EB-2022-0086
Enbridge Dawn to Corunna Replacement Project

Interrogatories of Environmental Defence

June 10, 2022

Interrogatory # 1-ED-1

Reference: Exhibit B, Tab 1, Schedule 1

Questions:

(a) Please fully describe the assumptions and criteria for a "storage design day" referred to on page 8.

(b) Please provide a table comparing the assumptions and criteria for a storage design day with the respective planning design days for the Enbridge rate zone and the Union rate zone.

(c) Page 10 states: "an Asset Health Review ("AHR") was performed in 2018 and updated in 2021 (as part of the Company's comprehensive Reliability, Availability and Maintainability ("RAM") Study for the CCS, which was completed by DNV)."
Please file this.

(d) Per page 14: "Enbridge Gas is currently managing component availability via internally stocked critical spares, where deemed necessary and feasible."
Please provide a list of this stock of critical spares. Please estimate the cost to double the stock of critical spares.

(e) Per page 14: "On design day or peak storage withdrawal day, if any 1 of the 10 operating CCS units is out of service for a prolonged period of time and replaced in function by K711, no LCU unit would be available should another unit be lost."
Please approximately define "prolonged time" in hours and/or minutes. Please list all the instances in which 2 of the 10 operating CSS units were out of service but exclude planned outages for maintenance.

(f) Please provide a table listing the volume of gas provided at the peak and annually from each of the following units assuming they were running at full capacity: K701, K702, K703, and K711.

(g) Per page 15: "In Enbridge Gas's experience, the OEM is increasingly challenged to supply parts in a timely manner for units K705-K708."
Please estimate the cost of acquiring the same stock of critical spares as Enbridge has for K701-K703.

(h) Per page 16: "For example, during withdrawal season, using the last 10 years of Dawn pricing data across January, February, and March, the loss of an additional CCS unit on a peak winter day (in addition to K705) would have ranged in cost for delivered supply between approximately $800,000 to $11 million for a single day."
Please provide the underlying calculations. Is this the total cost of the delivered supply or

the incremental cost of the delivered supply in comparison to supply from storage? Please provide the incremental cost.

(i) Per page 17: “Further, as CCS compressor units K705-K708 are of similar makes and models (KVR) as the remaining CCS units (K704, K709, K710 and K711)… By disassembling units K705-K708, salvaging interchangeable spare parts, and storing them within the Company’s inventory for future use, the risk of experiencing extended downtime for future repairs to those units (as well as the cost of the same) is expected to be significantly mitigated.”
Has Enbridge explored purchasing a compressor of similar make and model (KVR) that is no longer in use from another utility for spare parts?

(j) Are any compressors of a similar make and model (KVR) present in the Enbridge system? If yes, please provide the number and where they are located.

(k) Are any compressors of a similar age as K701-K703 present in the Enbridge system? If yes, please provide the number and where they are located.

(l) Are any compressors of a similar age at K705-708 present in the Enbridge system? If yes, please provide the number and where they are located.

(m) Per page 19: “Results for compressor units K701-K703 and K705-K708 indicate that both engine and compressor failures are expected to occur within 2 years for all units.”
Please provide a list of all the compressor failures for these units that have occurred, the date they occurred, and the time it took to fix them.

(n) Per page 23: “To fully understand the risks to employee health and safety resulting from and the drivers for such events, Enbridge Gas conducted a CCS site-wide QRA that applied industry best practices (as recommended by DNV).”
Please provide a copy of the report or reports generated through this assessment.

(o) Per page 35: “The results also indicate that in terms of specific areas within the CCS site, risks are concentrated in compressor buildings 1 and 2, with building 1 having the highest risk.”
Please provide a list of the buildings and which compressors are housed in each building,

(p) What is the safety risk of having compressor units in close proximity? Is the concern that a unit will explode while staff are working on the neighbouring unit? Can this be mitigated in part by having greater redundancy (e.g. adding a compressor), so a unit can be shut off if staff are working adjacent to it?

(q) Does Enbridge have other locations that include “multiple compressor units in close proximity within a single building”? If yes, how many and where?

Interrogatory # 1-ED-2

Reference: Exhibit B, Tab 2, Schedule 1

Question:

(a) Page 4 refers to a conclusion from ICF’s natural gas market outlook. This is cited to ICFs Q4 2021 base case, which pre-dates the war in Ukraine and other factors. Please provide an updated analysis from ICF. Ideally this would be a copy of the ICF base case natural market outlook. If that is not possible due to concerns regarding proprietary information, please provide a summary and excerpt similar to that provided from the Q4 2021 version.

Interrogatory # 2-ED-3

Reference: Exhibit C, Tab 1, Schedule 1

Preamble: Per pages 6-7:

> The elimination of 20 PJ (5.6 TWh) of cost-based storage capacity and 0.67 PJ/d (7.8 GW) of design day storage withdrawal deliverability for EGD rate zone customers will have significant long-term consequences to the province.

Questions:

(a) Please confirm that Canada's 2030 Emissions Reduction Plan includes a target for carbon emissions associated with buildings to decline by 41% by 2030 from 2019 levels (to 53 CO_2e from 91 CO_2e) and that it targets a 22% reduction by 2026 from 2019 levels (to 71 CO_2e from 91 CO_2e). [1] If not, please explain.

(b) Please confirm that Canada's 2030 Emissions Reduction Plan has formal legal status under s. 9 of the *Canadian Net-Zero Emissions Accountability Act* in relation to the legally binding targets under that *Act*.[2] If not, please explain.

(c) Please complete the following table:

Demand Reduction Scenarios					
	2019 Levels	Reduced by 5%	Reduced by 10%	Reduced by 22%	Reduced by 41%
Annual Ontario demand at Dawn Hub (PJ)					
Design day demand at Dawn Hub (PJ/d)					

(d) Please complete the table above but in m3 figures instead of joules.

(e) Approximately what percent of Enbridge customer demand is used for buildings?

(f) Please confirm that Canada has committed to net-zero emissions from electricity generation by 2035. If not, please explain.

(g) Please confirm that Canada's 2030 Emissions Reduction Plan includes its commitment to net-zero emissions from electricity generation by 2035. If not, please explain.

[1] https://www.canada.ca/en/environment-climate-change/news/2022/03/2030-emissions-reduction-plan--canadas-next-steps-for-clean-air-and-a-strong-economy.html

[2] *Canadian Net-Zero Emissions Accountability Act*, s. 9.

(h) If gas-fired generation ends by 2035, how would that impact annual demand (PJ) and design day demand (PJ/d) at the Dawn Hub.
(i) Please provide the current annual demand (PJ) and design day demand (PJ/d) flowing through Dawn Hub for Ontario's gas plants.

Interrogatory # 1-ED-4

Reference: Exhibit B, Tab 1, Schedule 1

Preamble: Per page 7:

> "As far as Enbridge Gas is aware, there are no plans (either in the short or longer-term) to expand electricity infrastructure in the province at the scale required to replace the energy equivalent of natural gas storage and deliverability made accessible via Tecumseh storage and the existing CCS units. Accordingly, Enbridge Gas has assessed alternatives (both facility and non-facility) based on their ability to provide characteristics commensurate to the physical capacity made accessible and deliverability currently provided by the 7 CCS compressor units proposed to be retired and abandoned."

Questions:

(a) Enbridge refers to the scale of electricity infrastructure expansion needed to replace the energy equivalent of the project. With reference to this statement, approximately how much infrastructure (GW) does Enbridge believe is necessary? For instance, is it 7.8 GW or is it closer to one-third that amount (2.6 GW) after accounting for the higher efficiencies of heat pumps (e.g. minimum 3.1 co-efficient of performance for ground source heat pumps), the ability of thermal storage to move electrical heating demand off the peak, and opportunities for cost-effective building envelope energy efficiency improvements?
(b) Please estimate the scale of electricity infrastructure expansion needed to replace the energy equivalent of the project assuming electric heating achieved through fuel switching is generated at a design day COP of 3 (average over new equipment, including heat pumps, thermal storage, etc.) and all cost-effective building envelope energy efficiency measures are implemented.
(c) Please estimate the scale of electricity infrastructure expansion needed to replace the energy equivalent of the project assuming all cost-effective building envelope energy efficiency is implemented and all fuel switching utilizes the most efficient heat pumps and thermal storage that is achievable.
(d) If Enbridge cannot provide an answer to (b) and/or (c), please explain how it is qualified to opine on the scale of electricity infrastructure expansion needed to replace the energy equivalent of the project.
(e) Chris Neme of Energy Futures Group provided the following evidence in EB-2020-0091: "the IESO for this year forecast that winter peak demands will be about 2 gigawatts below summer peak demands. That suggests that you could likely electrify something like 10 percent of gas heating without requiring any significant capital additions on the

electric grid…"[3] Does Enbridge have any studies or analysis to disprove these statement? If yes, please provide all such studies and analysis and explain them in the interrogatory response.

(f) Chris Neme of Energy Futures Group provided the following evidence in EB-2020-0091: "Even larger amounts of electrification may not require significant changes in electric grids. And whether full electrification would require increases in electrification rates would depend on analysis that would have to be done on the marginal cost in the long-term of new generation transmission and distribution relative to current average rates." Does Enbridge have any studies or analysis to disprove these statements? If yes, please provide all such studies and analysis and explain them in the interrogatory response.

Interrogatory # 2-ED-5

Reference: Exhibit C, Tab 1, Schedule 1

Preamble: Per pages 6-7:

> The elimination of 20 PJ (5.6 TWh) of cost-based storage capacity and 0.67 PJ/d (7.8 GW) of design day storage withdrawal deliverability for EGD rate zone customers will have significant long-term consequences to the province. For comparative purposes, 5.6 TWh is approximately equal to the embedded electrical generation capacity in Ontario (6 TWh). 7.8 GW is approximately equal to:
>
> • 19% of Ontario's total electrical generation, import and storage capacity;
> • 74% of Ontario's existing nuclear generation capacity;
> • 83% of Ontario's existing hydro generation capacity;
> • 141% of Ontario's existing wind generation capacity; or
> • 287% of Ontario's existing solar generation capacity.
>
> As far as Enbridge Gas is aware, there are no plans (either in the short or longer-term) to expand electricity infrastructure in the province at the scale required to replace the energy equivalent of natural gas storage and deliverability made accessible via Tecumseh storage and the existing CCS units. Accordingly, Enbridge Gas has assessed alternatives (both facility and non-facility) based on their ability to provide characteristics commensurate to the physical capacity made accessible and deliverability currently provided by the 7 CCS compressor units proposed to be retired and abandoned.

Questions:

(a) Enbridge describes the energy provided by the project as 7.8 GW. However, fossil gas is combusted at efficiencies less than 100% and therefore it generates less than 7.8 GW of heat. Approximately how many GW of heat would be generated by 7.8 GW of gas? Please provide an answer on a best estimate basis with whatever simplifying assumptions and caveats are necessary. For example, please consider any data that Enbridge has

[3] EB-2020-0091, Transcript Volume 4, March 4, 2021, p. 98.

access to on average customer equipment efficiencies for furnaces and water heaters. Please provide all calculations and explain the basis for the answer.

(b) Please provide an estimate on a best efforts basis of the overall efficiency (AFUE) of space and water heating of Enbridge's single-family residential customers based on Enbridge's customer equipment survey (these survey results are typically filed in DSM proceedings).

(c) Please provide an estimate on a best efforts basis of the overall efficiency (AFUE) of space and water heating of Enbridge's commercial customers based on surveys or typical efficiencies of space and water heating equipment for large buildings.

(d) Please confirm that the energy required for heating can be reduced through cost-effective energy efficiency measures, which pay for themselves over time in avoided energy costs.

(e) Please confirm that NRCan states that "On a seasonal basis, the heating seasonal performance factor (HSPF) of market available units can vary from 7.1 to 13.2 (Region V). It is important to note that these HSPF estimates are for an area with a climate similar to Ottawa."[4] Does Enbridge disagree with NRCan? If yes, please justify the answer.

(f) Please confirm that HSPF 13.2 (region 5) is equivalent to a seasonal Co-efficient of Performance (sCOP) of 3.86. Please also confirm that the sCOP is the kWs of heat created by 1 kW of electricity input over an average heating season. Please also confirm that this is sometimes described as an efficiency of 386%. If any of this is not confirmed, please explain in detail and provide the correct answer.

(g) Please confirm that cold climate air-source heat pumps can have a COP greater than 2 even at -21 degrees Celsius.

(h) Please confirm that NRCan states that the range of available ground-source heat pumps goes up to a heating COP of 4.2 for closed loop applications and 5 for open loop applications.[5] Does Enbridge disagree with NRCan? If yes, please justify the answer.

(i) Please confirm that NRCan states that the minimum heating COP for ground-source heat pumps goes is 3.1 for closed loop applications and 3.6 for open loop applications.[6] Does Enbridge disagree with NRCan? If yes, please justify the answer.

(j) Please confirm that a $10,000 incentive is available to customers in Quebec with fossil fuel based central heating (including fossil gas) to convert to an electric thermal storage system.[7]

(k) Please confirm that incentives are available in Nova Scotia for electric thermal storage systems.[8]

(l) Please confirm that electric thermal storage systems are intended to reduce peak electrical heating demand.

(m) Please confirm that:

i. There are electric thermal storage units on the market now that can provide over 80,000 BTU/hr of heat during the day based on a 12-hour nighttime "charge."[9]

ii. They are also capable of utility control if desired.

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[4] https://www.nrcan.gc.ca/energy-efficiency/energy-star-canada/about/energy-star-announcements/publications/heating-and-cooling-heat-pump/6817

[5] *Ibid*.

[6] *Ibid*.

[7] Hydro Quebec: https://www.hydroquebec.com/residential/energy-wise/windows-heating-air-conditioning/thermal-storage/.

[8] Nova Scotia Power: https://www.nspower.ca/your-home/energy-products/electric-thermal-storage.

[9] Steffes, Off-Peak Heating, https://www.steffes.com/wp-content/uploads/2020/12/Steffes-Forced-Air-Furnace.pdf.

iii. This can reduce the electricity used to heat almost any home during the peak daytime hours almost to zero.
iv. This provides a huge shift in demand from peak to off-peak times without any loss in comfort or convenience.
If Enbridge does not agree, please justify the answer.

(n) Please explain how the 6 TWh and 7.8 TWh figures were derived. Please provide all calculations.
(o) Please convert 20 PJ and 0.67 PJ/d to m3 and m3/day. Please provide the conversion factors.

Interrogatory # 2-ED-6

Reference: Exhibit C, Tab 1, Schedule 1

Questions:

(a) On page 8 Enbridge states as follows: "The CCS facility provides EGD rate zone customers **up to** 0.67 PJ/d of design day withdrawal deliverability…" Why is the deliverability "up to" 0.67 PJ/d?
(b) What is the expected withdrawal deliverability in mid-February once the storage has been depleted by winter withdrawals up to that time? In light of that, how much deliverability can Enbridge rely on for design day system planning purposes?

Interrogatory # 2-ED-7

Reference: Exhibit B & C, Tab 1, Schedule 1

Preamble: Enbridge states as follows:

> "The access to storage capacity provided by the Dawn to Corunna project will reduce the NPV of commodity purchase costs over the 40-year life of the asset by $794 million, leading to a total reduction in the NPV of the cost-of-service to in-franchise customers of about $589 million relative to the Non-Replacement option." Exhibit C, Tab 1, Schedule 1, Page 9
>
> "For example, during withdrawal season, using the last 10 years of Dawn pricing data across January, February, and March, the loss of an additional CCS unit on a peak winter day (in addition to K705) would have ranged in cost for delivered supply between approximately $800,000 to $11 million for a single day." Exhibit B, Tab 1, Schedule 1, Page 16

Questions:

(a) Please reconcile the figures referenced in the two paragraphs above. Please include calculations and underlying figures.
(b) Please reconcile the two figures referenced in the first paragraph above.

Interrogatory # 2-ED-8

Reference: Exhibit C, Tab 1, Schedule 1

Preamble:

Table 1: NPV of Alternatives – 40-Year Term

Alternative		NPV ($ Millions)
Project	NPS 36 Pipeline	$(200)
Alternative 1	Natural Gas Fired Compression	$(212)
Alternative 2	Electric Drive Motor Compression	$(270)

Question:

(a) Please reproduce table one assuming a term ending in (i) 2035, (ii) 2045, and (iii) 2050.

Interrogatory # 2-ED-9

Reference: Exhibit C, Tab 1, Schedule 1

Preamble: Enbridge states at page 22 as follows:

> "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."

Questions:

(a) As the question of whether this option could meet to project need is potentially disputed in this proceeding, and the OEB has not decided on that issue, please provide the NPV analysis. Please also provide the NPV assuming a term ending in (i) 2035, (ii) 2045, and (iii) 2050.

(b) Under the alternative as defined by Enbridge, K701-K703 would be decommissioned and K705-K708 would remain in service. Seeing as the safety issues pertain to compressors located in close proximity to each other, would safety be improved in this alternative if a different set of compressors where decommissioned such that greater spacing would be allowed between units?

Interrogatory # 2-ED-10

Reference: Exhibit C, Tab 1, Schedule 1

Questions:

(a) Please provide a table comparing the access to storage (PJ) and deliverability (PJ/d) available via:
    i. One new Spartan e90 electric motor drive ("EMD") compressor unit;
    ii. One new Taurus 70 gas turbine compressor unit; and
    iii. Each of the existing CSS compressor units.
(b) Please calculate the capital cost, operating costs, and NPV for an option involving the construction of a single new compressor unit and maintaining the existing units in service to the extent necessary to supplement the new unit and provide the necessary redundancy. Please calculate the NPV based on a 40-year term and also based on terms ending in (i) 2035 and (ii) 2050.
(c) Please provide a table listing the permutations of existing compressors that could be retired if Enbridge were to purchase and install a single new compressor. For each row, please indicate the impact on facility safety. The goal is to get an idea of which compressors raise the most issues and whether better spacing between them can improve safety.
(d) Please provide a diagram or map with labels for each compressor and each building.
(e) Please reproduce the Table 1 in Exhibit C, Tab 1, Schedule 1, Attachment 1, adding the option discussed in this interrogatory and the NPV figures calculated in (b).

Interrogatory # 2-ED-11

Reference: Exhibit C, Tab 1, Schedule 1

Preamble:

> These questions relate to the possibility of a cheaper incremental reliable solution that would provide more time to get a better grasp on how much gas infrastructure will be needed in, say, 2030 (Canada's 2030 Emissions Reduction Plan targets a 41% decline in emissions from buildings by 2030 from 2019 levels), 2035 (Canada's target for zero-emissions electricity), or 2050 (national net zero target).
>
> For instance, an incremental solution could involve replacing 50% of the CSS capacity with a single new compressor for now, decommissioning one or two K700 series compressors for parts, keeping the other K700 series units around for the remaining 50% capacity and as backup, and using the additional operational flexibility to allow units to be turned off when needed to improve safety. In five or ten years from now it may be that a decision is made to buy second new compressor, or it may be that demand has dropped and that no more ratepayer investment is needed.

Questions:

(a) Please comment on the feasibility of the above potential solution.
(b) Putting aside for now a debate regarding feasibility, please estimate the cost-effectiveness (NPV) of the above potential solution.

(c) The above potential solution provides what is often called “option value” by allowing investments over time, which may allow for some of those investments to be avoided based on updated information. Putting aside for now a debate regarding feasibility, please provide an estimate of the option value.
(d) Please describe how option value is considered in Enbridge’s planning process. If it is not considered, please describe how it could be considered as it relates to solutions for this proceeding that may provide that value.

Interrogatory # 2-ED-12

Reference: Exhibit C, Tab 1, Schedule 1

Questions:

(a) Please provide all calculations, assumptions, and spreadsheets underlying the calculation of Table 2 on Exhibit C, Tab 1, Schedule 1, Page 1 and Table 1 in Exhibit C, Tab 1, Schedule 1, Attachment 1

Interrogatory # 2-ED-13

Reference: Exhibit C, Tab 1, Schedule 1

Questions:

(a) If the demand for storage were to decline by 20 PJ and demand for deliverability would decline by 0.67 PJ/d, would the project still be needed and/or cost-effective?
(b) Enbridge’s evidence refers to 20 PJ of storage capacity and 0.67 PJ/d of deliverability. How much of this would remain if units K701-703 and K705-708 were retired without being replaced by new compressors or a new pipeline?
(c) How much would demand need to decline (annual and peak) to allow:
    i. One of the compressors (K701-703 / 705-708) to be retired or reserved as an additional backup (i.e. LCU) without requiring replacement by a supply-side alternative;
    ii. Two of the compressors (K701-703 / 705-708) to be retired or reserved as additional backups (i.e. LCU) without requiring replacement by a supply-side alternative;
    iii. Three of the compressors (K701-703 / 705-708) to be retired or reserved as additional backups (i.e. LCU) without requiring replacement by a supply-side alternative;
    iv. Four of the compressors (K701-703 / 705-708) to be retired or reserved as additional backups (i.e. LCU) without requiring replacement by a supply-side alternative;
    v. Five of the compressors (K701-703 / 705-708) to be retired or reserved as additional backups (i.e. LCU) without requiring replacement by a supply-side alternative;

vi. Six of the compressors (K701-703 / 705-708) to be retired or reserved as additional backups (i.e. LCU) without requiring replacement by a supply-side alternative; and

vii. Seven of the compressors (K701-703 / 705-708) to be retired or reserved as additional backups (i.e. LCU) without requiring replacement by a supply-side alternative.

Interrogatory # 2-ED-14

Reference: Exhibit C, Tab 1, Schedule 1

Questions:

(a) What is the threshold in terms of declining demand (annual and peak) at which point the NPS 36 could be downsized without requiring a supplemental supply-side alternative? Please provide the threshold for each of the next three smaller standard pipe sizes.
(b) Please provide a table indicating the capital and operating savings for each of the pipe sizes referred to in (a) vis-à-vis the NPS 36.
(c) What is the threshold in terms of declining demand (annual and peak) at which point the NPS 36 would no longer be needed without requiring a supplemental supply-side alternative?

Interrogatory # 2-ED-15

Reference: Exhibit C, Tab 1, Schedule 1, Attachment 2

Preamble: Please ask ICF to provide responses to these questions.

Questions:

(a) If Dawn-Parkway demand increases, would that improve the relative cost-effectiveness of the NPS 36 pipeline option vis-à-vis the alternatives set out in ICF's report? Please explain the answer in detail.
(b) If Dawn-Parkway demand decreases, would that improve the relative cost-effectiveness of the alternatives set out in ICF's report vis-à-vis the NPS 36 pipeline option (but not necessarily impact which option is ultimately the most cost-effective)? Please explain the answer in detail.
(c) Please provide all of ICF's assumptions and forecasts for gas demand on the Dawn-Parkway system underlying its report. Please provide the response in PJs and m3.
(d) What is the threshold in terms of declining demand at which point an alternative in the ICF report becomes more cost-effective than the NPS 36 pipeline? We leave it to ICF to determine the best way to measure declining demand. For instance, ICF may wish to re-run the analysis with demand decreased by X % and indicate the percentage decline at which a market-based alternative becomes more cost-effective.
(e) Please provide the live excel spreadsheet calculating the cost-effectiveness of the most cost-effective option outlined ICF's report.

(f) Please calculate the relative cost-effectiveness (NPV) of an additional option, namely (a) the compressor capacity at CSS declines by 50% due to a partial retirement of some compressors and (b) the remaining capacity is made up by the most cost-effective market-based alternative.

Interrogatory # 2-ED-16

Reference: Exhibit C, Tab 1, Schedule 1

Preamble:

> These questions relate to the possibility that some of the storage facilities served by the CSS could be converted to store hydrogen only, and whether that might be relevant to decision-making for this project.

Questions:

(a) Please discuss the possibility of converting gas-fired power generation to burn hydrogen created through electrolysers and stored nearby (e.g. in a converted gas storage facility), to be used as a peaking service for electricity.
(b) Has Enbridge explored using any of its storage facilities in Ontario for a hydrogen-only system? If yes, please provide any applicable studies or slide decks.
(c) Please provide a map showing the proximity of the storage facilities connected to the Corunna Compressor Station to existing gas-fired power generation facilities. Please list the design day demand of those facilities.

Interrogatory # 2-ED-17

Reference: Exhibit C, Tab 1, Schedule 1 & Exhibit D, Tab 1, Schedule 1

Preamble: Per Exhibit D, Tab 1, Schedule 1:

Table 1: Estimated Project Costs

Item #	Description	Pipeline Costs	Ancillary Costs	Total Costs
1.0	Materials	$11,800,354	$36,643,592	$48,443,946
2.0	Construction & Labour	$51,310,846	$28,993,020	$80,303,866
3.0	External Permitting & Lands	$15,322,222	$0	$15,322,222
4.0	Outside Services	$19,230,385	$15,702,325	$34,932,710
5.0	Direct Overheads	$1,295,000	$0	$1,295,000
6.0	Contingency	$13,180,351	$10,816,348	$23,996,699
7.0	IDC	$2,093,000	$0	2,093,000
8.0	**Project Cost**	**$114,232,158**	**$92,155,285**	**$206,387,443**
9.0	Indirect Overheads & Loadings	$26,277,051	$18,085,209	44,362,260
10.0	**Total Project Costs**	**$140,509,209**	**$110,240,494**	**$250,749,703**

NOTE:
The total costs set out in Table 1 include abandonment of the existing seven CCS compressor units K701-K703 and K705-K708 amounting to $14.5 million.

Questions:

(a) Please reproduce the Table 1 in Exhibit C, Tab 1, Schedule 1, Attachment 1, including indirect overheads and loadings.
(b) Do indirect overheads and loadings have a differential impact on capital costs versus ongoing operating costs?
(c) What line in the above table is the $14.5 million abandonment cost included in?
(d) Are abandonment costs for pipelines treated differently than abandonment costs for compressors?
(e) Does Enbridge earn the same rate of return on capital invested in compressors as in pipelines? Please explain.
(f) Is the depreciation period the same for investments into compressors as in pipelines? Please explain.

Interrogatory # 2-ED-18

Reference: Exhibit C, Tab 1, Schedule 1

Questions:

(a) What is the expected lifetime of the proposed pipeline?
(b) When would the proposed pipeline be fully depreciated?
(c) What will the undepreciated balance of the proposed pipeline costs be in (i) 2035, (ii) 2040, and (iii) 2050?
(d) Has Enbridge conducted an analysis to assess the likelihood, if any, that the proposed pipeline will be stranded or underutilized before the end of its lifetime? If yes, please file said analysis.
(e) Please estimate the probability (if any) that the proposed pipeline will be stranded or underutilized before the end of its lifetime. Please provide the response as a probability

(%) or a range of probabilities. For instance, if there is no chance, please indicate the probability as 0%.