, 2021) executed between DNV and Enbridge Gas Inc.

8 DNV MANAGEMENT SYSTEM

The DNV Management System is an integrated quality, HSE (health, safety and environment) and business administration management system.

DNV's Management System is certified to ISO 9001, ISO 14001 and ISO 45001. There is one ISO 9001 certificate for each of DNV's business areas, while Group wide certificates apply for the ISO 14001 and ISO 45001 certification. All certificates are issued by the Dutch accredited certification body DEKRA Certification B.V.

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9 DNV IN BRIEF

Driven by its purpose, to safeguard life, property, and the environment, DNV helps tackle the challenges and global transformations facing its customers and the world today and is a trusted voice for many of the world's most successful and forward-thinking companies.

In the maritime industry

DNV is the world's leading classification society and a recognized advisor for the maritime industry. We enhance safety, quality, energy efficiency and environmental performance of the global shipping industry – across all vessel types and offshore structures. We invest heavily in research and development to find solutions, together with the industry, that address strategic, operational or regulatory challenges.

In the energy industry

We provide assurance to the entire energy value chain through our advisory, monitoring, verification, and certification services. As the world's leading resource of independent energy experts and technical advisors, we help industries and governments to navigate the many complex, interrelated transitions taking place globally and regionally, in the energy industry. We are committed to realizing the goals of the Paris Agreement, and support our customers to transition faster to a deeply decarbonized energy system.

For management system certification, supply chain and product assurance

DNV is one of the world's leading certification, assurance and risk management providers. Whether certifying a company's management system or products, providing training, or assessing supply chains, and digital assets, we enable customers and stakeholders to make critical decisions with confidence. We are committed to support our customers to transition and realize their long-term strategic goals sustainably, collectively contributing to the UN Susta nable Development Goals.

DNV is a world-leading provider of digital solutions and software applications with focus on the energy, maritime and healthcare markets. Our solutions are used worldwide to manage risk and performance for wind turbines, electric grids, pipelines, processing plants, offshore structures, ships, and more. Supported by our domain knowledge and Veracity assurance platform, we enable companies to digitize and manage business critical activities in a sustainable, cost-efficient, safe and secure way.

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APPENDIX A – DNV EXPERIENCE

DNV has over 30 years' experience of reliability/availability studies of oil and gas assets around the world and has performed over 1500 RAM and Performance Forecasting studies in that period. A summary of DNV's recent RAM experience is provided below.

Year	Client	Project Description
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APPENDIX B – RESUMES

Neil David Wragg

Senior Principal Consultant

Personal statistics

Nationality: British
Date of Birth: May 01, 1974

Current position

Senior Principal Consultant (Performance Forecasting)

Currently heading up DNV's Performance Forecasting team in Loughborough (UK) and responsible for managing their global project portfolio. In his current role, Neil's responsibilities include:

- Supporting DNV's Performance Forecasting global business stream
- Supporting development of new Asset Performance services
- Supporting development of DNV's RAM modelling software tools
- Project Management / Client Interface
- Technical governance of all Performance Forecasting / RAM related projects
- Technical authority on RAM modelling

Languages

Language	**Native**	**Speaking**	**Reading**	**Writing**
English (United Kingdom)	✓	High	High	High
French		Low	Low	Low

Education

Field of **expertise**	**University/School**	**Year**
Master of Engineering, Chemical Engineering	University of Nottingham	Oct 1991 - Jul 1995

Summary of professional experience

Neil is a chartered engineer with IChemE, and has over 25 years' experience in Performance Forecasting, Reliability Analysis and Process Engineering in the oil and gas industry.

Currently heading up DNV's Performance Forecasting team in Loughborough (UK) and responsible for managing their global project portfolio. He has specialist knowledge and experience in reliability and availability modelling techniques and has presented technical papers in this field at conferences worldwide. Also experienced in Lead Engineer and Project Manager roles, working for a number of major upstream engineering design contractors on completion of proposals, conceptual studies, front-end and detailed design projects (both onshore and offshore developments).

Memberships

Chartered Member (CEng MIChemE)		Aug 2000 - Present
Role:	Institute of Chemical Engineers	

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Employment

DNV	**Feb 2005 - Present**

Position: Senior Principal Consultant

Selection of Recent Projects:

2020 - CPOC - Petronas / PTT offshore operational RAM Study

2020 - MODEC - Equinor Bacalau FPSO RAM study

2020 - Siccar Point - Cambo integrated subsea and FPSO RAM study

2020 - Repsol Sinopec - UK North Sea offshore operational RAM Review

2019 - MODEC - Shell Gato Do Mato FPSO RAM study

2019 - Centrica Storage - RAM Study for offshore field tie-in to UK gas terminal

2019 - MODEC - Total Generic FPSO RAM study

2019 - National Grid - UK Gas Import Terminals - Operational RAM Study

2019 - MODEC - Woodside SNE FPSO Pre-FEED RAM study

2019 - Sembcorp Marine - Cambo FPSO FEED RAM study

2019 - Siccar Point - Cambo FPSO Pre-FEED RAM study

2019 - Glencore - RAM study for field expansion project, onshore oil production facility, Chad

2019 - National Grid - Pipeline Maintenance Centre emergency spares holding analysis

2018 - Bumi Armada - Kraken FPSO Operational RAM update

2018 - KPO - RAM study for field expansion project, onshore production facility, Kazakhstan

2018 - JIP - RAM Industry Guideline

2017 - United Utilities - Update to RAM assessment of water treatment facility and network

2017 - Glencore - RAM study for field expansion project, onshore oil production facility, Chad

2017 - Confidential - Clean gas power and CO2 storage concept design RAM assessment

2017 - Centrica - RAM assessment of offshore gas storage / onshore processing facilities, UK

2017 - Cameron - RAM study of new-build MEG reclamation plant for offshore platform

2016 - Nexen - RAM assessment of gas field tie-back to existing offshore platform, UK

2016 - Confidential client - Due Diligence on behalf of buyer, for multiple asset sale

2016 - Glencore - Operational RAM assessment of onshore oil production facility, Chad

2016 - Scotia Gas Networks - Logistics study of LNG tanker operations, UK gas networks

2016 - United Utilities - RAM assessment of water treatment facility and network

2016 - Tullow- RAM study for field expansion project, production facilities, offshore Ghana

2016 - QGC - Detailed RAM assessment of coal seam gas compression facilities, Australia

2015 - QGC -RAM on electrical power supply for coal seam gas facilities, Australia

2015 - Nexen - Operational RAM on Water Injection and Power Gen facilities, UK North Sea

2015 - Talisman - Operational RAM for oil / gas production facilities, offshore Malaysia

2015 - BG USA - RAM for gas pipeline and compression facilities feed to Lake Charles LNG

2015 - Nexen - Concept RAM on new Water Injection and Power Generation facilities, UK

Halliburton KBR	**Jan 2001 - Feb 2005**

Position: Senior Process Engineer

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Employment

Description:	Lead Engineer and Project Engineer roles on FEED and detailed design projects for onshore and offshore developments Familiar with current project techniques and procedures and the use of recognised design standards and recommended practices (e.g. BS, API).	
Kvaerner Oil & Gas Limited		**May 1997 - Jul 2000**
Position:	Flow Assurance Engineer	
Description:	Specialist knowledge and experience of subsea/flow assurance issues such as line size optimisation, insulation selection, hydrate/wax management, chemical injection, pigging, liquid hold-up management, start-up, shutdown, ramp-up, turndown, depressurisation. Experience in using software tools for process and multiphase pipeline simulation, including HYSYS, PROVISION, OLGA and PIPESIM.	
Brown & Root Limited		**Sep 1995 - May 1997**
Position:	Graduate Process Engineer	
Description:	2 years on the graduate training program, working on completion of proposals, conceptual studies, front-end and detailed design projects (both onshore and offshore developments). Process design responsibilities included development of UFDs, PFDs, P&IDs, Instrument and Process Datasheets, Operating Guides, C&E Diagrams, Safety Analysis Tables, equipment sizing, HAZOPS/HAZIDS, technical report writing and interfacing with suppliers.	

Papers and publications

The following is a selection of papers written and presented by Neil Wragg at industry conferences worldwide:

- “Advanced RAM Modelling”, Lean, Reliability & Asset Management Conference, UK 2020
- “Asset Risk Management (ARM) - Are you managing your water and wastewater asset risks effectively?”, DNV GL Webinar, 2020
- "Maintenance Planning & Equipment Criticality Modelling", British Water Conference, UK 2017
- "Small Scale LNG in Island Energy Systems – Performance and Logistics Assessment", DNV GL Technology Leadership Seminar, Arnhem 2016
- "The Value of RAM in Operations", RAMS Asia Conference, KL Malaysia 2016
- “Measuring up! Using RAM to Improve Production Efficiency”, IMechE Conference, Aberdeen, 2014
- “Benchmarking Your Asset’s Performance”, Digital Energy, Aberdeen 2013
- “OPTAGON™: Pushing the Boundaries”; GPA (Europe) Operations, Reliability & Maintenance Conference, Amsterdam, Netherlands, 2011.
- “Exploiting benefits from expanded applications of reliability modelling with OPTAGON software”; GPA (Europe) Annual Conference, Venice, Italy, 2009
- “Optimising the LNG Supply Chain”; IGEM Annual Conference, Loughborough, UK, 2009.
- “Optimising Design and Maximising Performance of Complex Integrated Asset Systems using OPTAGON™”; ERTC Asset Maximisation Conference, Lisbon, Portugal, 2008.

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Rachel Parker

Principal Consultant

Current position

Rachel is a Principal Consultant within DNV Energy Systems' Asset Performance Solutions Team in Loughborough, UK

Education

Field of expertise	University/School	Year
Doctor of Philosophy, Reliability Engineering	Loughborough University	Jul 2005
Bachelor of Engineering, Mathematical Engineering	Loughborough University	Jul 2001

Summary of professional experience

Dr Rachel Parker has worked in the oil and gas industry for over 10 years and has extensive experience of hazard, consequence, risk and reliability assessment techniques with application to a wide range of projects. These include Reliability, Availability and Maintainability (RAM) assessments and fire and explosion modelling for both onshore and offshore installations.

Rachel is currently part of DNV's Asset Performance Solutions team and has the following key responsibilities:

- Providing specialist technical input into the delivery of Performance Forecasting related projects
- Involvement in conceptual, feasibility, front end design studies through to debottlenecking and troubleshooting of operational assets for offshore platforms, pipelines, gas processing terminals and LNG facilities
- Technical contribution to projects through governance, mentoring and training to reliability engineering and RAM modelling consultancy services
- Project management / client interface
- Developing business opportunities with new and existing clients
- Supporting the development of Performance Forecasting / RAM services including DNV's RAM modelling software, OPTAGON
- Identifying potential opportunities to expand into new areas
- Understand customer's current and emerging business needs

Employment

DNV	**Jul 2010 - Present**
Position:	Principal Consultant
Description:	Management and technical lead on Performance Forecasting projects within the Risk Advisory department, predominantly managing Reliability, Availability and Maintainability (RAM) studies for onshore and offshore oil and gas assets.
Aker Solutions	**Jun 2008 - Jun 2010**
Position:	Senior Safety Engineer
Description:	Performed consequence and risk studies to predict dispersion, fire and blast overpressure consequences of chemical releases to assess the potential for human and environmental harm.
Advantica	**Apr 2006 - May 2008**
Position:	Senior Safety Engineer
Description:	Applied hazard, consequence and risk assessment techniques to a wide range of projects in the oil and gas industry, including pipeline risk assessments and fire and explosion modelling for both onshore and offshore installations

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Rolls-Royce	**Apr 2005 - Mar 2006**
Position:	Control System Safety Engineer
Description:	Ensured acceptable levels of safety, reliability, and availability for civil aerospace engine control systems. Performed control system safety analyses using fault tree analysis and numerical modelling techniques.
Loughborough University	**Sep 2001 - Mar 2005**
Position:	PhD in Risk and Reliability
Description:	PhD in Risk and Reliability sponsored by the MoD Defence Procurement Agency (DPA) and supported by the Engineering and Physical Sciences Research Council (EPSRC). This required development of analytical and statistical approaches to the solution of phased mission systems through use of Fault Tree Analysis (FTA), Markov methods, and Monte Carlo simulation.

Projects

Recent RAM Studies **Jul 2010 - Present**

- 2020 - Siccar Point - Cambo integrated subsea and FPSO RAM study
- 2019 - Centrica Storage - RAM Study for offshore field tie-in to UK gas terminal
- 2019 - MODEC - Total Generic FPSO RAM study
- 2019 - National Grid - UK Gas Import Terminals - Operational RAM Study
- 2019 - MODEC - Woodside SNE FPSO Pre-FEED RAM study
- 2019 - Sembcorp Marine - Cambo FPSO FEED RAM study
- 2019 - Siccar Point - Cambo FPSO Pre-FEED RAM study
- 2019 - Glencore - RAM study for field expansion project, onshore oil production facility, Chad
- 2019 - National Grid - Pipeline Maintenance Centre emergency spares holding analysis
- 2018 - KPO - RAM study for field expansion project, onshore production facility, Kazakhstan
- 2018 - JIP - RAM Industry Guideline
- 2017 – United Utilities – Update to RAM assessment of new water treatment facility and network
- 2017 - Glencore – RAM study for field expansion project, onshore oil production facility, Africa
- 2017 – Confidential – Clean gas power and CO2 storage concept design RAM assessment
- 2017 - Centrica - Operational RAM assessment of offshore gas storage / onshore processing facilities, UK
- 2016 – Confidential client – Due Diligence on behalf of buyer, for multiple asset sale
- 2016 - Glencore - Operational RAM assessment of integrated oil onshore oil production facility, Africa
- 2016 - Scotia Gas Networks - Logistics study of LNG tanker operations, UK gas distribution networks
- 2016 - United Utilities - RAM assessment of new water treatment facility and water distribution network
- 2015 – Nexen – Operational RAM on existing Water Injection and Power Gen facilities, UK North Sea
- 2015 – Hess – RAM study for new fixed platform tied back to existing host facility, Danish North Sea
- 2015 – Tullow – Operational RAM for existing integrated subsea/FPSO, offshore Ghana
- 2015 – Nexen – Concept RAM on new Water Injection and Power Generation facilities, UK North Sea
- 2014 – BG Tunisia – Operational RAM update for offshore / onshore integrated gas production facility
- 2014 – Fluor – Update to FEED RAM study for LNG liquefaction / export terminal, Mozambique
- 2014 – Aker - BG Jackdaw pre FEED RAM for offshore gas platform design optimisation
- 2014 – Enquest – Operational RAM assessment on 3 oil production facilities (FPSOs), UK North sea.
- 2014 – Tullow - Independent RAM review for FPSO, as part of EPC FEED design competition, Ghana
- 2013 – BG Tunisia – Operational RAM update for offshore / onshore integrated gas production facility

Papers and publications

- "Phased Mission Modelling Using Fault Tree Analysis",15th ARTS (Advances in Reliability Technology Symposium) international conference, Loughborough, 2003.
- "Phased Mission Modelling Using Fault Tree Analysis", Proceedings of the Institution of Mechanical Engineers Part E, June 2004.
- "How a RAM Study Can Save £M", IGEM Young Persons Network Paper Competition, February 2013.

Other Information

- Engineering Associate Member of the Institution of Gas Engineers and Managers (IGEM)

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Jeremy Johnson, P.Eng.

Engineer, Compliance and Risk Solutions

Mr. Johnson is a Pipeline Engineer and Project Manager working in the Compliance and Risk Solutions group at DNV Canada, Ltd. He has over nine years of experience in the pipeline industry focused on pipeline integrity and risk management, pipeline operator regulatory compliance, management system and protection program auditing, and pipeline management systems and program development.

Mr. Johnson has authored assessment and audit reports evaluating pipeline operator management systems and protection programs including pipeline integrity, safety management, damage prevention, public awareness, emergency management, and control room management. Acting as lead auditor, Mr. Johnson has performed numerous evaluations of pipeline operator programs, processes, and procedures and as well has written operating procedures and management system program and process level documentation.

Mr. Johnson has in-depth knowledge of Canadian and US regulations, standards, and pipeline operational program requirements. Other experiences include reviews of regulatory applications, incident and root cause investigations, and assessments of changes to pipeline industry standards and codes.

Mr. Johnson has additionally project managed pipeline technical analyses including:

- Pipeline failure dispersion modelling
- Carbon dioxide pipeline conversion studies
- Wildfire thermal radiation studies for aboveground facilities
- Pipeline and facility Reliability, Availability, and Maintainability (RAM) studies

Education

Bachelor of Science in Chemical Engineering (2011), University of Calgary

Experience

Engineer Compliance and Risk Solutions	DNV Canada, Ltd.	2015–Present
Engineer in Training – EIT Compliance Solutions	Det Norske Veritas (Canada) Ltd.	2011-2015
Alliance Pipeline	Engineering Summer Student	2010

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About DNV

DNV is the independent expert in risk management and assurance, operating in more than 100 countries. Through its broad experience and deep expertise DNV advances safety and sustainable performance, sets industry benchmarks, and inspires and invents solutions.

Whether assessing a new ship design, optimizing the performance of a wind farm, analyzing sensor data from a gas pipeline or certifying a food company's supply chain, DNV enables its customers and their stakeholders to make critical decisions with confidence.

Driven by its purpose, to safeguard life, property, and the environment, DNV helps tackle the challenges and global transformations facing its customers and the world today and is a trusted voice for many of the world's most successful and forward-thinking companies.

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, Attachment 1, p. 24

Preamble:

The included report states: The model will use reliability data specific to the Corunna facility, extracted from Asset Health Report "StorageAHR-2021AHR-BF20210408" [3] – this data is based on historical CMMS records (MAXIMO). Each compressor unit will be defined by the following systems:

We would like to understand what data is contained in the historic CMMS records.

Question:

Do the historic CMMS records include data for Dawn?
a) Other storage facilities in the Enbridge Inc. operations?
    i) If so for either, how is it used?

Response

Enbridge Gas assumes that FRPO intended to refer to Exhibit B, Tab 1, Schedule 1, Attachment 2, p. 15.

a) The historical CMMS records that were used as the basis for the AHR analysis include only the data associated with the units at the CCS. While the CMMS records do contain the data for all facilities, only the data associated with the CCS compressor units has been used in the AHR study.

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit B, Tab 2, Schedule 1, p. 1

Question:

Please confirm that this tab and schedule of the evidence on the Dawn Hub inextricably includes the Dawn operations also.

Response

The referenced exhibit of evidence includes consideration of Dawn operations.

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit B, Tab 2, Schedule 1, p. 3-4, para. 8

Question:

Please confirm that the cold anomalies seen in the Feb. 2021 storm were centered in the central (longitudinal) US.

a) Further, please confirm that the gas price spikes, and devastating outages were caused by more by lack of resiliency of the gas facilities and gas/electric interface infrastructure than the presence or absence of storage in these markets.

Response

It is Enbridge Gas's understanding that the cold weather event that occurred in February 2021 was most impactful in Texas and neighboring states. However, as North America's natural gas transmission and storage systems are integrated, the impacts of such events were felt far beyond the physical location of the event itself.[1] In fact, during the event in Texas, the Dawn Hub extended its supply footprint to help balance the North American natural gas grid west of Dawn while also reliably serving ratepayers in Ontario and downstream.

a) It is Enbridge Gas's understanding that the devastating outages were caused by freeze-offs of gas facilities and gas/electric facilities as the region experienced widespread outages. Enbridge Gas cannot speak to the interconnectivity of storage facilities in this region. However, Enbridge Gas understands the importance of

[1] Exhibit B, Tab 2, Schedule 1. p. 4, "…natural gas prices in Oklahoma and Texas, two of North America's largest production zones, spiked (10–100 times higher than prices at the Dawn Hub as detailed in Figure 1). Atmos Energy Corp., a natural gas distribution company that serves more than 3 million customers across 8 U.S. states – reported that it had accrued roughly $2.5 to $3.5 billion in natural gas purchases, mainly for its Colorado, Kansas and Texas jurisdictions, due to this event."

maintaining reliable infrastructure to meet its contractual obligations during design day/extreme events.

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit B, Tab 2, Schedule 1, p. 6

Preamble:

EGI evidence states: Accordingly, Enbridge Gas holds 43.5 PJ of inventory in storage annually in order to provide 1.89 PJ/d of in-franchise deliverability to serve EGD rate zone customers on February 28 design day (typically the peak of winter seasonal demand).

Question:

We would like to understand more about this design day practice.

When specifically did EGD decide to maintain 43.5 PJ (or comparable based upon withdrawal requirement) of inventory in storage until Feb. 28th.

a) Please provide the internal study produced when this approach was instituted.

b) Please produce any evidence provided to the Board and any subsequent Board approval of this approach.

c) Please provide the evidence produced for the NGEIR proceeding that provided EGD's approach to maintaining an inventory threshold by a design date to effect deliverability needed.

d) Please confirm the 43.5PJ represents just less than half of the space available to in-franchise customers in the EGD rate zone.

e) Please provide the amount of this space whose cost is allocated to the non-utility operations.

f) If the amount of storage fell to 22PJ on a February 28th design day, would the non-utility be able to maintain its full contractual withdrawal commitments (as captured in the current withdrawal schedule from in place ex-franchise contracts) to its ex-franchise customers from the CCS.
   i. If yes, please specifically explain how the deliverability would be maintained.
   ii. If not, how is the cost allocation of the 43.5PJ justified? Please explain with the calculations provided.

Response

a) & b)
Utility customers have a maximum storage inventory of 99.4 PJ. 43.5 PJ is the level of inventory beyond which deliverability from the storage assets begins to decline. As a result, Enbridge Gas plans to hold a minimum of 43.5 PJ of inventory until the end of February in order to ensure that deliverability of 1.9 PJ/d is available to meet design day demands, which are assumed to occur prior to March 1 annually. After March 1, the Company plans to withdraw gas from storage.

Planning to hold the utility customers' storage balance to a minimum of 43.5 PJ until the end of February was not determined using an internal study. This approach was instituted in response to winter 2013/14 (i.e., the polar vortex winter) as a strategy to increase the flexibility of the EGD rate zone portfolio of assets by reducing the reliance utility customers have on potentially costly Dawn spot purchases late in the winter season during prolonged cold winters.

At the time, Enbridge Gas Distribution Inc. ("EGD") provided a description of this change in the planned operation of utility customer storage assets to the OEB at EB-2015-0114, Exhibit D1, Tab 2, Schedule 1, p. 9. EGD did not seek OEB approval for this planning change, and the OEB did not raise any issues in this regard.

c) EGD's planned utilization of utility customer's storage was not an issue contemplated at NGEIR proceeding.

d) 43.5 PJ/99.4 PJ ≈ 44%, which is less than half of the space available for EGD rate zone customers.

e) All the aforementioned storage space is for the sole use of utility customers.

f) Yes. If the in-franchise customers hold 22 PJ of inventory on a storage design day Enbridge Gas can still meet the contraction obligations of its ex-franchise storage contracts.

   i) Through non-utility investment, EGD created both storage space and deliverability through several projects. The deliverability associated with these projects covers the deliverability requirement for ex-franchise storage contracts.

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit C, Tab 1, Schedule 1

Preamble:

Preamble: We would like to understand the scope of the study, assumptions made and the alternatives that were considered and, perhaps, those that were not.

Question:

Please file the study(ies), technical reports and summary model outputs that assessed the alternatives described in this schedule.

Response

Enbridge Gas evaluated both facility and non-facility (including supply-side) alternatives to the proposed Project. A summary of the model results for each facility alternative is included as Attachment 1 to this response. For supply-side alternatives, Enbridge Gas retained ICF to perform modeling and pricing impacts to the Dawn Hub and this report is included as Attachment 2 to this response.

For facility alternatives, Enbridge Gas did not produce studies or technical reports. Rather, the Company relied upon its extensive experience in developing cost estimates and constructing compression and pipeline infrastructure.

For the Electric Drive Motor Compression alternative, please see the response at Exhibit I.SEC.13, for additional considerations that should be included as part of further evaluation of this alternative.

Dawn To Corunna Scenario Results Summary

Baseline W23/24

Storage Pool Details				
Description	From-Node Pressure	Hysteresis (psig)	Flow (MMscfd)	Current Inventory (mmscf)
Airport SF	342	-120	27	1,664
Bentpath East SF	382	0	0	2,057
Bentpath SF	830	-24	580	5,390
Bickford pool SF	366	-45	250	8,042
Black Creek SF	745	-130	73	750
Bluewater SF	363	-60	18	651
Booth Creek SF	397	-80	0	810
Chatham D SF	518	-50	10	1,430
Corunna SF	349	0	0	1,899
Covney SF	310	0	0	1,144
Crowland SF	338	-8	25	358
Dawn 156 SF	468	-60	997	16,046
Dawn 167 SF	544	-30	0	3,946
Dawn 47-49 SF	370	-15	40	2,115
Dawn 59-85 SF	781	-40	661	7,510
Dow A SF	423	-10	65	1,977
Dow Moore SF	491	-20	183	10,584
Edys Mills SF	262	-30	0	819
Enniskillen SF	470	-10	17	1,622
Heritage SF	884	0	7	777
Ladysmith SF	1,103	-28	457	7,300
Mandaumin SF	448	-130	22	1,705
Mld Kimball SF	877	-43	988	24,785
Oil City SF	275	-15	0	494
Oil Springs East SF	252	-40	0	1,108
Payne SF	271	-20	0	6,047
Rosedale SF	840	-30	189	3,360
Seckerton SF	349	0	0	4,808
Sombra SF	588	-100	12	2,667
South Kimball SF	898	-48	753	16,490
St. Clair SF	327	-80	2	507
Terminus SF	343	-40	115	4,711
Tipperary North SF	1,319	-8	0	1,793
Tipperary South SF	994	-8	0	1,853
Waubuno SF	444	-5	57	3,994
Wilkesport SF	675	-38	155	6,160
Total			**5,702**	**157,373**

Compression Details					
Description	From-Node Pressure	To-Node Pressure	Flow (mmscfd)	Result Power Utilized (hp)	Result Volumetric Fuel (mmscfd)
BKD CS	322	322	0	0	0.0
C-Plant CS	203	697	120	18,414	3.1
D-Plant CS	201	698	424	29,559	5.5
DWA CS	384	743	65	2,650	0.5
E-Plant CS	676	909	2,546	39,100	6.4
F-Plant CS	694	910	1,675	24,550	4.0
G-Plant CS	699	894	0	0	0.0
H-Plant CS	690	899	2,362	30,678	5.7
I-Plant CS	316	698	990	47,200	6.8
J-Plant CS	695	913	697	12,275	2.0
K701-2 CS	677	851	251	5,000	0.9
K703 CS	677	851	125	2,500	0.4
K704 CS	457	851	81	3,000	0.5
K705 CS	676	851	281	3,707	0.7
K706 CS	457	850	101	3,750	0.7
K707-8 CS	675	851	542	7,500	1.4
K709 CS	676	851	271	3,750	0.6
K710 CS	675	851	271	3,750	0.6
K711 CS	457	847	0	0	0.0
K712-13 CS	680	844	0	0	0.0
K714-15 CS	680	729	0	0	0.0
K801-2 CS	558	735	155	2,533	0.5
K803 CS	557	735	72	1,448	0.3
K901 CS	500	876	10	334	0.1
PYN CS	271	271	0	0	0.0
WBO CS	373	373	0	0	0.0
				241,698	**40.5**

Pool	From-Node Pressure	Hysteresis (psig)	Flow (MMscfd)	Current Inventory (mmscf)
Black Creek SF	745	-130	73	750
Chatham D SF	518	-50	10	1,430
Corunna SF	349	0	0	1,899
Covney SF	310	0	0	1,144
Crowland SF	338	-8	25	358
Dow Moore SF	491	-20	183	10,584
Ladysmith SF	1,103	-28	457	7,300
Mld Kimball SF	877	-43	988	24,785
Seckerton SF	349	0	0	4,808
South Kimball SF	898	-48	753	16,490
Wilkesport SF	675	-38	155	6,160
Total			**2,643**	**75,708**

	Pressure (psi)	Flow (MMscfd)
CCS TR1	847	1,000
CCS TR2	849	996
CCS TR7	-	-
Payne Dawn	702	457
Dawn TR1	705	1,000
Dawn TR2	705	996
Dawn TR7	-	-
H-Header	699	
Dawn TSLE	699	
CCS to Dawn		2,453

Dawn To Corunna Scenario Results Summary

NPS 30 Pipeline

Storage Pool Details				
Description	From-Node Pressure	Hysteresis (psig)	Flow (MMscfd)	Current Inventory (mmscf)
Airport SF	342	-120	27	1,664
Bentpath East SF	382	0	0	2,057
Bentpath SF	830	-24	579	5,390
Bickford SF	366	-45	250	8,042
Black Creek SF	745	-130	73	750
Bluewater SF	363	-60	18	651
Booth Creek SF	397	-80	0	810
Chatham D SF	518	-50	10	1,430
Corunna SF	349	0	0	1,899
Coveny SF	310	0	0	1,144
Crowland SF	338	-8	25	358
DAWN 156 SF	483	-60	1,032	16,523
DAWN 167 SF	544	-30	0	3,946
Dawn 47-49 SF	370	-15	40	2,115
Dawn 59-85 SF	781	-40	659	7,510
Dow A SF	423	-10	65	1,977
Dow Moore SF	445	-20	289	9,584
Edys Mills SF	262	-30	0	819
Enniskillen SF	470	-10	17	1,622
Heritage SF	884	0	7	777
Ladysmith SF	954	-28	461	6,210
Mandaumin SF	448	-130	22	1,705
Mid Kimball SF	921	-43	857	26,126
Oil City SF	275	-15	0	494
Oil Springs East SF	252	-40	0	1,108
Payne SF	271	-20	0	6,047
Rosedale SF	841	-30	191	3,365
Seckerton SF	349	0	0	4,808
Sombra SF	588	-100	12	2,667
South Kimball SF	935	-48	665	17,234
St. Clair pool	327	-80	2	507
Terminus SF	343	-40	115	4,711
Tipp N SF	1,319	-8	0	1,793
Tipp S SF	994	-8	0	1,853
Waubuno SF	391	-5	47	3,517
Wilkesport SF	675	-38	155	6,160
Total			5,618	**157,373**

Compression Details					
Description	From-Node Pressure	To-Node Pressure	Flow (mmscfd)	Result Power Utilized (hp)	Result Volumetric Fuel (mmscfd)
BKD CS	322	322	0	0	0.0
C-Plant CS	203	697	115	18,420	3.1
D-Plant CS	201	698	421	29,388	5.4
E-Plant CS	676	910	2,548	39,100	6.4
F-Plant CS	695	910	1,678	24,550	4.0
G-Plant CS	699	894	0	0	0.0
H-Plant CS	690	899	2,358	30,663	5.7
I-Plant CS	326	699	1,025	47,200	6.8
J-Plant CS	695	913	697	12,275	2.0
K701-2 CS	775	775	0	0	0.0
K703 CS	775	775	0	0	0.0
K704 CS	547	775	126	2,724	0.5
K705 CS	548	775	0	0	0.0
K706 CS	362	775	0	0	0.0
K707-8 CS	775	775	0	0	0.0
K709 CS	360	548	144	3,750	0.6
K710 CS	361	548	145	3,750	0.6
K711 CS	547	775	162	3,500	0.6
K712-13 CS	774	774	0	0	0.0
K714-15 CS	774	774	0	0	0.0
K801-2 CS	558	735	155	2,533	0.5
K803 CS	557	735	72	1,448	0.3
K901 CS	500	876	10	334	0.1
PYN CS	271	271	0	0	0.0
WBO CS	331	332	0	0	0.0
				219,634	**36.6**

Pool	From-Node Pressure	Hysteresis (psig)	Flow (MMscfd)	Current Inventory (mmscf)
Black Creek SF	745	-130	73	750
Chatham D SF	518	-50	10	1,430
Corunna SF	349	0	0	1,899
Coveny SF	310	0	0	1,144
Crowland SF	338	-8	25	358
Dow Moore SF	445	-20	289	9,584
Ladysmith SF	954	-28	461	6,210
Mid Kimball SF	921	-43	857	26,126
Seckerton SF	349	0	0	4,808
South Kimball SF	935	-48	665	17,234
Wilkesport SF	675	-38	155	6,160
			2,534	**75,703**

	Pressure (psi)	Flow (MMscfd)
CCS TR1	775	710
CCS TR2	775	708
CCS TR7	774	688
Payne Dawn	700	242
Dawn TR1	700	710
Dawn TR2	700	708
Dawn TR7	700	688
H-Header	699	-
Dawn TSLE	699	-
CCS to Dawn		2,347

Dawn To Corunna Scenario Results Summary

NPS 36 Pipeline

Storage Pool Details

Description	From-Node Pressure	Hysteresis (psig)	Flow (MMscfd)	Current Inventory (mmscf)
Airport SF	342	-120	27	1,664
Bentpath East SF	382	0	0	2,057
Bentpath SF	831	-24	580	5,400
Bickford SF	366	-45	249	8,042
Black Creek SF	745	-130	73	750
Bluewater SF	363	-60	18	651
Booth Creek SF	397	-80	0	810
Chatham D SF	518	-50	10	1,430
Corunna SF	349	0	0	1,899
Coveny SF	310	0	0	1,144
Crowland SF	338	-8	25	358
DAWN 156 SF	482	-60	1,029	16,498
DAWN 167 SF	544	-30	0	3,946
Dawn 47-49 SF	370	-15	40	2,115
Dawn 59-85 SF	783	-40	659	7,525
Dow A SF	423	-10	65	1,977
Dow Moore SF	468	-20	358	10,084
Edys Mills SF	262	-30	0	819
Enniskillen SF	470	-10	17	1,622
Heritage SF	884	0	7	777
Ladysmith SF	952	-28	464	6,200
Mandaumin SF	448	-130	22	1,705
Mid Kimball SF	917	-43	885	26,006
Oil City SF	275	-15	0	494
Oil Springs East SF	252	-40	0	1,108
Payne SF	271	-20	0	6,047
Rosedale SF	841	-30	189	3,365
Seckerton SF	349	0	0	4,808
Sombra SF	588	-100	12	2,667
South Kimball SF	917	-48	645	16,864
St. Clair pool	327	-80	2	507
Terminus SF	343	-40	115	4,711
Tipp N SF	1,319	-8	0	1,793
Tipp S SF	994	-8	0	1,853
Waubuno SF	391	-5	62	3,517
Wilkesport SF	675	-38	155	6,160
Total			5,708	**157,373**

Compression Details

Description	From-Node Pressure	To-Node Pressure	Flow (mmscfd)	Result Power Utilized (hp)	Result Volumetric Fuel (mmscfd)
BKD CS	322	322	0	0	0.0
C-Plant CS	203	700	189	18,494	3.1
D-Plant CS	200	700	540	37,100	6.9
DWA CS	384	743	65	2,650	0.5
E-Plant CS	678	910	2,561	39,100	6.4
F-Plant CS	696	910	1,680	24,550	4.0
G-Plant CS	699	894	0	0	0.0
H-Plant CS	691	899	2,340	30,398	5.6
I-Plant CS	326	700	1,022	47,200	6.8
J-Plant CS	697	913	700	12,275	2.0
K701-2 CS	762	762	0	0	0.0
K703 CS	762	762	0	0	0.0
K704 CS	677	763	177	1,421	0.2
K705 CS	678	762	0	0	0.0
K706 CS	354	762	0	0	0.0
K707-8 CS	762	762	0	0	0.0
K709 CS	353	678	94	3,750	0.6
K710 CS	354	678	83	3,313	0.6
K711 CS	678	761	0	0	0.0
K712-13 CS	761	761	0	0	0.0
K714-15 CS	761	761	0	0	0.0
K801-2 CS	558	735	155	2,533	0.5
K803 CS	557	735	72	1,448	0.3
K901 CS	500	876	10	334	0.1
PYN CS	271	271	0	0	0.0
WBO CS	294	294	0	0	0.0
				224,565	**37.6**

Pool	From-Node Pressure	Hysteresis (psig)	Flow (MMscfd)	Current Inventory (mmscf)
Black Creek SF	745	-130	73	750
Chatham D SF	518	-50	10	1,430
Corunna SF	349	0	0	1,899
Coveny SF	310	0	0	1,144
Crowland SF	338	-8	25	358
Dow Moore SF	468	-20	358	10,084
Ladysmith SF	952	-28	464	6,200
Mid Kimball SF	917	-43	885	26,006
Seckerton SF	349	0	0	4,808
South Kimball SF	917	-48	645	16,864
Wilkesport SF	675	-38	155	6,160
Total			**2,616**	**75,703**

	Pressure (psi)	Flow (MMscfd)
CCS TR1	761	630
CCS TR2	761	628
CCS TR7	761	990
Payne Dawn	205	206
Dawn TR1	702	630
Dawn TR2	702	628
Dawn TR7	702	990
H-Header	701	-
Dawn TSLE	700	-
CCS to Dawn		2,454

Dawn To Corunna Scenario Results Summary

T70/E90 - No LCU

Storage Pool Details				
Description	From-Node Pressure	Hysteresis (psig)	Flow (MMscfd)	Current Inventory (mmscf)
Airport SF	342	-120	27	1,664
Bentpath East SF	382	0	0	2,057
Bentpath SF	830	-24	580	5,389
Bickford SF	366	-45	250	8,042
Black Creek SF	745	-130	73	750
Bluewater SF	363	-60	18	651
Booth Creek SF	397	-80	0	810
Chatham D SF	518	-50	10	1,430
Corunna SF	349	0	0	1,899
Coveny SF	310	0	0	1,144
Crowland SF	338	-8	25	358
Dawn 156 SF	468	-60	997	16,046
Dawn 167 SF	544	-30	0	3,946
Dawn 47-49 SF	370	-15	40	2,115
Dawn 59-85 SF	781	-40	659	7,505
Dow A SF	423	-10	65	1,977
Dow Moore SF	491	-20	89	10,584
Edys Mills SF	262	-30	0	819
Enniskillen SF	470	-10	17	1,622
Heritage SF	884	0	7	777
Ladysmith SF	1,108	-28	460	7,335
Mandaumin SF	448	-130	22	1,705
Mid Kimball SF	877	-43	1,070	24,785
Oil City SF	275	-15	0	494
Oil Springs East SF	252	-40	0	1,108
Payne SF	271	-20	0	6,047
Rosedale SF	840	-30	190	3,360
Seckerton SF	349	0	0	4,808
Sombra SF	588	-100	12	2,667
South Kimball SF	896	-48	796	16,461
St. Clair SF	327	-80	2	507
Terminus SF	343	-40	115	4,711
Tipperary North SF	1,319	-8	0	1,793
Tipperary South SF	994	-8	0	1,853
Waubuno SF	444	-5	57	3,994
Wilkesport SF	675	-38	155	6,160
Total			5,737	**157,373**

Compression Details					
Description	From-Node Pressure	To-Node Pressure	Flow (mmscfd)	Result Power Utilized (hp)	Result Volumetric Fuel (mmscfd)
BKD CS	322	322	0	0	0.0
C-Plant CS	203	697	123	18,409	3.1
D-Plant CS	201	698	422	29,416	5.4
DWA CS	384	743	65	2,650	0.5
E-Plant CS	676	909	2,533	39,100	6.4
F-Plant CS	694	910	1,671	24,550	4.0
G-Plant CS	317	894	0	0	0.0
H-Plant CS	690	899	2,380	30,892	5.7
I-Plant CS	316	698	990	47,200	6.8
J-Plant CS	695	913	697	12,275	2.0
K701-2 CS	650	848	0	0	0.0
K703 CS	650	848	0	0	0.0
K704 CS	480	848	89	3,000	0.5
K705 CS	650	848	0	0	0.0
K706 CS	480	848	0	0	0.0
K707-8 CS	650	848	0	0	0.0
K709 CS	649	848	235	3,750	0.6
K710 CS	649	848	235	3,750	0.6
K711 CS	480	847	0	0	0.0
K712-13 CS	648	848	697	11,100	2.3
K714-15 CS	647	848	694	11,100	2.3
K801-2 CS	558	735	155	2,533	0.5
K803 CS	557	735	72	1,448	0.3
K901 CS	500	876	10	334	0.1
PYN CS	271	271	0	0	0.0
WBO CS	373	373	0	0	0.0
				241,507	**41.1**

Pool	From-Node Pressure	Hysteresis (psig)	Flow (MMscfd)	Current Inventory (mmscf)
Black Creek SF	745	-130	73	750
Chatham D SF	518	-50	10	1,430
Corunna SF	349	0	0	1,899
Coveny SF	310	0	0	1,144
Crowland SF	338	-8	25	358
Dow Moore SF	491	-20	89	10,584
Ladysmith SF	1,108	-28	460	7,335
Mid Kimball SF	877	-43	1,070	24,785
Seckerton SF	349	0	0	4,808
South Kimball SF	896	-48	796	16,461
Wilkesport SF	675	-38	155	6,160
			2,678	**75,714**

	Pressure (psi)	Flow (MMscfd)
CCS TR1	847	1,021
CCS TR2	848	1,006
CCS TR7	-	-
Payne Dawn	834	460
Dawn TR1	700	1,021
Dawn TR2	700	1,006
Dawn TR7	-	-
H-Header	699	-
Dawn TSLE	699	-
CCS to Dawn		2,488

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit C, Tab 1, Schedule 1, p.19

Preamble:

EGI evidence states: This alternative also provides a 1:1 replacement in total horsepower via installation of two new Spartan e90 electric motor drive ("EMD") compressor units on the west side of the CCS, station modifications at CCS and Dawn, and retirement and abandonment of the existing compressor units and related facilities. This alternative also includes additional costs for a new 27.7 KVA substation and backup generator to provide reliable power for the EMD compressor units.18 This alternative has been estimated to cost approximately $217 million.

Question:

Please provide a description of the Spartan e90 motor drives.

a) Please provide a description of the benefits of variable drive speeds for electric compressors.

b) Please confirm that the units contemplated as alternatives were variable drive.

c) Please provide a summary of all of the K700 compressors range of compression (similar to Table 1 of B/T1/S1) that shows capability and function.
    i. Individually, which compressors could one variable drive Spartan e90's replace?
    ii. Using the order of expected need to replace (as described in response to Question 11), how many of the removed compressors' function could one Spartan replace before the second one is needed.
    iii. Using the order of replacement, would the parts salvaged from the removed compressors provide additional parts in inventory to refurbish/repair other compressors potentially extended their forecasted life. Please answer in detail.

Response

In preparing this response Enbridge Gas found an error in its pre-filed evidence. New compression at the CCS would be located on the east side of Tecumseh Rd, not the west side. Enbridge Gas currently owns the land in question (on the eastern side of Tecumseh Road) but has not yet constructed a station site or any other facilities on it.

a) The existing CCS compressors are reciprocating large bore integral compressors. These compressors have a narrow speed range, however, capacity control is provided by varying clearance volume in the compressor cylinders.

   Compression coupled to an EMD driver would be a centrifugal compressor system. For centrifugal compressors, capacity control is achieved by varying the compressor speed. A centrifugal compressor without variable speed will narrow the operating range of the compressor to such an extreme, that the resulting single speed unit would only be operable for a few days per year.

b) Both gas turbine and EMD powered units would have to employ variable speed.

c) Table 1 below provides Compressor Ranges in a format similar to that set out in Exhibit B, Tab 1, Schedule 1, Table 1.

Table 1

Function	Units	Description	Compressor Ranges
Low Suction Pressure	K709, K710.	Units required to effectively access the lowest pressure gas in storage pools in Withdrawal Mode. These units are also utilized for Injection Mode.	500 to 900 psig withdrawal; 350 to 700 psig withdrawal; 250 to 500 psig withdrawal
Mid-range Pressure	K701, K702, K703, K705, K706, K707, K708.	Units required to provide mid-range compression for both Injection and Withdrawal Modes.	700 to 1350 psig injection; 1000 to 1500 psig injection
High Discharge Pressure	K704, K711.	Units required during Injection Mode to fill the top end of the storage pools. K704 is also utilized for Withdrawal Mode. K711 is held in reserve as LCU.	700 to 1500 psig injection; 200 to 750 psig withdrawal

i. The response to this question is dependent upon the size of the new compressor. A single new compressor with a Spartan e90 could replace any individual existing reciprocating (K700 series) compressor.

ii. Please see the response at Exhibit I.FRPO.11, for units to be removed. The response to this question is dependent upon the model of Spartan and size of the new compressors. A single new compressor in the 10 MW range (Spartan e90) could replace up to four existing reciprocating (K700 series) compressors. This is the same sized unit the Company evaluated as part of the Electric Drive Motor (EMD) facility alternative. The response at Exhibit I.SEC.13 provides additional information on this alternative as well as the benefits of replacing all 7 units at one time.

iii. The first three CCS units proposed for replacement are K701 – K703. These units are rated at 2,500 HP. Some newer systems like iBalance can be transferred to the remaining compressor units. However, internal parts like: crankshaft, turbochargers, cylinder heads, pistons, rods, rod packing, are not transferrable to any of the remaining CCS compressor units.

CCS compressor units K705 – K708 are all the same engine design and internal parts can be used interchangeably. Units K705 – K708 engine internal parts can be interchanged with units K709 – K711. Units K705 – K708 compressor internal parts have low commonality with units K709 – K711. Unit K704 is the only 8-cylinder unit in the CCS compressor fleet. There is low parts commonality between units K705 – K708 with unit K704, limited to cylinder heads, engine pistons, and connecting rod/bearings.

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit C, Tab 1, Schedule 1, p.19

Preamble:

EGI evidence states: This alternative also provides a 1:1 replacement in total horsepower via installation of two new Spartan e90 electric motor drive (“EMD”) compressor units on the west side of the CCS, station modifications at CCS and Dawn, and retirement and abandonment of the existing compressor units and related facilities. This alternative also includes additional costs for a new 27.7 KVA substation and backup generator to provide reliable power for the EMD compressor units.18 This alternative has been estimated to cost approximately $217 million.

Question:

In a scenario that the first K700 compressor is removed and replaced by one Spartan e90, for each of the CCS, Dawn and for the combined operations, please provide:

a) The working storage space and peak injection capability for the resulting facilities.

b) The working storage space and peak withdrawal capabilities for the resulting facilities.

Response

a) & b)
This scenario does not represent a viable alternative, as it does not address the reliability or obsolescence risk for units K702, K703 and K705-K708 and does not address the existing safety risk to Company personnel.

However, if one compressor was abandoned and replaced with one Spartan e90 there would be no loss of working storage space, peak injection capability or peak withdrawal capability.

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit C, Tab 1, Schedule 1, p.19

Preamble:

EGI evidence states: This alternative provides a 1:1 replacement in design day storage system withdrawal capacity compared to the existing compressor units at the CCS facility that are proposed to be retired and abandoned. The NPS 36 pipeline will also provide equivalent storage injection capacity via existing compression units located within Dawn.

We want to understand how the preferred alternative has been described as a 1:1 replacement.

Question:

Hypothetically, if NPS 30 were used as the replacement pipe for the seven compressors, for each of the CCS, Dawn and for the combined operations, please provide:

a) The working storage space and peak injection capability for the resulting facilities.

b) The working storage space and peak withdrawal capabilities for the resulting facilities.

Response

a) Constructing a NPS 30 pipeline instead of a NPS 36 pipeline would not have any impact on the storage capacity or the peak injectability for the CCS or Dawn Operations Center.

b) As described in Exhibit C, Tab 1, Schedule 1, Paragraph 25, the ETEE alternative examined the extent to which the pipeline size of the preferred alternative could be reduced from an NPS 36 to an NPS 30. Enbridge Gas has determined that design day deliverability would be reduced by 90 TJ/d.

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit C, Tab 1, Schedule 1, p.19

Preamble:

EGI evidence states: This alternative also provides a 1:1 replacement in total horsepower via installation of two new Spartan e90 electric motor drive ("EMD") compressor units on the west side of the CCS, station modifications at CCS and Dawn, and retirement and abandonment of the existing compressor units and related facilities. This alternative also includes additional costs for a new 27.7 KVA substation and backup generator to provide reliable power for the EMD compressor units.18 This alternative has been estimated to cost approximately $217 million.

Question:

Please file the study that provided the assessment of the electric alternatives, including costing of the substation and maintenance requirements.

Response

Enbridge Gas's analysis encompassed the utilization of internal cost estimating processes to develop a high-level cost estimate. No formal study results were produced other than what is provided in pre-filed evidence. Please see the response at Exhibit I.ED.12, for additional detail on this assessment.

Enbridge Gas also engaged Hydro One Ltd. to confirm that there is sufficient existing capacity to service the increased electric load for the EMD option. However, as noted in the response at Exhibit I.SEC.13, the Company's estimate included a backup power generator to provide backup power to station components such as pumps, controls, etc. The cost estimate did not include the cost of a backup gas driven motor to run the EMD in event of a hydro grid failure that would make this alternative further uneconomic compared to the proposed Project.

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit C, Tab 1, Schedule 1, p.19

Preamble:

EGI evidence states: This alternative also provides a 1:1 replacement in total horsepower via installation of two new Spartan e90 electric motor drive ("EMD") compressor units on the west side of the CCS, station modifications at CCS and Dawn, and retirement and abandonment of the existing compressor units and related facilities. This alternative also includes additional costs for a new 27.7 KVA substation and backup generator to provide reliable power for the EMD compressor units.18 This alternative has been estimated to cost approximately $217 million.

Question:

Please redo the economics and NPV placing one Spartan EM in place in the first year, determine in which year it would be forecasted that the second new compressor would be needed, the add a second compressor when warranted in that year.

a) Please ensure that you provide the detail on the timelines specifying which compressor(s) is assumed to be removed and the reason for removal (consistent with responses in Question 11).

b) Please provide the amount of compression (in HP and MW) for the loss of each of the compressors which ultimately drive the addition of the second compressor.

c) Please provide EGI's opinion of the efficacy of this approach and, specifically, reasons why it would not work, if any.

<u>Response</u>

a) Please see the response at Exhibit I. FRPO.11 a) and b) for confirmation of the number of compressors to be retired (7) and the timing of retirement/abandonment (November 1, 2023). The reasons are described in Exhibit B section of evidence that details the Project need and reiterated within responses to related interrogatories.

b) Please see the response at Exhibit I. ED.10, which provides the amount of compression in HP for the loss of each incremental compressor. MW is not relevant to the existing CCS compressor units.

c) Please see the response at Exhibit I.SEC.13, which provides reasoning as to why a staged approach to replacing the 7 CCS compressor units is not feasible as it:

   i. Does not alleviate the obsolescence, reliability and safety risks to customer personnel that is driving the need for the current Application;

   ii. Is not cost-effective; and therefore,

   iii. Is not in the best interest of ratepayers.

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit C, Tab 1, Schedule 1, p.19

Preamble:

EGI evidence states: NPV analysis was not completed for the Repair + Replace alternative as it is not able to adequately satisfy the project need as described in Exhibit B. While the capital cost of this alternative is lower than the proposed Project alternative described above (NPS 36 Pipeline), the O&M cost is nearly double. The alternative's inability to adequately satisfy the project need led the Company to determine that this alternative is not preferrable.

While EGI's view is that the option does not meet the project need that the company defined, we believe it would still be important to inform the Board on the expected costs of O&M in the event other alternatives are considered especially since the costing is done.

Question:

Please provide the NPV determination for this option showing all of the source numbers and assumptions made.

Response

Please see the response at Exhibit I.ED.8.

For assumptions used to calculate the O&M and capital cost for the Repair + Replace Alternative shown in Exhibit C, Tab 1, Schedule 1, Table 2, please see the response at Exhibit I.ED.12.

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit C, Tab 1, Schedule 1, p.19

Preamble:

EGI evidence states: NPV analysis was not completed for the Repair + Replace alternative as it is not able to adequately satisfy the project need as described in Exhibit B. While the capital cost of this alternative is lower than the proposed Project alternative described above (NPS 36 Pipeline), the O&M cost is nearly double. The alternative's inability to adequately satisfy the project need led the Company to determine that this alternative is not preferrable.

While EGI's view is that the option does not meet the project need that the company defined, we believe it would still be important to inform the Board on the expected costs of O&M in the event other alternatives are considered especially since the costing is done.

Question:

Using the baseline provided by EGI responses on storage capability in our initial questions, if the Board approves the NPS 36 project along the lines proposed, would EGI provide an annual report on their working storage capacity and deliverability?

a) Further, would EGI provide annual reporting on the resulting incremental contracts provided by the incremental capability?
    i. If not, why not?

Response

Enbridge Gas provides a Design Day Capacity Report on its website that is updated annually with Working Gas Capacity and Design Peak Withdrawal Capacity.

https://www.enbridgegas.com/storage-transportation/operational-information/storage-reporting

a) Please see the response at Exhibit I.FRPO.32.

ENBRIDGE GAS INC.

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

INTERROGATORY

Reference:

Exhibit C, Tab 1, Schedule 1, p.19

Preamble:

EGI evidence states: NPV analysis was not completed for the Repair + Replace alternative as it is not able to adequately satisfy the project need as described in Exhibit B. While the capital cost of this alternative is lower than the proposed Project alternative described above (NPS 36 Pipeline), the O&M cost is nearly double. The alternative's inability to adequately satisfy the project need led the Company to determine that this alternative is not preferrable.

While EGI's view is that the option does not meet the project need that the company defined, we believe it would still be important to inform the Board on the expected costs of O&M in the event other alternatives are considered especially since the costing is done.

Question:

Please provide EGI's opinion on whether it would be appropriate for ratepayers to benefit from the incremental contracting derived from the installation of the proposed NPS 36 and the removal of compression over time.

Response

The Project replaces the existing system capacity and does not provide the ability for incremental contracting.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Industrial Gas Users Association ("IGUA")

INTERROGATORY

Reference:

ExB/T1/S1/Att1/p3.

Preamble:

The Sarnia-Lambton Economic Partnership letter filed in support of the application references the importance of "[m]aintaining the reliability to meet demand in Sarnia-Lambton's heavy industrial sector including the Province of Ontario's only Petrochemical and Refining Complex". It is IGUA's understanding that there has been some recent service interruptions experienced on the Sarnia industrial line.

Question:

a) Please discuss any service interruption/reliability issues experienced on the Sarnia industrial line during the past two winters.

b) Is there a relationship between the current operation of the compressors proposed for replacement and the reliability of service on the Sarnia industrial line?

c) If there is, please explain the relationship and whether, and if so how, the proposed project is expected to impact such service reliability.

d) If there is not, please briefly indicate the reasons for any recent service interruption/reliability issues on the Sarnia industrial line.

Response

a) There have been no service interruption or reliability issues on the Sarnia Industrial Line over the past two winters.

b) & c)
There is no relation between the current operation of the compressors proposed for replacement and the Sarnia Industrial Line, as the CCS does not supply the Sarnia Industrial line.

d) There has been one interruption starting on August 9th, 2021 at 8:00 am and ending on August 10th, 2021 at 10:00 am due to planned pipeline maintenance during construction that occurred as part of the Sarnia Industrial Line Project (EB-2019-0218). This outage impacted one customer.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Industrial Gas Users Association ("IGUA")

INTERROGATORY

Reference:

ExB/T2/S1/p6/paragraph 13.

Preamble:

The evidence states that the operational flexibility provided by physical storage capacity allows EGI "to respond to short-term demand variations quickly and with limited administrative support".

Question:

Please explain what is meant by "administrative support" in the referenced evidence excerpt.

Response

The term "administrative support" refers to the commercial and operational processes associated with responding to short-term demand variations using third-party balancing services or intra-day gas supply purchases, instead of using physical storage capacity. These processes can include:

(i) matching nominations of intra-day services with a third-party service provider;
(ii) negotiating intra-day gas commodity purchases;
(iii) executing a contract with a third party on short notice for the use of intra-day balancing services or the purchase of intra-day gas commodity; and
(iv) monitoring and correcting any imbalances on upstream or downstream pipelines that may result from the inability to manage intra-day demand variations as they arise.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Industrial Gas Users Association ("IGUA")

INTERROGATORY

Reference:

ExC/T1/S1/p18/paragraph 31 and p20/paragraph 38.

Preamble:

The evidence indicates that in comparing the proposed project to replacement of the existing compressors with new gas compressors the carbon emissions resulting from compression in either scenario were considered.

Question:

Please provide the quantities and associated costs assumed for lifetime carbon emissions for each of the proposed project and the new gas compressor alternative.

Response

Table 1 provides calculations of the quantity and cost of carbon emissions. Assumptions applied to support the calculations in Table 1 are set out below.

Table 1

Alternative	NPS36 Pipeline	2x Natural Gas Powered Compressors	2x Electric Motor Driven Compressors
Annual Fuel / Electricity Usage	8,642	9,392	38,465,245
	10^3m3	10^3m3	kwh
	$ 1,135,826.70	**$ 1,234,399.95**	**$ 5,692,856.26**
Annual Emissions (tCO2e)	17,469	19,648	0
Annual Emissions (cost)	**$ 954,768.20**	**$ 1,073,861.44**	$ -
Total	**$ 2,090,595**	**$ 2,308,261**	**$ 5,692,856**

Pipeline Assumptions

- Annual Fuel Usage – 4% reduction in fuel usage based on the average fuel consumption for existing CCS units when using the average fuel burn rate for compressor units at Dawn. An average burn rate was used, due to the various combinations of compressors that could be used at Dawn on any given day. The 4% is based on Plant G published burn rates.

Gas Driven Compression Assumptions

- Annual Fuel Usage – 8% increase in fuel consumption based on the average fuel burn rate for a Solar Taurus 70 at Dawn (Plant F).

Electric Motor Driven Compression Assumptions

- Annual Electricity Usage – EMD operates at 90% efficiency. The HP for current units at Corunna converted to equivalent MW and average 5 year run time @ utility rate of 0.148 $/kwh

Common Assumptions

- Annual Emissions (Carbon Cost) – fuel consumption converted to equivalent tonnes of CO_2e. Does not include fugitive emissions

- Based on the Federal Carbon Pricing Program, although the carbon cost applies to Enbridge Gas Storage and Transmission Operations combustion emissions, due to the Output Based Pricing System Regulation (which provides some cost relief to industry), the applied carbon cost is currently estimated at 34% of the cost/tCO_2e, with carbon price at \$50/tCO_2e in 2022 and increasing by \$15 per year out to 2030 (resulting in a carbon price of \$170/tCO_2e by 2030).

- Average annual cost of carbon over 40 years: \$54.66.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe ("PP")

INTERROGATORY

Reference:

Enbridge Gas Inc. has identified the need to abandon, remove and replace up to seven (7) reciprocating compressor units located at the Corunna Compressor Station ("CCS")… [Exhibit A, Tab 2, Schedule 1, Page 1 of 4]

Question:

a) Please provide how Enbridge will determine how many of the 7 compressor units would be replaced and the analysis approach behind that decision.

b) Please explain why all 11 compressor units at this site can't be removed if the new pipeline is constructed.

c) Please explain what the minimum number of compressors is for this site in order for it to operate and what the storage system impacts are if additional compressors were removed.

d) Please provide any reports and/or analysis that support retaining 4 compressors at the Corunna site and replacing only 7 compressors due to reliability, obsolescence and safety concerns.

Response

a) Enbridge has determined that all 7 compressor units will be retired and replaced as part of the Project (K701-703, K705-K708).

b) As stated in Exhibit B, Tab 1, Schedule 1, p. 9, Enbridge Gas requires CCS units K704, K709, K710 and K711 going forward as they provide a specific operational fit and without them the Company would not be able to fill storage on injection or meet design day withdrawals.

c) Currently, all 11 CCS compressor units are required to maintain access to cost-based storage capacity for EGD rate zone customers during design day conditions (including LCU), for the reasons set out in Exhibits B and C.

Assuming construction of the proposed Project, a minimum of 4 compressors is required at the CCS site to provide safe and reliable operation of the storage system while maintaining storage space and deliverability as referenced in Exhibit B, Tab 1, Schedule 1, p. 9. When these 4 compressors reach their end-of-life Enbridge Gas will review the facilities and the demand at that time to determine the best alternative to meet in-franchise design day demands. One of the options will be the like-for-like replacement of horsepower provided by the 4 compressors remaining at CCS.

d) Please see the response at Exhibit I.CME.1 Attachment 4.

Following construction of the proposed Project, the individual risk for the most exposed worker groups moves from Region 1, which is above the upper risk threshold, to Region 2 ‘conditionally tolerable’.[1]

[1] Individual risk results for the most exposed workers are displayed in Table 1-1 of the DNV report.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe ("PP")

INTERROGATORY

Reference:

Enbridge Gas Inc. has identified the need to abandon, remove and replace up to seven (7) reciprocating compressor units located at the Corunna Compressor Station ("CCS")… [Exhibit A, Tab 2, Schedule 1, Page 1 of 4]

Question:

a) Is this project part of a broader plan for gas storage assets and operation or a stand-alone project? If it is part of a broader plan, please provide a copy of that document. If not, please explain why this project was not assessed as part of the broader storage system.

b) Please explain what existing pipelines connected to other compressor stations cannot be used instead of building an additional new pipeline.

c) Aside from replacing up to 7 compressors, please identify any other benefits that would result from the project (if any).

Response

a) This Project forms part of Enbridge Gas's 2021-2025 Asset Management Plan which can be found at EB-2020-0181, Exhibit C, Tab 2, Schedule 1.

b) Please see the response at Exhibit I.STAFF.3.

c) The benefits of the Project are summarized in Exhibit B, Tab 1, Schedule 1, pp. 28 – 31.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe ("PP")

INTERROGATORY

Reference:

Figure 1 EB-2022-0086, Exhibit B, Tab 1, Schedule 1

Question:

a) Does Figure 1 show all compressor stations in the storage system or only Corunna?

b) Please provide a version of Figure 1 (or equivalent map) showing all compressor stations in the storage system.

c) For each compressor station referred to in part b (above), please provide short description of the purpose and how it relates to Corunna.

Response

a) Figure 1 shows the CCS and the Dawn Operations Centre. These are the primary compressor stations in the Enbridge Gas storage system.

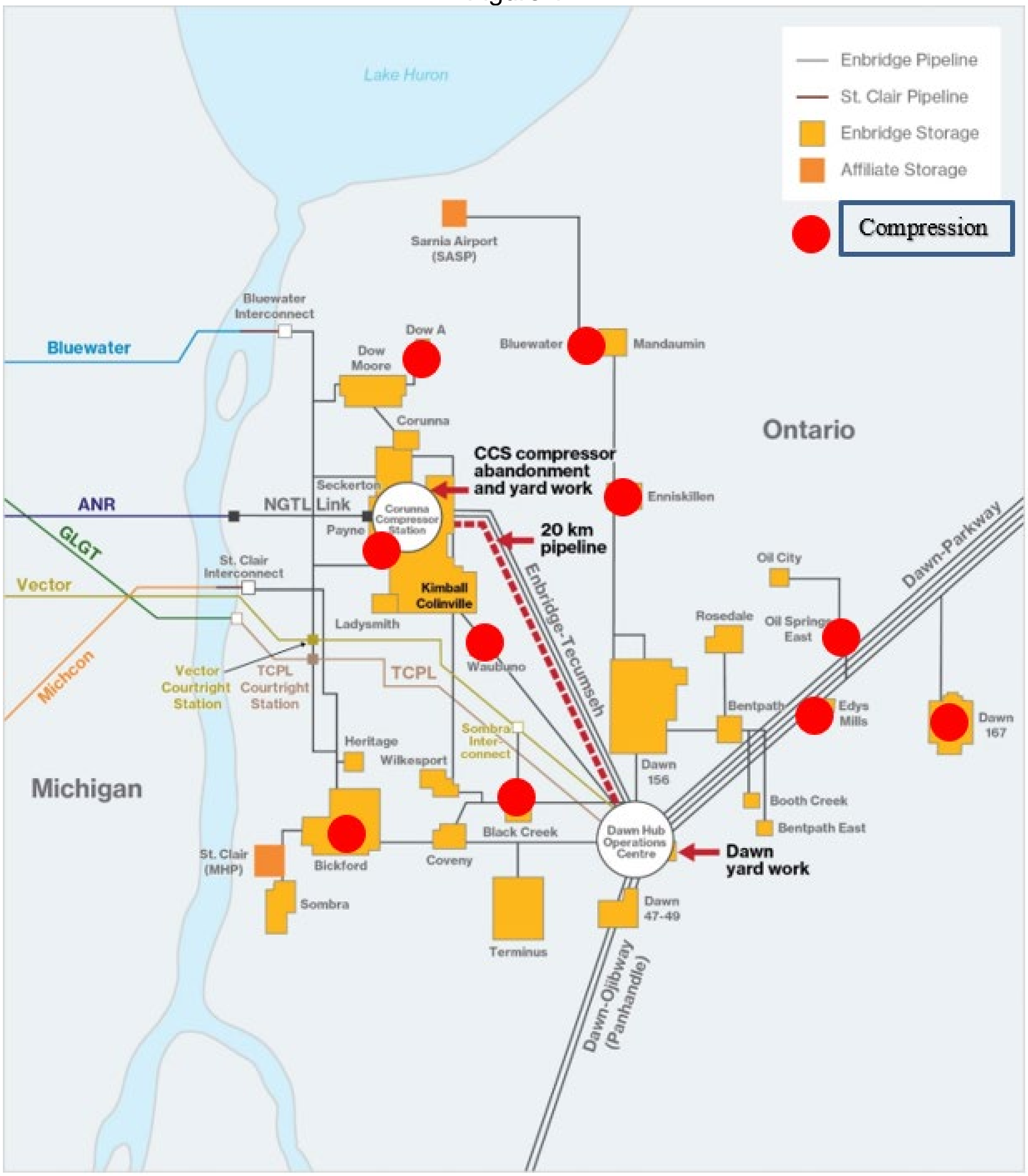
b) In addition to the primary compression highlighted in Figure 1, the included map highlights the remaining compression locations in the storage system except for Chatham D, Tipperary, Crowland and Hagar. Chatham D, Tipperary, Crowland and Hagar compressors are remote facilities located outside the mapped area dedicated to the local operation of their corresponding storage pools/facilities.

c) Table 1 summarizes the purpose of each compressor in the storage system. Figure 1 sets out the location of each compressor described in Table 1 (excluding remote facilities).

Table 1

Compressor	**Purpose**
CCS	Primary compressor station for EGD rate zone storage system.
Dawn	Primary compressor station for Union rate zones' storage system. In addition, all gas to/from the EGD rate zone storage system flows through Dawn.
Sombra Compressor Station	Compressor station for Black Creek, Coveny and Wilkesport Pools. This station is connected to Dawn through a NPS 16 TSLE pipeline.
Waubuno	Utilized on injection to fill the top portion of the Waubuno storage pool. No relation to the CCS.
Payne	Utilized on injection to fill the top portion of the Payne storage pool. Following the construction of the NPS 24 pipeline between CCS and the Payne pool in 2022 the Payne pool will be able to receive gas from both Dawn and the CCS.
Dawn 167	Utilized on injection and withdrawal to fill and empty the Dawn 167 storage pool. No relation to the CCS.
Edys Mills	Utilized on injection and withdrawal to fill and empty the Edys Mills storage pool. No relation to the CCS.
Oil Springs East	Utilized on injection and withdrawal to fill and empty the Oil Springs East storage pool. No relation to the CCS.
Airport	Utilized on injection to fill the top portion of the Airport, Bluewater and Mandaumin storage pools. No relation to the CCS.
Bickford	Utilized on injection to fill the top portion of the Bickford, Terminus, Sombra and St. Clair storage pools. No relation to the CCS.
Dow A	Utilized on injection to fill the top portion of the Dow A storage pool. Used on withdrawal to meet the prevailing pressure in the Sarnia Industrial Line. No relation to the CCS.
Enniskillen	Utilized on injection to fill the top portion of the Enniskillen storage pool. No relation to the CCS.
Remote Facilities, Not Shown in the Figure	
Tipperary	Utilized on injection and withdrawal to fill and empty the Tipperary storage pool. No relation to the CCS. Tipperary is located west of the community Clinton ON.
Chatham D	Utilized on injection and withdrawal to fill and empty the Chatham D storage pool. No relation to the CCS. Chatham D is located southwest of the community of Dresden ON.
Crowland	Utilized on injection and withdrawal to fill and empty the Crowland storage pool. No relation to the CCS. Crowland is located east of the city of Welland, ON.
Hagar Compressor	Utilized for liquid natural gas (LNG) production, storage and vaporization. No relation to the CCS. Hagar is located east of the city of Sudbury, ON.

Figure 1


Enbridge Pipeline
St. Clair Pipeline
Enbridge Storage
Affiliate Storage
Compression
Lake Huron
Sarnia Airport (SASP)
Bluewater Interconnect
Bluewater
Dow A
Dow Moore
Mandaumin
Corunna
CCS compressor abandonment and yard work
Ontario
Seckerton
ANR
NGTL Link
Corunna Compressor Station
Enniskillen
Payne
20 km pipeline
GLGT
St. Clair Interconnect
Enbridge-Tecumseh
Kimball Colinville
Oil City
Dawn-Parkway
Vector
Ladysmith
Rosedale
Oil Springs East
Vector Courtright Station
TCPL Courtright Station
TCPL
Waubuno
Michcon
Bentpath
Edys Mills
Dawn 167
Sombra Interconnect
Heritage
Wilkesport
Dawn 156
Michigan
Booth Creek
Bentpath East
Black Creek
Dawn Hub Operations Centre
St. Clair (MHP)
Bickford
Coveny
Dawn yard work
Sombra
Dawn 47-49
Terminus
Dawn-Ojibway (Panhandle)

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe ("PP")

INTERROGATORY

Reference:

Figure 1 EB-2022-0086, Exhibit B, Tab 1, Schedule 1

Question:

a) Please identify when this project was first identified as being potentially required and explain why the urgency has increased to the point requiring action.

b) Please provide the reference and excerpt from the most current updated Enbridge Asset Management Plan outlining details on this project and where it ranks against other projects in the current Asset Management Plan.

Response

a) The Project was initially identified as being required in 2017 as Enbridge Gas prepared investments to support the 2018-27 Asset Management Plan.[1] In that plan, the issues of reliability and obsolescence for units K701-K703 were identified. Additionally, as part of the 2022 Rates (Phase 2) proceeding Enbridge Gas filed an Asset Management Plan Addendum,[2] which highlighted that since the 2021-2025 AMP was completed the Company has also identified increasing reliability and obsolescence concerns with compressor units K705-K708 as well as employee safety concerns with the broader Corunna Compressor Station site that must be addressed.

The urgency to proceed with the Project is supported both by the results of the Quantitative Risk Assessment ("QRA"), which has identified that continued operation of the site in its current state exceeds the upper risk threshold, and the Reliability Availability and Maintainability study ("RAM Study") which demonstrates the potential shortfall resulting from compressor failures.

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[1] EB-2017-0306/EB-2017-0307, Exhibit C.STAFF.54, Attachment 1.
[2] EB-2021-0148, Exhibit B, Tab 2, Schedule 3.

b) Please see the AMP excerpts and references below:

> Dawn to Corunna Strategy Development[3]
> The Corunna Compressor Station (CCS) is comprised of 11 reciprocating compressors. With the units having been in service for more than 50 years, obsolescence, reliability and employee safety concerns have been identified. Further risk assessment has been completed and has confirmed that risks at this location must be addressed. 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 replace the capacity. The in-service date is targeted for November 1, 2023.
>
> +$67.9M - Dawn to Corunna required in 2023 based on site-wide assessment.[4]
>
> Variance due to pacing of large projects including Dawn to Corunna, SCRW: Station-Renewal In-Place, Dehydration Expansion and SCOR: Meter Area Upgrade Ph 1 and Ph 2.[5]

The Project has been evaluated via the GDS Risk Management process. The investment timing and scope of work for investments that rely on the GDS Risk Management process is typically more complex – investment timing is confirmed outside of Copperleaf optimization and as such Dawn-Corunna cannot be directly ranked against other projects in the asset management plan.

The risk level is in Region 1, indicating the risk is considered to be at or above the upper threshold and must be treated (Exhibit B, Tab 1, Schedule 1, p. 23).

[3] EB-2021-0148, Exhibit B, Tab 2, Schedule 3, p. 8
[4] EB-2021-0148, Exhibit B, Tab 2, Schedule 3, p.10 (Table 5.1-1)
[5] EB-2021-0148, Exhibit B, Tab 2, Schedule 3, p.12 (Table 5.1-3)

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe ("PP")

INTERROGATORY

Reference:

"the Company has experienced continued and increasing compressor unit downtime and long lead repair time." [Exhibit B, Tab 1, Schedule 1, Paragraph 25]

Question:

a) Please provide a log and related information outlining the downtime for each of the 11 compressors at the Corunna Station.

b) Please summary what incremental O&M or Capital costs resulted from the downtime and long lead time repair.

c) Please provide information related to each compressor at the Corunna Station illustrating the magnitude of "increasing compressor downtime".

Response

a) Please see Table 1 for compressor unit downtime data for last 6 years, 2016-2021.

Table 1

Corunna Units	Outage (Run Hours)					
	2016	2017	2018	2019	2020	2021
K701	1,070	1,645	2,473	3,321	5,205*	8,760*
K702	861	873	637	2,405	1,210	2,902
K703	4,085	5,844	1,673	1,746	1,114	985
K704	530	245	821	1,932	1,415	3,109
K705	580	1,715	6,347	8,201	1,876	463
K706	751	4,685	4,982	1,072	2,019	1,438
K707	375	267	732	1,740	8,783	4,249
K708	623	299	804	2,568	3,566	2,629
K709	234	457	2,300	898	5,776	4,057
K710	472	924	1,895	5,869	1,243	6,118
K711	621	1,621	881	2,055	2,350	1,381
Total	10,201	18,575	23,544	31,805	34,558	36,090
	* Outage time based on a decision not to run the unit in absence of the foundation repair					

As shown in Table 1 above, unit K701 has been down for the majority of 2019 and for 2020 and 2021. The unit went down on a high web deflection event indicating crankshaft misalignment in December 2018. As the cause of this event was determined to be foundation damage, it was decided not to run the unit due to the increasing risk of crankshaft failure until the foundation was repaired or replaced. The unit was then left unavailable with option to operate as last-on and the damaged block was left unrepaired in anticipation of the current Project Application.

For more details on all major unplanned outages for the period 2016-2021, see the table and Gantt Chart shown Attachment 1 to this response. Included in this file are all unplanned events that were 5 days or more in duration.

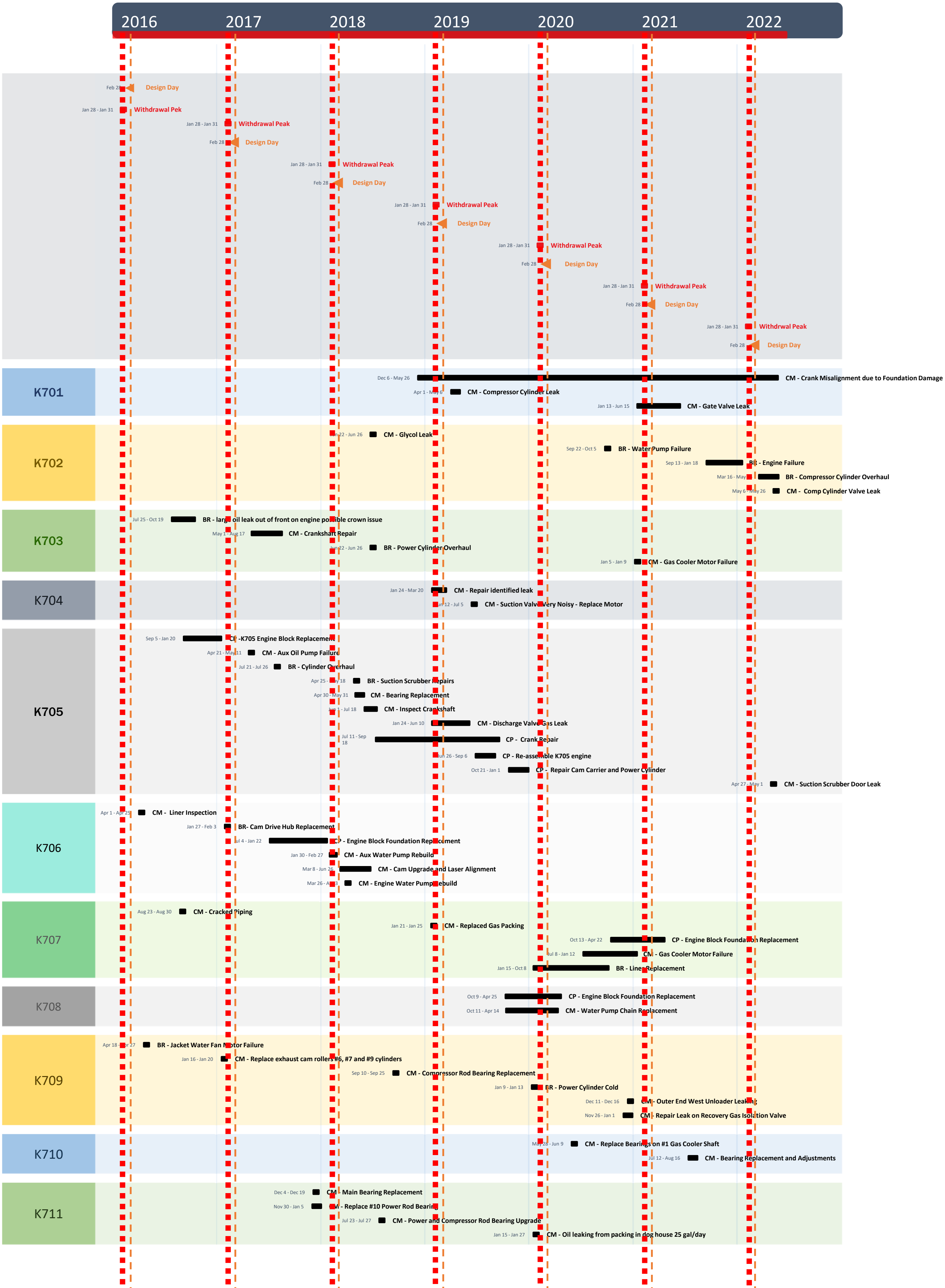
b) O&M costs are not tracked at the CCS at the asset level or through work orders directly. The O&M costs are tracked only to the site level. Please see the response at Exhibit I.FRPO.6, for 2017-2021 O&M proxied by run hours. It is not possible to report on the historical costs associated with specific, historical equipment failures. However, some of the capital costs associated with major outages are available and shown in Table 2 below.

Table 2

Unit	Title	Start date	End date	Duration (days)	Capital Cost ($)
K705	CP -K705 Engine Block Replacement	09/05/2016	01/20/2017	138	3,548,323
K706	CP - Engine Block Foundation Replacement	07/04/2017	01/22/2018	203	7,440,785
K705	CP - Crank Repair (Replacement)	07/11/2018	09/18/2019	435	5,510,603
K708	CP - Engine Block Foundation Replacement	10/09/2019	04/25/2020	200	3,699,421
K707	CP - Engine Block Foundation Replacement	10/13/2020	04/22/2021	192	4,319,063
Total Capital Costs ($) from 2016-2021					**24,518,195**

c) Please see the response at part a) and Exhibit I.SEC.4.

Unit	Title	Description	Start date	End date	Duration (days)
K701	CM - Crank Misalignment due to Foundation Damage	during Oil Change, checked web deflections and bearing clearances, found high web deflection on #5 power, found clearance under #1 main bearing. Main bearing work completed. *Unit left unavailable with option to operate as last-on due to foundation damage. The damaged block was left unrepaired in anticipation of the upcoming renewal project.	12/06/2018	Ongoing	1268* As of May 26, 2022
K701	CM - Compressor Cylinder Leak	Replaced o-ring on valve cap to repair leak	04/01/2019	05/06/2019	36
K701	CM - Gate Valve Leak	Upon inspection we found that the packing gland is cracked and needs to be replaced or repaired	01/13/2021	06/15/2021	154
K702	CM - Glycol Leak	pump seal was leaking removed old pump and installed re-built water pump from the warehouse	06/22/2018	06/26/2018	5
K702	BR - Water Pump Failure	K702 has a knock coming from the water pump, a bushing was wore out on the water pump drive gear shaft causing the gears to not mesh properly, removed the gear case and water pump, had TREL repair the damaged drive gear and make new bronze bushings, re-assembled the gear case using a used spare shaft from a gear case we had sitting in the warehouse, installed a new rebuilt water pump from inventory, installed hardened cotter pins in the water pump drive chain	09/22/2020	10/05/2020	14
K702	BR - Engine Failure	A large knocking noise started and emergency stop was used	09/13/2021	01/18/2022	128
K702	BR - Compressor Cylinder Overhaul		03/16/2022	05/26/2022	72
K702	CM - Comp Cylinder Valve Leak	Suction scrubber door/comp cyl 1 valve cap leaking, installed new seal on door waiting to be pressured up, new O-ring was installed on valve cap	05/06/2022	05/26/2022	21
K703	BR - Cracked Crown	Large oil leak out of front on engine possible crown issue, repaired K703 Cracked Crowns	07/25/2016	10/19/2016	87
K703	CM - Crankshaft Repair	disassembled top and bottom end of engine so that the crankshaft was bare, removed flywheel, loosened timing chain, removed all but three main bearings,-installed all new (Dresser-Rand) main bearings, found that the top half of the bearing had lots of crush and the bottom half had very little, #11 main bearing is not an elliptical bearing,-recorded web deflections, checked bearing clearances, installed end seal and baffle plate, installed flywheel and torqued to 1800ft/lbs, rechecked bearing clearances and web deflections on #10 and #11 main (good), installed compressor rods with old bearings, installed all power rods with old bearings, reassembled top end of engine and tightened timing chain, bump checked compressor and power rods (good), checked crosshead pin clearances (good), when unit was test run we heard a loud ticking sounds from the flywheel end, we found that the baffle plate for the crank end seal had been damaged when the flywheel was being torqued, we removed the flywheel again and replaced the baffle plate, test ran the unit again and the noise was gone	05/01/2017	08/17/2017	109
K703	BR - Power Cylinder Overhaul	Disassembled #7 power cylinder and inspected all parts, found that the piston crown was cracked in two places, inspected all other parts and found no issues, deglazed power cylinder, checked piston cutout for proper alignment (good), installed new piston with new rings and installed cylinder with new o-ring, cleaned and installed used head with a new copper gasket, re-assembled all top end auxiliary parts with new gaskets, -installed rocker arm with new lifters and set tappets, cleaned out that bay of the crankcase and installed doors with new gaskets, boroscoped PCC pot after water was installed (good)	06/22/2018	06/26/2018	5
K703	CM - Gas Cooler Motor Failure	K703 #2 gas cooler fan wont run, motor has been replaced	01/05/2021	01/09/2021	5
K704	CM - Repair identified leak	#N/A	01/24/2019	03/20/2019	56
K704	CM - Suction Valve Very Noisy - Replace Motor	Preoper motor arrived and installed on vlave actuator, valve tested and put back into service	06/12/2019	07/05/2019	24
K705	CP -K705 Engine Block Replacement		09/05/2016	01/20/2017	138
K705	CM - Aux Oil Pump Failure	Rebuilt the gear case with all new bearing and seals	04/21/2017	05/11/2017	21
K705	BR - Cylinder Overhaul	Engine was running with pre-ignition in #7 cylinder, pressure tested cylinder and found no compression, air was leaking from combustion chamber down into the crankcase	07/21/2017	07/26/2017	6
K705	BR - Suction Scrubber Repairs	During the scrubber inspection and filter replacement it was noticed one of the filter supports near the top of the vessel was broken.	04/25/2018	05/18/2018	24
K705	CM - Bearing Replacement	Installed new WIW main bearings in unit, C35used all new main bearing shims	04/30/2018	05/31/2018	32
K705	CM - Inspect Crankshaft	This unit has a damaged crankshaft, in the summer of 2017 we had some issues with this unit	06/01/2018	07/18/2018	48
K705	CM - Discharge Valve Gas Leak	Repair identified leak, the valves mentioned are on the greasing list for 2019	01/24/2019	06/10/2019	138
K705	CP - Crank Repair (Replacement)	This Project Work Order was initially created as O&M spend . It has since been risk ranked and approved for Capital Spend	07/11/2018	09/18/2019	435
K705	CP - Re-assemble K705 engine		06/26/2019	09/06/2019	73
K705	CP - Repair Cam Carrier and Power Cylinder	pened filter vessel and removed filters, the 2 magnets that were in the vessel had a lot of metal filings in them, cleaned filter pot, checked clean side to make sure no filings were there (it looked good), installed new oil filters, installed magnets in every filter, re-used old door o-ring, also drained oil from the bottom leg of piping and the oil cooler	10/21/2019	01/01/2020	73
K705	CM - Suction Scrubber Door Leak	Cleaned seal and closed back up waiting to be pressured up to check for leaks	04/27/2022	05/01/2022	5
K706	CM - Liner Inspection	Removed liner and inspected for cavitation along the top o-ring groove, found some cavitation but nothing too serious (see pictures attached), cleaned up the liner and holder and installed new copper gasket and o-rings, re-assembled the liner 90* from the original position in the holder	04/01/2016	04/25/2016	25
K706	BR- Cam Drive Hub Replacement	Problem: the unit would not roll over during the start sequence, Robertshaw valve was rebuilt, both seals on the air starter and cam reset housing were inspected, no change	01/27/2017	02/03/2017	8
K706	CP - Engine Block Foundation Replacement		07/04/2017	01/22/2018	203
K706	CM - Aux Water Pump Rebuild	Sandarin rebuilt the pump and motor, we installed the pump with new gaskets, studs and nuts	01/30/2018	02/27/2018	29
K706	CM/CP - Cam Upgrade and Laser Alignment	PCG laser aligned cam carriers on both sides of the engine, Cam carriers were shimmed and re-dowled as needed, Checked drive gears on both sides for contact and back lash and adjusted the end cover to set correctly, Installed the upgrader cams and torqued all bolts, Wire tied the dowels on the drive ends, Installed push rods and rocker arms and set tappets, Completed the timing of the cams	03/08/2018	06/26/2018	111
K706	CM - Engine Water Pump Rebuild	Engine water pump is installed	03/26/2018	04/03/2018	9
K707	CM - Cracked Piping	Cracked nipple where vent piping threads into bypass, work completed. As builting to be completed in the coming weeks	08/23/2016	08/30/2016	8
K707	CM - Replaced Gas Packing	replaced gas packing and oil packing on all cylinders, found that the nose cone gasket was leaking on #4 cylinder, replaced the packing case on #4 cylinder because we couldn't seat the new nose cone gasket	01/21/2019	01/25/2019	5
K707	CP - Engine Block Foundation Replacement		10/13/2020	04/22/2021	192
K707	CM - Gas Cooler Motor Failure	K703 #2 gas cooler fan wont run, motor has been replaced	07/08/2020	01/12/2021	189
K707	BR - Liner Replacement	during chain PM's we found moisture in the crankcase that was causing a lot of rusting internally, after investigating we found that the liners were leaking glycol from around the o-ring area, oil change to remove contaminated oil was completed under a different WO, replaced water pump chain under different WO, disassembled top end , installed new DR liners into refurbished Air Correct holders using D-R O-rings that came in the liner crates, cleaned up pistons and installed new rings, checked ring clearances in liner and on piston (good), re-assembled top end, cleaned and re-used the same heads, used DR gasket kits to install new gaskets everywhere on the top end, installed water and gas piping with new o-rings, pressure tested glycol system and found no major leaks, had operations put water in the unit and turn the warm up's on, this was the first time the new plant glycol was going in K707 engine , first we noticed some glycol leaking between the head and liner externally on some of the cylinders, after letting the engine sit a few days we started noticing glycol leaking internally around the liners the same as it was before , removed #6 cylinder to investigate, took liner and holder to TREL to verify measurement and machine work, found that the bronze o-ring area wasn't square to the top head gasket surface, suspected that the liners weren't sealing properly when the head was being torqued down because faces weren't square, the original holders were taken to Goodman Brown to be reconditioned, they squared up the holders and refinished the bronze sealing area, we tore down the top end again and installed the new refinished holders with the same new DR liners, installed all new O-rings and gaskets, had operations fill unit with water, found that all liners were still leaking internally past the o-ring sealing area, removed #8 cylinder to investigate because it was leaking the worse, Jim took the liner and holder to Goodman Brown with Tony Tebo, they found that the finish on the bronze was not to spec and was too porous, suspected that glycol was able to leak past the O-rings because of an improper finish, Goodman Brown refinished the bronze area again using an older method used previously to get the finish within spec, Installed the new refinished holder back in #8 cylinder with the DR liner using all new O-rings and gasket kit, operations put water back in unit and we found that glycol was still leaking internally from the o-ring area, removed #8 cylinder again to investigate, decided that there was maybe an issue with the hardness of the DR liner o-rings, ordered 90 durometer Viton O-rings and installed them on the #8 liner, re-installed #8 cylinder and checked for leaks internally, found no glycol leaking, decided that we should do another cylinder to verify this would fix the problem, removed #6 cylinder and installed 90 durometer Viton O-rings on the liner, assembled cylinder and checked for leaks, cylinder was not leaking, disassembled the rest of the top end and installed new 90 durometer viton O-rings on all liners, used all new gaskets, filled unit with water and found no leaks internally, we still have a couple cylinders leaking between the head and the holder externally but they seal up with the warm ups on, still investigating why that is. Conclusion: all holders are refinished from Goodman Brown using the older method of bronzing that produced the proper finish, 90 durometer Viton O-rings from RPS Machine were used on all liners and most holders, #8 cylinder does not have a 90 durometer o-ring around the outside of the holder -we can watch it for oil leaks and see if it makes a difference, K707 foundation project is starting now and we will test run unit after it is	01/15/2020	10/08/2020	268
K708	CP - Engine Block Foundation Replacement		10/09/2019	04/25/2020	200
K708	CM - Water Pump Chain Replacement	new water pump chain was installed due to older one being stretched and could not be adjusted to proper tension, hardened cotter pins were installed, chain tension was set	10/11/2019	04/14/2020	187
K709	BR - Jacket Water Fan Motor Failure	Installed new motor, installed new overload switch, change witing in starter to reflect 2 winding motor	04/18/2016	04/27/2016	10
K709	CM - Replace exhaust cam rollers #6, #7 and #9 cylinders	when changing the cam roolers on#6,7,9 exhaust we noticed some wear on the exhaust cam lobes so we replaced all three cams and upgraded the lock wires on the cam bolts to Nord-Loc washers	01/16/2017	01/20/2017	5
K709	CM - Compressor Rod Bearing Replacement	Replaced Compressor Rod Bearings	09/10/2018	09/25/2018	16
K709	BR - Power Cylinder Cold	Replaced plug and check , corrected the problem	01/09/2020	01/13/2020	5
K709	CM - Outer End West Unloader Leaking	After unit was pressured up I checked for leaks and found none	12/11/2020	12/16/2020	6
K709	CM - Repair Leak on Recovery Gas Isolation Valve	inspected leak found stem of valve leaking and needs replaced	11/26/2020	01/01/2021	37
K710	CM - Replace Bearings on #1 Gas Cooler Shaft	Installed New Bearings on Cooler Shaft	05/28/2020	06/09/2020	13
K710	CM - Bearing Replacement and Adjustments	Bearing Repair Work Complete	07/12/2021	08/16/2021	36
K711	CM - Main Bearing Replacement	Removed DR main bearings because they were pulling away from the saddle and we had clearance behind the bearings, installed new Washington Iron Works main bearings, #11 main bearing has an elliptical bearing in it, all bearing, shim sizes and bearing clearances were measured and recorded (attached), installed oil passage ways and wired bolts, measured and recorded crank thrust (attached), during bearing checks we found that #1 and #8 main had .001" clearance under the crank, looked up our last clearance checks from 2015 and found that clearance under #1 and #8 were there before, also found during clearance checks that a couple bearings had some clearance between the frame and the bearing, it was only in a spot about an inch down from the split line and not in very deep, probable due to some fretting on the saddle, not a bearing issue	12/04/2017	12/19/2017	16
K711	CM - Replace #10 Power Rod Bearing	During our oil change we found that #10 power rod bearing was cracked,when we removed the bearing we found that the bearing was smashed to pieces on the rod half,we disassembled #10 cylinder and removed the power rod, we measured the bore for the power rod and found that it was only .001 out of round (good),we removed the bearing from #5 power rod and found that it was showing early signs of failure,the oil hole on the rod half was starting to extrude into the oil passageway in the rod,-we installed a new DR bearing in #5 power rod,we believe the power rod bearing issues are related to the issues we have had with the DR main bearings (issues with snap, crush and possibly material),we have ordered a set of Washington Iron works power and compressor rod bearings and are planning to change all bearings out later,installed new DR bearing in #10,deglazed cylinder liner and installed new piston rings on piston and assembled,-installed new re-built cylinder head ,bump checked both #10 and #5 power rods (#10: .012" / #5: .0125),installed water and checked for leaks (good),installed oil and test ran,checked bearing temperatures at the different intervals and everything looked normal	11/30/2017	01/05/2018	37
K711	CM - Power and Compressor Rod Bearing Upgrade	We are upgrading all of our bearings to Washington Iron Works due to material issues with the Terra Corp bearings , the main bearings have already been changed out to WIW, replaced all of the power rod bearings,minimal cleaning was required because the bearings had just been replaced a few years ago ,the only abnormal thing that we found was some pitting on the bearings where the oil relief groove is cut into it,the pitting got worse as we moved towards the flywheel end,at the flywheel end some were bad enough that it had eaten right through to the back side of the bearing ,-pictures were taken and sent to Tony Tebo at D-R for input,replaced all compressor rod bearings ,-no issues were found, -torqued all bolts and installed new cotter pins , cleaned out the crankcase and installed doors with new gaskets,monitored bearing temps during test run,all temperatures looked good	07/23/2018	07/27/2018	5
K711	CM - Oil leaking from packing in dog house 25 gal/day	Inspected and will repair when unit is available	01/15/2020	01/27/2020	13


2016
2017
2018
2019
2020
2021
2022
Feb 28 Design Day
Jan 28 - Jan 31 Withdrawal Pek
Jan 28 - Jan 31 Withdrawal Peak
Feb 28 Design Day
Jan 28 - Jan 31 Withdrawal Peak
Feb 28 Design Day
Jan 28 - Jan 31 Withdrawal Peak
Feb 28 Design Day
Jan 28 - Jan 31 Withdrawal Peak
Feb 28 Design Day
Jan 28 - Jan 31 Withdrawal Peak
Feb 28 Design Day
Jan 28 - Jan 31 Withdrwal Peak
Feb 28 Design Day
K701
Dec 6 - May 26 CM - Crank Misalignment due to Foundation Damage
Apr 1 - May 6 CM - Compressor Cylinder Leak
Jan 13 - Jun 15 CM - Gate Valve Leak
K702
CM - Glycol Leak
Sep 22 - Oct 5 BR - Water Pump Failure
Sep 13 - Jan 18 BR - Engine Failure
BR - Compressor Cylinder Overhaul
CM - Comp Cylinder Valve Leak
K703
Jul 25 - Oct 19 BR - large oil leak out of front on engine possible crown issue
May 1 - Aug 17 CM - Crankshaft Repair
BR - Power Cylinder Overhaul
Jan 5 - Jan 9 CM - Gas Cooler Motor Failure
K704
Jan 24 - Mar 20 CM - Repair identified leak
CM - Suction Valve Very Noisy - Replace Motor
K705
Sep 5 - Jan 20 CP -K705 Engine Block Replacement
CM - Aux Oil Pump Failure
Jul 21 - Jul 26 BR - Cylinder Overhaul
BR - Suction Scrubber Repairs
Apr 30 - May 31 CM - Bearing Replacement
CM - Inspect Crankshaft
Jan 24 - Jun 10 CM - Discharge Valve Gas Leak
CP - Crank Repair
CP - Re-assemble K705 engine
Oct 21 - Jan 1 CP - Repair Cam Carrier and Power Cylinder
CM - Suction Scrubber Door Leak
K706
CM - Liner Inspection
Jan 27 - Feb 3 BR- Cam Drive Hub Replacement
CP - Engine Block Foundation Replacement
Jan 30 - Feb 27 CM - Aux Water Pump Rebuild
CM - Cam Upgrade and Laser Alignment
CM - Engine Water Pump Rebuild
K707
Aug 23 - Aug 30 CM - Cracked Piping
Jan 21 - Jan 25 CM - Replaced Gas Packing
Oct 13 - Apr 22 CP - Engine Block Foundation Replacement
CM - Gas Cooler Motor Failure
Jan 15 - Oct 8 BR - Liner Replacement
K708
Oct 9 - Apr 25 CP - Engine Block Foundation Replacement
Oct 11 - Apr 14 CM - Water Pump Chain Replacement
K709
BR - Jacket Water Fan Motor Failure
Jan 16 - Jan 20 CM - Replace exhaust cam rollers #6, #7 and #9 cylinders
Sep 10 - Sep 25 CM - Compressor Rod Bearing Replacement
Jan 9 - Jan 13 BR - Power Cylinder Cold
Dec 11 - Dec 16 CM - Outer End West Unloader Leaking
Nov 26 - Jan 1 CM - Repair Leak on Recovery Gas Isolation Valve
K710
CM - Replace Bearings on #1 Gas Cooler Shaft
CM - Bearing Replacement and Adjustments
K711
Dec 4 - Dec 19 CM - Main Bearing Replacement
Nov 30 - Jan 5 CM - Replace #10 Power Rod Bearing
Jul 23 - Jul 27 CM - Power and Compressor Rod Bearing Upgrade
Jan 15 - Jan 27 CM - Oil leaking from packing in dog house 25 gal/day

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe ("PP")

INTERROGATORY

Reference:

"Enbridge Gas serves approximately 3.8 million customers in over 500 communities in Ontario through an integrated network of over 84,000 km of natural gas pipelines" [Exhibit B, Tab 1, Schedule 1, Paragraph 13]

Question:

Please provide a source reference for the over 500 communities in Ontario served by Enbridge and reconcile this against the total of 444 municipalities that exist in Ontario (of which Enbridge serves a subset).

Response

Enbridge Gas has referenced "communities" and not "Municipalities". Several communities served by Enbridge Gas can be represented within a single Municipality.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe ("PP")

INTERROGATORY

Reference:

"Enbridge Gas serves approximately 3.8 million customers in over 500 communities in Ontario through an integrated network of over 84,000 km of natural gas pipelines" [Exhibit B, Tab 1, Schedule 1, Paragraph 13]

Question:

Please provide the date of installation and HP rating for each of the 11 compressors at the Corunna Station and indicate which of these units are proposed to be replaced through this project.

Response

Please see Table 1.

Table 1

YEAR	**Unit**	**HP (ISO Rating)**	**To be Replaced as Part of This Project**
1964	K-701	2500	Yes
1964	K-702	2500	Yes
1964	K-703	2500	Yes
1968	K-704	3000	No
1970	K-705	3750	Yes
1972	K-706	3750	Yes
1973	K-707	3750	Yes
1974	K-708	3750	Yes
1980	K-709	3750	No
1983	K-710	3750	No
1995	K-711	3750	No

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe ("PP")

INTERROGATORY

Reference:

Enbridge's application references EB-2020-0181, Enbridge Gas Inc. Asset Management Plan 2021-2025, Exhibit C, Tab 2, Schedule 1, pp. 194-195.

Question:

a) The 2021 Asset Management Plan reference provided above indicates that Enbridge is "using 40 years as a guideline for indicating a critical point in an asset's life…" [page 194 of above reference]. Please provide the basis for using 40 years as a guideline.

b) The graph in Figure 5.5-4: Age Range of Compressor Plant Installation [page 194 of above reference] indicates that 14 compressors exceed the 40 year Enbridge replacement guideline. Please explain why only 7 are being considered for replacement.

Response

a) The reference to 40 years as a guideline for indicating a critical point in an asset's life in the EGI 2021-2025 Asset Management Plan[1] was made regarding gas turbine driven centrifugal compressors and is described as the age beyond which manufacturers have suggested to Enbridge Gas that support of such equipment may no longer be available. This age may be one of many factors which serves as a trigger to reassess equipment maintenance and renewal plans for these assets. However, the 40-year guideline has no bearing in this particular application, as the need is supported by the specific issues outlined in Exhibit B, Tab 1, Schedule 1, pp. 13-23, the RAM study report[2] and Quantitative Risk Assessment[3].

[1] EB-2020-0181, Exhibit C, Tab 2, Schedule 1, P. 194.
[2] Exhibit B, Tab 1, Schedule 1, Attachment 2.
[3] Exhibit I.CME.1.

b) As stated at Exhibit B, Tab 1, Schedule 1, Page 10:

> K704, K709, K710 and K711 units provide a specific operational fit as part of the CCS injection and withdrawal seasonal cycles and cannot be replaced as part of the Project. On injection, units K704 and K711 will continue to be required after completion of the Project to compress gas arriving from Dawn to fill the top end of the pools to their Planned Maximum Operating Pressure ("PMOP"). On withdrawal, units K709 and K710 will be required to provide a low suction pressure from the CCS to allow the storage pools to reach cushion pressure or minimum operating pressure. These compressors (or equivalent horsepower) will always be required at CCS to achieve a full cycle of the 9 storage pools connected to the CCS, including after the completion of the Project.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe ("PP")

INTERROGATORY

Reference:

"Enbridge Gas assessed 4 facility alternatives capable of providing design day storage capacity equivalent to the existing 7 CCS compressor units proposed to be retired and abandoned" [Exhibit C, Tab 1, Schedule 1, Page 18 of 25]

Question:

a) Please provide any documentation and/or analysis conducted that validates that the current design capacity for the Corunna Station is needed to meet future needs over the next 40 years.

b) Please provide documentation on any IRP analysis and options conducted for this project.

c) Please confirm that Enbridge did not conduct a 40 year demand forecast to validate the peak demand capacity that would be provided by the project options consider and the proposed project. If Enbridge did conduct that analysis, please provide a copy.

Response

a) & c)
As outlined in Exhibit B, Tab 1, Schedule 1, the Project is not underpinned by a custom 40-year projection of design day demand. Completing such a forecast strictly for the Project is not necessary to support its need. The Project seeks to maintain existing EGD rate zone storage capacity required to meet the Company's current actual firm service obligations to ratepayers which are the best indication of future demand.

The EGD rate zone utility customer load balancing portfolio consists of cost of service (or cost-based) storage, market-based storage, daily commodity purchases, and third-party delivered supply. Of these options, cost of service storage is the preferred option as it is the most flexible, reliable, and cost-effective asset for load balancing purposes. Enbridge Gas determined that utility customer design day demand would need to decrease by approximately 27% (approximately 1.1 PJ) before it would consider reducing any amount of cost-based storage as Enbridge Gas would seek to reduce other load balancing assets first.

Accordingly, Enbridge Gas has no basis to conclude that EGD rate zone design day demand for cost-based storage will decline in either the short or long-term.

b) Enbridge Gas included all IRP analysis at Exhibit C, Tab 1, Schedule 1, pp. 6-17.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe ("PP")

INTERROGATORY

Question:

Please confirm that the Environmental Report only assessed the proposed pipeline option selected by Enbridge and did not compare the other alternatives identified in the Leave to Construct application. If that is incorrect, please provide the references to where all project alternatives were compared from an Environmental and Socio-economic perspective.

Response

Confirmed.

The Environmental Report evaluated alternative pipeline routes and identified a preferred route for the Project. The route selection process is outlined in Section 2.0 Route Selection of the Environmental Report.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe ("PP")

INTERROGATORY

Question:

If the proposed pipeline alternative is approved, where will compression for peak storage come from?

Response

As described in Exhibit C, Tab 1 Schedule 1, the Project provides a complete replacement of design day storage system withdrawal capability.

The Project eliminates pressure losses between the CCS and Dawn thereby directly eliminating the need for additional design day compression without changing utilization of Dawn compression.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe ("PP")

INTERROGATORY

Question:

a) Enbridge is currently coordinating its rebasing application for 2024. Please explain how this project relates (if at all) with rebasing.

b) Enbridge indicates that if the OEB approves this project, it may be included in Enbridge's 2023 Rates (Phase 2-ICM) application. Will Enbridge proceed with this project if it does not receive ICM funding?

Response

a) Enbridge Gas will seek to include the cost of the Project in its test year revenue requirement as part of the Company's 2024 rebasing application.

b) The Company will not be seeking ICM treatment for the Project.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe ("PP")

INTERROGATORY

Question:

Please provide an updated project schedule including major milestones including permits and approvals.

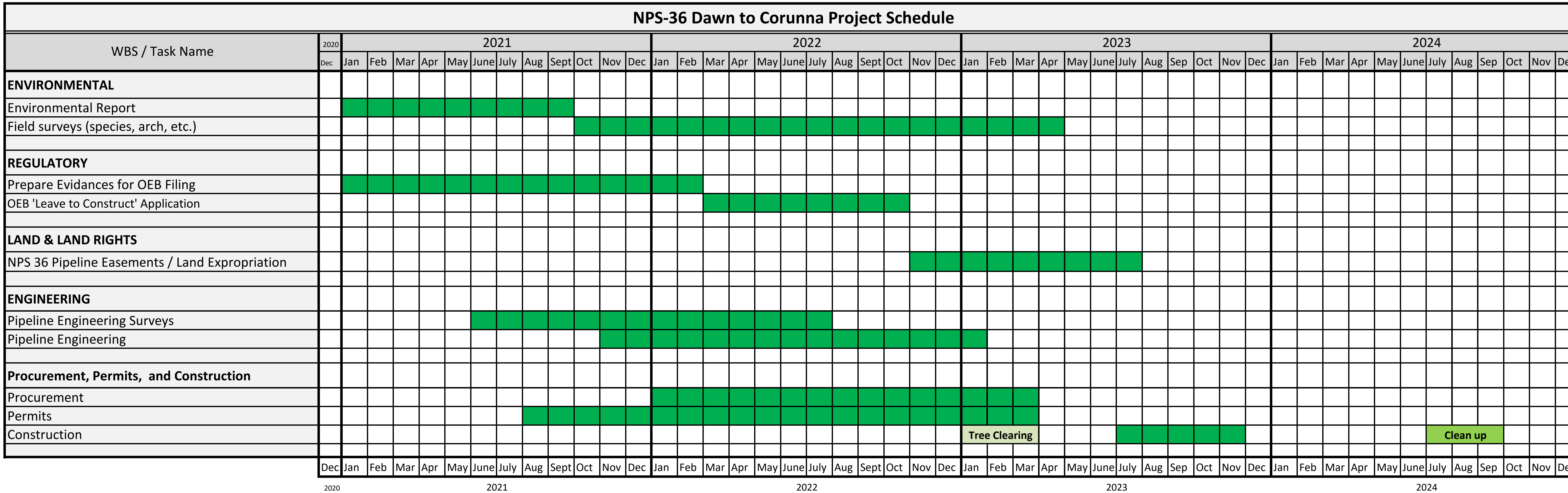
Response

Enbridge Gas has made one minor change to the Construction Schedule filed at Exhibit E, Tab 1, Schedule 1, Attachment 1. Field Surveys were originally scheduled to be completed in March, 2023 and are now scheduled to be completed in April, 2023. Please see an updated Construction Schedule at Attachment 1 to this response.

An update for the status/timing for permits and approvals required for the Project, found at Exhibit G, Tab 1, Schedule 1, p. 4, has been provided in Table 1 below.

Table 1: Permits/Authorizations Required

Approval/Permit or Authorization Required	**Timing/Status**
Fisheries and Oceans Canada ("DFO")	Field studies are ongoing, Enbridge Gas will apply for permitting/approval in Summer, 2022.
Ministry of Environment, Conservation and Parks ("MECP")	Field studies are ongoing, Enbridge Gas will apply for permitting/approval in Summer, 2022.
Ministry of Heritage, Sport, Tourism and Culture Industries ("MHSTCI")	The Stage 1 AA was submitted to the MHSTCI for review on September 21, 2021 and entered onto the Ontario Public Register on September 22, 2021. The Stage 2 AA field surveys are ongoing, Enbridge Gas will receive archaeological clearance for the Stage 2 AA prior to construction start.
St. Clair Region Conservation Authority ("SCRCA")	Field studies are ongoing, Enbridge Gas will apply for permitting/approval in Summer, 2022.
Lambton County	In progress. Enbridge Gas will receive permits prior to pre-work and start of construction.
St. Clair Township	In progress. Enbridge Gas will receive permits prior to pre-work and start of construction.
Township of Dawn-Euphemia	In progress. Enbridge Gas will receive permits prior to pre-work and start of construction.
Landowner agreements for easements, temporary working space, and/or storage sites	Please see the response at Exhibit I.STAFF.15 a).
Third-party utility crossing agreements including Hydro One	In progress. Enbridge Gas will receive permits prior to pre-work and start of construction.


NPS-36 Dawn to Corunna Project Schedule
WBS / Task Name
2020
Dec
2021
2022
2023
2024
Jan Feb Mar Apr May June July Aug Sept Oct Nov Dec
Jan Feb Mar Apr May June July Aug Sep Oct Nov Dec
ENVIRONMENTAL
Environmental Report
Field surveys (species, arch, etc.)
REGULATORY
Prepare Evidances for OEB Filing
OEB 'Leave to Construct' Application
LAND & LAND RIGHTS
NPS 36 Pipeline Easements / Land Expropriation
ENGINEERING
Pipeline Engineering Surveys
Pipeline Engineering
Procurement, Permits, and Construction
Procurement
Permits
Construction
Tree Clearing
Clean up

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition ("SEC")

INTERROGATORY

Reference:

[A]

Question:

Please provide a copy of all materials provided to Enbridge Inc. and EGI's Board of Directors related to the proposed project.

Response

Please see Attachment 1 to this response.

Dawn to Corunna Project

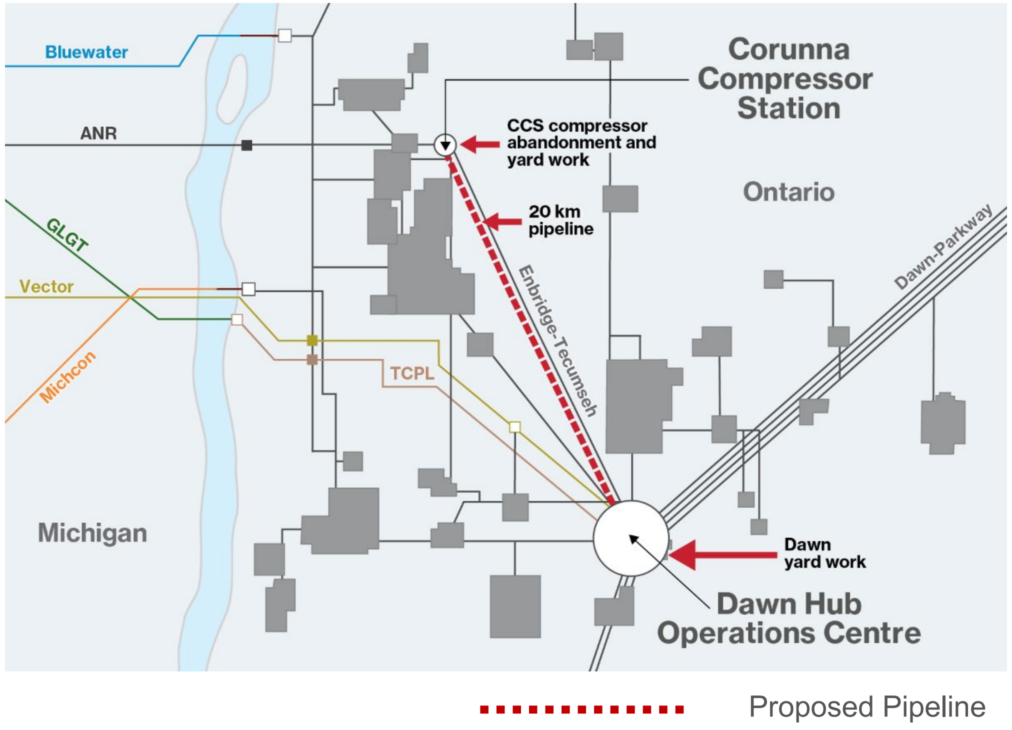
Board of Directors

October 26, 2021

Background

- The Corunna Compressor Station (CCS) has 11 reciprocating compressor units totalling 36,750 HP and range in installation date from 1964 to 1995.
- The project will retire and abandon 7 compressor units and build a ~20km Nominal Pipe Size (NPS) 36 pipeline from Dawn to CCS creating a third pipeline loop between these stations. The project maintains the same system deliverability by utilizing the new pipeline and operating existing Dawn compression.
- The main drivers are decreasing reliability and obsolescence based on failure frequency, lack of access to Original Equipment Manufacturer (OEM) parts, and health and safety risk due to density of equipment in a building. Currently, short-term mitigations are in place to reduce the safety risk to tolerable level.
- The pipeline solution is the lowest lifecycle cost alternative, reinforces the existing 30" pipelines installed in the 1970s and reduces the cost of future capital maintenance work.
- The project is expected to allocate 100% of capital to the regulated rate base, as the existing facilities being replaced have been included in the regulated business.

Project Map



Core replacement of end-of-life facilities fully recoverable under regulatory framework

ENBRIDGE

Scope	• <u>Pipeline</u>: Install ~20km NPS 36 pipeline between Dawn Compressor Station and CCS • <u>Tie-ins</u>: Header and valve connections at CCS and header and valve connections and filtration at Dawn • <u>Abandonment</u>: Abandonment of K701-K703, K705-K708 compressors and abandonment of Tecumseh Meter Runs at Dawn • Same system deliverability is maintained by sending higher pressure from Dawn on injection and delivering lower pressure to Dawn on withdrawal
Capex	• CAD $251 MM (including $2 MM of IDC and $45 MM of capitalized overhead)
Commercial Terms	• Regulated cost of service project per OEB's Incremental Capital Module ("ICM") in 2023. • In 2024 and subsequent years the project will be included in rate base and earn regulated return.
Key Dates	• Receive Enbridge Board approval (Nov 2021) • Submit Ontario Energy Board leave to construct application (Nov 2021) • Receive Ontario Energy Board approval (July 2022) • Begin expropriation (if required) (August 2022) • Commence construction pipeline and station work (Jan 2023) • In service (November 2023)
Capacity	Replaces existing system deliverability of 0.7 PJ/d

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- The project will address the critical infrastructure reliability, obsolescence and safety risks
  - Abandonment of 7 compressors ranging from 49 to 59 years of age addresses risk of obsolescence
  - Operational reliability of K701-703 compressor units declining with failure frequency greater than comparable new units
- Individual health & safety risk exceeds health & industry standard safety criteria based on:
  - Density of equipment in a given building; and presence of people and time in buildings. Several short-term mitigations have been implemented and a tracking mechanism was developed to help manage the risk
- Project improves long-term reliability that supports future investment at the Dawn hub
- Project provides the opportunity to put capital on low-risk regulated project providing reasonable regulated return

Project Scorecard

Low	Medium	High

Key Attribute	Rank	Considerations
Strategic Fit	High (green)	• Replacement of critical infrastructure supporting storage operations • Maintain reliable and safe operation while reinforcing the CCS to Dawn pipeline corridor
Commercial Risk	High (green)	• Regulated cost of service project
Financial Reward	High (green)	• Low risk regulated return
Ability to Execute	High (green)	• Low complexity; rural terrain • Limited permit requirements
ESG	Medium (yellow)	• Some emissions reduction with utilization of compression at Dawn[1] - aligned with future emission reduction plans • Significant reduction in personal safety risk

Project aligned with core business model enhancing reliability at the Dawn hub

[1] The same volume of gas will be injected and withdrawn from storage by using compression at Dawn versus CCS. The project will reduce annual emissions by ~0.5% relative to the current assets.

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Financial Evaluation

Project Description

- The revenue requirement for the total project is assumed as annual cost of service, with an allowed ROE of ~9% in 2023, ~8.9% for 2024-2028 and ~8.8% for each subsequent period.[1]
- Tax benefit of abandonment cost is kept by EGI during tolling period.
- Evaluation parameters include:
  - $251MM CAPEX (including IDC and overheads)
  - 40 year asset life
  - 64:36 debt to equity ratio
  - 3.7% cost of debt
  - 26.5% Tax Rate
  - Terminal value set to the book value of equity

Financial Outlook

in $MM	2021-23	2024	2025	2026	2027	2028
Equity Cash Flow	(82.2)	5.8	9.9	9.7	9.5	9.3
EBITDA	(11.1)	18.3	20.6	20.4	20.2	20.0
Earnings	3.8	7.7	7.7	7.5	7.3	7.1
DCF	4.3	13.9	14.0	13.8	13.6	13.4
D/EBITDA		8.5x	7.4x	7.3x	7.1x	7.0x
Annual ROE		8.9%	8.9%	8.9%	8.9%	8.9%

DCFROE	**9.2%**
EV/EBITDA	12.3x
ROCE (5yr avg.)	5.9%

Investment realizes a strong return from low risk cost of service investment

[1] Assumption reflects the current forecast of allowed ROE for 2024 and 2029 for EGI.

Risk Summary

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High | Medium | Low

Base Case DCFROE 9.2%

Risk	Mitigation	Assessment	Sensitivity	ΔDCFROE
Capital Cost • *Unanticipated cost overruns above ICM application capital* • *Increase in cost as class estimate is refined and route secured*	• Majority of Capital will not be deployed until Leave to Construct (LTC) approval from OEB, expected in Q3 2022 • Once approved, at rebasing prudently incurred capital (including overruns) is eligible for recovery		40% increase in capex over ICM application estimate	(0.2%)
Regulatory • *Cost Allocation –Risk that the OEB directs some other allocation of costs to the unregulated businesses.* • *Intervenors and/or OEB staff oppose the construction of the proposed facilities causing delayed OEB approval and/or unfavourable conditions of approval.* • *OEB may approve lower than forecasted Allowed ROE in future re-basing period*	• Filing Ernst & Young report on Unregulated Storage Cost Allocation or referring to EGI's prior filings. • Complete Integrated Resource Planning Assessment early and lead evidence on alternatives considered. • EGI is developing overall regulatory strategy for re-basing post the current settlement, and this project is part of the overall strategy		~25bps reduction to project allowed ROE rate	(0.3%)
Lands/Environment/Schedule • *9 month expropriation included in schedule; maximum historical duration is 13 months (4-6 month schedule delay factoring in winter construction)* • *Potential schedule risk based on Species at Risk (SAR) within the project area with permit approval taking up to 8 to 12 months*	• Early engagement with landowners and municipal stakeholders to obtain access agreement for pipeline installation • Successful negotiations with landowner groups (i.e. Canadian Association of Energy and Pipeline Landowner Associations) • Potential to increase construction crew size to reduce impact of the delay carried with increased cost • Impacts to rate recovery accruing to in-service delay will be managed through approved regulatory mechanisms • Early consultations were initiated with key agencies to streamline SAR application development; early land access critical to begin environmental assessments		Project in-service delayed by 6 months	(0.4%)
Net-Zero Target *Cost Required to meet net-zero from ISD*	• Emission costs are passed-through to customers		NA	NA

Recommendation

Management recommends that the Board of Directors of Enbridge Inc. (the "Board") (a) take no exception to, and (b) defer to the Board of Directors of Enbridge Gas Inc. (the "Corporation") with respect to, the approval of the following:

- Dawn to Corunna Project, as revised (the "Project"), including the authority of the Corporation and the officers of the Corporation to take all such action, and to cause the subsidiaries of the Corporation to take all such action, necessary or advisable to effectuate the Project consistent with the project materials provided to the Board (the "Project Memo");

Management recommends that the Board approve funding for the Project, including:

- A major capital appropriation of $251 million for the Project, including AIDC, for an aggregate capital expenditure for the Project not to exceed $251 million;
- A corresponding increase to the applicable budgets, to the extent necessary or appropriate; and
- Entry by Enbridge Inc. or its subsidiaries into such funding arrangements as may be required on terms as approved by the Executive Vice President & Chief Financial Officer or the Vice-President, Treasury & Enterprise Risk of Enbridge Inc.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition ("SEC")

INTERROGATORY

Reference:

[A]

Question:

Please provide a copy of any internal business case, or similar document, regarding the proposed project.

Response

Please see the response at Exhibit I.SEC.1 Attachment 1.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition ("SEC")

INTERROGATORY

Reference:

[B-1-1]

Question:

Please provide the forecast remaining net book value of the assets that EGI proposed to retire as part of this project.

Response

The net book value of the CCS compressor units proposed to be retired and abandoned as part of the Project is $0.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition ("SEC")

INTERROGATORY

Reference:

[B-1-1, p.11, para. 25]

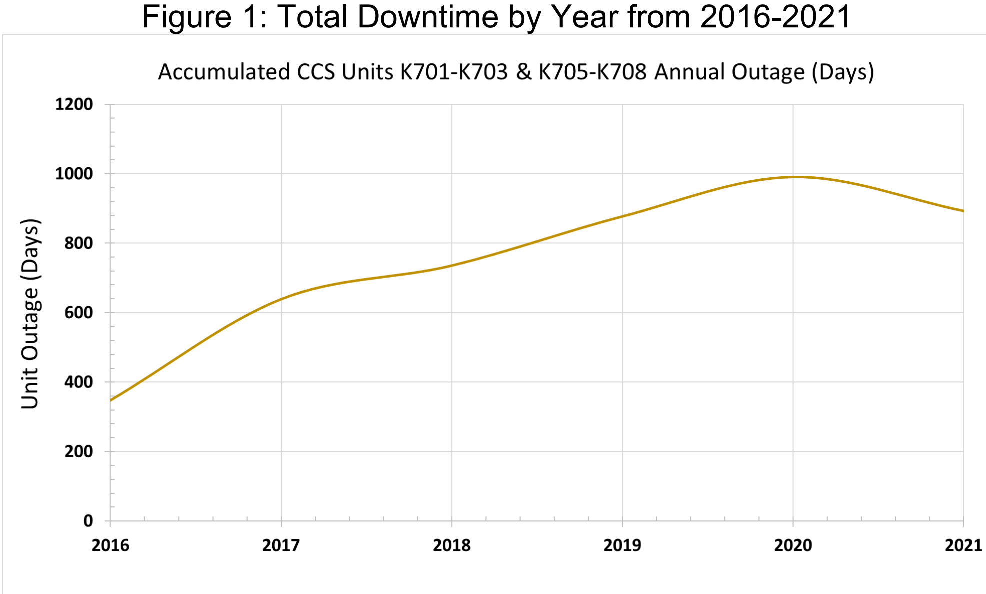
Question:

Please provide data or records showing continued and increasing compressor unit downtime, and long lead repair time related to the obsolescence and reliability issues of compressor units.

Response

Please see the response at Exhibit I.PP.5 a), for the data that underpins Figure 1 below. Figure 1 shows the total downtime for the CCS units K701-703 and K705-708 by year for the period 2016-2021.

Figure 1: Total Downtime by Year from 2016-2021



ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition ("SEC")

INTERROGATORY

Reference:

[B-1-1, p.14, para. 32]

Question:

Please provide data or records showing the number of design days that actually occurred in the past 10 years. Please also provide forecast for the occurrence of design days for the next 10 years.

Response

The Design Day heating degree day for Union South Rate Zone is 43.1 HDD as measured at the London Airport weather station.

In the past 10 years a 43.1 HDD was experienced on February 15, 2015 (equaled); and a 43.0 HDD was experienced on January 30, 2019 (0.1 HDD less).

Future extreme cold weather events cannot be predicted and as such, the Company does not utilize a forecast of the occurrence of design days to plan/design its systems. Instead, Enbridge Gas relies on historical temperature data.

ENBRIDGE GAS INC.

Answer to Interrogatory from School Energy Coalition (“SEC”)

INTERROGATORY

Reference:

[B-1-1, p.14, para. 32]

Question:

Please estimate the time that it will take for replacement to be procured to cover system shortfall.

Response

The Company cannot provide a specific estimate of the time it may take to procure replacement supply to cover a potential system shortfall as a result of a failed CCS compressor unit. Timing may vary significantly depending upon various factors outside of Enbridge Gas’s control which include, but are not limited to:

i) the timing of the compressor failure(s) in relation to NAESB nomination windows and availability of counterparty representatives to execute a transaction (for example, failures occurring late in the day, on weekends, or on holidays will generally result in longer timeframes for procurement of replacement supplies);
ii) the current natural gas market supply conditions at the time of the failure, which dictate the availability of supply;
iii) the demand on Enbridge Gas’s systems, which determines the volume of replacement supply that is required (higher volumes would generally take longer to procure and have higher risk of being unavailable on short notice); and
iv) the nature of the equipment failure such that the Company is able to reliably estimate the length of the resulting outage and therefore the term in which replacement supply will be required.

Depending on the above factors, the timeframe required to procure adequate replacement supplies may range from a few hours to days.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition ("SEC")

INTERROGATORY

Reference:

[B-1-1, p.17, para. 36]

Question:

Please provide supporting details for the estimated $16 million savings in planned maintenance capital expenditures from 2023 – 2032, as result of the retirement of the compressor units.

Response

Please see the response at Exhibit I.STAFF.10 a).

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition ("SEC")

INTERROGATORY

Reference:

[B-1-1, p.18, para. 40]

Question:

Please provide justifications to the assumption of 2,000 run hours per year. Please also provide the actual run hours per year for each of the compressors for the past 5 years.

Response

Table shows the operating hours for each of the 11 compressor units for the period 2013-2021. The overall average run hours for the past 5 years (2017-2021) is 1,751 hours based on this data set.

Table 1: Average Run Hours between 2013-2021

Corunna Units	Online (Run Hours)									
	2013	2014	2015	2016	2017	2018	2019	2020	2021	Average
K701	1154	741	1067	887	334	913	107			271
K702	433	626	361	299	1062	905	614	825	912	864
K703	38	150	2016	477	139	1520	1135	2088	1376	1252
K704	3818	3188	3456	2141	2250	2265	1896	2809	1882	2220
K705	3340	4523	2705	1935	3046	1243	102	3195	3029	2123
K706	2622	2782	2661	1332	1235	1176	4685	2015	2460	2314
K707	3633	1591	2353	2425	4416	3384	3927		662	2478
K708	2388	3414	4759	2680	3566	3687	3335	1504	2319	2882
K709	872	2418	1527	430	1065	629	1443	673	1270	1016
K710	681	217	848	476	751	1453	1569	1446	799	1203
K711	2334	4124	2907	2507	2911	3208	2096	2752	2244	2642
					Overall Average 2017-2021					1751

As stated in Exhibit B, the Asset Health Review ("AHR") was performed in 2018 as part of the RAM Study for the CCS. Subject matter experts at the time of the AHR's development recommended the assumption of 2,000 run hours per year based on the average actuals for the 2013-2017 period. As shown in Table 2 below, the average run hours between 2013-2017 was 1,929 hours, which was rounded up to 2,000 for the purposes of the RAM.

Table 2: Average Run Hours between 2013-2017

Corunna Units	Online (Run Hours)					
	2013	2014	2015	2016	2017	Average
K701	1154	741	1067	887	334	837
K702	433	626	361	299	1062	556
K703	38	150	2016	477	139	564
K704	3818	3188	3456	2141	2250	2971
K705	3340	4523	2705	1935	3046	3110
K706	2622	2782	2661	1332	1235	2126
K707	3633	1591	2353	2425	4416	2883
K708	2388	3414	4759	2680	3566	3361
K709	872	2418	1527	430	1065	1262
K710	681	217	848	476	751	595
K711	2334	4124	2907	2507	2911	2957
	Overall Average 2013-2017					**1929**

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition ("SEC")

INTERROGATORY

Reference:

[B-1-1, p.22, para. 46]

Question:

Please confirm if there were any other major repairs, comparable to the 2018 K705 crankshaft repair that occurred to any of the K701-K703 and K705-K708 compressors in the past 10 years. If yes, please provide cost details of the repairs.

Response

Table 1 below summarizes major repair events that occurred between 2012-2022 that were 90 days or more in duration. Please see the response at Exhibit I.PP.5 b), for capital cost details of the repairs.

As shown in Table 1 below, unit K701 has been down since 2018, for more detail on the foundation damage experienced on unit K701 please see the response at Exhibit I.PP.5 a).

Table 1

Unit	Title[1]	Start date	End date	Downtime (days)
K710	BR - Main Bearing Failure	3/12/2014	7/10/2014	120
K708	EV - Frame Alignment and Re-gout	9/10/2014	8/18/2015	342
K701	CM - Replaced rollers and cams	9/10/2014	2/3/2015	146
K711	BR - Bent Crankshaft	3/16/2015	6/26/2015	102
K705	CP -K705 Engine Block Replacement	09/05/2016	01/20/2017	138
K703	CM - Crankshaft Repair	05/01/2017	08/17/2017	109
K706	CP - Engine Block Foundation Replacement	07/04/2017	01/22/2018	203
K706	CM/CP - Cam Upgrade and Laser Alignment	03/08/2018	06/26/2018	111
K705	CP - Crank Repair (Replacement)	07/11/2018	09/18/2019	435
K701	CM - Crank Misalignment due to Foundation Damage (1)	12/06/2018	Ongoing	1,268 (2)
K705	CM - Discharge Valve Gas Leak	01/24/2019	06/10/2019	138
K708	CP - Engine Block Foundation Replacement	10/09/2019	04/25/2020	200
K708	CM - Water Pump Chain Replacement	10/11/2019	04/14/2020	187
K707	BR - Liner Replacement	01/15/2020	10/08/2020	268
K707	CM - Gas Cooler Motor Failure	07/08/2020	01/12/2021	189
K707	CP - Engine Block Foundation Replacement	10/13/2020	04/22/2021	192
K701	CM - Gate Valve Leak	01/13/2021	06/15/2021	154
K702	BR - Engine Failure	09/13/2021	01/18/2022	128

NOTES:
(1) Unit left unavailable with option to operate as last-on.
(2) As of May 26, 2022.

[1] BR = Breakdown; EV = Event; CM = Corrective Maintenance; CP = Capital Project

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition ("SEC")

INTERROGATORY

Reference:

[B-1-1, p.23, para. 47]

Question:

Please provide all reports and materials consulted and produced for the QRA referenced therein.

Response

Please see the response at Exhibit I.CME.1, Attachment 1.

Materials and references used in the QRA include:

- Corunna Compressor Station (CCS) Flow Diagram Main Gas Systems – Refer to QRA Report page 7.
- CCS Piping and Instrumentation Diagram (P&ID) – Refer to QRA Report Section 6.2, page 20.
- CCS Shutdown-Alarm Key – Refer to QRA Report Section 2.3, page 9.
- Compressor run hours record and operating conditions – Refer to QRA Report Section 5.4, page 15, and Section 2.2, page 8.
- DNV GL's Failure Frequency Guidance – Refer to QRA Report Section 6.3, page 21.
- Risk Assessment Data Directory – Process Release Frequencies" report 434-01, International Association of Oil & Gas Producers (IOGP) 2019 – Refer to QRA Report Section 6.3, page 21, and Section 6.4, page 24.
- 10th Report of the European Gas Pipeline Incident Data Group (EGIG) – Refer to QRA Report Section 6.4, page 24.
- Company internal data on occupancy and manning at the CCS – Refer to QRA Report Section 8.1, page 51.
- Enbridge Framework Standard – Risk Management – Refer to QRA Report Section 4, page 12.

- CAN/CSA-Z767-17 Process Safety Management – Refer to QRA Report Section 9.1, page 57.
- Risk-based Inspection API Recommended Practice 580. 3rd Ed. (2016). Washington, DC: American Petroleum Institute – Refer to QRA Report Section 6.3, page 23.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition ("SEC")

INTERROGATORY

Reference:

[B-1-1, p.26, para. 52]

Question:

Please explain whether there is an industry-wide trend of reducing the average number of compressors at compression centres in order to mitigate safety risks.

Response

Enbridge Gas is not aware of an industry-wide trend of reducing the number of compressors at compression centres in operation solely to mitigate safety risks.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition ("SEC")

INTERROGATORY

Reference:

[B-1-1, Attachment 2, p.5, 7]

Question:

SEC notes that K704 and K711 (HP) are responsible for 99.56% of the total gas injection shortfall and K710 and K709 (LP) are responsible for 86.77% of the total gas withdrawal shortfall. Has EGI considered the option of only replacing the K704 and K711 (HP), and the K710 and K709 (LP) compressors capacity with another method of compression? Alternatively, has EGI considered pre-emptively replacing high risk parts of these four compressor units?

Response

Enbridge Gas has not considered this alternative as this does not address the obsolescence, reliability and safety risks driving the need to retire K701-703, K705-708. Further, K704, K709, K710 and K711 provide a specific operational fit as part of the CCS injection and withdrawal seasonal cycles and cannot be replaced as part of the Project. Please see the response at Exhibit I.STAFF.11 a), for further discussion of operational fit.

Yes, the Company plans to pre-emptively replace the K704 foundation (please see the response to Exhibit I.FRPO.15 for further detail). The Company is able to safely and reliably operate these units for the foreseeable future, however, when these units are no longer safe or reliable to operate they will need to be replaced with compression at CCS.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition ("SEC")

INTERROGATORY

Reference:

[C-1-1]

Question:

EGI assessed alternatives based on a scenario where it retires and abandons all 7 CCS compressor units, without the construction of a new NPS 36 pipeline and related work. Please explain why EGI did not model or consider any alternatives that would involve retirement of only some of the 7 compressor units.

Response

Enbridge Gas did consider an alternative that retires less than 7 compressors. As outlined in Exhibit C, the Repair + Replace Alternative considers retiring only 3 compressor units (K701 – K703) and constructing an NPS 20 pipeline from CCS to Dawn to replace the equivalent capacity at a capital cost of $160 million and an NPV of ($208 million).[1] However, this alternative does not address the shortfall risk of having to procure gas supply for multiple unit outages as a result of continued downtime for maintenance, repairs and unplanned events. Further, it does not address the imminent need to resolve the obsolescence, declining reliability and increasing safety risks to Company personnel underlying the proposed Project Application.[2] As it is uneconomic and does not resolve the underlying system constraints driving the need for the Project this alternative has been deemed to be infeasible.

The Company has analyzed other alternatives that could be combined with the Repair + Replace Alternative and found that they were uneconomic and similarly infeasible.

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[1] Exhibit C, Tab 1, Schedule 1, Paras 42-45. This alternative is less economic than the proposed Project due to the incremental O&M costs required to maintain CCS units K705-K708.
[2] Exhibit B, Tab 1, Schedule 1, p. 29: Short-term mitigations do not represent a solution to the obsolescence, reliability and safety risks presented at CCS and ultimately do not address the Project need.

Additional Phased-In Repair + Replace Alternatives

All additional alternatives assessed are significantly more expensive than the Project. This is because significant cost savings are realized through economies of scale by replacing all 7 compressor units at one time with an NPS 36 pipeline. In addition to the cost of the Repair + Replace Alternative (NPS 20 pipeline replacing K701-703 at a capital cost of $160 million) and assuming that K705-708 were replaced or "phased-in" at some point in the near future after the Repair + Replace Alternative is constructed, this alternative would require either:

- **A Taurus 70 compressor:** This would be built at CCS at a new location on the east side[3] of Tecumseh Road with an estimated capital cost of $161 million in 2023 dollars, totaling $321 million when combined with the Repair + Replace alternative cost.

- **A Spartan e90 compressor:** This would be built at CCS at a new location on the east side[3] of Tecumseh Road with an estimated capital cost of $169 million in 2023 dollars, totaling $329 million when combined with the Repair + Replace alternative cost.

- **An additional NPS 30 pipeline:** This pipeline would run from the CCS to Dawn with capital cost estimated at approximately $140 million in 2023 dollars, totaling $300 million with the Repair + Replace alternative cost.

Any new Taurus 70 or Spartan e90 compressor built would be installed on the east side of Tecumseh Road on greenfield property owned by the Company as there is not sufficient room within the existing CCS yard for new compression. Installing a single 10,000 – 12,000 HP compressor (Taurus 70, Spartan e90 EMD paired with Solar C45 compressor) as part of a phased-in approach would leave the Company with a single point of failure without LCU in the event the single unit goes down putting EGD rate zone customers at increased risk of experiencing a shortfall in the future (especially under design day conditions).[4]

Update to Electric Motor Drive Compression Alternative Analysis

For the Company to further consider the Electric Drive Motor Compression Alternative, it would need to assess the reliability of the electric grid infrastructure and costs to install

[3] Enbridge Gas incorrectly noted this as the west side of the existing station within Exhibit C.

[4] The Company considered this for each of the Natural Gas Fired Compression and Electric Drive Motor Compression alternatives which include 2 units on the east side of the road. Both units are required to be utilized on design day and are backed up by K711, which does not provide full redundancy should 1 of the 2 units not be available.

backup power generation in the event hydro service is interrupted. Existing backup power at CCS today is only sized to provide power supply to controls and supply motor loads for cooling fans, pumps. Backup power for a 10 MW EMD alternative would come at an incremental cost that is not included in the current estimate, making it even more uneconomic. In addition, building the NPS 36 pipeline and utilizing Dawn horsepower provides a backup power benefit compared to the CCS compression alternatives as the Dawn Operations Centre has a Power Generation system that provides site-wide backup power capabilities to maintain the operation in the event of loss of utility power. The Power Generation system has the capability to operate in parallel with the utility grid, disconnected from the grid (self-generated power) and includes an automated microgrid black starting capability that significantly enhances power system reliability for critical infrastructure.

The Company assumed a hydro rate of $0.148/kWh in O&M costs for the Electric Motor Drive Compression alternative based existing rates at the Parkway Compressor Station.[5] Upon further review, in the assessment of the Electric Motor Drive Compression alternative, the Company has not accounted for all global adjustment and delivery charges and should be using a hydro rate of $0.18/kWh. This adjustment in hydro rate increases the NPV of the EMD alternative from ($270 million) to ($289 million).

Summary

After this additional analysis, the proposed Project remains the most cost-effective and reliable alternative to address the Project need and serve the firm demands of Enbridge Gas's customers.

In summary, to phase-in the retirement of the 7 CCS compressor units would cost between $300 -$333 million (see Table 1) compared to the Project at $206 million and would expose ratepayers to increase risk of shortfall. A gradual phase in and rebuild of compression is not cost-effective and does not address the imminent need to address the obsolescence, reliability and safety issues at CCS. Further, as displayed in table 4.6 of the RAM which indicates an increasing frequency of failures for these units, Enbridge Gas anticipates that the pace of failure and replacement under such a strategy could be rapid and would be somewhat out of the Company's, ratepayers and the OEB's control.

[5] Exhibit C, Tab 1, Schedule 1, Table 2 and Exhibit C, Tab 1 Schedule 1, p. 19

Table 1

Alternative	Capacity (TJ/d)	Capital Cost ($Million)	O&M Cost ($Million)	Unitized Cost ($Million/TJ/d)	NPV ($Million)
Non-Facility Alternatives					
Commercial Alternative + ETEE + Reduced Facilities	680	191[1]	3,936 – 3,967	6.13 – 6.18	N/A
Facility Alternatives					
Natural Gas Fired Compression	680	211	3.88/yr	0.31	(212)
Electric Motor Drive Compression	680	217	6.84/yr	0.32	(270)
EMD Compression with Update O&M	680	217	8.07/yr	0.32	(289)
NPS 36 Pipeline	680	206	2.99/yr	0.30	(200)
LNG Storage	680	541	2.62/yr	0.80	N/A
Repair Alternative					
Repair + Replace*	680	160	5.33/yr	0.24	(208)
Phased-in Facility Alternatives					
Repair + Replace + Taurus 70	680	321			N/A
Repair + Replace + Spartan e90 EMD	680	329			N/A
Repair + Replace + NPS 30	680	300			N/A

NOTES:

[1] In Exhibit C, Tab 1, Schedule 1, p. 1, Table 2 the Commercial + ETEE + Reduced Facilities alternative was mistakenly listed at $235MM which is the loaded cost of the alternative. All other capital costs are provided as unloaded costs. This alternative remains $15 million less than the NPS 36 Pipeline (the Project) and is updated to reflect an unloaded cost of $191 million.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition ("SEC")

INTERROGATORY

Reference:

[C-1-1, Attachment 1]

Question:

Please provide a copy of the model used to calculate the NPV of the proposed project and the considered alternatives, with formulas intact. Please include details and all assumptions made.

Response

The Excel model used to calculate the NPV of the Project, the natural gas fired compression alternative, and the electric drive motor compression alternative has been included as Attachment 1 to this response.

Table 1 below summarizes the major assumptions used in the NPV analysis. For further details on certain assumptions used, please refer to the response at Exhibit I.ED.12 a).

Table 1

Dawn to Corunna Replacement Project – Listing of Key NPV Parameters and Assumptions	
Project Time Horizon	40 years commencing at project in-service date of November 1, 2023
Discount Rate	Incremental after-tax weighted average cost of capital of 4.92%
Operating and Maintenance Expense	Estimated incremental cost
Annual Inflation on O&M Expense	2.00%
Municipal Tax	Estimated incremental cost
Annual Inflation on Municipal Tax	1.80%
Income Tax Rate	26.50%
Capital Cost Allowance	Current Canada Revenue Agency approved CCA rates

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition ("SEC")

INTERROGATORY

Reference:

[C-1-1, Attachment 2, p.61]

Question:

Please confirm if ICF has consulted any other source of storage unit rates other than those provided on p.61. If yes, please provide them, if not, please explain why not.

Response

Enbridge Gas provided ICF confidential storage offers made by third parties to Enbridge Gas in response to storage RFPs. This storage pricing data was included in ICF's regression analysis of the value of storage based on the space and deliverability characteristics in each contract shown in Exhibit C, Tab1, Schedule1, Attachment 2, p. 41.

Enbridge Gas also provided ICF the in-franchise storage cost of service (2019), including fixed storage costs (including the unit rate of Enbridge Gas storage at Dawn, equivalent to "contracted" storage) and variable storage costs.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition ("SEC")

INTERROGATORY

Reference:

[C-1-1, Attachment 2, p.8]

Question:

If market-based storage capacity cannot be made available in a timely manner, please explain if market rate storage option could be adopted in long term if EGI phases out old compressor units at CCS gradually over years.

Response

As explained in the response at Exhibit I.SEC.13, a phase out of existing compressor units at CCS is not a cost-effective or feasible solution to address the imminent need of obsolescence, declining reliability and increasing safety risks.

In Exhibit C, Tab 1, Schedule 1, Attachment 2, p. 8, ICF outlined challenges that the Company could experience with acquiring market-based storage capacity in a timely manner:

> While in theory, there is sufficient market-based storage capacity to offset the storage capabilities that would be lost due to the retirement of the Corunna compressor capacity, most if not all of the available storage capacity is currently contracted, hence Enbridge would be required to wait until current contracts with other storage users expire, and then bid higher prices than current market participants are willing to pay in order to contract for the rights to use this storage, or make sufficiently attractive offers to other storage contract holders to obtain the rights to storage capacity prior to the expiration of current contracts.

It is important to note that Enbridge Gas may need to access storage markets beyond Dawn to replace all lost storage capacity resulting from the retirement of the CCS units. In this scenario, transportation capacity would also be required to connect the replacement storage capacity to Dawn. The addition of transportation capacity would create further availability/reliability concerns and increase the total cost of the market-based storage alternative.

Despite the identified risks associated with availability of market-based storage, market-based storage was evaluated as a potential alternative for meeting the Project need.[1] This evaluation concluded that the cost of using a market-based storage alternative over a 40-year time horizon would likely range between $519 - $556 million dollars more expensive than the Project, making this alternative unreasonably uneconomic.

[1] Exhibit C, Tab 1, Schedule 1, paragraphs 13 – 16,

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition ("SEC")

INTERROGATORY

Reference:

[D-1-1, p.1, Table 1] With respect to project costs:

Question:

a) Please explain in detail what aspects are considered "pipeline costs" as opposed to "ancillary costs".
b) Please provide the date in which the cost estimate included in Table 1 was derived.
c) Please explain what the expected impact the current inflationary environment will have on the proposed costs and how EGI plans to mitigate the impact.

Response

a) The "pipeline costs" column in Table 1 captures all costs related to the NPS 36 pipeline installation ("TR 7"), including: engineering design, regulatory, environmental studies, archeological investigations, environmental and municipal permits, land right acquisition for right of way, materials (including pipe, fittings and valves), construction management, and general contractor.

   The "ancillary costs" column in Table 1 includes all station construction and compressor abandonment costs estimated for the Project, including: engineering design, environmental studies, environmental and municipal permits, materials (including station piping, valves, actuators, fittings, and flanges), buildings, instrumentation, measurement electrical power and fencing.

b) The estimated project costs included in Table 1 were derived in November 2021.

c) The current cost estimate includes an allocation for inflation of 2% of the total project cost estimate. To mitigate impacts of inflation, Enbridge Gas will procure resources (land, material and labour) required for the Project through its internal Supply Chain department by requesting bids for resources and selecting best value from vendors that meet Project objectives. For areas where there are typical vendors that support construction (survey, NDE, inspection) existing contracts will be utilized that have established pricing.

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition ("SEC")

INTERROGATORY

Reference:

[D-1-1] With respect to the allocation of costs:

Question:

a) Please explain how EGI currently categorizes and allocates, for cost allocation purposes, the costs of the CCS compressor units that it plans to retire as part of this application, and how that may or may not be different than the proposed new pipeline.
b) Please confirm that the CCS compressor units that EGI plans to retire currently serve both utility and non-utility storage operations.
c) If part (b) is confirmed, please explain how those costs are currently allocated between EGI's utility and non-utility operations.
d) Please confirm that the new NPS 36 pipe will service both utility and non-utility storage operations.
e) If part (d) is confirmed, please explain how EGI plans to allocate costs between utility and non-utility operations

Response

a) & e)
Enbridge Gas classifies the costs of the CCS compressor units to storage transmission and compression and allocates the costs to rate classes in proportion to design day demand.

The question of cost allocation associated with the Project is not at issue as part of the current proceeding and is more appropriately dealt with as part of Enbridge Gas's forthcoming 2024 rate rebasing application.

b) Confirmed.

c) The CCS compressor units were used to support Enbridge Gas Distribution Inc.'s ("EGD") utility business prior to the OEB's Natural Gas Electricity Interface Review ("NGEIR") (EB-2005-0551). Accordingly, for rate-making purposes, the CCS compressor units are part of Enbridge Gas's utility operations.

d) Confirmed.

In the NGEIR Decision with Reasons, the OEB accepted that Enbridge Gas (EGD and Union) made investments in both utility and non-utility storage assets:[1]

> In the Board's view, Union's existing storage assets are, in substance, a combination of "utility assets" required to serve Union's in-franchise distribution customers and "non-utility assets" that are not required for regulated utility operations and that are sold in the competitive storage market.[2]

Post-NGIER, Enbridge Gas (EGD and Union) has invested in both the development market-based storage through the addition of new facilities paid for by the non-utility business[3] as well as investments in maintenance of facilities at the Dawn Hub to ensure safe and reliable storage operations paid for by the utility business.

Due to the integrated nature of the Dawn Hub, and as the Dawn Hub has grown over time, utility and non-utility space and molecules are inherently interconnected and cannot be separated operationally. As such, the Project will serve both utility and non-utility operations.

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[1] EB-2005-0551, Decision with Reasons, November 7, 2006, P. 82.
[2] Union had developed almost 18 Bcf of capacity through greenfield developments from 1999-2007, when the NGEIR Decision was issued by the OEB.
[3] These facilities include wells, pipelines and compressors within the integrated storage system at the Dawn Hub.

ENBRIDGE GAS INC.

Answer to Interrogatory from
TransCanada Pipelines Limited ("TCPL")

INTERROGATORY

Reference:

i. Exhibit B, Tab 1, Schedule 1, Page 3 of 31, Paragraph 6.
ii. EB-2021-0148, 2022 Rates (Phase 2) Application, Exhibit B, Tab 2, Schedule 1, Appendix G, Page 4 of 4.

Preamble:

In Reference i), EGI states that if the Dawn to Corunna Replacement Project (the Project) meets the criteria for rate recovery through the Incremental Capital Module (ICM) mechanism then EGI may file an ICM request for cost recovery as part of EGI's 2023 Rates (Phase 2) application.

In Reference ii), EGI provides a table showing the Derivation of 2022 Incremental Capital Module Rates by Rate Class, including the ICM Revenue Requirement, Forecast Usage, and the resulting ICM Rate.

Question:

a) If the Project is approved and is found to be fully eligible for ICM treatment, please confirm whether EGI would expect an ICM rate rider to apply to Rate 332, Rate M12, Rate M12-X, or Rate C1 rate classes for cost recovery associated with the Project.

b) If EGI expects an ICM rate rider to apply to any of the rate classes identified in a), please quantify the ICM rate riders that EGI currently anticipates would apply to such rate classes by providing a table in similar form as that provided in Reference ii). Please list all assumptions made in the analysis.

c) If the Project is approved but is not found to be eligible for ICM treatment, please explain how the costs associated with the Project would be treated by EGI and how such treatment could impact the rates paid by customers, including the rate classes identified in a).

<u>Response</u>

a) b) & c)
The Company will not be seeking ICM treatment for the Project.

The issues of cost allocation associated with the Project is not at issue as part of the current proceeding and is more appropriately dealt with as part of Enbridge Gas's forthcoming 2024 rate rebasing application.

ENBRIDGE GAS INC.

Answer to Interrogatory from
TransCanada Pipelines Limited ("TCPL")

INTERROGATORY

Reference:

i. Exhibit B, Tab 1, Schedule 1, Page 6 of 31, Paragraph 15 and 16.
ii. Exhibit B, Tab 1, Schedule 1, Page 8 of 31, Paragraph 18.
iii. Exhibit B, Tab 1, Schedule 1, Page 7 of 31, Figure 2.

Preamble:

In Reference i), EGI describes how the Corunna Compressor Station (CCS) is a part of the Dawn Hub which connects to transmission pipelines that transport gas from storage to downstream markets. EGI also describes the storage pools and storage pool pipelines served by the CCS.

In Reference ii), EGI describes the existing NPS 30 transmission pipelines known as TR1 and TR2 which connect the CCS to the Dawn Hub Operations Centre.
In Reference iii), EGI shows a map of the Dawn Hub and Storage Facilities including interconnected pipelines upstream and downstream of the facilities.

Question:

a) Do any of the upstream pipelines shown in Reference iii) (i.e., Bluewater, ANR, GLGT, Great Lakes Canada, Vector, Michcon, Panhandle) connect to or serve the CCS facility either directly or indirectly, without first delivering to the Dawn Hub Operations Centre? If so, please provide details of such upstream pipeline connections to the CCS, including the connection sizes and capacities, and explain how the CCS is served by these pipelines.

b) If approved and put into service as applied for, how will the Project affect the capacities, throughput or operations of the storage pool pipelines, the TR1 or TR2 NPS 30 pipelines, the Sarnia Industrial Line (SIL), each of the upstream pipelines identified in a), or the Dawn-Parkway transmission system? Please explain and quantify any such capacity, throughput, pressure, receipt and delivery, or other operational effects.

c) Please provide a table quantifying the monthly gas flows into and out of each of the CCS and the Dawn Hub Operations Centre since 2018 up to March 2022.

d) Please explain whether EGI expects the monthly gas flows into and out of each of the CCS and the Dawn Hub Operations Centre to be impacted as a result of the Project. If monthly flow impacts are expected, please quantify such impacts in a similar table as provided for in c) and explain the reasons for the impacts.

<u>Response</u>

a) The ANR pipeline indirectly connects to the CCS. The ANR pipeline connects to the NPS 24 Link pipeline owned by NGTL ("Niagara Gas Transmission Limited"). Natural gas flowing on the Link pipeline is delivered to the discharge side of the CCS and flows to Dawn through TR1 and TR2. The Link pipeline does not serve the CCS and has an import capacity of 190 TJ/d.

   The Vector pipeline indirectly connections to CCS at the Vector-Sombra Interconnect at the Sombra Compressor Station. The Vector Sombra-Interconnect is an NPS 16 pipeline with an import capacity of 222 TJ/d and an export capacity of 22 TJ/d.

b) The Project will not have any impact on the capacity of the storage pool pipelines, TR1 or TR2. TR1 and TR2 will continue to be an important connection between CCS and Dawn following the construction of the Project.

   The operational impact of the Project on TR1 and TR2 is discussed in Exhibit C, Tab 1, Schedule 1, p. 24. The proposed station modifications at Dawn and CCS affect the receipt and delivery pressures at Dawn. Currently, deliveries to Dawn from the CCS reach a maximum pressure of 4,826 kPa. The proposed station modifications will allow for delivery pressures ranging from 1,379 kPa – 6,160 kPa. Gas leaving Dawn and flowing into TR1 and TR2 is currently limited by the Maximum Operating Pressure ("MOP") of TR1 (6,446 kPa). The proposed station modifications will allow for delivery pressures from Dawn of up 9,307 kPa on TR7.

   The project will not have any impact on any of the upstream pipelines discussed in part a), the Sarnia Industrial Line ("SIL"), or the Dawn-Parkway system.

c) Please see Attachment 1.

d) Enbridge Gas does not expect any material change to monthly gas flows into or out of the CCS and Dawn to occur as a result the Project. Gas flows into and out of the

CCS are required to fill and empty the storage pools connected to the CCS. The capacity of these pools is not impacted by the Project.

Units 10^3m^3

Year	Month	Dawn Parkway Delivery	Dawn Parkway Receipt	Great Lakes Receipt	Great Lakes Delivery	Vector Receipt	Vector Delivery	Bluewater Receipt	Bluewater Delivery
2018	1	3,455,776	0	857,069	0	896,747	0	74,814	0
	2	2,350,784	0	769,048	0	670,391	0	65,083	0
	3	2,264,845	0	606,029	0	643,016	0	83,086	0
	4	1,817,577	0	832,481	0	640,590	0	47,785	0
	5	15,873	145,291	602,617	0	160,805	0	6,782	0
	6	10,456	231,965	584,894	0	525,756	0	61	0
	7	115,698	99,233	691,775	0	617,931	0	25	0
	8	167,128	119,353	737,506	0	836,266	0	0	0
	9	48,524	128,362	657,655	0	842,786	0	0	0
	10	715,260	8,527	478,373	0	639,716	0	0	0
	11	2,014,429	0	679,253	0	1,181,504	0	9,129	0
	12	2,669,133	0	864,111	0	1,195,703	0	38,687	0
2019	1	3,480,701	0	580,269	0	910,853	0	66,401	0
	2	3,149,825	0	429,315	0	1,066,860	0	50,854	0
	3	2,634,832	0	577,926	0	1,051,084	0	40,376	0
	4	1,109,693	0	557,070	0	719,161	0	12,223	0
	5	312,255	58,302	599,907	0	689,782	0	10,489	0
	6	0	273,777	531,991	0	579,864	0	360	0
	7	85,696	85,617	440,789	0	622,918	0	0	0
	8	76,361	129,455	582,429	0	905,940	0	0	0
	9	5,012	233,806	428,820	0	863,826	0	12	0
	10	328,976	7,402	112,706	0	712,819	0	0	0
	11	2,034,747	0	574,456	0	1,109,495	0	4,916	0
	12	2,833,873	0	893,751	0	1,409,480	0	42,702	0
2020	1	2,834,692	0	434,947	0	1,158,232	0	49,394	0
	2	2,761,896	0	472,837	0	842,801	0	14,959	0
	3	1,728,930	0	498,090	0	952,156	0	54,326	0
	4	984,063	0	413,133	0	715,351	0	1,254	0
	5	276,882	123,947	403,534	0	640,791	0	-216	0
	6	5,789	191,389	388,103	0	641,995	0	-1,337	0
	7	127,365	22,654	447,240	0	722,635	0	0	0
	8	66,103	122,342	256,376	0	399,040	0	0	0
	9	10,827	234,523	290,922	0	580,816	0	1	0
	10	563,593	0	262,518	0	652,109	0	0	0
	11	1,283,402	0	431,083	0	878,570	0	14,047	0
	12	2,592,648	0	650,295	0	933,648	0	13,103	0
2021	1	3,009,488	0	608,944	0	900,182	0	30,048	0
	2	3,343,309	0	418,405	0	676,282	0	51,521	0
	3	1,981,921	0	725,516	0	1,122,409	0	1,500	0
	4	729,746	11,714	545,440	0	733,026	0	0	0
	5	220,258	112,179	443,624	0	726,378	0	0	0
	6	88,184	172,809	501,211	0	626,438	0	4	0
	7	88,974	90,358	559,649	0	520,956	0	0	0
	8	221,343	71,227	606,461	0	570,448	0	0	0
	9	18,382	156,500	660,544	0	576,943	0	0	0
	10	250,122	53,020	532,493	0	272,604	0	0	0
	11	1,743,642	0	691,345	0	1,037,255	0	0	0
	12	2,555,436	0	884,487	0	1,294,816	0	20,785	0
2022	1	4,015,664	0	398,465	0	907,807	0	28,807	0
	2	3,158,081	0	547,078	0	805,348	0	210	0
	3	2,401,296	0	935,562	0	1,210,329	0	15,004	0

Ojibway Receipt	Ojibway Delivery	ANR Receipt	ANR Delivery	Michcon Receipt	Michcon Delivery	CCS Receipt	CCS Delivery
94,390	0	77,248	0	118,944	0	0	674,257
96,196	0	67,608	0	92,650	0	0	302,777
78,290	0	66,443	0	75,736	0	0	721,691
83,761	0	0	0	73,879	0	0	280,606
54,757	0	0	0	74,287	0	382,184	0
53,304	0	0	0	70,115	0	521,526	0
46,993	0	0	0	63,773	0	519,046	0
6,575	0	0	0	67,464	0	470,896	0
68,931	0	0	0	67,264	0	440,762	0
80,289	0	0	0	78,828	0	170,048	0
104,185	0	90,958	0	151,089	0	0	355,986
109,624	0	72,931	0	161,009	0	0	315,780
107,984	0	79,854	0	157,315	0	0	899,881
96,788	0	61,252	0	143,040	0	0	706,926
108,518	0	68,012	0	144,644	0	0	659,256
89,353	0	0	0	119,288	0	24,534	0
57,373	0	0	0	115,767	0	395,090	0
74,465	0	0	0	103,935	0	457,637	0
74,732	0	0	0	111,305	0	483,398	0
52,100	0	0	0	107,581	0	530,490	0
72,010	0	0	0	107,943	0	481,818	0
92,172	0	0	0	114,306	0	348,630	0
90,038	0	82,661	0	106,113	0	0	369,148
97,999	0	88,944	0	151,448	0	0	190,151
90,279	0	67,048	0	141,305	0	0	548,999
85,281	0	65,887	0	111,527	0	0	875,224
78,916	0	67,483	0	123,905	0	0	346,341
74,733	0	0	0	109,165	0	0	130,281
62,374	0	0	0	112,579	0	184,098	0
70,747	0	0	0	106,609	0	512,330	0
74,018	0	0	0	114,991	0	438,092	0
47,585	0	0	0	123,749	0	401,311	0
47,299	0	0	0	99,981	0	494,646	0
73,458	0	0	0	144,450	0	155,081	0
81,421	0	47,938	0	115,539	0	0	61,223
94,919	0	85,383	0	137,237	0	0	543,420
98,060	0	67,574	0	137,256	0	0	841,341
81,540	0	53,927	0	130,554	0	0	1,020,928
95,693	0	75,198	0	133,339	0	0	289,956
74,652	0	108	0	106,468	0	131,481	0
75,355	0	0	0	106,092	0	144,270	0
72,183	0	0	0	110,241	0	521,042	0
82,886	0	0	0	111,168	0	543,272	0
69,797	0	0	0	113,003	0	448,468	0
63,420	0	0	0	117,205	0	435,539	0
82,999	0	0	0	33,562	0	263,694	0
72,858	0	0	0	108,423	0	0	23,585
92,438	0	78,742	0	154,726	0	0	299,804
91,651	0	74,501	0	164,891	0	0	1,460,736
75,878	0	57,389	0	139,869	0	0	920,719
98,185	0	82,875	0	147,251	0	0	295,112

ENBRIDGE GAS INC.

Answer to Interrogatory from
TransCanada Pipelines Limited ("TCPL")

INTERROGATORY

Reference:

i. Exhibit B, Tab 1, Schedule 1, Page 3 of 31, Paragraph 5.
ii. Exhibit B, Tab 1, Schedule 1, Page 2 of 31, Figure 1.
iii. Exhibit B, Tab 2, Schedule 1, Page 7 of 8, Paragraph 15.
iv. Exhibit B, Tab 2, Schedule 1, Page 7 of 8, Table 1.
v. Exhibit C, Tab 1, Schedule 1, Attachment 2, Page 57 of 66.
vi. EB-2022-0072, 2022 Annual Gas Supply Plan Update, Page 18, Figure 8.
vii. Exhibit C, Tab 1, Schedule 1, Page 24 of 25, Paragraph 48.

Preamble:

In Reference i), EGI describes how the project is designed to maintain design day storage capacity/deliverability and equivalent injectability; is being driven by system reliability, obsolescence, and employee safety concerns; and will not create any incremental design day space and/or deliverability.

In Reference ii), EGI shows a map of the Dawn to Corunna Replacement Project. For the purposes of this interrogatory, the facilities at the Corunna Compressor Station, the facilities at the Dawn Hub Operations Centre, and the three 20 km pipelines connecting the two facilities (two existing NPS 30 lines and one proposed NPS 36 line) will be referred to as the "Dawn to Corunna System".

Reference iii) describes how EGI expects the forecast storage requirements for bundled in-franchise customers to be in excess of the allocated cost-based storage space. EGI also projects forecast customer demand to increase, meaning the requirement for storage space in excess of the allocated cost-based storage is expected to continue for the foreseeable future.

In Reference iv), EGI presents a table showing the in-franchise storage requirement forecast out to 2024/25. The table shows a storage requirement for the EGD Rate Zone in excess of the available cost-based storage.

In Reference v), ICF states that the CER is projecting continued long-term growth in Ontario gas demand for residential, commercial, and industrial customers.
In Reference vi), EGI presents evidence prepared by ICF for the purposes of the 2022 Annual Gas Supply Plan Update showing significant growth in Ontario natural gas demand out to 2045.

In Reference vii), EGI states that constructing an NPS 36 pipeline will enable Enbridge Gas to maintain regulated withdrawal capacity of 1.89 PJ/d; maintain regulated injection capacity of 0.84 PJ/d; and maintain the regulated working capacity of 99.4 PJ.

Question:

a) Does EGI expect more injection and withdrawal capacity will be required in the future for the Dawn to Corunna System or to serve the EGD Rate Zone if the forecast growth in References iii) through vi) materializes? If so, when would EGI expect such an expansion of injection and withdrawal capability to be necessary, and how much incremental capacity could be required? Please provide answers for the period to the year 2024/25, and for the period from 2024/25 to 2045.

b) If the answer to a) is yes, please explain EGI's expectations for where the gas supply for such an expansion would be sourced, and how such gas would be transported to the Dawn to Corunna System or the EGD Rate Zone.

c) Given the forecast growth in References iii) through vi), please explain why EGI is proposing to maintain design day storage capacity/deliverability and equivalent injectability as stated in Reference i) rather than proposing to create incremental design day space and/or deliverability to meet future requirements?

d) Did EGI consider the future expandability of the Dawn to Corunna System when evaluating the Project and its alternatives? Please explain why or why not, and what factors were considered.

e) If EGI were to expand the Dawn to Corunna System beyond the capacity envisioned in the Project, what facility upgrades might be contemplated to increase injection and withdrawal capacity?

f) If the project is completed as applied for (maintaining the capacities listed in Reference vii) by retiring seven compressor units and constructing 20km of "NPS 36 pipeline), please quantify the maximum injection and withdrawal capacities that could be added in the future by installing incremental compression at the CCS?

g) Is EGI aware of any storage expansion projects in the Dawn area that could drive a need for incremental injection/withdrawal capacity for the Dawn to Corunna System? If so, please describe the location, capacity, and timeline of such projects.

<u>Response</u>

a) b) & c)
In accordance with the Natural Gas Electricity Interface Review ("NGEIR") Decision[1] and confirmed in the OEB's Decision and Order regarding the Company's Mergers, Acquisitions and Divestitures ("MAADs") proceedings, the amount of cost-based storage reserved for EGD rate zone customers was fixed at 99.4 PJ. As described in paragraph 12 at Exhibit B, Tab 2, Schedule 1, pp. 5-6, the 99.4 PJ of cost-based storage has a fixed maximum storage withdrawal rate of 1.9 PJ/d and a fixed maximum storage injection rate of 0.84 PJ/d.

Enbridge Gas contracts for market-based storage services to meet EGD rate zone requirements beyond these fixed amounts. The Company's plans to serve the seasonal balancing, reliability and security of supply needs of the EGD rate zone will be considered as part of future Gas Supply Plans and Annual Gas Supply Plan Updates.

d) e) & f)
Enbridge Gas considers and routinely evaluates the future expandability of the Dawn Hub based on customer demand and future market forecasts. The Company has not received a request for incremental storage demand at this time and as such, has not evaluated alternatives with incremental facilities (or non-facility alternatives for that matter) to the proposed Project. Specifically, Enbridge Gas does not have any plans to add additional compression to the CCS beyond the scope of the Project.

If, through market solicitation for incremental long-term storage demand the Company identifies a need for increased capacity in the future, then depending upon the exact nature of the demand and the assessment of alternatives at that time (facility and/or non-facility), the Company may require some form of approval from the OEB.

g) In addition, Enbridge Gas is evaluating storage enhancement projects at the Kimball-Colinville and Waubuno Storage Pools with projected in-service dates between 2024 and 2026.The projects are in the early phases of evaluation, project engineering and design, and Enbridge Gas internal management approval.

[1] EB-2005-0551 - Decision with Reasons, November 7, 2006.