ISSUE 1: Need for Project

Preamble: Prior to specifying our inquiries to Enbridge Gas Inc. (EGI), we want to make note that some of our inquiries will pertain to Dawn. From the application, it is pretty clear that the Corunna Compressor Station (CCS) and Dawn are piped to each other and have many common facilities such that they integrally linked in providing injection and withdrawal capabilities between the storage pools and demands on these pools. While the focus on the application is the CCS, we believe it is essential that the Board is informed regarding the operating relationship between Dawn and the CCS to understand the existing capability and the potential capability after the proposed and alternative facilities are added.

In addition, while the focus of the evidence speaks to meeting the in-franchise needs of the EGD rate zone, it obscures the demands placed on the integrated storage network by the non-utility storage services provided by EGI. Nevertheless, to understand the full capabilities of the compressor facilities, the total storage service including the regulated, non-utility service capability must be included in assessments that ought to have been considered with this project. We submit that the Board should be informed on the total capabilities of the storage network in view of the proposed changes.

As a result, we would ask the company to provide the information requested to reduce the need for further steps of discovery which would impact regulatory efficiency.

REF: Exhibit B, Tab 1, Schedule 1, p. 7-8 including Figure 2

Preamble: Figure 2 provides a good overview of the piping network in and around the storage area of EGI.

We would like to understand and clarify the interconnections between the two central compressor stations, the storage pools and the pipelines moving gas out of the area.

1) Please provide the size and MAOP of all EGI-owned lines depicted in Figure 2.
   a) Paragraph 18 refers the two NPS 30 pipelines that run directly between the CCS and Dawn. However, there is a pipeline that goes from Dawn to Wabuno which seems to extend to the Kimball-Colinville pool and, perhaps, the CCS. Please clarify if this pipeline connects through Wabuno to the CCS.
   b) Please clarify if the pipeline depicted as the vertical line that runs through TCPL Courtright and Vector Courtright north toward Sarnia is the Sarnia Industrial Line.
      i) If so, can the CCS provide natural gas service into the Sarnia Industrial line?
         (1) If yes, what is the daily demand that can theoretically be provided?
         (2) How much of the daily demand of that Sarnia industrial system does the CCS provide on a peak day for the 2021/22 winter?

2) Please provide the study that EGI or Enbridge Inc. undertook to evaluate the synergy and integration opportunities of the two previously separate storage operations of the CCS and Dawn. We understand that EGI/EI may be concerned about confidentiality. Therefore, we respect if the submission of this study may require confidentiality treatment for which we will comply with the Board's practice directions in handling.
   a) If no such study exists, please explain why a newly-integrated utility would not undertake a study to determine if two physically linked operations which perform the same type of functionality would not be studied to determine how the integrated operations may be refined to create additional capacity.

3) Please confirm that the CCS compressors provide compression operations that serve both the utility and non-utility storage services.

Preamble: In the following interrogatory and in some interrogatories later in our questions, we use the terms working storage space, peak injection capability and peak withdrawal capabilities. While we believe the specific definition of these parameters should be provided by EGI, we want to ensure that there is a common frame of reference.

So, for example, with certain infrastructure in place, the working storage space available would be: what is specific storage capacity available between the design minimum expected at the end of the withdrawal season and the maximum amount that could be injected at the end of the injection season.

4) Using the above example as a reference for a consistent definition from which various alternatives can be compared, please provide EGI's working definition of:
   a) Working storage space (we have requested the space for both injection and withdrawal in respect of hysteresis or other limitations which would differentiate injection and withdrawal)
   b) Peak injection capability (TJ/day at some consistent reference parameters)
   c) Peak withdrawal capability (TJ/day at some consistent reference parameters)

5) For each of the CCS, Dawn and for the combined operations, please provide:
   a) The working storage space and peak injection capability for the existing facilities.
   b) The working storage space and peak withdrawal capabilities for the existing facilities.
   c) The working storage space and peak injection capability for the existing facilities if two, three or four of the existing (determined by EGI as a smaller half from a necessity and condition point of view as a first step) are removed.
   d) The working storage space and peak withdrawal capabilities for the existing facilities if two, three or four of the existing (determined by EGI as a smaller half from a necessity and condition point of view as a first step) are removed.
   e) The working storage space and peak injection capability for the existing facilities if all seven compressors are removed.

f) The working storage space and peak withdrawal capabilities for the existing facilities if all seven are removed.
g) The working storage space and peak injection capability for the proposed facilities.
h) The working storage space and peak withdrawal capabilities for the proposed facilities.

REF: Exhibit B, Tab 1, Schedule 1, p. 9-16 including Table 1

Preamble: Footnote 6 states: *It is anticipated that when these units reach their end of life they will be replaced with new compressor facilities at the CCS.*

We are interested in the relative age and current condition of the compressors and the impact of individual compressor failures on storage operations.

6) For each compressor listed in Table 1, please provide:
   a) the year of installation of each of the respective compressors
   b) the year of and the specific compressor for any significant overhaul of the compressor internals since their date of installation
   c) The amount spent on O&M or betterment capital spent on each compressor in the last 5 years

7) In the last 10 years, please provide the following for any compressor failures that created a short notice limitation to storage services for in-franchise or ex-franchise service:
   a) The compressor affected
   b) The date of the incident
   c) The amount of notice provided to ex-franchise customers for curtailment
   d) The amount of time from the notice of outage to:
      i) Restoration of full service (i.e., no further curtailment)
      ii) Complete repair of the compressor to allow return to service

8) In addition to the answers above on compressor failures that caused service limitations, if a compressor failed and Compressor K711 was activated as backup, please provide:
   a) The compressor affected
   b) The date of the incident
   c) The amount of time to complete the repair of the compressor to allow return to service

9) Please file the EGI Priority of Storage Service Schedule
   a) Please clarify if the priority of service is different for each of the legacy utility storage contracts

10) Footnote 13 indicates that compressors K705-708 are interchangeable and EGI only needs three to be in operation. Therefore, in a scenario whereby two of those compressors are inoperable, can K7o4 or K711 provide some of the functionality of the two compressors offline?
   a) Please explain what operations cannot be performed and why?
   b) How were the daily impacts of $0.8-11M per day calculated?
      i) Did these calculations take into account any support from K704 or K711?
         (1) If so, how?
         (2) If not, what would be the result if K711 were used to mitigate?

11) Numerous times in the evidence, EGI states that it will replace up to seven compressors. While we respect that which compressors and in what order will likely depend on operational issues that may arise in the coming years, with the best information it has at this time, please provide EGI's opinion on:
   a) What would the order of replacement be?
   b) In what year would EGI forecast the replacement?
   c) What compressors are very unlikely to be replaced by the proposed pipe or other mitigation steps the company may envision at this time.

REF: Exhibit B, Tab 1, Schedule 1, p. 27

Preamble: EGI evidence states: *Finally, this short-term mitigant may require that the Company make additional pressure control retrofits on the two existing NPS 30 transmission lines (TR1 and TR2) connecting the CCS to Dawn at significant expense to ratepayers.*

We would like to understand more about risk mitigation that could be employed.

12) Please provide a cost estimate of this pressure control retrofit.

REF: Exhibit B, Tab 1, Schedule 1, p. 28

Preamble: EGI evidence states: *Further, considering the obsolescence and reliability concerns discussed above, there is a heightened probability that repairs could require extended outage windows. The RAM Study specifically estimates that on average more than 6,500 hours per year of downtime will be required for units K701-K703 and units K705-K708.*

While the study produced seems to project downtime, we would like to understand the historic downtime of the compressors.

13) In a table, for each compressor, please provide the actual downtime of each of the units due to required maintenance or repair.

REF: Exhibit B, Tab 1, Schedule 1, p. 30-31

Preamble: EGI evidence states: *Aside from the assessments and studies discussed above, the Company's conclusions were also informed by…*

- *ICF's forecast calling for increased seasonal storage values and winter price volatility;*

14) Please file the report referenced.
   a) Please specify where the content of the report was used in the evidence and potentially decision-making.

REF: Exhibit B, Tab 1, Schedule 1, Attachment 1, p. 4-5

Preamble: The included report states: *The higher shortfall in earlier years is caused by a higher likelihood of foundation failures of units K704 (HP duty) and K701 (MP duty) as compared to the other CCS units, with the former having a high impact in injection capability, given its low level of redundancy…*

- *Units K-704 and K-711 (HP units) are responsible for 99.56% of the total Gas Injection shortfall. In absolute terms, this represents 309,784.3 x103 m3 of Gas Injection Shortfall (2.25%). This is attributed to the combined 'N' configuration that these units exhibit for the majority of the time that they are required to operate.*
- *Foundations are the most significant contributor to Gas Injection Shortfall, accounting for 31.37% of total shortfall (97,605.7 x103 m3, 0.71% absolute). This is attributed to the long duration associated with the repair of this maintainable item.*

From our read of the evidence, compressor K704 provides specific duty that reduces the likelihood that it would be replaced in the short term. Therefore, we would like to understand more about the foundation repair.

15) Please provide:
   a) The forecast year of repair
   b) The cost of the repair
   c) The amount of downtime estimated

d) EGI's approach to minimizing the impact of this downtime on peak operations where K704 provides important service

REF: Exhibit B, Tab 1, Schedule 1, Attachment 1, p. 6

Preamble: The included report states: *The figure below presents a yearly breakdown of the Base Case Gas Withdrawal Shortfall over the 5-year review period. During the 5 years assessed, the mean Withdrawal Efficiency of the Corunna facilities against Demand is 98.40%; 17,872,477 x103 m3 of gas was withdrawn against a Demand of 18,162,200 x103 m3.*

We would like to understand this shortfall management.

16) Please provide the actual shortfall over the last 5 years.
   a) Please confirm that the CCS does not have contingency space like Dawn.
   b) What amount of deliverability is associated with the Dawn contingency space?
   c) Does Dawn provide this contingency space in support of the CCS?
      i) If not, why not?
      ii) If so, how much CCS shortfall can the Dawn contingency space provide?
   d) If Dawn operations are not used, how has EGI managed this CCS shortfall?

REF: Exhibit B, Tab 1, Schedule 1, Attachment 1, p. 10

Preamble: The included report states: *CCS has two modes of operation: injection and withdrawal. Injection operating mode takes gas from the two twin NPS 30 transmission pipelines from Dawn and flows the gas through CCS to the offsite storage pools*

We would like to understand the injection operations against the risks defined in this evidence.

17) Please describe how EGI develops an injection/withdrawal schedule for the CCS on an annual basis.
   a) Please include how the integration with Dawn operations contributes to that schedule.
   b) Please file the summary injection schedule (from the last two versions prior to injection season) which highlights expected downtime for the CCS compressors for the last two injection seasons.

18) What is the minimum pressure assumed, under design conditions, that the gas will be received from the NPS 30 lines from Dawn during the injection season?
   a) Does the CCS draw gas from other pipelines during the injection season?
   b) If so, please provide the pipelines and the range of delivery pressures from these pipelines at the CCS during the last two injection seasons?

c) Over those last two injection seasons, for each pipeline including the two NPS 30 pipelines from Dawn, what percentage of days does the receipt pressure drop below the minimum pressure from Dawn?
   i) Please describe the impact that incremental pressure from these pipelines including Dawn has on runtime during the injection season.
      (1) For each compressor, please provide a summary of expected runtime from the injection schedule over the last 2 years and the actual runtime experienced.
   ii) Please describe the impact that the incremental pressure above minimum design pressure in the injection schedule has on risks associated with downtime during the injection season.

REF: Exhibit B, Tab 1, Schedule 1, Attachment 1, p. 15

Preamble: The included report states: *The following list details the Base Case models basis and assumptions, which are considered in more detail in the following sections:*
• *Period of study: This RAM study is based on a 5-year look-ahead period*

We would like to understand more about the scope of the work in this study.

19) Please provide the RFP for the work.
   a) Please provide the terms of reference or comparable that defines the scope of the work.
   b) How was recent history of the compressor operations of the CCS used in developing the results of this study.
      i) Please be specific and provide any comparisons of actual vs. projected from working papers or other documents not filed.
         (1) If not available, please describe why this was not done.

REF: Exhibit B, Tab 1, Schedule 1, Attachment 1, p. 24

Preamble: The included report states: *The model will use reliability data specific to the Corunna facility, extracted from Asset Health Report "StorageAHR-2021AHR-BF20210408" [3] – this data is based on historical CMMS records (MAXIMO). Each compressor unit will be defined by the following systems:*

We would like to understand what data is contained in the historic CMMS records.

20) Do the historic CMMS records include data for Dawn?
   a) Other storage facilities in the Enbridge Inc. operations?
      i) If so for either, how is it used?

REF: Exhibit B, Tab 2, Schedule 1, p. 1

21) Please confirm that this tab and schedule of the evidence on the Dawn Hub inextricably includes the Dawn operations also.

REF: Exhibit B, Tab 2, Schedule 1, p. 3-4, para. 8

22) Please confirm that the cold anomalies seen in the Feb. 2021 storm were centered in the central (longitudinal) US.
   a) Further, please confirm that the gas price spikes, and devastating outages were caused by more by lack of resiliency of the gas facilities and gas/electric interface infrastructure than the presence or absence of storage in these markets.

REF: Exhibit B, Tab 2, Schedule 1, p. 6

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

We would like to understand more about this design day practice.

23) When specifically did EGD decide to maintain 43.5 PJ (or comparable based upon withdrawal requirement) of inventory in storage until Feb. 28th.
   a) Please provide the internal study produced when this approach was instituted.
   b) Please produce any evidence provided to the Board and any subsequent Board approval of this approach.
   c) Please provide the evidence produced for the NGEIR proceeding that provided EGD's approach to maintaining an inventory threshold by a design date to effect deliverability needed.
   d) Please confirm the 43.5PJ represents just less than half of the space available to in-franchise customers in the EGD rate zone.
   e) Please provide the amount of this space whose cost is allocated to the non-utility operations.
   f) If the amount of storage fell to 22PJ on a February 28th design day, would the non-utility be able to maintain its full contractual withdrawal commitments (as captured in the current withdrawal schedule from in place ex-franchise contracts) to its ex-franchise customers from the CCS.
      i) If yes, please specifically explain how the deliverability would be maintained.
      ii) If not, how is the cost allocation of the 43.5PJ justified? Please explain with the calculations provided.

ISSUE 2: Project Alternatives

REF: Exhibit C, Tab 1, Schedule 1

Preamble: We would like to understand the scope of the study, assumptions made and the alternatives that were considered and, perhaps, those that were not.

24) Please file the study(ies), technical reports and summary model outputs that assessed the alternatives described in this schedule.

REF: Exhibit C, Tab 1, Schedule 1, p.19

Preamble: EGI evidence states: *This alternative also provides a 1:1 replacement in total horsepower via installation of two new Spartan e90 electric motor drive ("EMD") compressor units on the west side of the CCS, station modifications at CCS and Dawn, and retirement and abandonment of the existing compressor units and related facilities. This alternative also includes additional costs for a new 27.7 KVA substation and backup generator to provide reliable power for the EMD compressor units.18 This alternative has been estimated to cost approximately $217 million.*

25) Please provide a description of the Spartan e90 motor drives.
   a) Please provide a description of the benefits of variable drive speeds for electric compressors.
   b) Please confirm that the units contemplated as alternatives were variable drive.
   c) Please provide a summary of all of the K700 compressors range of compression (similar to Table 1 of B/T1/S1) that shows capability and function.
      i) Individually, which compressors could one variable drive Spartan e90's replace?
      ii) Using the order of expected need to replace (as described in response to Question 11), how many of the removed compressors' function could one Spartan replace before the second one is needed.
      iii) Using the order of replacement, would the parts salvaged from the removed compressors provide additional parts in inventory to refurbish/repair other compressors potentially extended their forecasted life. Please answer in detail.

26) In a scenario that the first K700 compressor is removed and replaced by one Spartan e90, for each of the CCS, Dawn and for the combined operations, please provide:
   a) The working storage space and peak injection capability for the resulting facilities.
   b) The working storage space and peak withdrawal capabilities for the resulting facilities.

REF: Exhibit C, Tab 1, Schedule 1, p.19

Preamble: EGI evidence states: *This alternative provides a 1:1 replacement in design day storage system withdrawal capacity compared to the existing compressor units at the CCS facility that are proposed to be retired and abandoned. The NPS 36 pipeline will also provide equivalent storage injection capacity via existing compression units located within Dawn.*

We want to understand how the preferred alternative has been described as a 1:1 replacement.

27) Hypothetically, if NPS 30 were used as the replacement pipe for the seven compressors, for each of the CCS, Dawn and for the combined operations, please provide:
   a) The working storage space and peak injection capability for the resulting facilities.
   b) The working storage space and peak withdrawal capabilities for the resulting facilities.

ISSUE 3 Project Cost and Economics

REF: Exhibit C, Tab 1, Schedule 1, p.19

Preamble: EGI evidence states: *This alternative also provides a 1:1 replacement in total horsepower via installation of two new Spartan e90 electric motor drive ("EMD") compressor units on the west side of the CCS, station modifications at CCS and Dawn, and retirement and abandonment of the existing compressor units and related facilities. This alternative also includes additional costs for a new 27.7 KVA substation and backup generator to provide reliable power for the EMD compressor units.18 This alternative has been estimated to cost approximately $217 million.*

28) Please file the study that provided the assessment of the electric alternatives, including costing of the substation and maintenance requirements.

29) Please redo the economics and NPV placing one Spartan EMD in place in the first year, determine in which year it would be forecasted that the second new compressor would be needed, the add a second compressor when warranted in that year.

a) Please ensure that you provide the detail on the timelines specifying which compressor(s) is assumed to be removed and the reason for removal (consistent with responses in Question 11).
b) Please provide the amount of compression (in HP and MW) for the loss of each of the compressors which ultimately drive the addition of the second compressor.
c) Please provide EGI's opinion of the efficacy of this approach and, specifically, reasons why it would not work, if any.

REF: Exhibit C, Tab 1, Schedule 1, p.19

Preamble: EGI evidence states: *NPV analysis was not completed for the Repair + Replace alternative as it is not able to adequately satisfy the project need as described in Exhibit B. While the capital cost of this alternative is lower than the proposed Project alternative described above (NPS 36 Pipeline), the O&M cost is nearly double. The alternative's inability to adequately satisfy the project need led the Company to determine that this alternative is not preferrable.*

While EGI's view is that the option does not meet the project need that the company defined, we believe it would still be important to inform the Board on the expected costs of O&M in the event other alternatives are considered especially since the costing is done.

30) Please provide the NPV determination for this option showing all of the source numbers and assumptions made.

ISSUE 7 Conditions of Approval

Reporting

31) Using the baseline provided by EGI responses on storage capability in our initial questions, if the Board approves the NPS 36 project along the lines proposed, would EGI provide an annual report on their working storage capacity and deliverability?
   a) Further, would EGI provide annual reporting on the resulting incremental contracts provided by the incremental capability?
      i) If not, why not?

32) Please provide EGI's opinion on whether it would be appropriate for ratepayers to benefit from the incremental contracting derived from the installation of the proposed NPS 36 and the removal of compression over time.