ENBRIDGE

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October 11, 2022

VIA EMAIL and RESS

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

Dear Nancy Marconi:

Re: Enbridge Gas Inc. (Enbridge Gas)
Ontario Energy Board (OEB) File: EB-2022-0086
Dawn to Corunna Replacement Project
Reply Argument

In accordance with OEB correspondence filed on September 30, 2022, enclosed please find the Reply Argument from Enbridge Gas in the above noted proceeding.

Please contact the undersigned if you have any questions.

Yours truly,

(Original Digitally Signed)

Adam Stiers
Manager, Regulatory Applications - Leave to Construct

cc.: C. Keizer (Torys)
R. Murray (OEB Staff)
EB-2022-0086 (Intervenors)

ONTARIO ENERGY BOARD

IN THE MATTER OF the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Schedule B, and in particular, sections 90 (1) and 97 thereof;

AND IN THE MATTER OF an Application by Enbridge Gas Inc. for an Order or Orders granting leave to construct natural gas pipelines and ancillary facilities from the Township of Dawn-Euphemia to St. Clair Township;

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.

ENBRIDGE GAS INC.

REPLY SUBMISSIONS

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A. Introduction

1. These are the reply submissions of Enbridge Gas Inc. ("Enbridge Gas" or the "Company") in its leave-to-construct application in respect of the Dawn to Corunna Replacement Project (the "Project"). These submissions should be read in conjunction with the Company's Argument-in-Chief which broadly summarizes the evidentiary record in this proceeding.[1]

2. In their submissions, intervenors have made efforts to downplay the condition, obsolescence, and safety risks of the compressor units of the Corunna Compressor Station (the "CCS") that Enbridge Gas intends to replace with the Project and to portray this as a complicated project. However, the record is clear as to the condition and obsolescence of the units and the unacceptable risk to ratepayers and the market presented by current and growing failures of the compressors and the unacceptable level of safety risk for Enbridge Gas personnel.

3. Furthermore, the Project is a utility integration solution that reduces ratepayer and worker risk, provides equivalent storage service as the lowest cost alternative, leverages existing Dawn Storage compression capacity, and reduces overall system emissions. At its simplest, the Project provides a one-to-one capacity replacement of existing design day storage deliverability (withdrawal) and seasonal injection capability. As part of the Dawn Hub, which includes the CCS and Dawn, the Project leverages higher Dawn compression discharge pressure to fill storage during injection operations and reduces pressure losses between the CCS and Dawn on withdrawal. The Project, using the connection to Dawn, effectively replaces the function of units K701-K703 and K705-K708 on a one for one basis, delivering the same flow from storage for the benefit of ratepayers. This will include the added benefit of improved reliability not only because of the replacement of the retiring compressor units with the proposed pipeline, the former being inherently more prone to failure by virtue of their thousands of mechanical parts, but also because the Project will reduce the amount of gas compressed by the remaining units from 2.6

[1] EB-2022-0086, Enbridge Gas Inc. Argument-in-Chief (September 6, 2022)

PJ to 0.2 PJ on design day. This substantially reduces the complexity and increases the reliability of the integrated storage system. In the event of a compressor failure, only a small portion of flow would be at risk.

4. The Project is in the public interest and the requested relief should be granted. The CCS is critical to satisfying design day demand and because of condition and obsolescence there is an unacceptable and ever expanding risk of failure (in terms of both severity and frequency) which cannot be managed effectively or economically without the Project. Relative to the Project, there is no other alternative that is as economic or cost effective and that adequately reduces the reliability and safety risk. In this regard, OEB staff supports the Project. Enbridge Gas's responses to intervenors objecting to the Project are set out below.

B. Need (Obsolescence and Reliability)

5. Objections to the need for the Project were primarily raised by the Schools Energy Coalition ("SEC"), the Federation of Rental-housing Providers of Ontario ("FRPO"), and Energy Probe. Environmental Defence ("ED") and Canadian Manufacturers and Exporters ("CME") adopted the submissions of SEC and FRPO. Pollution Probe likewise asserted that need was not established. Pollution Probe's submissions in this regard are tied to its position on alternatives and Enbridge Gas's reply in that regard are dealt with in that section. Below Enbridge Gas replies to the submissions of SEC, FRPO and Energy Probe.

6. SEC does not dispute either the importance of the CCS or the broader integrated storage system to meeting design day demand and agreed that the Project is the most economic option to replace the seven existing CCS compressor units, which due to degrading condition will have an impact on reliability. However, SEC objects to the application on the basis that Enbridge Gas does not need to place the proposed Project into service in 2023.[2] In reaching this conclusion, SEC took an overly narrow interpretation of the evidence by focusing only on one general aspect of the Reliability, Availability and Maintainability ("RAM") Study. Based on SEC's

[2] SEC Written Submissions, p. 2

overly narrow interpretation of the evidence, SEC believes that project need does not materialize until after 2026.[3]

7. SEC's narrow interpretation should be rejected for two reasons. First, SEC has ignored the fact that the deterioration of the seven existing CCS compressor units and their increasing obsolescence will lead to increasing and significant downtimes that must be considered in the context of the facility's operation as critical infrastructure. Second, in interpreting the RAM Study, SEC failed to consider the unique functionality of the units and how that can impact overall injection and withdrawal capabilities.

SEC ignores deterioration and obsolescence leading to significant downtimes

8. The CCS is critical to satisfying design day demand. Because of condition and increasing obsolescence there is an unacceptable risk of failure which cannot be managed effectively or economically without the Project. Compressor units K701-K703 account for 20% of the available compressor power at CCS. All three units are the same make, model (KVT) and vintage (1964). The KVT compressor model has been out of production for 40 years. As a result, there are only 19 of these units in operation globally and only one of those operating units has been retrofit similar to units K701-K703. The original equipment manufacturer does not stock spares in inventory for cast or forged components (e.g., crankshafts). This means that long lead times result when repairs require replacement components to be cast or forged, cured, custom machined, and polished.

9. The increasing obsolescence of compressor units K701-K703 hampers the Company's ability to maintain these units, increases repair time, and elevates risk especially since operational flexibility becomes limited or non-existent (depending on demand conditions) if other failures occur.[4]

10. CCS compressor units K705-K708 provide compression to mid-range pressure and account for 41% of the compressor power at the CCS. These 4 units are of the same

[3] Ibid

[4] Exhibit B-1-1, pp. 13-14, paras 31-32

make, model (KVR) and range in vintage (1970-1974). The OEM is increasingly challenged to supply parts in a timely manner for these units. For example, the Company sought to replace a broken crankshaft on unit K705 in 2018, which led to 18 months of unit downtime.[5]

11. On design day, if any 1 of the 10 operating CCS units is out of service for a prolonged period of time, with unit K711 operating, no Loss of Critical Unit (“LCU”) capability is available should another unit be lost. This scenario could result in a high consequence event, which would compromise the reliability of the system and the ability to serve firm customers. Due to the unique nature of each CCS compressor unit relating to its configuration, and the specific compression needs at the time (low, medium, or high pressure) during injection or withdrawal, the remaining compressor units that have not failed may not be suitable to avoid a shortfall.[6]

12. For example, during the unit K705 outage, the CCS had no spare mid-range pressure units, and units K706-K708 were operated at a greater number of hours as a result. This further exacerbated their respective reliability risk and maintainability issues. If a single additional compressor unit failed during the prolonged outage, full storage inventory levels would not have been achieved by the end of the 2018 injection season and the Company would have been forced to rely on other physical and/or market-based storage and supply alternatives at significant incremental cost and risk to ratepayers. In the case of unit K705, had a second compressor failure occurred on a high demand day during January through March, the Company could have experienced a volumetric shortfall ranging from 186 TJ/d (for failures of any of units K701, K702 or K703) to 230 TJ/d (for failures of any of units K706, K707 or K708). In this case, the procurement of delivered service for the period that the

[5] Exhibit B-1-1, p. 15, para 34. Anecdotally, little more than a week prior to this submission, Enbridge Gas was forced to take CCS compressor units K705 and K706 out of operation for an estimated duration of two weeks for unplanned mechanical repairs.

[6] Exhibit B-1-1, p. 14, para 32

second compressor was unavailable would have ranged in cost for delivered supply between approximately $800,000 to $11 million for a single day.[7]

13. Had a prolonged secondary unit failure occurred in combination with an inability to procure natural gas on the spot market (e.g., during peak winter design conditions), services to contract class customers could have been interrupted and/or up to 185,000 residential customers could have experienced an outage during the coldest time of the year. This scenario and associated risks are unacceptable given the Company's firm service obligations.[8]

14. Table 1 below contains CCS compressor unit downtime data for the last six years (2016-2021). As is indicated, the outage hours for the retiring units K701-K703 and K705-K708 are material and increasing overall.[9]

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						

15. Based on an Asset Health Review ("AHR") performed in 2018 and updated in 2021 (as part of the Company's RAM Study for the CCS, completed by DNV GL), Enbridge Gas identified serious and increasing obsolescence and reliability risks associated with the compressor units K701-K703 and K705-K708. This is due to both the amount of repair downtime experienced and system shortfall that could

[7] Exhibit B-1-1, p. 22, para 46
[8] *Ibid*
[9] Exhibit I.PP.5(a)

result from their failure considering the criticality of these facilities to meet peak design conditions. The AHR considers failure data from the Company's maintenance management system to calculate the probability of failure, which is in turn converted into a Storage Health Index ("SHI") to indicate the predicted time to failure for a specific asset.[10]

16. The AHR indicated that the compression asset sub-classes (foundation, crankshaft, engine, compressor, after cooler, heating & cooling system, and valving system) are more susceptible to failures due to multiple mechanical parts and complex interdependencies, with engines and compressors having the lowest asset health and being the least reliable asset sub-classes. Further, results for CCS units K701-K703 and units K705-K708 indicate that both engine and compressor failures are expected to occur within 2 years for all units.[11]

17. The RAM Study relies on key inputs from the AHR to inform asset reliability, availability, and maintainability.[12] The study helps to quantify the likelihood of failure to meet the operational objectives or demands and to estimate the impact of such failure in terms of resulting shortfall compared to an expected or target demand. The SHI results and the instantaneous mean time between failures for each compression asset sub-class (noted above) were used to model total down times for each CCS unit over the next 5 years, according to operational cycles (injection and withdrawal).[13]

18. According to the results of the RAM Study, over the 5-year forecast period, the units to be replaced by the Project, units K701-703 and units K705-K708, account for approximately 70% of the total down time of 695 days for withdrawal and 606 days for injection.[14]

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[10] Exhibit B-1-1, p. 18, para 39
[11] Exhibit B-1-1, p. 19, para 41
[12] Exhibit B-1-1, p. 17, para 38
[13] Exhibit B-1-1, p. 21, para 42
[14] Exhibit B-1-1, p. 21, Table 4

19. The obsolescence and reliability concerns with the CCS compressor units discussed above, including maintainability and time to repair, all contribute to increased deliverability and financial risk as all units are required to operate in order to achieve design day flow rates. SEC did not take into account this significant and material risk related to operational contingency.

SEC failed to interpret the RAM Study in the appropriate operational context

20. In addition to ignoring the above facts, the RAM Study results, and the implication of the foregoing to the operational risk of the CCS, SEC also failed to fully interpret the results of the RAM Study.

21. In support of its position, SEC pointed to a RAM Study conclusion regarding the decline in the impact of failures on overall reliability as measured by decreased injection and withdrawal capabilities. However, in doing so, SEC failed to account for the fact that the overall results are skewed as a result of the relationship between the unit outage and the functional use of that unit in the injection or withdrawal process. The trend identified in the RAM Study arose because of the criticality of unit K704. Unit K704, which is not being replaced, is and will continue to be required to compress gas arriving from Dawn to fill the top end of the storage pools to their planned maximum operating pressure.[15] Regarding the impact of unit K704 on the likelihood for failures, the RAM study stated:

> "Despite the expected increase in plant deterioration each year, which results in higher number of failures each year, it is forecasted that Gas Injection Shortfall will decrease from 2022 to 2026. This decreasing trend is attributed to the potential incipient 1st foundation failure of units K704 (HP duty) and K701 (MP duty), likely to occur in early years due to them not yet being replaced (unlike other units), with the former having a high impact in injection capability, given its low level of redundancy. As a result, given the long downtime duration associated with this maintainable item (between 1-5 months), the high impact on shortfall in years surpasses the impact on shortfall associated with plant deterioration."[16]

[15] Exhibit B-1-1, p. 7, para 10

[16] Exhibit B-1-1, Attachment 2, p. 31

22. In effect, the impact of the forecasted unit K704 outage is dominant over the shortfall trend associated with plant deterioration and occurring early in the forecast period, thereby skewing the results such that reliability related to injection appears to be improving notwithstanding the impact of deterioration of units in the remaining forecast years. In fact, it masks the impact of shorter outages forecasted for other units and contributing to the operational risk of failure as described above. According to the RAM Study, this is also the factor contributing to the trend of the forecast withdrawal shortfall.[17] It should also be noted that the slight downward trend amounts to less than a 2% decrease in shortfall.[18]

23. In ignoring the foregoing, SEC fails to recognize the key factor that results in exposing ratepayers to material and significant risks of failures in the absence of LCU protection. As a result, SEC's assertion should not be accepted. As noted above, based on the RAM Study, the retiring units, K701-703 and K705-K708, account for approximately 70% of the total aggregate downtimes over the 5-year forecast period.[19] This is the critical issue that exposes ratepayers to the risk described above and should be the basis on which the OEB applies the RAM Study. SEC also incorrectly asserts that the evidence shows that the outage time for these seven units have stabilized and is showing a downward trend. In support of its position, SEC points to a graph set out in Figure 1 below showing total unit outage days per year for units K701-703 and K705-K708.[20]

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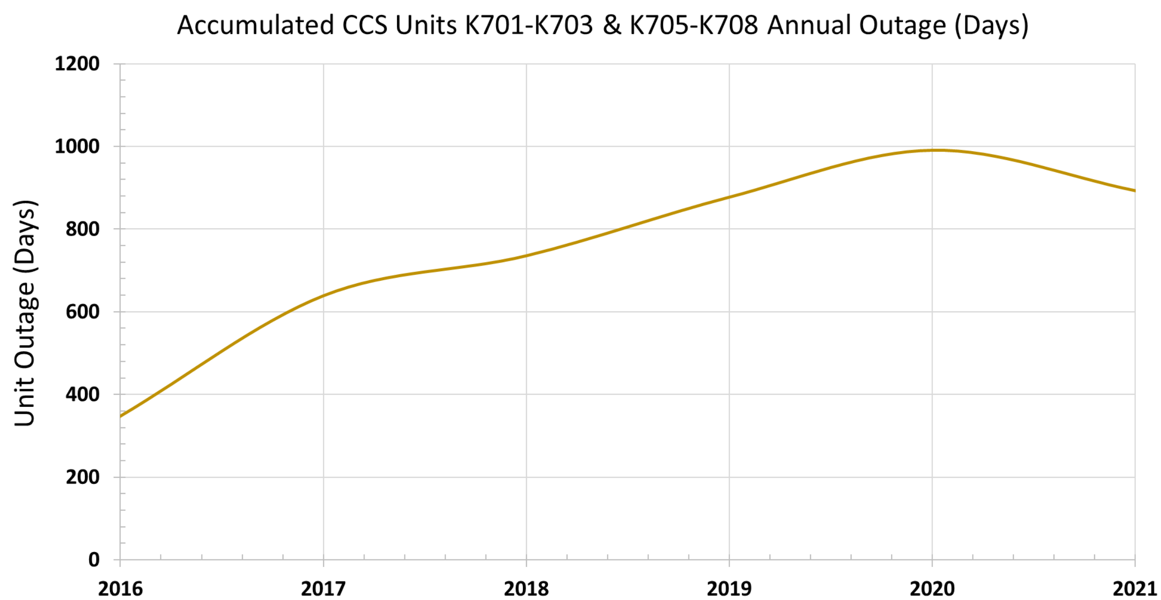
[17] Exhibit B-1-1, Attachment 2, p. 38

[18] Exhibit B-1-1, Attachment 2, p. 46, Figure 6.3 - % difference between 2022/23 and 2026/27.

[19] Exhibit B-1-1, Attachment 2, p. 34, Table 5.3 and p. 41, Table 5.7

[20] Exhibit I.SEC.4

Figure 1



24. However, SEC clearly misinterprets the chart by ignoring the clear steady upward trend from just under 400-unit outage days in 2016, to 1,000-unit outage days in 2020. The graph represents an increase of 185% between 2016 and 2020 and 157% between 2016 and 2021. This in no way represents a stabilizing trend. There is a slight decline in 2021 which is only one year of data. It should be noted that SEC cites the RAM Study for the basis of its conclusion. However, this is also incorrect as the RAM Study does not include all planned maintenance activities. The graph referenced by SEC is produced in Exhibit I.SEC.4 and is based on actual downtime data produced by Enbridge Gas in response to Exhibit I.PP.5(a). The RAM Study did not reach the conclusion asserted by SEC.

25. Building on this erroneous conclusion, SEC asserts that the one-year decline tied to the maintenance repairs made over the previous period will continue to trend downwards. Aside from the fact that a one-year fluctuation is not the basis of a trend, SEC provides no basis for its conclusion that previous maintenance is the contributor to an ongoing downward trend. Instead, SEC references Enbridge Gas's response to Exhibit I.SEC.9 wherein Enbridge Gas has detailed major repair events, which further demonstrate the deteriorating condition of the units in question.

26. SEC notes that in addition to the maintenance expense of $17.2 million, Enbridge Gas has spent $25.2 million in capital since 2017 on the seven retiring units. Based upon its incorrect analysis, SEC believes that the Project should be deferred to enable ratepayers to “enjoy” the benefits of those expenditures. There is no basis for this assertion. The expenditures were made to remedy deteriorating assets that will continue to deteriorate and fail at an increasing rate for potentially longer periods of time given increasing equipment obsolescence. If the units are not retired via the Project, more expenditures will have to be made and material and significant ratepayer risk will continue. The only clear solution is the Project, which will provide stable capital cost for many years to come and reduce ratepayer risk to an acceptable level.

27. SEC also employed its narrow interpretation of the RAM Study to conclude that the Project does not resolve the reliability concerns related to the CCS because units K704 and K709-K711 remain in service.[21] This is not the case. The Project fundamentally improves the overall system reliability of the CCS. SEC focused only on the contributions to gas shortfalls in injection or withdrawal modes related to units K704 and K711 and units K709 and K710, which are not being replaced. These units contribute to most of the gas shortfall over the 5-year forecast period because, as identified in the RAM Study, these units exhibit the combined “N” configuration the majority of the time when operating. “N” configuration references a configuration where no redundancy is in place to accommodate any failure or maintenance operation. As can be seen in the RAM Study,[22] from July 1 to Oct 31, units K704 and K711 are running in parallel to meet demand with no redundancy. Similarly for withdrawal, the Low-Pressure units K709 and K710 are required to operate in a configuration with no redundancy which similar to units K704 and K711 on injection means that any failure of these units results in immediate impact to shortfall. The shortfall related to units K704 and K711 is not driven by the inherent equipment

[21] Pollution Probe raised a similar submission regarding K704 (although mistakenly identified as K705 in Pollution Probe’s submissions). Enbridge Gas rejects those submission for the same reasons as stated in respect of SEC’s submissions in this regard.

[22] Exhibit B-1-1, Attachment 2, pp. 18-20

reliability. The AHR shows that the reliability of units K704 and K711 is the highest.[23] With respect to unit K709 and K710, while their reliability is similar to unit K705-K708, the primary driver for shortfall associated with these units is their criticality (operating with no redundancy) rather than their equipment reliability. These units need to remain in operations, similar to units K704 and K711, due to their specific function.[24] The proposed project, which retires the 7 CCS units and replaces them with the pipeline, mitigates the shortfall risk posed by units K704 and K711 and K709 and K710 by significantly reducing the time that units K704 and K711 are required on injection and by reducing the flows required by units K709 and K710 on withdrawal.[25] This alternative clearly addresses the risk of shortfall attributed to these units.[26] Through the reduction in run time of these units, the safety risk is also positively impacted by reduced maintenance requirements as well as fewer hours in which compressor plants are pressurized.

28. Furthermore, the Project also mitigates the risk of outages in the remaining units K704 and K709-K711 because the Project reduces the volume of gas being compressed by the CCS on design day and thereby reduces the risk to ratepayers in the event of a failure of those units. As stated in the Technical Conference:

> "Starting at the Corunna compressor station, 2.6 petajoules of gas is withdrawn from storage, **with .5 petajoules bypassing compression and 2.1 petajoules flowing through the compressors at the Corunna compressor station**, as shown on the schematic.
>
> The discharge pressure from the compressors entering TR1 and TR2 is 5,865 kilopascals.
>
> The pressure entering the pipelines must be high enough to overcome the pressure drop along the pipelines to ensure that gas arrives at Dawn at approximately 4,825 kilopascals. This gas is then commingled or mixed with compressed gas from the Dawn storage pools. The commingled storage gas is then further compressed and dehydrated before flowing into the company's transmission systems.

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[23] Exhibit B-1-1, p 20, Table 3

[24] Technical Conference, Day 1 Transcript, pp. 206-208

[25] Technical Conference, Day 1 Transcript, p. 18

[26] Technical Conference, Day 1 Transcript, pp. 152-153

> So with the abandonment of the seven compressor units and the construction of TR 7, four units will remain at the Corunna compressor station, K704 and 709 through 711.
>
> Following the construction of the project, the delivered pressure at Dawn will remain the same. The total flow from the storage pools connected to Corunna will also remain unchanged at 2.6 petajoules.
>
> As a result of constructing the TR 7 pipeline, the pressure losses between Corunna and Dawn are reduced, and therefore the discharge pressure from the compressors entering TR1, 2, and 7 pipelines is also reduced to 5,237 kilopascals.
>
> While the flow from storage remains the same at 2.6 petajoules, **only 0.2 petajoules is being compressed at Corunna on design day**, using the three remaining units and holding 711 in LCU. **This substantially reduces the complexity and increases the reliability of the integrated storage system. Further, in the event of a compressor failure, only a small portion of flow would be at risk."**[27] (emphasis added)

As noted above, on design day Enbridge Gas is currently relying on compression at CCS to lift the pressure for 2.1 petajoules (80% of the design day flow from CCS) of natural gas volumes flowing through the CCS. Following the construction of the Project, only 0.2 petajoules (8%) of natural gas volumes flowing through the CCS will require compression (at CCS). This greatly increases the reliability of the CCS.

29. As noted in the RAM Study, under the current CCS configuration, because of their functionality units K704 and K709-K711 account for a large part of the total gas injection and withdrawal shortfall over the 5-year forecast period. The total shortfall is an unacceptable risk. Upon completion of the Project, because only a small portion of flow would be subject to compression by these compressors the total gas injection and withdrawal shortfall would be reduced, thereby improving reliability relative to the current risk exposure experienced by ratepayers.

30. In addition, the Project reduces the risks associated with obsolescence related to units K704 and K709-K711 since units K705-K708 are of similar makes and models (KVR) as the remaining CCS units and their retirement will provide the Company with access to a variety of additional OEM spare parts that can be used to maintain the remaining units. By disassembling units K705-K708, salvaging interchangeable

[27] Technical Conference, Day 1 Transcript, pp. 15-16

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.[28]

31. SEC makes reference to the RAM Study's statement that low frequency high consequence events (worst-case scenarios), at least with respect to major components (crankshaft, engine, aftercooler, and valve system items) will not contribute significantly to capacity shortfalls. However, the risk of multiple failures and the significance of the worst-case scenarios as a contributor to the overall shortfall are unrelated to each other. Multiple compressor failures may occur on design day due to combinations of higher frequency events or the low frequency types of events.[29] The RAM Study has shown that all of the potential failures (worst-case and otherwise) contribute to a shortfall level that creates an unacceptable risk.[30] Any combination of failures that occur at the same time (multiple compressor failures) can occur on design day leading to a very significant consequence.[31]

32. SEC again failed to consider key findings. As noted, with an expected 70% of the downtime over the 5-year forecast period for the seven retiring units, a unit outage will place greater reliance on the remaining units and elevate risk because of an absence of LCU capability due to the need for the dedicated LCU operating to meet demand. This fact combined with the reliability improvements to the remaining compressor clearly show that the Project eliminates unit failures and eliminates risk.

33. Based on the foregoing, SEC's submissions regarding the deferral of the Project should be rejected.[32] With need clearly established and the Project as the least cost

[28] Exhibit B-1-1, p. 17

[29] Please see the response at Exhibit I.PP.5, which provides a listing of unplanned outages that occurred from 2016-2021 that were 5 days or greater in duration. Importantly, a comparison of Table 1 above with outage details set out in Exhibit I.PP.5, Attachment 1 reveals that there were many more shorter duration unplanned events that occurred during this same time period. Please also see Exhibit B-1-1, Attachment 2, Table 4.5 for additional context.

[30] Exhibit I.CME.2 (b)-(d) states that 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.

[31] Exhibit B-1-1, p. 22, para 46

[32] SEC Submissions, p. 6

alternative, there is no basis to defer the Project for rate impacts, pending the completion of a new system and asset plan or cost allocation is more appropriately considered in Enbridge Gas's rebasing application.

FRPO incorrectly relies on run to failure and concludes there is LCU protection

34. FRPO asserts that project need was not established because (i) there were no failures that led to the interruption of firm service, and (ii) there exists LCU protection. FRPO's position should not be accepted.

35. With respect to FRPO's belief that there needs to be evidence of a failure that results in the interruption of firm service, FRPO is in effect advocating a run to failure standard for critical infrastructure. Given the critical nature of the CCS to the EGD rate zone, such a standard would expose ratepayers to unacceptable levels of risk. Based on FRPO's view, the investment would only be needed if ratepayers were harmed. However, good utility practice is to avoid harming ratepayers while appropriately responding to poor conditioned and obsolete assets such as the seven compressor units in question. As the operator of such assets, it is Enbridge Gas's responsibility to plan for their retirement and replacement while maintaining the safety and reliability of its systems and services. This is Enbridge Gas's practice and is the basis of investment planning adopted by the OEB for both natural gas and electricity.[33]

36. Regarding the availability of the LCU protection, this is also not a justifiable basis to assert that the Project is not needed. For critical assets, it is also good utility practice to have contingency in the system in the event of failure (this practice also differs in its criticality for natural gas vs. electricity systems since the latter can often recover more swiftly from outages or interruptions of service). This requirement is independent of the condition or obsolescence of the assets, given that failures could happen for other reasons. However, condition and obsolescence do matter when failure occurs, and the remaining assets (also poor conditioned and obsolete) must have higher than normal run times to compensate for the failure. The condition or

[33] Technical Conference, Day 1 Transcript, p. 20, ln. 10-18

obsolescence of the remaining assets becomes critical since there would be no LCU capability and their failure means the intended service will not occur and a negative consequence to customers. This is a risk and consequence that Enbridge Gas intends to avoid with the Project. As noted above, given the unique functionality of the units, a loss of unit K705, for example, means that units K706-K708 must work harder and given their condition and obsolescence expose the ratepayer to unacceptable risk of failure that can only be remedied by a market solution that can be very costly.[34]

Energy Probe wrongly concludes that reasons for retirement are not relevant

37. Energy Probe asserts that Enbridge Gas has not established need for the Project. The basis of Energy Probe's position appears to be that Enbridge Gas's management and Board of Directors have made a decision to retire the seven units and because the OEB would not need to approve that retirement, the reasons for the retirement are not relevant to the OEB's approval of the Project.[35] This is based on a belief by Energy Probe that Enbridge Gas will retire the units with or without the Project's approval.

38. Energy Probe's submissions should be given no weight. Clearly Enbridge Gas's decision to retire the seven units is relevant to the need of the Project and its approval since the Project is designed to replace the retiring units and to maintain storage at its current level for the EGD rate zone. The units are obsolete and will be subject to continuing and increasing levels of failure exposing the ratepayer to the operational risk of insufficient storage and the financial risk of obtaining gas at significant cost from the market potentially on a peak demand day. It is not Enbridge Gas's objective to eliminate the current storage (as suggested by Energy Probe), but rather to sustain it.

[34] Exhibit B-1-1, p. 15, para 34; Exhibit B-1-1, p. 22, para 46

[35] Energy Probe, p. 4

C. Need (Safety Risks)

39. Submissions were primarily made by SEC, Pollution Probe, ED and FRPO to challenge the aspect of Project need that is based on safety risks from the existing configuration of the CCS. Their main arguments include: (i) Enbridge Gas began to consider the proximity of compressors as health and safety risks in 2021 as part of a Qualitative Risk Assessment ("QRA") and these risks are not novel or an emergency requiring immediate action;[36] (ii) Enbridge Gas has not assessed or prioritized the safety risks at the CCS relative to other facilities;[37] (iii) the QRA analyzed generic accidental releases across the industry, rather than for the CCS or Enbridge Gas's asset pool;[38] (iv) there has not been any non-compliance with applicable legislation, code or industry standard regarding minimum compressor distance;[39] and (v) the chance of a significant leak is low and existing safety systems help to mitigate risks.[40] Below Enbridge Gas replies to these arguments and shows why they should be rejected by the Board.

A robust risk management process (based on industry standards and objective criteria) shows unacceptable worker safety risks that must be prioritized for mitigation

40. The issues associated with compressor proximity and occupancy of workers in compressor buildings were identified earlier than 2021, contrary to SEC's assertion. The application of risk evaluation framework (including the criteria for identifying intolerable risk) was described in Enbridge Gas's rate applications dating back at least to 2018.[41] For instance, a 2018 risk assessment for the Meter Area Upgrade indicated that workers could be exposed to intolerable risk, which was tied closely to

[36] SEC Submissions, p. 5; Pollution Probe Submissions, p. 7; CME Submissions, p. 2

[37] Pollution Probe Submissions, p. 6

[38] CME Submissions, p. 2

[39] SEC Submissions, p. 5

[40] FRPO Submissions, p. 3

[41] For example, see EB-2018-0305, Exhibit C1-2-1, p. 74, Figure 4-1-7, and EB-2017-0306/EB-2017-0307, Exhibit C.STAFF.54, Attachment 1, p. 40, Figure 4-8.

worker occupancy and equipment density; and this work ultimately led to the QRA for the CCS.[42]

41. The arguments raised by SEC, CME, and Pollution Probe that safety risks at the CCS are not novel or significant enough to warrant the proposed Project are based on a partial and flawed understanding of the evidence. Of course, not every health and safety risk warrants immediate asset retirement or capital intervention, but Enbridge Gas must act responsibly to identify and treat intolerable risks to the safety of the public and its workers. That is precisely the objective of the Company's robust risk management framework, which includes the quantitative evaluation of risks against a set of objective criteria to determine whether a risk is significant enough to warrant action and, if so, the associated urgency. This approach ensures that the highest risks are treated within an appropriate timeline and premature intervention is avoided for lower risks. Specifically, Enbridge Gas's QRA methodology was rigorously developed and advanced over the years, with reference to industry recognized and internationally established practices and criteria:

- The Company's risk management process is consistent with ISO 31000.[43] The risk tolerance criteria applied by Enbridge Gas align with the criteria proposed by the CSA Risk Management Task Force Technical Committee for Z662 and the criteria adopted by the BC Oil and Gas Commission, UK Health & Safety Executive and a major North American energy company.[44]

- Enbridge Gas began using QRAs in 2004. In the ensuing 17-year period, the Company worked to establish a broader application of QRA to understand safety risks associated with catastrophic incidents.[45] The development and adoption of QRA is also consistent with the OEB's direction in the Company's 2014-2018

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[42] Exhibit JT 1.7, pp. 1-2
[43] Exhibit I.CME.2, pp. 2-6
[44] *Ibid*, p. 5
[45] Exhibit JT 1.6

rates application to implement more robust risk-based analysis in support of decision making.[46]

- For the CCS in particular, it took the Company at least 2 years[47] to further implement and advance a QRA methodology that aligns with best practices and that was verified by DNV as being an appropriate method.[48]

42. It is misleading to claim that the safety risks at the CCS have not changed and have only become an issue in 2021 as the result of a new methodology. As noted above, intolerable safety risks due to compressor building configurations and occupancy were first identified in 2018, and Enbridge Gas spent another two years[49] to confirm and establish the proper means for evaluating safety risks due to catastrophic incidents. The QRA is based on the current state and configuration of the CCS and does not (nor is it intended to) represent the historical risk profile of the CCS. The fact is that equipment density at the site had increased over 58 years due to expansion to meet gas demand,[50] along with increased occupancy,[51] increased amounts of gas being transferred and higher complexity of operations which all contribute to the safety risk.[52] As compressors age and decline in health and reliability, safety risks to workers are further exacerbated as workers need to spend more time working on the equipment. The interaction among and impact of factors

[46] *Ibid*, p. 2

[47] Exhibit JT 1.7, p. 2

[48] Exhibit I.CME.1, Attachment 2

[49] See Exhibit I.CME.1, Attachment 1, revision history (with Rev. 0A dated November 22, 2020).

[50] Units K701-703 were installed in 1964, units K705-708 were installed between 1970 and 1974, units K709-710 were installed between 1980 and 1983, and unit K711 was installed in 1995. Contrary to CME's submission that "most compressors have been installed at the CCS since 1983" (p. 2), the majority of the units were installed between 1964 and 1974 (age between 48 and 58 years). Also see Exhibit B-1-1, pp. 13-17 and Exhibit KT1.1.

[51] The QRA considers the proximity of workers to the assets as a key input to the calculation of the risk of injury or fatality. As the occupancy of the buildings increases, the risk of someone being present when a loss-of-containment event occurs is increased. Also see Exhibit B-1-1, para. 55.

[52] Although much has been discussed in this proceeding about how layout, design and time spent by workers contribute to safety risk, other factors also contribute to the risk profile, such as the throughput (i.e., the amount of gas transferred which can be characterized via pressure profile and flowrate), how the site is being operated (i.e., the various operating modes of the site), and maintenance plan. These other factors are further discussed in the QRA report (Exhibit I.CME.1, Attachment 1, sections 2 and 5).

such as equipment density, location of and time spent by workers at the site, pressure level of equipment, and modes of operations are dynamic in nature, which is why a robust and comprehensive risk assessment was necessary to understand the intricate relationship between these factors and obtain a quantitative measurement of safety risks.

43. As IGUA noted in its written submissions, Ontario's gas storage resources and system are critical to the safe and reliable supply of gas to the province.[53] As a responsible asset manager and employer, Enbridge Gas cannot leave safety risks inadequately mitigated where they are found to be intolerable using objective criteria, especially given the importance of protecting workers against known risk exposure and the criticality of the CCS. It should be recognized that the reliability and safety concerns identified at the CCS go hand in hand, i.e., safety can be improved if reliability is maintained. It is the combination of these two risks that strongly support the need for the Project. Despite Pollution Probe's suggestion that the past capital enhancements at the CCS somehow meant a credible safety concern must not have existed,[54] Enbridge Gas has maintained the level of expenditures required to keep the facility operating to meet its intended objectives, as any prudent asset manager would do for critical aging assets during the asset lifecycle. Past investment does not mean the assessed risks stemming from the site can be ignored going forward or somehow have not existed. In addition to the reliability and obsolescence risks discussed above, deferring the Project until at least 2027 as some intervenors suggest would mean continuing to expose workers at the CCS to risks that are intolerable compared to recognized industry standards for another five or more years, which would not be justified or responsible.

Enbridge Gas has prioritized various sites similar to the CCS for risk assessment

44. Pollution Probe claims that Enbridge Gas failed to assess and prioritize the safety risks associated with the CCS relative to other facilities; however, that is not what

[53] IGUA Submissions, p. 1
[54] Pollution Probe Submissions, p. 7

the evidence shows. Enbridge Gas has identified a number of other sites sharing common characteristics with the CCS (in regard to higher equipment density in buildings and higher occupancy rates) for risk assessment.[55] 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 as the CCS QRA, Enbridge Gas found that the Hagar site has a risk level for process, worker and public safety that is considered acceptable which does not necessitate immediate risk reduction measures through capital investment. The same follows for the other sites assessed since they each have a lower risk profile.[56]

The QRA applied industry accidental release data to appropriately account for catastrophic events that could seriously endanger worker safety

45. With respect to the use of industry accidental release data as input for the QRA, it has been detailed in evidence why this approach was necessary and appropriate,[57] contrary to CME's criticism.[58] In summary, although Enbridge Gas has some failure rate data for the CCS site, the sample size is considered small relative to industry published datasets, and they are not in a usable format for the QRA. Using a small sample size means it would be reasonable to expect that extremely rare events (such as larger release sizes) may not be accounted for, thereby skewing the release frequencies and causing the risks associated with such rare events to be underestimated. Consequently, the industry accidental release data was used as recommended by the expert advice of DNV and is consistent with the guidance set out in CSA Z662,[59] which is discussed in greater detail below. The practice of using published data also aligns with international practices in quantifying safety risk due to hazardous releases resulting from loss of containment of hazardous material.[60]

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[55] Exhibit I.ED.1(q)

[56] *Ibid*

[57] Exhibit I.CME.1, Attachment 1, Section 6.3

[58] CME Submissions, p. 2

[59] CSA Z662-10, Annex B, Section 5.3.1.3

[60] Exhibit 1.CME.1 Attachment 2, p. 6-7 "Generic release frequencies for above ground equipment are from the "Risk Assessment Data Directory – Process Release Frequencies" report 434-01 published

46. It is important to note that the data sets used for QRAs are not stagnant, as they are managed by reputable organizations and updated on a regular basis. In addition, that data is not the only key input to the QRA, and is combined with other site-specific factors, including but not limited to site layout, building occupancy, operating pressure profiles, modes of operations, and implementation of safety systems.[61] Therefore, it is not appropriate to discredit the assessment as CME has done, simply because published release data instead of site-specific release data is used in the QRA.

47. Since many factors as discussed above need to be considered in a QRA, the QRA can only provide a snapshot in time what the risk profile is like at the site, it cannot be interpreted as historical or future representation of risk of CCS.

Compliance with minimum compressor distance standards does not guarantee worker safety

48. SEC argues that Enbridge Gas has not pointed to non-compliance with any applicable legislation, code or industry standard regarding minimum compressor distance.[62] In doing so, SEC fails to recognize the statutory obligation of every employer in Ontario to "take every precaution reasonable in the circumstances for the protection of a worker",[63] and appears to incorrectly relate compliance with design codes to Enbridge Gas's over-arching obligation to ensure worker safety.

49. Maintaining minimum distance between compressors cannot in itself guarantee that safety risk is being managed. Although minimum distance can help to restrict the amount of equipment per unit area, the risk exposure of a worker is still dictated by where they need to work, how long they need to be there, and the level of pressure that the equipment contains (i.e., the potential energy release in case of a loss of containment), and the worker's ability to respond to a release event. As noted

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by the IOGP." "This is a widely used and accepted source for generic release frequencies, including for on-shore plants."

[61] As detailed in Exhibit 1.CME.1, Attachment 1.

[62] SEC Submissions, p. 5

[63] *Ontario Health and Safety Act*, s. 25(2)(h)

above, the QRA was conducted to understand the dynamic and intricate relationship among relevant factors contributing to the CCS's risk profile to determine if action is required and the associated urgency.

50. It is common in regulations and standards to find requirements on risk management. For example, one of the regulations applicable to Enbridge Gas is the TSSA Code Adoption Document in which standard CSA Z662 is referenced. Z662, in clause 1.2, calls out gas compressor stations as an in-scope system that is subject to the standard and, in clause 3.2, outlines the elements that a risk management process shall include (including risk acceptance criteria, risk assessment, and risk control). These clauses are not as prescriptive as some of the engineering standards or technical requirements, but importantly, they recognize that maintaining minimum compliance alone may not be adequate and that having a robust risk management framework is essential for the safe and reliable operation of natural gas pipeline systems.

51. All these factors are dynamic in nature, a risk assessment needs to be done to understand the intricate relationship between all these factors, and to measure it against risk evaluation criteria to determine if action is required and the urgency to act.

52. With respect to the above-noted statutory obligation of employers under the *Ontario Health and Safety Act* ("OHSA"), in discharging this obligation it is incumbent on Enbridge Gas to understand the hazards that design and layout of the CCS pose in combination with the occupancy rates and other relevant risk factors. In light of the findings of the QRA based on industry recognized practices and criteria, Enbridge Gas does not believe it would be sufficient to point to compliance with minimum design requirements as the basis for reasonably discharging its obligation to protect workers. As an example, CSA Z662 explicitly outlines that the significance of risks should be obtained by reviewing the body of literature on risk acceptance criteria and considering the precedents established both nationally and internationally in

other industries.[64] The efforts undertaken by Enbridge Gas to understand the safety risks to workers at the CCS (and to develop and prioritize mitigation measures in response) are consistent with an employer's obligations in this regard. In the Company's view, it would be irresponsible (and a contravention of the Company's OHSA duties) to manage worker safety risks based on minimum standards alone, and to ignore the risk management practices and criteria that are currently or expected to be adopted in the industry.

Existing safety systems at the CCS do not adequately mitigate known risks to worker safety

53. FRPO is partially correct in asserting that the chance of a significant leak is relatively low and existing safety systems help to mitigate risks further,[65] but it fails to recognize that these considerations are already factored into the QRA and therefore FRPO errs in its conclusion that the identified safety risks do not support Project need. The results of the QRA clearly show that the likelihood of these types of events are not low enough to result in an acceptable risk level compared to applicable risk evaluation criteria.[66] Risk is the combination of likelihood and consequence which means that even if a likelihood is considered low or rare, a high consequence may still result in a high risk that exceeds evaluation criteria. It is precisely to counter the tendency (and bias) exhibited by FRPO that a rigorous mathematical methodology, as outlined in the QRA report, was deployed to avoid incorrect and potentially dangerous conclusions.

<u>D. Alternatives</u>

54. Of the intervenors objecting to the Project, FRPO, Energy Probe and Pollution Probe provided submissions on Enbridge Gas's alternatives analysis. ED, SEC and CME supported the submissions of FRPO. Enbridge Gas's reply submissions in this

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[64] CSA Z662-10, Annex B, Section 5.3.1.3

[65] FRPO Submissions, p. 3

[66] Exhibit B-1-1, p. 23. Also see the QRA report at Exhibit I.CME.1 Attachment 1, which in Section 10 demonstrates the results of the risk assessment considering likelihood of release scenarios and the consequences. Table 31 of the report identifies the risk associated with each employee group and shows that there are some employee groups that have a risk in excess of the risk limit.

regard are below and, contrary to the submissions of the intervenors, provide clear evidentiary support of the Project as the preferred alternative.

FRPO and Energy Probe are incorrect that integrated operations provide an alternative

55. FRPO asserts that Enbridge Gas has not demonstrated that the Project is the best alternative to meet the storage needs of the EGD rate zone. This assertion is premised firstly on the belief that Enbridge Gas did not sufficiently explore alternatives related to the integrated operations of the legacy EGD and Union storage facilities. The same position is held by Energy Probe.[67] ED adopts the position of FRPO. FRPO holds that view despite the fact that Enbridge Gas stated in its pre-filed evidence, interrogatories, and technical conference testimony both how Enbridge Gas's integrated storage system operates and how its limitations make it impossible to provide added storage or injection/withdrawal capability with respect to either the current CCS or the Project when units K01-K703 and K705-K708 are retired.

56. Contrary to the assertion of FRPO and Energy Probe, there was a clear consideration of the integration of the CCS and Dawn as part of the Dawn Hub and the acceptance of the Project as the best alternative to resolve the need related to the CCS. The submissions of FRPO and Energy Probe in this regard should be given no weight.

57. As stated in Enbridge Gas's direct response to FRPO's inquiry as to whether it evaluated the integration opportunities of the CCS and Dawn storage system (forming part of the Dawn Hub):

> "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. **<u>The integration of the systems does not have any impact on the storage capacity of the individual storage pools.</u>** 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. **<u>In</u>**

[67] Energy Probe Submissions, p. 7

> **<u>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.</u>**"[68] (emphasis added)

58. Enbridge Gas further reiterated that 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 the CCS. 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.[69]

59. When outages or reliability is an issue, Enbridge Gas indicated that 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. 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.[70]

60. 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

[68] Exhibit I.FRPO.2
[69] Exhibit I.FRPO.7
[70] Exhibit I.FRPO.16(d)

combined benefits on design day as both legacy operations are bounded by the facilities currently in place.[71]

61. Also as stated in Enbridge Gas's presentation at the outset of the Technical Conference:

> "And finally, storage provides balancing on every day of the year to help manage supply and demand variations. This is a critical part that upstream pipelines cannot provide. The company has established a design day methodology to ensure there are sufficient facilities to meet the demands on design day, and throughout the injection and withdrawal season.
>
> **The current integrated storage system does not contain excess capacity that would facilitate the abandonment of existing compressor units without the construction of replacement facilities.**"[72] (emphasis added)

62. As part of further extensive questioning by Mr. Quinn on behalf of FRPO, Enbridge Gas further elaborated on the integrated nature of the CCS and Dawn facilities that form part of the Dawn Hub:

> MR. QUINN: Okay. So starting with the question we asked here -- we had asked about Enbridge and Union coming together and integrating these facilities. Clearly, there had to be a model that provided ability to analyze the integrated storage network. Is that correct?
>
> MR. PARDY: Yes, that's correct. So since integration, we have taken our -- I would say separate models and combined them into one combined model that we used to do our analysis on.
>
> MR. QUINN: And when you did that, did you find any additional synergies that were created as a result of working the two network -- or two legacy networks together?
>
> MR. PARDY: I think this goes back to some of the earlier points. So no, **we didn't find any additional synergies just by creating a combined model, and the reason is the systems -- like pre-integration and today, the systems are connected and they are connected based on the premise that -- or the EGD or Corunna provides gas to Dawn at a specific pressure, and that Dawn provides gas to the other system at a specific pressure.**
>
> So all of the facilities at Dawn are designed around that assumption, and all of the facilities at EGD or at Corunna are designed around the same assumption.

[71] Exhibit I.FRPO.17(a)

[72] Technical Conference, Day 1 Transcript, p. 12

> So when you look at combining the system, yes, we have an integrated model that we can look at how we can operate. **But from a design day perspective, there is not -- there was no excess facilities in place that would create any incremental deliverability**.[73] (emphasis added)

63. Regarding the system's constraints and limitations, as part of the examination by Mr. Quinn, Enbridge Gas stated:

> MR. QUINN: Okay. So I want to break that down a little bit. What I hear you saying is you held the design pressures constant.
>
> MR. PARDY: We **<u>have to</u>** hold them constant.
>
> MR. QUINN: Why do you have to hold them constant?
>
> MR. PARDY: So today -- and I apologize for speaking in imperial units here, but today the gas coming from Corunna shows up at Dawn at 700 PSI and all the facilities at Dawn are sized to meet that 700 PSI delivery pressure. So supplies from TransCanada, Vector come in at 700 pounds. Supplies from the Corunna compressor station shows up at 700 pounds. The Union storage comes into our storage compressors at Dawn, and those are compressed at 700 pounds.
>
> So now everything in the yard, I will say, is at that 700-pound level and then it is compressed using the transmission horsepower to get it out to the line pressure.
>
> **<u>So if Corunna shows up at a lower pressure, then I need more storage horsepower to do that, and currently we're using all of that storage horsepower to compress the Union storage pools because that's what that compression was designed to do.</u>**[74](emphasis added)

64. Also, regarding the facilities operation as an integrated facility, the record clearly shows the following:

> MR. QUINN: But when you take it as an integrated facility, Mr. Pardy, you have a bigger pipe between the two. You have Dawn capability, some of which is not fully engaged or needed at that point, but you could use it to transport higher pressure gas to the Corunna facility, reducing the amount of load on -- the amount of energy required from the compressors to put that same amount of gas in the ground.
>
> So they have the capability to put more into the ground as a result, because there's higher pressure that arrives at Corunna.
>
> MR. PARDY: There is higher pressure that arises at Corunna, but there is less compressors.

[73] Technical Conference, Day 1 Transcript, pp. 45-46

[74] Technical Conference, Day 1 Transcript, pp. 46-47

> MR. QUINN: Yes, so --
>
> MR. PARDY: So if you look at the total, it is -- one is meant to replicate the other, right. So the combination of pipe and existing compression and pipe and future compression what is available are equal.
>
> So it is not -- and that is the way the system was sized. So you are correct, in the past we -- if we're discharging at 700 pounds from Dawn to move to Corunna, it is going to arrive at Corunna at a lower pressure. Then we need more compression at Corunna to compress that gas into storage.
>
> In the future, once we build the pipe, the higher pressure gas leaves Dawn and we eliminate that mid range compression, and we can inject directly into storage.
>
> And then at some point later in the season, we turn on K711 and K704 to top up those pools, as we did in the past.
>
> So you are correct. We -- like the system will operate differently, but the facilities are designed to mimic what is there today. So it doesn't add anything additionally. It is equal, pipe and compression versus pipe and compression.[75]

65. Finally, Enbridge Gas undertook at the Technical Conference to explain what asset or class of assets is the constraint that limits the ability to increase the amount of capability of Dawn to pull on Dawn-related storage assets to supplement a shortfall coming from Corunna.[76] Consistent with the foregoing, this analysis was set out in detail in Exhibit JT2.8. Contrary to Mr. Quinn's assertions in FRPO's submissions that he "pleaded for a greater understanding of the integrated operations", Enbridge Gas clearly, consistently and transparently articulated throughout the proceeding how those integrated operations function, their limitations and the implications for the CCS and the Project.

FRPO's assertion regarding one electric compressor is incorrect

66. FRPO further indicates that there is an opportunity to install one initial electric compressor to allow Enbridge Gas to remove the units in question over time.[77] FRPO wholly ignores the evidence that clearly demonstrates that this is not economically feasible and does not resolve the underlying reliability, obsolescence

[75] Technical Conference, Day 1 Transcript, pp. 35-36
[76] Technical Conference, Day 1 Transcript, pp. 59-60
[77] FRPO Submissions, p. 6

or safety concerns driving the need for the proposed Project.[78] At FRPO's request, Enbridge Gas produced a table that showed the flow from CCS to Dawn based on certain scenarios. As the Project is a one-for-one alternative to the current retiring units the Project provides a design day peak flow of 2,733 TJ/day. Based on the table provided the only other alternative that offered a similar design day was the scenario where K701-K703 and K705 were replaced with a Spartan E90 electric compressor with a flow of 2,765 TJ/day.[79] While design day peak flow is consistent, this alternative is unworkable for the following reasons:[80]

- Installing a single 10,000 – 12,000 HP compressor (such as a 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 capability in the event the single unit goes down. This increases the risk of EGD rate zone customers experiencing a material shortfall in the future (especially under design day conditions).[81] In effect, since a single electric compressor replaces units K701-K703 and K705 or any other combination of compressors, the failure of the single electric compressor would be equivalent to the simultaneous failure of all replaced compressors – in this case units K701-K703 and K705.

- A Spartan e90 compressor 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. The Company would need to assess the reliability of the electric grid infrastructure and the costs to install backup power generation in the event power service is interrupted. Existing backup power at CCS is only sized to provide power supply to controls and supply motor loads for cooling fans and pumps. Backup power would come

[78] Exhibit JT2.8

[79] Exhibit K1.3

[80] Replacing all 7 compressors with a Spartan leaves the integrated storage system with a deliverability deficit on Design Day of 666 TJ/day with a short fall in the EGD rate zone of 367 TJ/day with an estimated cost of $240 million (Exhibit JT 2.8)

[81] Exhibit I.SEC.13, p. 2

at an incremental cost that is not included in the current estimate, making this scenario even more uneconomic.[82] This is in stark contrast to the Project where building the NPS 36 pipeline and utilizing Dawn horsepower provides a backup power benefit 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.[83]

- This scenario does not address the imminent need to resolve the obsolescence, declining reliability and increasing safety risks to Company personnel underlying the proposed Project Application. As a result, the remaining units will have to be replaced over time given their age and obsolescence. Based on Enbridge Gas's analysis with respect to the Repair + Replace Alternative, where three units were replaced with an NPS 20 pipeline, that alternative's cost of $160 million combined with the estimated capital cost for a Spartan compressor of $169 million results in an overall cost in the range of $300-$333 million to ultimately retire all 7 compressors over time.[84] The Project is superior in this regard with significant cost savings realized through economies of scale by replacing all seven compressor units at one time with an NPS 36 pipeline for a total project cost of $206 million.

- Although the retirement of compressors would reduce equipment density. The safety risks would still exceed the upper risk threshold for Enbridge Gas personnel – in particular for those classified as Operator or Mechanic.[85]

FRPO's assertions regarding adjustment of EGD rate zone storage inventory targets are incorrect

67. While FRPO admits that adjustments made to EGD rate zone storage inventory targets following the winter of 2013/2014 is not a determinable issue, it incorrectly claims that only through discovery in the current proceeding did it become aware of

[82] Exhibit I.FRPO.28 and I.SEC.13
[83] Exhibit I.SEC.13
[84] Exhibit I.SEC.13
[85] Exhibit I.ED.10

the same.[86] In fact, the topic was discussed extensively as part of the OEB's 2014 Natural Gas Market Review proceeding (EB-2014-0289) and the Enbridge Gas Distribution Inc. 2015 Rate Adjustment proceeding (EB-2014-0276); Mr. Quinn having made submissions in the former process strongly supporting the benefit of using such inventory targets,[87] and directly questioning Enbridge Gas Distribution Inc. in the latter during a Technical Conference, where the inventory targets were provided to FRPO as an undertaking.[88] Since 2014, the Company has also made reference to its storage inventory targets in each of its 5-Year Gas Supply Plan,[89] and its 2020[90] 2021[91] and 2022[92] Annual Gas Supply Plan Updates, having included the same statement in each:

> "The inclusion of storage assets in the Plan provides a cost effective, reliable and secure alternative to purchasing commodity when required by customers, which is consistent with the Board's guiding principles. **Storage provides the Plan further operational flexibility and aligns with the target to fill storage at November 1, maintain sufficient inventory at February 28 to provide required deliverability from all storage assets, and maintain inventory at March 31 to provide sufficient deliverability to meet peak day demand in March.**"(emphasis added)

68. Enbridge Gas does not agree with FRPO's conclusion that the practical effect of adjusting storage inventory targets is to reduce availability of storage for seasonal load balancing by up to 25%.[93] The adjusted inventory target ensures there is sufficient storage inventories to meet design day demand until February 28, after which these inventories are drawn down as needed for the remainder of the season.

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86 FRPO Submissions, p. 7

87 EB-2014-0289, FRPO Evidence – NGMR – Winter of 2013/14 Storage Target Approach (November 24, 2014)

88 EB-2014-0276, Technical Conference, Transcript (February 25, 2015), p. 14; EB-2014-0276 Exhibit TCU1.1 (March 3, 2015)

89 EB-2019-0137, Enbridge Gas 5-Year Gas Supply Plan, p. 43

90 EB-2020-0135, Enbridge Gas 2020 Annual Gas Supply Plan Update, p. 36

91 EB-2021-0004, Enbridge Gas 2021 Annual Gas Supply Plan Update, p. 33

92 EB-2022-0072, Enbridge Gas 2022 Annual Gas Supply Plan Update, p. 42

93 FRPO Submissions, p. 7

The point of this adjustment was to mitigate the Company's reliance on potentially higher-priced natural gas (e.g., procured from the spot market) during periods of severe cold weather.

Pollution Probe's "do nothing" approach is inappropriate

69. Pollution Probe asserts that leave to construct should be denied in favour of the alternative of monitoring, maintaining and replacing the compressors only if required. In effect, Pollution Probe is advocating a "do nothing" approach. Pollution Probe's position is not in any way supported by the evidence in this proceeding. At its most basic level it seems only to be a statement that the facts in evidence do not exist and that the application is only a means for Enbridge Gas to build infrastructure, which is not the case. The condition and obsolescence of the compressors are real (other intervenors recognize this fact).[94] Failures are occurring at an increasing rate with unacceptable shortfalls projected that the Project prevents or mitigates. There is a loss of LCU capability on failure. There are unacceptable safety concerns. All of which requires that actions beyond Pollution Probe's do nothing approach to be undertaken. In this regard, the Project is the best alternative.

70. Pollution Probe's position appears to be partly based on the premise that compressors across Enbridge Gas's system, and in particular the storage system connected (directly or indirectly) to the Dawn Hub, are numerous and routinely used and that there is a high level of redundancy already in place at the CCS and the Project unnecessary. However, Pollution Probe provides no evidence to support the statement that there is a high level of redundancy.[95] As shown above, because of the various functional aspects of the compressors (low, medium and high pressure), loss of individual compressors completing those functions place greater reliance on the other compressors responsible for that function with no LCU capability. Furthermore, the integrated storage system has no ability to access additional gas on a design day.

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[94] SEC Submissions, p.2

[95] Pollution Probe Submissions, p. 3

71. Pollution Probe's belief is also based on its view there is a large variety of more cost-effective options available to Enbridge Gas, such as maintaining and supply-side contingency options. Pollution Probe did not identify what these alternatives are or provide any evidence in support of its position. This is because there is no evidence in this regard. Instead, what the evidence shows is a full canvas of the alternatives and the fact that the Project is the best alternative. Enbridge Gas's alternatives analysis was fully set out in Exhibit C-1-1 and summarized in a table in Exhibit I.SEC.13. Pollution Probe did not challenge the evidentiary basis or show why the analysis was not correct.

72. With respect to Pollution Probe's reference to supply side options, Enbridge Gas notes that it found that no non-facility alternatives, either alone or in combination with other facility and/or non-facility alternatives, can avoid or reduce the proposed facilities needed to replace the storage capacity lost at a reasonable cost to ratepayers in comparison to the proposed Project. Further, investments in supply-side alternatives alone would serve only to defer the proposed Project on a short-term basis, resulting in greater exposure of ratepayers to risk of shortfall/outage and a greater long-term cost to ratepayers than simply proceeding with the proposed Project.[96]

73. Pollution Probe also asserts that Enbridge Gas did not conduct a proper IRP alternative assessment in alignment with the OEB's requirements.[97] Pollution Probe bases this assertion on the OEB's encouragement provided in its St. Laurent Ottawa North Replacement Project (EB-2020-0293) Decision and Order, which states that Enbridge Gas, to the extent applicable, should undertake in-depth quantitative and qualitative analyses of alternatives that specifically include IRP, DSM programs and decarbonization efforts. In this case, it is not possible for the Company to implement and resolve the system constraint within the timeframe required. As a result, further IRP assessment is not applicable.[98] Notwithstanding the fact that Enbridge Gas was

[96] Exhibit C-1-1, pp. 7-10
[97] Pollution Probe Submissions, pp. 10-13
[98] Exhibit C-1-1, para 8

not required to conduct an IRP assessment, the Company pro-actively evaluated both supply-side and demand-side IRP alternatives including market-based storage, delivered services, upstream pipeline capacity, and enhanced targeted energy efficiency ("ETEE").[99] Contrary to Pollution Probe's submissions, the alternatives assessment conducted by the Company were thorough, realistic, and thoughtful. In particular, Enbridge Gas's Delivered Supply + ETEE alternative assessment accounted for the procurement of a supply-side alternative in the short-term (from 2023-2027) to provide the time required for a broader ETEE program to be implemented and for the Company to realize the requisite demand reductions from ETEE investment necessary to replace the Project.[100]

74. Pollution Probe also challenged the demand side management ("DSM") results set out within the Posterity Group's model on the basis that they underestimate the net benefits to Ontario rate payers.[101] Without basis in evidence, Pollution Probe claims that the model is not valid and results are inconsistent with historical demand side management results. Pollution Probe goes on to submit that Enbridge Gas's alternatives analysis is inaccurate because DSM programs provide net economic benefits to Ontario rate payers in the ratio of approximately $3 in benefits for every dollar spent.

75. Pollution Probe's submissions on the topics of DSM and Enbridge Gas's alternatives assessment are unsupported by the evidence, inappropriately rely upon the TRC+ test results from an unrelated broad-based DSM application proceeding making conclusions for a facility project, and completely ignore the feasibility of the ETEE alternatives assessed. What the evidence does support is the fact that the delivered supply + ETEE alternative assessed carries additional price and reliability risk compared to the proposed Project and is unable to replace the storage capacity lost

[99] Exhibit C, Tab 1, Schedule 1, pp. 6-17
[100] Exhibit C-1-1, p. 15
[101] Pollution Probe Submissions, p. 11

as a result of retiring the existing CCS compressor units, either in its entirely or in-part compared to the proposed Project.[102]

E. Indigenous Consultation

76. In its submissions, Three Fires Group Inc. ("TFG") argues that Enbridge Gas failed to carry out adequate Indigenous consultation before rejecting alternatives to the Project, and that the Company's efforts in this regard are inconsistent with its obligations and internal policies and with the goal of engaging communities early in the project development process.[103] TFG also argues that Enbridge Gas should be required to reconsider its 100-meter boundary limit for the cumulative effects assessment study area, and that Enbridge Gas's proposed activities and mitigation measures related to water crossings do not adequately protect aquatic species and resources that are subject to the Aboriginal and treaty rights of Chippewas of Kettle and Stony Point First Nation ("CKSPFN") and Caldwell First Nation ("CFN", together with CKSPFN, the "Three Fires First Nations").[104] As discussed below, TFG's arguments about inadequate consultation are not consistent with the legal principles of the duty to consult and the evidentiary record before the Board and unreasonably characterize Enbridge Gas's efforts at meaningful and early engagement. Further, contrary to TFG's assertion that Enbridge Gas has not appropriately identified and accounted for certain environmental impacts that the Project may pose, there is copious evidence on the record to demonstrate the rigorous assessment of potential environmental impacts and cumulative effects from the Project as well as the mitigation measures required.

Enbridge Gas has undertaken meaningful and early Indigenous consultation

77. Consistent with Enbridge Inc.'s Indigenous Peoples Policy and applicable legal principles, Enbridge Gas sought to achieve meaningful and early engagement so that the Indigenous groups' input could help inform the planned Project and avoid or

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[102] Exhibit C-1-1, pp.7-8, p. 15, p. 17

[103] TFG Submissions, Section III.A.

[104] TFG Submissions, Section III.D and III.E. Note that the "Three Fires First Nations" refers to Chippewas of Kettle and Stony Point First Nation and Caldwell First Nation.

minimize impacts on their rights and interests. As key context based on the relevant legal framework, the Crown's duty to consult (which is often delegated to project proponents to undertake the procedural aspects of consultation and in this case was delegated to Enbridge Gas) is about the right to a meaningful process rather than a particular outcome, and there must be give and take in good faith on all sides.[105] The process is a two-way street, such that Indigenous groups cannot frustrate reasonable good faith efforts via refusal to participate or set unreasonable conditions,[106] and Indigenous groups have an obligation to set out their interests and concerns and respond to overtures in a timely way.[107] This is particularly important given that different matters may be of particular concern to each Indigenous group. The consultation process does not provide a "veto" right over final Crown decisions, nor is there a duty to agree.[108]

78. Consistent with these principles, both prior to and during the OEB proceeding, Enbridge Gas undertook engagement with Indigenous groups in good faith with a view to gathering relevant information from Indigenous groups and addressing their concerns (e.g., by providing further information, answering specific questions, making additional commitments and/or offering Indigenous groups the opportunity to actively engage in field work). On a number of occasions, Enbridge Gas requested the input of Indigenous groups in order to better understand how any potential impacts from the Project on Indigenous interests could be avoided or mitigated.

79. TFG's assertion that Enbridge Gas failed to engage with Indigenous groups meaningfully and early in the planning stages of the Project appears to reflect an inaccurate understanding of the process that was followed by the Company. In January 2021, well over a year before the Application was filed, Enbridge Gas representatives reached out to Indigenous groups in the area notifying them of a

[105] *Haida v. British Columbia (Minister of Forests)*, 2004 SCC 73 [***Haida***] at para. 42

[106] *Halfway River First Nation v. British Columbia,* [1999] BCJ 1880 at para. 161; *Nunatukavut Community Council Inc. v. Canada (Attorney General)*, 2015 FC 981 at para. 212

[107] *Ktunaxa Nation v. British Columbia,* 2017 SCC 54 at para. 80; *Michipicoten First Nation v Minister of Natural Resources and Forests et al,* 2016 ONSC 6899 at para. 79

[108] *Haida*, para. 48.

potential project and asking to commence engagement with the various communities. The preliminary notice specifically acknowledged that the Project was in the preliminary stages and various options were being examined based on a number of factors.[109] In April 2021, based on the Indigenous groups the Ministry of Energy identified as having or potentially having Aboriginal or treaty rights that may be adversely affected by the Project, Enbridge Gas provided each group a formal Project description, outlining further details of the Project and offering capacity funding to support timely technical reviews of documents, participation in field work and engagement in meaningful consultation.[110] This offer was later accepted by (and capacity funding agreements were entered into with) a number of Indigenous groups.[111] Enbridge Gas subsequently held two virtual open houses, conducted one-on-one meetings with Indigenous groups, and responded to any questions or comments raised.[112]

80. Although CFN was not part of the list identified by the Crown, when CFN identified its interest in the Project to Enbridge Gas, Enbridge Gas offered similar opportunities to CFN to provide comments, meet to discuss any concerns regarding the Project, and participate in field work.[113] CFN also had the opportunity to participate in the OEB proceeding, which included the opportunity to ask questions in both writing and orally and make submissions to the OEB.

81. To date, Indigenous groups have had significant opportunities to raise any questions or concerns regarding the Project, including through less formal avenues (e.g., one-on-one meetings/emails, as noted above) as well as through the OEB proceeding. Where those questions or concerns have been raised, Enbridge Gas has provided answers or made reasonable attempts to address their concerns. For example, Enbridge Gas's responses to both the Walpole Island First Nation and Aamjiwnaang

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[109] Exhibit H-1-1, Attachment 6, Attachment 1.1, Attachment 2.1, Attachment 3.1, Attachment 4.1, Attachment 5.1

[110] Exhibit H-1-1, Attachment 6, Line Items 1.2, 1.3, 2.2, 2.3, 3.2, 3.3, 4.2, 4.3, 5.2, 5.3

[111] Exhibit I.CKSPFN.8(h).

[112] Exhibit H-1-1, Attachment 6 Exhibit I.CKSPFN.8(k).

[113] Technical Conference, Day 2 Transcript, p. 136

First Nation's comments on the Environmental Report addressed a wide range of concerns, questions and requests, including those related to: access to reports and surveys; study methodologies; fugitive emissions; and additional permitting processes.[114] Enbridge Gas also answered the wide-ranging questions of CFN and CKSPFN put forward during the OEB proceeding, including questions regarding the cumulative effects methodology[115] and fugitive emissions[116]. TFG may not agree with some of Enbridge Gas's responses, including, for example, with regard to the cumulative effects methodology or the extent of residual effects. However, as noted above, agreement is not required for there to be meaningful consultation. The parties can have different perspectives as long as those perspectives are reasonable.

82. In addition, TFG argues that Enbridge Gas failed to adequately consult on Project alternatives, which is a flawed argument for two main reasons. First, the duty to consult is triggered by the specific Crown decision at issue, which in this case is the OEB decision on the leave to construct application. Accordingly, consultation and engagement were necessarily focused on the Project, since it is the planned work (as opposed to the alternatives not pursued) that may potentially impact Indigenous interests. Secondly, and in any event, questions regarding potential alternatives to the Project and the corresponding route could have been raised for discussion and response at any time during the engagement process. By way of example, Enbridge Gas provided a presentation in August 2021 regarding the route selection for the Project in response to a request by the AFN[117] and, following the Environmental Report being made available for comment in September 2021, Enbridge Gas considered the comments received and provided detailed responses to address the concerns and questions raised.[118]

[114] Exhibit F-1-1, Attachments 3 and 4
[115] Exhibit I.CKSPFN.2
[116] Exhibit I.CKSPFN.3
[117] Exhibit H-1-1, Attachment 5
[118] *Ibid*

83. In addition to the opportunity to discuss potential alternatives before the application was filed, a full description of the analysis of alternatives, both facility and non-facility, was included in the application[119] and therefore, the Indigenous groups and their representatives had a further opportunity to ask questions about potential alternatives both in writing through interrogatories as well as orally at the Technical Conference. As has been recognized by the Supreme Court of Canada, the regulatory process itself can provide an opportunity for effective consultation.[120]

84. The issue of alternatives to the Project was first raised by the CKSPFN and CFN in interrogatories in this proceeding.[121] Despite the fact that the issue of potential alternatives was not raised as a concern earlier on in the consultation process, Enbridge Gas clearly acknowledged its willingness to answer any questions about alternatives to the Project.[122] As is evident from the record, the issue of alternatives has been the subject of significant discussion since it was raised during the proceeding.

85. For these reasons, TFG's argument that Enbridge Gas did not adequately consult Indigenous groups on Project alternatives and that Enbridge Gas failed to carry out early and meaningful consultation is contrary to the record before the Board and should be rejected. Enbridge Gas agrees with TFG in principle that Indigenous groups must be given adequate time and resources to understand and comment on impacts stemming from a project. This is precisely why, as noted above, Enbridge Gas offered Indigenous groups capacity funding and opportunities to participate in field work monitoring early on in the process. Going forward, Enbridge Gas remains committed to engaging with Indigenous groups throughout the lifecycle of the Project to ensure any impacts on Aboriginal or treaty rights are addressed as appropriate.[123]

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[119] Exhibit C-1-1

[120] *Taku River Tlingit First Nation v British Columbia (Project Assessment Director),* 2004 SCC 74 at para 40; *Chippewas of the Thames First Nation v Enbridge Pipelines Inc*, 2017 SCC 41 at para. 1; and *Clyde River (Hamlet) v Petroleum Geo-Services Inc*, 2017 SCC 40 at para. 22

[121] Exhibit I.CKSPFN.4

[122] Exhibit I.CKSPFN.4(c)

[123] Exhibit H-1-1, p. 4

Enbridge Gas has effectively considered the potential Project impact on waterways and associated comments from Indigenous groups

86. TFG argues that Enbridge Gas's proposed mitigation measures related to water crossings during construction do not adequately protect aquatic species and resources subject to the Three Fires First Nations' Aboriginal and treaty rights,[124] and that Enbridge Gas has not fully consulted with CKSPFN regarding impacts to waterways subject to CKSPFN's Water Assertion.[125] Enbridge Gas disagrees. CKSPFN (and other Indigenous communities) had an opportunity to comment on the Environmental Report and participate in field assessments. In fact, CKSPFN did provide comments on the Environmental Report to which Enbridge Gas responded.[126]

87. The Environmental Report for the Project addressed the potential impacts and recommended mitigation and protective measures on environmental features, including aquatic features.[127] Enbridge Gas responded to CKSPFN's comments on the Environmental Report including their interest in fish and fish habitat and invited CKSPFN to participate in the fish community sampling and the fish and mussel habitat assessments.[128] Detailed results of these and other natural heritage surveys will be shared with CKSPFN in a Natural Heritage Report upon its release at the end of 2022.

88. With respect to CKSPFN's 2017 Water Rights Assertion in particular, Enbridge Gas was first informed of the Assertion on May 11, 2022 in a virtual meeting between the parties and confirmed receipt of the Assertion on June 10, 2022.[129] Enbridge Gas has carefully considered the Assertion and responded to a variety of questions from

[124] TFG Submissions, Section D, para. 47

[125] TFG Submissions, Section D, para. 52

[126] Technical Conference, Day 2 Transcript, pp. 106-107; Exhibit JT2.12

[127] See specifically Table 5.1 of the Environmental Report at Exhibit F, Tab 1, Schedule 1, Attachment 1, p. 68.

[128] Exhibit JT2.12 specifies that Enbridge Gas will be responding to CKSPFN's comments on the Environmental Report by August 31, 2022. Enbridge Gas provided the responses to CKSPFN by email on August 30, 2022.

[129] Exhibit I.CKSPFN.8 response b) and k) line item 2.23

the CKSPFN regarding its asserted water rights during this OEB proceeding.[130] The Company has also explained in detail the approach to water crossings and the related mitigation measures to protect aquatic species and resources.[131]

89. Moreover, Enbridge Gas has provided CKSPFN with the generic sediment control plans that detail the general construction practices and mitigation measures for completing the watercourse crossings associated with this Project. The generic sediment control plans have been reviewed and approved by the DFO as part of the agreement between Enbridge Gas and DFO. These plans when implemented are expected to result in a low risk of harmful alteration or disruption (known as HADD) as defined under the *Fisheries Act*, and thus no further approvals for these plans are required from the DFO.[132]

90. As another layer of regulatory scrutiny, permitting processes related to water crossings that may impact at-risk species could result in the introduction of further mitigation measures and conditions to protect any such species and their habitat. Initial applications for such water crossings have been submitted to the DFO (under the Species at Risk Act) and the provincial Ministry of Environment, Conservation and Parks (under the Endangered Species Act). Enbridge Gas will consult with interested Indigenous Communities in due course as part of those approval processes.

91. Enbridge Gas is of the view that it has been able to provide a reasonable and sufficient response to any Project-specific comments and concerns that the TFG has raised to date. In other words, TFG has not raised (and Enbridge Gas is not otherwise aware of) any potential impacts the Project may have on Aboriginal rights that Enbridge Gas has not addressed through its proposed mitigation measures and commitments on the Project and its engagement with TFG (or the communities represented by TFG).

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[130] Exhibit I.CKSPFN.8
[131] Exhibit I.CKSPFN.8 (d)
[132] Exhibit JT2.12

Enbridge Gas has effectively assessed the potential cumulative and residual effects for the Project

92. TFG submits that Enbridge Gas failed to consult with Indigenous communities prior to a determination of the boundary limit for the cumulative effects study area, and that the default 100 metre boundary is inadequate.[133] Enbridge Gas appreciates TFG's input regarding the cumulative effects study area, has considered it and is of the view that an appropriate cumulative effects assessment was performed. Specifically, the 100-metre boundary is appropriate given the limited residual Project effects (i.e., those that remain after mitigation) that are anticipated to be interactive with other concurrent, unrelated projects.[134] The cumulative effects assessment and the associated study area were delineated in accordance with Section 4.3.14 of the OEB's Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario, 7th Edition, (2016) (the "Guidelines"). As explained in Section 6.2 of the Environmental Report, 100 metres represents an approximate boundary and does not preclude any projects or impacts that may exist beyond that distance from being considered. The methodologies used to conduct the cumulative effects assessment (as detailed in Section 6.1 of the Environmental Report) are the same as those applied for other Enbridge Gas projects that have been approved by the OEB in the past.[135] Importantly, OEB staff's submissions are supportive of the application in this regard, noting that the Environmental Report meets the requirements of the Guidelines and that OEB staff has no concerns with the environmental aspects of the Project.[136]

93. While TFG expresses concern that the Project's residual impacts will extend far beyond 100 metres,[137] the study undertaken to assess potential Project impacts indicates that provided the mitigation and protective measures outlined in this report are implemented and that concurrent projects implement similar mitigation and

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[133] TFG Submissions, Section E
[134] Exhibit I.CKSPFN.2 (j) & (k)
[135] *ibid*
[136] OEB Staff Submissions, pp. 13-14
[137] TFG Submissions, Section E, para. 57

protective measures, potential cumulative effects are not anticipated to occur, or if they do occur are not anticipated to be significant.[138] It is noteworthy that the vast majority of the Project is situated within existing sites, corridors or road allowances.

The Project will result in an overall decrease in fugitive methane emissions

94. TFG also submits that the proposed pipeline will result in an increase in fugitive emissions emitted throughout the treaty lands and traditional territory of the Three Fires First Nations, and that this increase will lead to increased costs for ratepayers due to pass through charges under the federal and provincial GHG pricing schemes.[139] This argument is not supported by the evidence in this proceeding, which shows that replacing the seven CCS compressors to be retired with the proposed pipeline will result in an overall decrease in fugitive methane emissions compared to the baseline.[140] Specifically, the decrease in emissions will total approximately 600 tCO_2e/year over current levels (methane accounting for approximately 595 tCO_2e/year).[141] Moreover, both the Output-based Pricing System ("OBPS") component of the Federal Carbon Pricing Backstop and the Ontario Emissions Performance Standards program (which replaced the OBPS in Ontario as of January 1, 2022) apply only to stationary combustion and flaring emissions, and not to fugitive methane emissions as TFG incorrectly suggests.[142] As such, TFG's claims in this regard should be rejected. It is also worth noting that Enbridge Gas is developing and implementing a Scope 1 and Scope 2 GHG emissions reduction strategy,[143] which will identify and assess cost effective opportunities to reduce emissions from its facilities (including fugitive emissions).

95. In specific response to TFG's requests set out in paragraph 78 of its submission, Enbridge Gas submits the following:

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[138] Exhibit F-1-1, Attachment 1, Section 6.5
[139] TFG Submissions, Section III.C
[140] Exhibit JT1.18
[141] Exhibit I.CKSPFN.3 (f)
[142] Exhibit I.ED.12, p. 3; and Exhibit I.IGUA.3, p. 2
[143] Exhibit I.CKSPFN.4 (a)

- Enbridge Gas has meaningfully engaged with TFG and other potentially affected Indigenous groups, as identified by the MOE, early in the planning stages of the Project and while Enbridge Gas has expressed that a goal of its engagement is to aim to secure the free, prior and informed consent of potentially affected Indigenous groups with respect to the Project, this is not a legal requirement, therefore, the Board should not impose such a condition on the Project;[144]

- Information regarding the alternatives to the Project was provided in this proceeding and Enbridge Gas has responded to TFG's questions regarding alternatives;

- As recognized by TFG in paragraph 35 of its submission, Enbridge Gas will commit to providing TFG with the Natural Heritage Report, Fisheries Act and Species at Risk Act applications, and any Archaeological reports for review and comment and Enbridge Gas has committed to providing TFG with capacity funding for these sorts of initiatives;

- Enbridge Gas will commit to providing monitoring opportunities for a representative from CKSPFN and Caldwell First Nation during HDD or dam and pump activities in relation to the Project;

- Enbridge Gas will commit to providing TFG with monthly reports during construction for the Project, which will include information on construction progress, environmental considerations and other matters of importance to TFG;

- Enbridge Gas will commit to continuing to engage with TFG about cumulative effects;

- Enbridge Gas commits to including information about drug and alcohol use, Indigenous cultural awareness and human trafficking as part of on-site orientation during construction and submits that a condition as set out in

[144] *Coldwater Indian Band et al. v. Attorney General of Canada, Trans Mountain Pipeline ULC et al.,* 2020 FCA 34 at para. 194, Exhibit H, Tab 1, Schedule 1, Attachment 6 indicates Enbridge Gas commenced its engagement in January 2021, well over a year before the Application was filed.

paragraph 78(ix) of TFG's submission is not necessary in relation to the Project given its scale and scope; and

- That Enbridge Gas understands that the OEB has launched a process to update the Guidelines.[145]

96. Enbridge Gas submits that it has meaningfully engaged Indigenous groups potentially affected by the Project, as identified by the MOE, including TFG and the Three Fires First Nations, to ensure any potential impacts the Project may have on Aboriginal rights can be avoided or mitigated. Given the commitments made by Enbridge Gas in this proceeding and through its engagement with Indigenous groups, TFG and the Three Fires First Nations' participation in this regulatory process and the conditions, which may be added to any OEB approval of the Project, Enbridge Gas submits that the MOE should find the duty to consult to have been satisfied in the circumstances.

F. Energy Transition

97. ED argues that the Project should be deferred given the potential impact of future gas demand scenarios in light of the federal government's emissions reduction targets under the *Canadian Net-Zero Emissions Accountability Act*.[146] In particular, ED identifies three elements of the federal emission reduction plan that it claims could impact gas demand: targeted emissions reductions from the building sector, net-zero power generation by 2035, and economy-wide net zero by 2050. ED speculates that "These official plans and legally binding targets will certainly have an impact on gas demand", which could "in turn, impact the relative cost-effectiveness of the various alternatives under consideration".[147] ED also suggests without any basis that achieving net-zero by 2050 means the Project assets may no longer be

[145] https://engagewithus.oeb.ca/ontario-pipeline-coordinating-committee/news_feed/oeb-launches-project-to-update-environmental-guidelines-for-location-construction-and-operation-of-hydrocarbon-pipelines-and-facilities-in-ontario

[146] ED Submissions, p. 2

[147] *Ibid*, p. 3

used and useful by that time.[148] ED's argument is flawed and speculative and should be rejected by the Board, as further explained below.

98. First, despite ED's characterization of the *Canadian Net-Zero Emissions Accountability Act*, the legislation does not bind Enbridge Gas or any other emitters to specific emissions reduction targets. As described by the Government of Canada, "the Act establishes a legally binding process to set five-year national emissions-reduction targets as well as develop credible, science-based emissions-reduction plans to achieve each target".[149] Instead of mandating specific targets for different industry sectors or jurisdictions, the Act requires the federal government to establish national targets (i.e., 40-45% below 2005 levels by 2030 and net-zero emissions by 2050) and assess and report on the progress made over time. To achieve this, a myriad of policies, strategies and measures are needed, as highlighted in the federal 2030 Emission Reduction Plan (to be updated in successor plans) and as pursued by various provinces and municipalities. Notably, the Federal Carbon Pricing Backstop was enacted by Parliament through the *Greenhouse Gas Pollution Pricing Act*, under which Enbridge Gas as a large Ontario emitter is currently subject to the federal carbon charge on fossil fuels for its customer-related emissions as well as the Ontario Emission Performance Standards ("EPS") for its facility-related emissions.

99. Enbridge Gas will continue to manage and fulfill its compliance obligations under these regulatory requirements as well as any other applicable GHG emission reduction programs.[150] In addition, Enbridge Gas has a key role in supporting the corporate emissions targets that form part of Enbridge Inc.'s ESG goals, including to reach net-zero by 2050 through a diversified approach to decarbonization.[151] However, the fact is there are no specified binding emissions reduction targets on

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[148] *Ibid*, p. 4

[149] https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/climate-plan-overview/emissions-reduction-2030/plan/overview.html

[150] Such as the federal Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) and the federal Clean Fuel Regulations.

[151] Exhibit F-1-1, Attachment 4, p. 1

Enbridge Gas or the natural gas sector in Ontario as a result of the federal targets, and there is currently no clarity as to how the different levels of governments will achieve their emissions reduction goals.

100. Secondly, ED's suggestions that "the need for capacity may decline and/or disappear over time"[152] and that the Project assets may no longer be used and useful by 2050[153] as a result of the federal targets are entirely speculative. Similar views were also expressed by Pollution Probe[154] and TFG[155]. In fact, the extent of reduction on gas demand and its impact (if any) on peak capacity requirements is entirely uncertain at this point. As Enbridge Gas explained in response to ED's questions at the Technical Conference, it is not reasonable or feasible to expect the Company to translate potential national volumetric reductions into regional gas capacity requirements; and the fact is that even if the impact on annual demand is known, it is not necessarily indicative of the potential extent of peak reductions.[156] Nevertheless, ED chooses to ignore this important consideration and claims without basis in its submissions that "it is entirely feasible to at least develop a range of reasonable assumptions so that parties can examine the range of potential outcomes".[157] This is a bold assertion that is unsupported by any probative evidence on the record. Contrary to ED's claim, attempting to make such modelling assumptions for the sake of coming up with a scenario (or range of scenarios) would be arbitrary and speculative,[158] and would not yield any meaningful results to inform the consideration of relevant issues in this proceeding.[159]

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[152] ED Submissions, p. 3

[153] ED Submissions, p. 4

[154] PP Submissions, p. 9

[155] TFG Submissions, p. 13

[156] Technical Conference, Day 1 Transcript, p. 143, ln. 1-3; p. 145, ln. 20-24; p. 146, ln. 27-28

[157] ED Submissions, p. 4

[158] *Supra* note 156

[159] Also see Exhibit I.ED.3 e) h) & i), where ED asked about customer demand associated with buildings and gas plants and the impact of phasing out gas-fired generation on annual demand and design day demand. In response, EGI indicated that "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". The electricity system in Ontario is constantly evolving, as exemplified within the government of Ontario's most recent announcement on October 7 that in order to ensure system

101. Thirdly, ED argues that the federal emission reduction targets could lead to demand reductions that render the Project redundant.[160] However, this argument ignores the reality that even the most aggressive demand-reduction scenarios would not eliminate the need for the Project.[161] In fact, there needs to be "a design day demand reduction of 44 percent in the EGD rate zone for the project to not be needed in its entirety".[162] This reduction equates to approximately 1.8 PJs on a design day[163], which is equivalent to approximately 2.3 million average residential homes disconnecting from Enbridge Gas's system and converting all existing appliances to alternative forms of energy.[164] As the steward of infrastructure/assets that are critical to Ontario's gas consumers and economy, Enbridge Gas cannot simply ignore the known risks on its system (including risks related to reliability, obsolescence and safety, as highlighted above) and instead make decisions based on conjectures that are beyond the realm of what is realistic. To do so would be highly imprudent for any asset manager, much less the owner and operator of critical infrastructure that is counted on by millions of Ontarians every day of the year.

G. Other Issues

102. Pollution Probe also makes various submissions regarding negotiations between Enbridge Gas and CAEPLA-DCLC, the forms of lands rights agreements proposed by Enbridge Gas, outstanding permits and approvals, and citing what Pollution Probe describes as past reported instances of environmental and socio-economic non-compliance with OEB conditions of approval or landowner agreements.[165] It isn't

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reliability and keep costs down Ontario is proceeding with its plan to procure up to 1,500 MW of natural gas-fired electricity generation to resolve a projected shortfall beginning in 2025 and 2026 (https://news.ontario.ca/en/release/1002373/ontario-building-more-electricity-generation-and-storage-to-meet-growing-demand). IESO has also recently concluded that phasing out natural gas electricity generation by 2030 is not feasible and would result in blackouts, and replacing natural gas fired electricity generation by 2030 would increase residential electricity bills by at least 60% (https://www.ieso.ca/en/Powering-Tomorrow/2021/Six-things-to-know-about-the-IESOs-study-on-phasing-out-gas-fired-generation-by-2030).

[160] ED Submissions, p. 4

[161] Technical Conference, Day 1 Transcript, p. 21, ln. 6-9

[162] *Ibid*, p. 21, ln. 10-12

[163] Exhibit JT1.9

[164] *Ibid*, p. 21, ln. 13-17

[165] Pollution Probe Submissions, pp. 15-16

clear exactly what Pollution Probe is requesting of the Board in these regards, but the OEB should give these submissions no weight.

103. Importantly, Enbridge Gas and CAEPLA-DCLC landowners have reached a settlement in principle regarding landowner issues and expect to jointly file updated copies of the agreed forms of Pipeline Easement, Temporary Land Use Agreement, and Letter of Understanding with the OEB (expected to be filed with the OEB shortly following the date of these reply submissions of Enbridge Gas).[166]

104. Regarding the ER and related matters, OEB staff submits that the ER meets the requirements of the OEB's Guidelines and that staff has no concerns with the environmental aspects of the Project, given that Enbridge Gas is committed to implementing the mitigation measures set out in the ER and to completing the Environmental Protection Plan ("EPP") prior to the start of construction.

105. OEB Staff notes that the OEB's Standard Conditions of Approval for LTC require Enbridge Gas to obtain all necessary approvals, permits, licences, and certificates needed to construct, operate and maintain the proposed Project and ensure that the environmental impacts of the Project are addressed, mitigated and monitored.[167] Enbridge Gas accepts these conditions and advised that it expects to have all required approvals, permits, licences, and certificates prior to the commencement of Project construction.

106. Finally, the instances of non-compliance associated with historical facility projects constructed by Enbridge Gas cited by Pollution Probe are contained within independent construction monitoring reports that were agreed to by the Company and/or a condition of leave to construct approval. The cited reports, which were submitted to the Company, OEB Staff, and landowners, are an effective and transparent record of landowner grievances and instances of non-compliance that have served as lessons-learned supporting improved construction practices going forward. In all such instances, and dependent upon the unique circumstances at the

[166] EB-2022-0086 CAEPLA-DCLC and Enbridge Gas Joint Update (September 30, 2022)
[167] OEB Staff Submissions, p. 14

time, Enbridge Gas works directly with affected landowners to further mitigate, resolve and/or compensate them for any non-compliance or damages that result from the same. Enbridge Gas has already agreed to hire an independent construction monitor as part of the proposed Project and accepts the OEB's standard conditions of approval regarding monitoring and reporting. No further direction or conditions are required of the OEB in this regard.

H. Relief Requested

107. Based on the foregoing, Enbridge Gas respectfully requests that the OEB, pursuant to section 90 of the Act, issue an Order granting leave to construct the pipelines and pursuant to section 97 of the Act, issue an Order approving the forms of Pipeline Easement and Temporary Land Use agreements set out at Exhibit G, Attachments 3 and 4 (or as otherwise amended as a result of negotiations between CAEPLA-DCLC and Enbridge Gas, and as jointly filed shortly following the date of these reply submissions of Enbridge Gas).

All of which is respectfully submitted this 11th day of October 2022.

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