April 14, 2023

Sara Payne
Minnesota Department of Commerce
85 7th Place E., Suite 280
Saint Paul, Minnesota 55101

Subject: **Enbridge Line 93 Decommissioning Cost Estimate Review**

Dear Ms. Payne:

WSP USA Inc. ("WSP") was requested by the Minnesota Department of Commerce ("Commerce") and Enbridge Energy, Limited Partnership ("Enbridge") to complete an independent review of the Enbridge Line 93 Decommissioning cost estimate prepared per the requirements set forth as described below, and report any noteworthy concerns with the estimated costs and the assumptions that were made during the preparation of the cost estimate.

BACKGROUND

Enbridge filed an application on April 24, 2015 with the Minnesota Public Utilities Commission ("Commission") for a certificate of need to abandon the Enbridge existing Line 3, a 34-inch diameter crude oil pipeline extending from the North Dakota – Minnesota border to the Minnesota – Wisconsin border, and replace it with a new 36-inch diameter crude oil pipeline to be known as Line 93. The Commission originally issued an Order Granting Certificate of Need for the Line 3 Replacement Project on September 5, 2018 and reissued an Order Granting Certificate of Need as modified on May 1, 2020 ("2020 Order"). The 2020 Order was contingent upon the establishment of a Decommissioning Trust Fund funded by Enbridge "*to cover the costs of decommissioning and removing the new Line 3 at the end of the pipeline's operation*." The Commission issued an Order on November 4, 2022, further directing Enbridge to draft a Trust Agreement for Notice and Comment and obtain an independently reviewed cost estimate for the total contribution amount to be included in the trust fund ("November 2022 Order").

Pursuant to Commission Orders, Enbridge submitted an updated decommissioning cost estimate, titled: "*Basis of Estimate - Line 3 Replacement Decommissioning Cost Estimate, Revised May 2022*" (the "2022 Cost Estimate"). In this estimate, Enbridge analyzed and updated the costs for complete removal of Line 93, incorporating guidance and lessons learned from the Canadian Energy Regulator's ("CER's") assessment of the issue, and the estimated costs of removal of Line 3. WSP agreed to independently review the 2022 Cost Estimate in accordance with the scope of work from WSP's proposal to Commerce and Enbridge dated December 8, 2022. As the independent engineer, WSP reported directly to Commerce as it relates to implementation of the scope of work. WSP's review was based on relevant information obtained from

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Enbridge, Commerce, and publicly available sources. A list of the project documents reviewed by WSP is included as Enclosure 1.

WSP completed the following scope of work:

1. Review the Enbridge "Basis of Estimate - Line 3 Replacement Decommissioning Cost Estimate, Revised May 2022"
2. Review and evaluate the reasonableness of Enbridge's use of the CER methodology and assumptions used to estimate costs, employing the level of detail and technical description appropriate to allow the Commission and others to adequately understand the estimates and WSP's opinions regarding those estimates
3. Prepare this letter report of the review setting forth WSP's findings and opinions concerning the reasonableness of the cost estimate

WSP prepared a first set of Requests for Information ("RFI Set 1"), numbered 1 through 4, and submitted it to Enbridge on December 28, 2022. Enbridge responded to WSP's RFI Set 1 on January 18, 2023. After reviewing Enbridge's response, WSP prepared RFI Set 2, numbered 1 through 5, and submitted it to Enbridge on March 20, 2023. Enbridge responded to WSP's RFI Set 2 on March 24, 2023. Enbridge's responses to WSP's RFI Sets 1 and 2 are included as Enclosure 2.

WSP'S UNDERSTANDING OF THE COST ESTIMATE DEVELOPMENT PROCESS

Canada's National Energy Board ("NEB", now CER) set forth requirements in the October 29, 2015 letter with regards to their review of all NEB-regulated pipeline companies' Abandonment Cost Estimate ("ACE"). To meet the NEB requirements, Enbridge developed a decommissioning ACE for NEB/CER in September 2016. Enbridge followed the NEB methodology but made assumptions to modify the proposed NEB scope. After review of the proposed estimates, NEB approved Enbridge's decommissioning ACE and assumptions for existing pipelines (April 2018). The NEB noted in its approval letter that its approval of the ACE has been based on, and are applicable only to, the application-specific and pipeline-specific information provided in Enbridge's filings, and the comments received on those filings.

In October 2018, Enbridge prepared the "*Line 93 ACE Breakdown*" (the "2018 Cost Estimate"), which was furnished by Enbridge to Commerce in June 2022 as part of Enbridge's response to Commerce's "*Request Number 1*" associated with the "*Enbridge Initial Comments, Attachment A*" (Enclosure 3). Enbridge followed the applicable NEB/CER methodology in preparing the 2018 Cost Estimate using unit costs and assumptions from Line 93 budgets, Line 93 construction cost estimates, and unit costs and assumptions from contractor's responses to Enbridge's August 2018 RFI regarding estimated costs for Line 93 removal. In developing their unit costs, Enbridge relied on their specific knowledge and expertise, and on information supported by a fixed pipeline removal scope, methods, and contractor estimates. This level of detail is representative of a cost estimate for a funding request (e.g., USACE ER 1110-2-1302[1] Class 3 estimate). Table 1, enclosed, presents a comparison between the 2018 and 2022 Cost Estimates, and indicates that Enbridge used contractor estimates for major cost categories (i.e., NEB/CER cost categories 4, 5, and 6). WSP believes Enbridge furnished sufficient information to Commerce to demonstrate a reasonable use of the NEB/CER methodology and assumptions, with sufficient details and technical descriptions to allow WSP to evaluate the 2022 Cost Estimate development process.

[1] ER 111-2-1302, Engineering and Design Civil Works Cost Engineering (2016) Paragraph 13.b (3), for Class 3 cost estimates.

REVIEW OF THE 2022 COST ESTIMATE

Enbridge followed applicable NEB/CER methodology for the 2018 Cost Estimate, which served as the basis for the 2022 Cost Estimate. Enbridge used applicable NEB/CER methodologies and the NEB/CER format in both the 2018 and 2022 Cost Estimates. Enbridge indicated that, due to the cost differences between Canada and the United States, only two of the cost categories from the NEB/CER methodology were taken directly from NEB/CER in the 2018 and 2022 Cost Estimates. Cost category 1, Engineering and Project Management, used an NEB/CER factor of 5% for pipeline projects greater than 500 kilometers (greater than 311 miles); and cost category 7, Contingency, used an NEB/CER-approved contingency factor of 13%. The remaining cost categories 2 through 6 were developed as described by Enbridge in Section 2 of the 2022 Cost Estimate: Estimate Methodology. WSP's review is provided below.

Inflation

As described in Section 2.8 of the 2022 Cost Estimate, Enbridge accounted for inflation by uniformly adding a 10.55% cumulative inflation factor to the 2018 Cost Estimate. The 10.55% factor was based on the Consumer Price Index ("CPI") data for this time period, as published by the U.S. Bureau of Labor Statistics ("BLS"). WSP's review of the CPI data published by the BLS for January 2018 to January 2022 estimates the inflation cost to be 13.43% (see BLS: https://data.bls.gov/cgi-bin/cpicalc.pl?cost1=100.00&year1=201801&year2=202201). This difference in the applied inflation rate would result in an estimated increase of approximately $25 million. RFI Set 2, Information Request No. #2 asked Enbridge to clarify the time frame used to estimate the inflation factor, as well as why that timeframe was chosen. Enbridge responded that the time frame for inflation was from September of 2018 to April 2022. Based on inflation rates published after submittal of the 2022 Cost Estimate, inflation rates for this time period are 14.53%. If the now-published inflation rate of 14.53% were applied, the difference would result in an estimated increase of approximately $45 million. Based on this, the current inflation rate should be used in the 2022 Cost Estimate, and the rate should be adjusted as needed during the cost estimate review process established by the Commission.

Cost Category 1: Engineering & Project Management

The 2022 Cost Estimate lists "Engineering and Project Management" as $56 million. Section 2.1 of Attachment A: Basis of Estimate, Line 3 Replacement Decommissioning Cost Estimate states that the applicable NEB/CER factor for "Engineering and Project Management" is 5%. However, applying this factor to the total costs results in a "Engineering and Project Management" cost of $51 million (if this contingency is not added in the total cost that would be used to apply this factor) or $57 million (if this contingency is added in the total cost that would be used to apply this factor). Enbridge's response to RFI Set 2, Information Request No. #5 explained that the 5% factor was added to the total cost and then rounded-down to the nearest million dollars, resulting in a proposed value of $56 million.

Cost Category 2: Permanent Decommissioning Preparation

Enbridge based the 2018 Cost Estimate for cost category 2.a: Land Access and Clean Up, on Line 93 construction phase estimates. Enbridge indicated costs were expected to be similar for removal and decommissioning as they would be for installation, and applied numeric factors to cost categories 2.a.ii – Consultants and 2.a.iv – Temporary Workspace/Ancillary Acquisitions ("TW/AA"). For the Consultants cost category, Enbridge used a factor of 33% of Line 93 construction. For the TW/AA cost category, Enbridge used a factor of 50% of Line 93 construction. RFI Set 2, Information Request No. #3 asked Enbridge to clarify why the factors were selected and how the factors were derived.

Enbridge responded that the costs in this category are to retain consultants for acquiring the necessary TW/AA and the costs to reimburse the landowners who will be impacted during the work. Both of these categories were derived from Line 93 construction costs, but decreased by the numeric factors above, because permanent easement for Line 93 has been acquired (i.e., fewer land rights acquisition are needed for removal as compared to construction). The Enbridge response and these numeric factors are reasonable, and are consistent with the Landowner Choice Program, where less than 30% (5 of 18) of the requests evaluated to-date proposed, or potentially need, additional TW/AA for pipeline removal or abandonment.

Cost Category 3: Pipeline Decommissioning In-Place

This Cost Category is not applicable to the 2022 Cost Estimate.

Cost Category 4: Special Treatment

These estimated costs were developed from contractor bids obtained for the 2018 Cost Estimate, which were based on unit costs and assumptions from contractor's responses to Enbridge's August 2018 RFI regarding estimated costs for Line 93 removal. Enbridge furnished sufficient information to demonstrate that their methodology and assumptions for the 2022 Cost Estimate development were reasonable.

Cost Category 5: Pipeline Removal

These estimated costs were developed from contractor bids obtained for the 2018 Cost Estimate, which were based on unit costs and assumptions from contractor's responses to Enbridge's August 2018 RFI regarding estimated costs for Line 93 removal. Note that the Cost Category 5 information in the 2022 Cost Estimate was presented differently than those prepared for the December 2019 Final Environmental Impact Statement ("FEIS") and the 2020 Landowner Choice Program. For example, the FEIS and Landowner Choice estimates were prepared for Line 3, not Line 93, and the Landowner Choice has different contingency factors and consist of smaller, separate projects that are reviewed individually for feasibility and cost. For this cost category, Enbridge furnished sufficient information to demonstrate that their methodology and assumptions for the 2022 Cost Estimate development were reasonable.

Cost Category 6: Facilities

The 2022 Cost Estimate for cost category 6, Facilities, is $111 million, which was higher than presented in the 2018 Cost Estimate, at approximately $16 million. The largest change was an increase in cost category 6.1, pump station costs, increasing from $7 million to $100 million. RFI Set 1, Information Request No. #4, asked Enbridge to clarify this change. In their RFI Set 1 response, Enbridge informed WSP that the 2018 Cost Estimate only included removing piping from the pump stations. Given the scope of removal contemplated in the Commission's orders for Line 93, the 2022 Cost Estimate includes removing all concrete and buildings and returning the pump station sites to their pre-construction state. RFI Set 2, Information Request No. #1, asked Enbridge to clarify the basis for the pump station costs. Enbridge responded that the estimate was a combination of contractor quotes and industry specific costs. The initial estimate Enbridge received from the contractor did not include removing concrete and buildings. Accordingly, Enbridge used the resource-loaded estimate and expanded it to include the rest of the removal activities by lengthening the schedule and adjusting the amount of equipment needed to perform the activities. Enbridge's response to this question adequately addressed our request, and no changes to the methodology are recommended.

Cost Category 7: Contingency

The Enbridge response to RFI Set 1, Information Request No. #2c, indicates that the contingency factor of 13% (cost category 7) from NEB/CER Table A-3 was used. However, the contingency factor noted in Amended Table A-3 (Enclosure 3) for cost category 7 is 25% and is consistent with the value that was used in NEB/CER Table A-4 (Enclosure 3). WSP requested clarification from Enbridge in RFI Set 2, Information Request No. #4, on why this factor was selected. Enbridge responded that they used their proprietary Systematic Contingency Estimating Tool to develop the contingency factor. In 2013, the NEB produced "*Reasons for Decision – Abandonment Cost Estimates (MH-001-2012)*" [2]. In this document, the NEB noted Enbridge's use of the Systematic Contingency Estimating Tool for developing a contingency factor, and commented that the pipeline companies in this document used different methodologies to determine their proposed contingency, but the NEB was of the view that each company adequately justified their proposed contingency, and approved them as filed. In 2016, Enbridge filed an updated decommissioning ACE with a 13% contingency factor; the updated ACE was approved by the NEB in April 2018. WSP notes that the level of detail that Enbridge included in the 2022 Cost Estimate is representative of a Class 3 estimate under USACE ER 1110-2-1302, which recommends a typical contingency range of 20% to 50%. For example, if the 2022 Cost Estimate contingency was set at 20%, this would result in an estimated cost increase of approximately $71 million. Based on this, the current contingency factor should be reviewed for adjustment during the cost estimate review process established by the Commission.

WSP understands that the CER continues to review and improve the ACE process. Any applicable changes, updates, or improvements to the CER's ACE process, including evaluating the contingency factor as applied by Enbridge, should be incorporated into the 2022 Cost Estimate, and incorporated into the cost estimate review process established by the Commission. This could include comparing estimates of construction-phase costs with actual construction-phase costs and incorporating updated information from Enbridge's contractors to improve the estimates in these cost categories.

FINDINGS AND OPINION

WSP reviewed Enbridge's use of the NEB/CER methodology to develop the 2022 Cost Estimate, as well as individual components, assumptions, factors, and contractor information considered by Enbridge in estimating the Line 93 removal costs. Based on this review and evaluation, WSP believes that, except with respect to the correct rate of inflation, the 2022 Cost Estimate approach and methodology used by Enbridge is reasonable, and that Enbridge furnished sufficient information to demonstrate their methodology and assumptions. WSP believes that the 2022 Cost Estimate is underestimated due to Enbridge's use of an inflation rate that is not current. It is also recommended that Enbridge consider the observations provided above to adjust the 2022 Cost Estimate, and to make adjustments as needed during the cost estimate review process established by the Commission.

[2] NEB, Reasons for Decision: Abandonment Cost Estimates (https://docs2.cer-rec.gc.ca/ll-eng/llisapi.dll/fetch/2000/90463/782060/782061/918229/918367/A50478-1_NEB_-_Reasons_for_Decision_-_Abandonment_Cost_Estimates_%28ACE%29_-_MH-001-2012.pdf?nodeid=918198&vernum=-2).

Should you have any questions or need clarification, please feel free to contact me at (612) 524-0943.

Sincerely,

Craig R. Anderson, P.E.	Preetam Kuchikulla
Project Manager	Project Engineer

FJS/ca

cc: Frank Smolenski, WSP

Encl.

Enclosure 1 :	List of Project Documents Reviewed
Enclosure 2 :	Enbridge RFI Set 1 and Set 2 Responses
Enclosure 3:	Enbridge Energy, Limited Partnership Information Request Response to Minnesota Department of Commerce's Requests 1 and 2
Enclosure 4:	Enbridge Energy, Limited Partnership's Initial Comments
Table 1 :	WSP Comparison of 2022 and 2018 Cost Estimate for Line 93 Abandonment (Decommissioning)

ENCLOSURE 1

LIST OF PROJECT DOCUMENTS REVIEWED

PROJECT DOCUMENTS REVIEWED

•	Enbridge's responses to Division of Energy Resources ("DER") Information Request ("IR") No. 1 and 2 [In the Matter of the Decommissioning Trust Fund for the Enbridge Energy, Limited Partnership Line 3 Replacement Pipeline MPUC [Minnesota Public Utilities Commission] Docket No. PL-9/CN-21-823, dated June 13, 2022].
•	Enbridge Energy Limited partnership's Initial comments in the matter of the Decommissioning Trust Fund for the Enbridge Energy, Limited Partnership Line 9 Replacement project. (MPUC Docket No. PL-9/CN-21-823), dated May 19, 2022.
•	Enbridge Energy, Limited Partnership Information Request Response, Response to RFI 1, Dated January 18, 2023.
•	Enbridge Energy, Limited Partnership Information Request Response, Response to RFI 2, Dated March 24, 2023.
•	Order directing Enbridge to Draft Trust Agreement for Notice and Comment, MPUC Docket No. PL-9/CN-21-823, Issue Date: November 4, 2022.
•	Enbridge Energy, Limited Partnership's comments accompanying draft trust agreement (MPUC Docket No. PL-9/CN-21-823).
•	Minnesota Public Utilities Commission, Notice of Comment Period in the matter of the Decommissioning Trust Fund for the Enbridge Energy, Limited Partnership Line 3 Replacement Pipeline, Issued: January 11, 2023.

ENCLOSURE 2

ENBRIDGE RFI SET 1 AND SET 2 RESPONSES

ENBRIDGE ENERGY, LIMITED PARTNERSHIP
INFORMATION REQUEST RESPONSE

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Information Request No. *#1*

Docket No.:	PL-9/CN-21-823
Response To:	WSP USA Inc. (“WSP”)
Requestor:	Craig Anderson
Date Received:	December 28, 2022

Question: Confirm the estimated costs shown on both furnished documents are in U.S. dollars.

Response: Confirmed.

Preparer:	David J. Hodek, P.E.
Title/Company:	Manager, Projects, Enbridge Energy, Limited Partnership
Email:	Dave.Hodek@enbridge.com
Telephone:	218-522-4828
Response Date:	January 18, 2023

ENBRIDGE ENERGY, LIMITED PARTNERSHIP
INFORMATION REQUEST RESPONSE

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Information Request No. *#2*

Docket No.:	PL-9/CN-21-823
Response To:	WSP USA Inc. ("WSP")
Requestor:	Craig Anderson
Date Received:	December 28, 2022

Question: For DER IR No.1, Attachment 1:

a. We understand that the Line 93 ACE ("abandonment cost estimate") was submitted as a searchable PDF, but it appears some of the cost line-items are referencing tabs from an Excel workbook. Please provide the Excel version of the Line 93 ACE.

b. Several of the individual cells on Amended Table A-3, under Comments/Explanation are truncated. Please provide a version of the Amended Table A-3 with all cell information shown.

c. Costs referenced in Amended Table A-3 are from *Enbridge LP – Cost Estimating Tool*. We understand the Cost Estimating Tool will not be furnished, therefore, please explain what information is derived from the estimating tool, and how the estimating tool is regularly updated or kept current to match market conditions.

d. Please provide an explanation for the green/yellow/red highlighting in the *Broad Category* column on the Line 3 (34") Table A-4.

e. Please provide a reference or the actual post-abandonment monitoring and remediation estimate from *Special Projects and Research*, indicated on the Line 3 (34") Table A-4, Item 3b.

f. Please explain why the *Total Cost for future abandonment activities - NEB Benchmark Low/High* shown on the Line 3 (34") Table A-4, do not match the total of the individual items shown above them.

Response:

A. An Excel version of the pdf is attached as Attachment A.

B. See Attachment A.

C. Tables A-3 and A-4 show the methodology approved by the National Energy Board ("NEB", now the Canada Energy Regulator, "CER") for decommissioning (referred to as abandonment by the NEB and CER) estimates. Enbridge included these tables with its prior information request response to illustrate that Enbridge used the same categories approved by the NEB/CER in its Decommissioning Cost Estimate ("DCE") for Line 93 in Minnesota. Enbridge used these tables as a reference, but these tables do not show the calculations for the DCE for Line 93. Table A-3 shows the factors approved by the NEB. Table A-4 is an example of the calculations completed for Line 3 in Canada. Given the cost differences between Canada and the US and that fact that full removal was calculated for Minnesota, only the Engineering and Project Management factor of 5% for pipeline projects greater than 500 km in length (Cost Category 1) and contingency factor of 13% (Cost Category 7) were used to calculate the DCE for Line 93. The cost factors for all other categories are from land access costs from the construction of Line 93 and contractor cost estimates for cleaning and purging of Line 93 and removing Line 93. In short, no costs from the cost estimating tool were used in the DCE for Line 93. Regardless, with respect to how that tool is updated, the tool is based on a combination of Factoring and Parametric Modeling for direct and indirect costs. The output of the tool consists of material, construction, land, and other applicable project costs including overheads. The estimating tool is periodically calibrated based on projects' actual cost. To keep up with the market conditions, the tool is updated periodically with commodity or producer price indices (e.g., steel price) and labor price indices (e.g., wages and compensation).

D. Enbridge believes that the color-coding was not intended to have specific significance but was used internally to identify various categories. Specifically: items in red do not apply for this decommissioning estimate because removal of the pipeline is contemplated; items in green were from contractor estimates; and items in yellow were internally developed.

E. The estimate referenced in this request was not used for the Line 93 DCE because it is not relevant, in that the referenced estimate was prepared for the NEB/CER and thus would not contemplate full pipeline removal like that required for Line 93. Because the referenced estimate was not used for the Line 93 DCE, it is not relevant, and Enbridge does not provide it here.

F. The NEB did not provide low or high benchmarks for Pipeline Purging and Cleaning, Special Treatment, Mainline Instrumentation Building and Pig Trap Assembly. To provide a complete estimate of the total cost for future abandonment activities for the NEB benchmark low and sigh estimates, Enbridge applied a range of +/-50% to its 2016 average cost for each missing category (pipeline purging and cleaning, special treatment, mainline instrumentation building and pig trap assembly) and used the low and high range with the pipeline features of Line 3 in Canada to calculate low and high ranges for each cost category that was missing from the NEB's benchmark. This methodology was approved by the NEB. The value for each category from Enbridge's low range was added to the sum of the NEB benchmark low to provide a complete estimate of the total cost for future abandonment activities for the NEB benchmark low. The value for each category from Enbridge's high range was added to the sum of the NEB benchmark low to provide a complete estimate of the total cost for future abandonment activities for the NEB benchmark high.

Please note that the totals in this table are the low and high NEB Benchmarks for Line 3 in Canada in 2016. They are not estimates for Line 93 in Minnesota. None of the values from the NEB benchmark low or NEB benchmark high were used in the Line 93 - ACE Breakdown. As described above, Tables A-3 and A-4 show the methodology approved by the NEB for decommissioning estimates. However, given the cost differences between Canada and the US and that full removal of Line 93 is contemplated in Minnesota as required by the Minnesota Public Utilities Commission ("MPUC"), only the Engineering and Project Management factor of 5% for pipeline projects greater than 500 km in length and contingency factor of 13% from Table A-3 were used in the DEC for Line 93. The cost factors for all other categories are from land access costs from the construction of Line 93 and contractor cost estimates for cleaning and purging of Line 93 and removing Line 93.

Preparer:	David J. Hodek , P.E.
Title/Company:	Manager, Projects, Enbridge Energy, Limited Partnership
Email:	Dave.Hodek@enbridge.com
Telephone:	218-522-4828
Response Date:	January 18, 2023

ENBRIDGE ENERGY, LIMITED PARTNERSHIP
INFORMATION REQUEST RESPONSE

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Information Request No. *#3*

Docket No.:	PL-9/CN-21-823
Response To:	WSP USA Inc. (“WSP”)
Requestor:	Craig Anderson
Date Received:	December 28, 2022

Question: For DER IR No.1, Attachment 2:

a. No questions or requests.

Response:
A. N/A

Preparer:	David J. Hodek , P.E
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Email:	Dave.Hodek@enbridge.com
Telephone:	218-522-4828
Response Date:	January 18, 2023

ENBRIDGE ENERGY, LIMITED PARTNERSHIP
INFORMATION REQUEST RESPONSE

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Information Request No. *#4*

Docket No.:	PL-9/CN-21-823
Response To:	WSP USA Inc. ("WSP")
Requestor:	Craig Anderson
Date Received:	December 28, 2022

Question: For Enbridge's Initial Comments, May 19, 2022:

a. Given the date of Attachment A (May 2022), were the topics from the Canada Energy Regulator's *ACE Review 2021* considered when developing the furnished version of Attachment A?

b. Please explain the discrepancy in Attachment A for the value of Item 6: Facilities. The spreadsheet subtotal for this item is $111,000,000 and the subtotal should be $111,300,000.

c. The *Line 93 – ACE Breakdown* provided as part of DER IR No. 1, Attachment 1, lists the total cost for Item 6: Facilities as $15,958,300. Attachment A lists the total cost for Item 6: Facilities as $111,000,000. In addition to the inflation-related increase, it appears there is a material increase in facilities costs due to an increase in Pump Station costs (approximately 15-times higher in Attachment A). Please provide additional information on the material change in the Pump Station costs.

Response:

A. No. The CER initiated the ACE Review 2021 in December 2021; however, the process is ongoing. The review has included the CER publishing discussion papers, written submissions on the discussion papers from participants and an oral hearing. The CER plans to issue a draft report in February 2023, followed by a process for written and oral comments by participants in the spring of 2023. A final report from the CER is not expected until June 2023. Given that the ACE Review 2021 is ongoing and the CER has not yet made any recommendations on the topics discussed during the review, Enbridge did not take those topics into account in the DCE for Line 93.

B. All estimates were rounded to the nearest million. In this case the $111,300 was rounded down to $111,000. Enbridge notes that a significant contingency was also included in the estimate.

C. The Attachment A referenced in this request included only a contractor estimate to remove piping from pump stations. Given the scope of removal contemplated in the MPUC's orders for Line 93 in Minnesota, the more recent estimate also includes an estimate to remove all concrete, buildings, and return pump station sites to pre-construction states.

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Telephone:	218-522-4828
Response Date:	January 18, 2023

ENBRIDGE ENERGY, LIMITED PARTNERSHIP
INFORMATION REQUEST NO. 2 RESPONSE

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Information Request No. *#1*

Docket No.:	PL-9/CN-21-823
Response To:	WSP USA Inc. ("WSP")
Requestor:	Craig Anderson
Date Received:	March 20, 2023

Question: The 2022 Cost Estimate for cost category 6.1, pump station costs, was shown as $100 million. In Enbridge's response to RFI No. 1, Enbridge clarified that the scope of removal in the 2022 Cost Estimate includes removing all concrete and buildings and returning the pump station sites to their pre-construction state. Please clarify the basis for the pump station costs in category 6.1. For example, was the estimate developed from contractor quotes, Enbridge unit costs, industry-specific costs, etc.?

Response:
The estimate was a combination of contractor quotes and industry specific cost. The initial estimate Enbridge received from the contractor did not include the removal of concrete and buildings. Accordingly, Enbridge used the resource-loaded estimate and expanded it to include the rest of the removal activities by lengthening the schedule and adjusting the amount of equipment needed to perform the activities.

Preparer:	David J. Hodek, P.E.
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Telephone:	218-522-4828
Response Date:	March 24, 2023

ENBRIDGE ENERGY, LIMITED PARTNERSHIP
INFORMATION REQUEST NO. 2 RESPONSE

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Information Request No. *#2*

Docket No.:	PL-9/CN-21-823
Response To:	WSP USA Inc. ("WSP")
Requestor:	Craig Anderson
Date Received:	March 24, 2023

Question: In Section 2.8 of the 2022 Cost Estimate, Enbridge indicated that it accounted for inflation by uniformly adding a 10.55% cumulative inflation factor to the 2018 Cost Estimate. The 10.55% factor was based on the Consumer Price Index (CPI) data for this time period, as published by the U.S. Bureau of Labor Statistics. WSP's review of the CPI data published by the U.S. Bureau of Labor Statistics for January 2018 to January 2022 estimates the inflation cost to be 13.43% (see BLS:https://data.bls.gov/cgibin/cpicalc.pl?costl=l00.00&yearl=201801&year2=202201). This difference in the applied inflation rate would result in an increase in the estimated costs. Please clarify the timeframe that was used to estimate the inflation factor as well as why that timeframe was chosen.

Response:
The time frame for inflation ranged from September of 2018 to April 2022. At the time of the development of this estimate, inflation rates were a projection and not published or solidified numbers. Based on inflation rates published after submittal of the 2022 Cost Estimate, inflation rates for this time period are 14.53%. If the now-published inflation rate of 14.53% were applied, the total decommissioning trust estimate would increase by approximately $45 million to $1,249,000,000.

Preparer:	David J. Hodek, P.E.
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Telephone:	218-522-4828
Response Date:	March 24, 2023

ENBRIDGE ENERGY, LIMITED PARTNERSHIP
INFORMATION REQUEST NO. 2 RESPONSE

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Information Request No. *#3*

Docket No.:	PL-9/CN-21-823
Response To:	WSP USA Inc. ("WSP")
Requestor:	Craig Anderson
Date Received:	March 20, 2023

Question: Enbridge based the 2018 Cost Estimate for cost category 2.a: Land Access and Clean Up, on Line 93 construction estimates. Enbridge indicated costs were expected to be similar for removal and decommissioning as they would be for installation, and applied numeric factors to cost categories 2.a.ii - Consultants (33% of Line 93 construction) and 2.a.iv - Temporary Workspace/Ancillary Acquisitions (50% of Line 93 construction). An explanation for the numeric factors was not provided with the 2018 Cost Estimate. Please clarify why these numeric factors were selected and how the numeric factors were derived.

Response:
Category 2.a.ii - Consultants and 2.a.iv -Temporary Workspace/Ancillary Acquisitions are connected to each other. The consultants referenced herein are responsible for acquiring the necessary workspace and ancillary acquisitions to execute the scope of work. The costs included as part of this estimate are for the salaries of the consultants and the costs to reimburse the landowners who will be impacted during the work. Both of these categories were decreased from Line 93 construction costs because permanent easement for Line 93 already being acquired, resulting in fewer land rights acquisition needs for removal as compared to construction.

Preparer:	David J. Hodek, P.E.
Title/Company:	Manager, Projects, Enbridge Energy, Limited Partnership
Email:	Dave.Hodek@enbridge.com
Telephone:	218-522-4828
Response Date:	March 24, 2023

ENBRIDGE ENERGY, LIMITED PARTNERSHIP
INFORMATION REQUEST NO. 2 RESPONSE

☐ **Not Public Document – Not For Public Disclosure**

☐ **Public Document – Not Public Data Has Been Excised**

☒ **Public Document**

Information Request No. *#4*

Docket No.:	PL-9/CN-21-823
Response To:	WSP USA Inc. ("WSP")
Requestor:	Craig Anderson
Date Received:	March 20, 2023

Question: Enbridge response to the WSP RFI No. 1, Information Request #2, Question c. indicates that the contingency factor of 13% (cost category 7) from NEB/CER Table A-3 was used. However, the contingency factor noted in Amended Table A-3 for cost category 7 is 25% and is consistent with the value that was used in NEB/CER Table A-4. Please clarify the adjustment of the contingency factor from 25% to 13 % and why this factor was selected.

Response:
The NEB's base case shown in Table A-4 included a contingency factor of 25% with the NEB noting:

> Contingency allowances are influenced by many factors, including the quality of the project cost estimate. Companies using the Base Case Unit Costs should apply a contingency factor as shown, as each of the individual Unit Cost estimates has considerable uncertainty in its estimation.[1]

Enbridge used the NEB's base case for some values, but also used its own proprietary estimating tool to develop the contingency factor. The NEB described Enbridge's approach as follows:

> Enbridge applied a proprietary Systematic Contingency Estimating Tool to determine the appropriate contingency amount for their abandonment cost estimates. Enbridge stated that the Systematic Contingency Estimating Tool is updated quarterly based on learnings from past projects. Enbridge further stated that this estimating tool is used on all projects of all sizes. Enbridge submitted that the Systematic Contingency Estimating Tool indicated that their cost estimates would fall under a Class III estimate using the AACEI

[1] National Energy Board, *Reasons for Decision Abandonment Cost Estimates MH-001-2012*, https://docs2.cer-rec.gc.ca/ll-eng/llisapi.dll/fetch/2000/90463/782060/782061/918229/918367/A50478-1_NEB_-_Reasons_for_Decision_-_Abandonment_Cost_Estimates_%28ACE%29_-_MH-001-2012.pdf?nodeid=918198&vernum=-2 at 77.

> classification system. However, since the actual occurrence of events would not be until many years in the future, Enbridge upgraded the estimate to a Class IV estimate.
>
> Enbridge stated that their approach for estimating contingency costs took into account unforeseen unknowns which may impact the scope of abandonment projects. Enbridge assumed a 13 per cent contingency with a 50 per cent probability of over-run or under-run.[2]

The NEB approved Enbridge's use of a contingency factor of 13% in its abandonment cost estimates, stating the following:

> The Board recognizes that all Applicants have used different methodologies to determine their proposed contingency. Despite these different methodologies, the Board is of the view that each Applicant has adequately justified their proposed contingency. The Board therefore finds that each Applicant's contingency is reasonable and approves each Applicant's contingency as filed.
> …[3]

Preparer:	David J. Hodek, P.E.
Title/Company:	Manager, Projects, Enbridge Energy, Limited Partnership
Email:	Dave.Hodek@enbridge.com
Telephone:	218-522-4828
Response Date:	March 24, 2023

[2] *Ibid* at 48 – 49.

[3] *Ibid* at 50 – 51.

ENBRIDGE ENERGY, LIMITED PARTNERSHIP
INFORMATION REQUEST NO. 2 RESPONSE

☐ **Not Public Document – Not For Public Disclosure**

☐ **Public Document – Not Public Data Has Been Excised**

☒ **Public Document**

Information Request No. *#5*

Docket No.:	PL-9/CN-21-823
Response To:	WSP USA Inc. ("WSP")
Requestor:	Craig Anderson
Date Received:	March 20, 2023

Question: The 2022 Cost Estimate lists "Engineering and Project Management" as $56 million. Section 2.1 of Attachment A: Basis of Estimate, Line 3 Replacement Decommissioning Cost Estimate states that the applicable CER factor for "Engineering and Project Management" is 5%. However, applying this factor to the total costs results in a "Engineering and Project Management" cost of $51 million (if this contingency is not added in the total cost that would be used to apply this factor) or $57 million (if this contingency is added in the total cost that would be used to apply this factor). Please explain the apparent discrepancy in the estimated value.

Response:
The $56 Million is derived from 5% factor of the total cost but is then rounded to the nearest million. As the budget did not exceed $56.5M the number is rounded down to $56 Million.

Preparer:	David J. Hodek, P.E.
Title/Company:	Manager, Projects, Enbridge Energy, Limited Partnership
Email:	Dave.Hodek@enbridge.com
Telephone:	218-522-4828
Response Date:	March 23, 2023

ENCLOSURE 3

ENBRIDGE ENERGY, LIMITED PARTNERSHIP INFORMATION REQUEST RESPONSE TO MINNESOTA DEPARTMENT OF COMMERCE'S REQUESTS 1 AND 2

Fredrikson & BYRON, P.A.

June 13, 2022

<u>VIA E-MAIL ONLY</u>

Greg Merz
Greg.Merz@ag.state.mn.us

Utility.Discovery@state.mn.us

Katherine Hinderlie
Katherine.Hinderlie@ag.state.mn.us

commerce.attorneys@ag.state.mn.us

Re: In the Matter of the Decommissioning Trust Fund for the Enbridge Energy, Limited Partnership Line 3 Replacement Pipeline
MPUC Docket No. PL-9/CN-21-823

Mr. Merz and Ms. Hinderlie:

Enbridge Energy, Limited Partnership submits the attached responses to the Minnesota Department of Commerce's Information Requests 1 and 2.

Please let me know if you have any questions regarding these responses.

Sincerely,

/s/ *Christina K. Brusven*

Christina K. Brusven
Attorney at Law
Direct Dial: 612.492.7412
Email: cbrusven@fredlaw.com

Minnesota Department of Commerce
85 7th Place East | Suite 280 | St. Paul, MN 55101
Information Request

Docket Nos: MPUC PL-9/CN-21-823
Requested From: Enbridge Energy Limited Partnership
Type of Inquiry: General

☐Nonpublic ☒Public
Date of Request: 05/26/2022
Response Due: 06/08/2022

SEND RESPONSE VIA EMAIL TO: Utility.Discovery@state.mn.us; commerce.attorneys@ag.state.mn.us; Katherine.Hinderlie@ag.state.mn.us; Greg.Merz@ag.state.mn.us
Assigned Attorney: Katherine Hinderlie; Greg Merz
Email Address(es): Katherine.Hinderlie@ag.state.mn.us; Greg.Merz@ag.state.mn.us
Phone Number(s): 651 757 1468; 651 757 1291

ADDITIONAL INSTRUCTIONS:
Each response must be submitted as a text searchable PDF, unless otherwise directed. Please include the docket number, request number, and respondent name and title on the answers. If your response contains Trade Secret data, please include a public copy.

Request Number:	**1**
Topic:	
Reference(s):	Enbridge Energy Limited Partnership's Initial Comments, Attachment A

Request:

Please provide all calculations used to determine the amount of each estimated expense line item listed in Enbridge Energy Limited Partnership's Initial Comments, Attachment A, at Section 3.0 Decommissioning Cost Estimate, together with all documents that you relied on or referred to in making each such calculation.

Response:

See the attached tables labelled Enbridge Response to DER IR No. 1_Attachment 1.

To be completed by responder

Response Date: June 13, 2022
Response by: Dave Hodek
Email Address: dave.hodek@enbridge.com
Phone Number: 218-522-4828

Line 93 - ACE Breakdown

	Broad Category	Source Location	Total	Nearest Million Total
1	**Engineering & Project Management**	**NEB Methodology**	**$41,698,322**	**$42,000,000**
2	**Permanent Deactivation Preparation**		**$61,278,930**	**$61,000,000**
a.	Land Access and Clean Up	Tab: 2a	$55,200,845	$55,000,000
b.	Pipeline Purging and Cleaning	Tab: 2b	$6,078,085	$6,000,000
3	**Pipeline Deactivation-in-Place**		-	$0
a.	Basic Pipeline Abandonment-in-Place	N/A	-	$0
b.	Provision for Post Abandonment Activities	N/A	-	$0
4	**Special Treatment (HDDs/Bores)**	**Tab: 4-5-6**	**$6,488,401**	**$6,000,000**
5	**Pipeline Removal**		**$750,240,800**	**$750,000,000**
a.	Removal and Backfilling	Tab: 4-5-6	$661,332,513	$661,000,000
b.	Land Restoration	Tab: 4-5-6	$88,908,287	$89,000,000
6	**Facilities**		**$15,958,300**	**$16,000,000**
a.	Meter Manifold	Tab: 4-5-6	$103,500	$0
b.	Valve Manifold	Tab: 4-5-6	$99,000	$0
c.	Electrical Building	Tab: 4-5-6	$1,739,200	$2,000,000
d	Maintenance Building	N/A @ PLM Shop	-	$0
e	Above Grade Tank	N/A - no removal	-	$0
f	Booster Pump Station	N/A - no removal	-	$0
g	Below Grade Sump Tank	Tab: 4-5-6	$846,400	$1,000,000
h	Mainline Valve (Remote)	Tab: 4-5-6	$5,943,600	$6,000,000
i	Mainline Valve (Manual)	N/A - no manual valves	-	$0
j	Mainline Instrument Building	Tab: 4-5-6	$474,000	$0
k	Pig Trap Assembly	Tab: 4-5-6	$133,600	$0
l	Pump Station			$0
	2-pump configuration	Tab: 4-5-6	$745,000	$1,000,000
	3-pump configuration	Tab: 4-5-6	$4,956,000	$5,000,000
	4-pump configuration	Tab: 4-5-6	$918,000	$1,000,000
m	Terminal Piping	N/A - included above	-	$0
7	**Contingency**	**NEB Methodology**	**$108,415,636**	**$108,000,000**
		Total	**$984,080,388**	**$984,000,000**

$983M was filed as the sum of the sub-categories, when rounded to nearest $million, only adds to $983M

Line 93 Deactivation Cost Estimating

WBS Description	Budget	Assumtions
Grand Total Section 2a	55,200,845	
Damages	25,566,735	
Agricultural Losses	21,213,536	
Crop Payments	21,213,536	From Line 3R
Timber Payments		Cleared ROW
Other Damages	4,353,199	
Close Proximity	1,280,000	From Line 3R
Other Damages	3,073,199	From Line 3R
Consultants	8,721,026	
Land Agents / Consents	8,721,026	33% of Line 3R
Easements	-	
Mainline Easements		Already obtained
Valve Site Easements		Already obtained
TWS + AA	6,677,718	
Temporary Work Space	6,020,269	50% of Line 3R
Ancillary Acquisitions	657,450	50% of Line 3R
Disbursements	1,225,913	
Field Office Expenses	1,225,913	From Line 3R
Regulatory	1,201,920	
Applications / Permits	1,201,920	From Line 3R
Survery & Studies	11,807,533	
Project Survey, Studies & Reports (Geotech)	3,313,565	From Line 3R
Preliminary Survey	3,993,968	From Line 3R
Construction Staking	4,500,000	Based on Line 3R

Segment 18 Cleaning Charges (2018.09.27)			Line 93 ACE		
Vendor	Desciption	Expended	Factor	Sub-total	Comment
[redacted]	Support	$ 136,152	2	$ 272,305	There will be two segments, doubling scope of work
[redacted]	Water Sampling	$ 54,735	0	$ -	No sampling required, not cleaning to leave in place.
[redacted]	Waste Svcs	$ 194,680	0.5	$ 97,340	S18 had 110k gallon of fluid in pig train, L93 design calls for 36k of diesel
[redacted]	Freight	$ 4,425	0.5	$ 2,213	S18 had 110k gallon of fluid in pig train, L93 design calls for 36k of diesel
[redacted]	Pig Tracking	$ 31,990	26	$ 822,601	S18 was 14 miles, L93 is approximately 360 miles
[redacted]	S18 Trap Assist	$ 10,581	2	$ 21,161	There will be two segments, doubling scope of work
[redacted]	Cleaning	$ 540,097	2	$ 1,080,195	There will be two segments, doubling scope of work
[redacted]	Cleaning - Mats	$ 158,994	2	$ 317,988	There will be two segments, doubling scope of work
[redacted]	Frac Tanks	$ 50,896	1	$ 50,896	There is approximately 40% of the volume, but two locations. Using same number
		$ 1,046,397		$ 2,664,697	

Cost Estimate from [redacted] **$3,413,387.50**

[redacted]

Ben Bouska
Enbridge
26 East Superior St.,
Duluth MN 55802

September 7th, 2018

RE: Budgetary Estimate for Line 93 Deinventory

The attached proposal is being submitted to Enbridge as a budgetary estimate to deinventory Line 93 utilizing nitrogen to propel pigs and displace the crude oil line fill from the 36" diameter by approximately 360 mile pipeline from Pembina ND to Minnesota/Wisconsin border.
The estimate is based on information provided by Enbridge including line profile, pump station location, pump station suction pressure, crude oil specification and other data.
The estimate was created based on the output of the [redacted] proprietary modelling for the displacement in combination with the development of a basic logistics plan for nitrogen delivery to the stations in a sequence to allow continuous displacement while minimizing nitrogen volumes required.
The estimate assumes that pump stations will be active until the approaching pig train is approximately 1 mile from the station to minimize head pressure and friction losses associated with propelling the crude oil column.
The pig train design is based on prior industry experience and is subject to amendment to meet client specifications or design preferences.

For summary purposes, our pricing is below:

- Deinventory of Line 93 ....$ 3,413,387.50

If you have any questions pertaining to project or need additional information please call me at [redacted]

Regards,

[redacted]

Enbridge Energy, Limited Partnership
Line 3 Replacement Project
Removal

Revision: 0
Date: 17-Aug-2018

ATTACHMENT E
PRICING WORKSHEET

	DESCRIPTION OF WORK	AMOUNT	TOTALS
MAINLINE		**LUMP SUM**	
Spread 1			
3.1.1.1	Removal and Backfilling	$ 104,625,419.83	
3.1.1.2	Land Restoration	$ 7,306,866.91	
3.1.1.3	Special Treatment	$ 1,351,671.27	
	Spread 1 Total		$113,283,958.02
Spread 2			
3.1.1.1	Removal and Backfilling	$ 113,658,404.91	
3.1.1.2	Land Restoration	$ 15,012,504.50	
3.1.1.3	Special Treatment	$ 540,668.51	
	Spread 2 Total		$129,211,577.91
Spread 3			
3.1.1.1	Removal and Backfilling	$ 124,546,319.66	
3.1.1.2	Land Restoration	$ 23,285,659.58	
3.1.1.3	Special Treatment	$ 1,081,337.02	
	Spread 3 Total		$148,913,316.26
Spread 4			
3.1.1.1	Removal and Backfilling	$ 143,731,451.84	
3.1.1.2	Land Restoration	$ 24,857,747.15	
3.1.1.3	Special Treatment	$ 1,622,005.53	
	Spread 4 Total		$170,211,204.51
Spread 5 (RA-22 Option)			
3.1.1.1	Removal and Backfilling	$ 174,770,917.02	
3.1.1.2	Land Restoration	$ 18,445,508.80	
3.1.1.3	Special Treatment	$ 1,892,718.54	
	Spread 5 (RA-22 Option) Total		$195,109,144.36
Total			
	Removal and Backfilling	$ **661,332,513.26**	
	Land Restoration	$ **88,908,286.93**	
	Special Treatment	$ **6,488,400.86**	
	MAINLINE 5 SPREADS WITH RA-22 SUB-TOTAL		**$756,729,201.06**
FACILITIES		**Unit Price (each)**	
3.1.2.1	Meter Manifold	$ 103,500.00	
3.1.2.1	Valve Manifold	$ 99,000.00	
3.1.2.2	Electrical Building	$ 217,400.00	
3.1.2.2	Instrumentation Building	$ 237,000.00	
3.1.2.3	Booster Pump Station	$ 477,700.00	
3.1.2.3	Pump Station: 4-pump configuration	$ 918,000.00	
	Pump Station: 3-pump configuration	$ 826,000.00	
	Pump Station: 2-pump configuration	$ 745,000.00	
3.1.2.4	Below Grade Sump Tank	$ 105,800.00	
3.1.2.5	Mainline Valve	$ 114,300.00	
3.1.2.6	Pig Trap Assembly	$ 66,800.00	
	FACILITIES UNIT PRICE TOTAL		**$3,910,500.00**

Amended Table A-3						Comments/ Explanation
Table A-3 Base Case Cost Definition Grid					December 2010	Enridge LP estimating tool has last updated on
	Broad Category	Method		May Include	Estimated Cost Factor Value (2010 C$)	
1	Engineering & Project Management	A	R	Reguatory, legal and finance support, external relations and land support, environment, health and safety support, operations support, stakeholder consultation. Detailed cost estimates, planning, applications, detailed engineering and environmental studies. Engineering and project management, construction management, project & cost control.	Apply the factor shown to sum of costs in categories (2a, 2b, 3a, 4, 5a, 5b and 6) If Pipeline abandonment project is / Apply <50 km: 20% 50 to 500 km: 10% >500 km: 5%	PM cost (marked up at the right column)from the Enbridge LP-cost estimating tool But use NEB's recommendation (5%)
	Pipe diameter definitions used in estimates below (as set out in Table A-1 of 4 March 2010 release				Pipe Diameter / Small / Medium / Large Imperial: 2" to 12" / >12" to <26" / ≥26" Metric: 60.3 mm to 323.9 mm / >323.9 mm to <660 mm / ≥660 mm	Example of Enbridge lines
2	**Abandonment Preparation** Factors combine 2a and 2b, applicable to all km of pipe, removed or left-in-place.					
2a	Land Access and Clean Up	A	R	Access rights & permits, temporary work space, damages, re-establish survey markers, as-built survey, update GIS, discharge rights.	Unit Cost per Kilometer — Pipe Diameter: Small / Medium / Large Range Low: $4,000 / $6,000 / $12,000 Range High: $6,000 / $16,000 / $18,000	Cost /KM comes from the LP -cost estimating Tool Applied for access to the segmentatiions, plugging activities
2b	Pipeline Purging and Cleaning	A	R	Pump or draw down gas; Pipeline pigging, cleaning and purging, including pre-cleaning pig runs. Isolate pipe sections, test pipe for cleanliness. Final cleaning pig runs (in N2), waste storage and disposal. Cleanliness verifications (testing and analysis).	This factor may be strongly influenced by pipeline terrain and by the product shipped. Those using the Base Case may choose to refine their estimates as follows: Pipeline Terrain / Gas Shipped / Oil Shipped Flat or Downhill: Low End / Mid Range Mountainous or Uphill: Mid Range / High End	Enbridge mainlines has 30% roling and 70% of flat land on average Purging and claning cost /KM of pipeline comes from LP-cost estimating tool. Backer and Huges provided purging and cleaning cost estimate for Line 3 (34")decommissioning ~ $15,000/KM (worst case scenerio). Considering another $4000 for some supporting contractors, $19,000 /KM can be validated.
3	**Pipeline Abandonment-in-Place**					
3a	Basic Pipeline Abandonment-in-Place	A	n/a	Install plugs to prevent water movement, removal of some underground appurtenances, backfilling and reclamation of dig sites. At the 9 September 2010 meeting, parties discussed whether to include removal of underground appurtenances in category 3a or in 6. The estimates shown to the right include removal of underground appurtenances.	Applicable to all km left-in-place. Unit Cost per kilometer. Unit costs depend less on pipe diameter and more on distance between plugs. High end of range is more applicable for challenging terrain, with more frequent plugs. Range Low: $10,000 Range High: $25,000	This item is included in the removal, segmentation, purge and cleaning scope

3b	Provision for Post Abandonment Activities	A and A+	n/a	Financial provisions for periodic monitoring and for contingencies, such as later removal of some pipeline/associated facilities if problems occur. Events include subsidence issues, pipe rising to surface, or discovery of contamination	Assumed annual monitoring costs $100,000 per 500 km pipe.					This cost was develop with LP Finance based on NEB guideline of events (pipe exposure and removal) per 100km, plus the monitoring cost for 100 year senario as annutiy factor for perpetuaty. $73770.3 is used for Line 3 from LP Finance's Tool (by Michael) The numbers from Column N to U are from Estimating Tool Run data (not used).
					Pipe Diameter		Small	Medium	Large	
					Assumed # of Events per year per 100 km					
							0.5	0.5	0.5	
					Assumed ratio of Event to unit cost 5(a&b) of planned removal & restoration of 1 km of right-of-way					
							0.1	0.2	0.3	
					Resulting Estimate of Provision, in $ per kilometer					
							$20,000	$60,000	$97,000	
4	Special Treatment	A+	n/a	Until possible future clarification from the NEB on any differences between default handling at river crossings and at other crossings, use the low end of 'cut, cap and fill' range provided for road, rail and utility crossings.	Pipe Diameter		Small	Medium	Large	Considering average utility corridor has a 140 M length of pipe crossing;using Enbridge North East Anthoney Henday Drive (NEAHD) Project groutfill cost (see groutfill and Removal Tab) per corridor 140 M length comparing to NEB,s proposed one. The N-U unit costs are per utility crossing.
					Unit cost per crossing of utility corridor					
				Cut, cap and fill with cellular material at crossings – road, rail, utility.	Range	Low	$30,000	$35,000	$50,000	
						High	$45,000	$60,000	$85,000	
										Cost of Groutfill per KM crossing of utility ,roads, railroad from NEAHD project and factored estimate(see the Groutfill/Removal cost Tab)
				Other environmentally sensitive areas. Further	Until further study is done, a placeholder unit cost of $50,000					Environmentally Sensetive Area was
5	**Pipeline Removal**									
5a	Pipeline Removal and Backfilling	n/a	R	Remove impediments and topsoil stripping, excavation, cutting and capping of pipelines, cutting of pipeline sections and removal to stockpile, loading and hauling of removed lines, disposal of lines, coating and associated facilities, backfill, compaction. Mobilization and demobilization may further increase costs, particularly for remote areas.	Cost applicable where pipe removed. Apply 100% of the unit cost for the first pipe and 25% of the unit cost for subsequent pipe, owned by the same company, in the same ditch.					Cost of Pipeline Removal and Backfilling as well restoration per KM was estimated using the Enbridge cost estimating tool and compared with NEAHD removal TIC cost. Average removal cost/KM comare to the NEB's proposed:
					Diameter of Largest		Small	Medium	Large	
					Unit cost per kilometer of pipe.					
					Range	Low	$100,000	$300,000	$450,000	
						High	$250,000	$800,000	$900,000	
5b	Pipeline Removal - Land Restoration	n/a	R	Restoration, reclamation and remediation of contamination, fencing and clean-up, soil decompaction, re-vegetation, inspection of removal activities.	Costs to restore simpler terrain are assumed to be already included in averages for 5a above, rough or mountainous terrain may add a further 10-15% to costs estimated for category 5a					cost per DI-KM
6	**Above-Ground Facilities (see Table A-4)**									
6a	All Facilities	A	R	Purging and cleaning piping and fabrications. Site reclamation (remediation of contamination, re	6 (a) and (b) applicable to all above-ground		Range $ per unit except as noted			

				Site reclamation, (remediation of contamination, re-contouring, replacement of topsoil, re-vegetation). This includes restoration of land as close as possible to the surrounding land Excludes the value of any above-ground facilities that may be salvaged and re-used.	all above-ground facilities.	Low	High
					Block Valve Assemblies	$15,000	$55,000
					Meter Station (Gas)	$50,000	$250,000
					Meter Station (Oil)	$50,000	$500,000
					Maintenance Base	$50,000	Could be Salvaged
6b	Portions Removed	n/a	R	Demolition (as applicable), haul material away. Removal of associated underground tanks.	Compressor Station Per mw *Application to Stations of*	*Under 5mW,* use up to $400,000 for *over 5mW* use up to $120,000	
				Removal of associated underground tanks.	Pump Station	$300,000	$1,500,000
				(includes storage tanks, tank manifolds, booster pumps)	Terminals		
6c	Portions Left in Place	A	n/a	Securing any facilities left in-place. (Not applicable, as all above ground, to be removed)	Other Facilities Reclamation		
7	Contingency			Contingency allowances are influenced by many factors, including the quality of the project cost estimate. Companies using the Base Case Unit Costs should apply a contingency factor as shown, as each of the individual Unit Cost estimates has considerable uncertainty in its estimation.	Applicable to estimates flowing from cost factors 2, 3a, 4, 5(a&b) and 6.		Approximately 25%

Line 3 (34 ")
Tables A-4
Total Estimated Costs

	Broad Category	Method		2016 Pipeline Features	2016 Average Cost	NEB Benchmark Low	NEB Benchmark High	Comments
1	Engineering & Project Management	A	R	n/a	5%	$10,853,550	$17,407,800	A general 5% is used for Engineering and Project Management because of the potential synergies with the other lines. Does not include Provision for Post Abandonment Activities
2	**Abandonment Preparation**							
a.	Land Access and Clean Up	A (and A+)	R		$9,000	$14,940,000	$22,410,000	The 2013 Enbridge Estimate combines the cost for 2a and 2b
b.	Pipeline Purging and Cleaning	A (and A+)	R	1245 km	$19,000	-	-	2016 Estimate based on Line 3 test run and quote from contractor as per cleaning procedures communicated to the NEB. There is no NEB benchmark
3	**Pipeline Abandonment-in-Place**							
a.	Basic Pipeline Abandonment in-Place	A	n/a	989 km	$0	$9,890,000	$24,725,000	The cost for Basic Pipeline Abandonment-in-place is included in Special Treatment and Removal because it includes the cost of plugs at every crossing and removed sections
b.	Provision for Post Abandonment Activities	A and A+	n/a	1063 km	$73,770	$103,111,000	$103,111,000	There will be synergies involved when monitoring lines in the same ROW. Cost based on the Post Abandonment Monitoring and Remediation estimate provided by Special Projects and Research.
4	Special Treatment	A+	n/a	74 km	$479,000	-	-	Newest estimate assumes that all special treatment sections will be grouted. Grouting estimate based on previous project costs. There is no NEB benchmark
5	**Pipeline Removal**							
a.	Pipeline Removal and Backfilling	n/a	R		$418,032	$81,900,000	$163,800,000	2016 estimate based on previous project costs. There will be synergies involved when removing lines in the same ROW
b.	Pipeline Removal - Land Restoration	n/a	R	182 km	$0	$0	$0	Cost is included in 5a
6	**Above-Ground Facilities**							
a.	All Facilities	A	R	___C_#				
	Valve stations (actuated)	n/a	R	33	$150,000	$495,000	$1,815,000	Newest estimate includes cost of the removal of the electrical instrumentation and the communication systems as well as the valve itself. There will be synergies involved when removing valves in the same ROW
	Valve stations (Manual)	n/a	R	69	$50,000	$1,035,000	$3,795,000	There will be synergies involved when removing valves in the same ROW
	Mainline Instrumentation Building	n/a	R	2	$76,000	-	-	Newest estimate is based of off 2013 Enbridge estimate. There is no NEB benchmark
	Pig Trap Assembly	n/a	R	11	$88,000	-	-	Newest estimate is based of off 2013 Enbridge estimate. There is no NEB benchmark
	Pump Stations (19 Stations)	n/a	R	196500 Hp	$42	$5,700,000	$28,500,000	
	Metering Stations	n/a	R					Included in Terminal Estimates
	Terminals (includes storage tanks, tank manifolds, booster pumps)	n/a	R					Included in Terminal Estimates
b.	Portions Removed	n/a	R	___C_#				Included in Terminal Estimates
c.	Portions Left in Place	A	n/a	____#				Included in Terminal Estimates
	Contingency			n/a	13%	$56,981,138	$91,390,950	Contingency has been reduced to 13%. Does not include Engineering & Project Management or Provision for Post Abandonment Activities
Total Cost for future abandonment activities						$315,016,188	$547,286,250	NEB Benchmark Total Cost includes Pipeline Purging and Cleaning, Special Treatment, Mainline Instrumentation Building and Pig Trap Assembly from the 2016 Enbridge Estimate as there was no benchmarks provided by the NEB for these categories

Line	**3**
Diameter (inches)	34
Removal Cost ($ per km)	491,802
Per NEB: Assumed Event per 100 KM	0.5
Assumed Events per KM	0.01
Per NEB: Ratio of Event to Unit Cost	0.3
Estimate per km for Post Abandonment Remediation ($)	737.70
Per NEB: Post Abandonment Monitoing per km ($)	200.00
Reduction in Monitoing Costs due to multiple lines	(200.00)
Dollar Estimate per km for Post abandonment Remediation	737.70
Enbridge Annuity Factor	100
Annuitized Costs Estimate for Post Abandonment Monitoring and Remediation ($)	**$ 73,770.30**

Minnesota Department of Commerce
85 7th Place East | Suite 280 | St. Paul, MN 55101
Information Request

Docket Nos: MPUC PL-9/CN-21-823
Requested From: Enbridge Energy Limited Partnership
Type of Inquiry: General

☐Nonpublic ☒ Public
Date of Request: 05/26/2022
Response Date: 06/13/2022

SEND RESPONSE VIA EMAIL TO: Utility.Discovery@state.mn.us; commerce.attorneys@ag.state.mn.us; Katherine.Hinderlie@ag.state.mn.us; Greg.Merz@ag.state.mn.us
Assigned Attorney: Katherine Hinderlie; Greg Merz
Email Address(es): Katherine.Hinderlie@ag.state.mn.us; Greg.Merz@ag.state.mn.us
Phone Number(s): 651 757 1468; 651 757 1291

ADDITIONAL INSTRUCTIONS:
Each response must be submitted as a text searchable PDF, unless otherwise directed. Please include the docket number, request number, and respondent name and title on the answers. If your response contains Trade Secret data, please include a public copy.

Request Number:	**2**
Topic:	
Reference(s):	Enbridge Energy Limited Partnership's Initial Comments, Attachment A

Request:

Please provide copies of each RFP referred to in Enbridge Limited Partnership's Initial Comments, Attachment A, and all documents provided with each such RFP.

Response:

See Enbridge Response to DER IR No. 2_Attachment 2. Given their lack of relevance, voluminous nature, and the inclusion of security information, as defined in Minn. Stat. § 13.37, subd. 1(a), Enbridge is not re-producing Attachments B, C, and D in response to this Request.

To be completed by responder

Response Date: June 13, 2022
Response by: Dave Hodek
Email Address: dave.hodek@enbridge.com
Phone Number: 218-522-4828

REQUEST FOR INFORMATION ("RFI")

REQUEST FOR INFORMATION NO: WPX-1268889-18

COMPANY NAME: Enbridge Energy, Limited Partnership ("**Company**")

PROJECT NAME: Line 3 Replacement ("L3R") Removal

ISSUE DATE: August 17, 2018

1. Introduction/Purpose and Instructions.

1.1. The purpose this Request for Information ("**RFI**") is to solicit responses ("**Responses**") from the suppliers invited to respond to this RFI ("**Respondents**") with the intent of gaining an understanding of interest, capabilities and capacity of each Respondent to provide the services or goods outlined below ("**Services/Goods**") for Company.

1.2. This RFI outlines all of the requirements for preparing and submitting a Response. Respondents should follow all of the requirements when preparing their Responses and ensure their Responses are complete.

1.3. Responses from this RFI may be used by Company as a basis for short-listing Respondents to participate in potential future procurement processes.

2. Qualifications.

2.1. There are no pre-determined limits as to the number of Respondents who will be short-listed.

2.2. Company reserves the right in its sole discretion to not proceed with any subsequent steps in this procurement process, and ultimately, to not short-list any Respondent(s) if suitable Reponses are not provided.

2.3. Company reserves the right to determine, in its sole judgment, a Response to be non-responsive, or to short-list one or more Respondents. Further, Company is not required to provide any reasons regarding the selection or non-selection of Respondent(s) for the short-list.

2.4. Company anticipates (but is not required) to issue a subsequent procurement process for Services/Goods (or any part of it) to short-listed Respondents.

2.5. This RFI is not a competitive bid process and will not result in a contract award for Services/Goods.

3. Services/Goods.

The scope of the Services/Goods is set out in Attachment A.

4. Response Timing & Receipt.

4.1. Respondents are requested to prepare their Responses using the RFI Package & Submission Format criteria set out in Section 13.

4.2. Responses should be received no later than the date and time identified below **("RFI Response Date")**:

RFI Response Date:	**August 24, 2018**
RFI Response Time:	**4:00 PM Central Time**

4.3. Company reserves the right not to consider any Responses improperly submitted or submitted after the RFI Response Date.

4.4. Any Responses received after the RFI Response Date may be reviewed at Company's sole discretion.

4.5. Respondent assumes full responsibility for delivery of the completed Response before the RFI Response Date.

4.6. Company is not responsible for any loss or delay with respect to the delivery of any Response.

4.7. Respondents shall submit their Responses by email in the Email Response Format set out below. The Responses must be sent to the Delivery Address for Email Response and using the Subject Line for Email Response set out below:

Subject Line for Email Response:	**RFI WPX-1268889-18** **L3R Mainline Removal**
Delivery Address for Email Response:	**ContractsUS@enbridge.com**

5. RFI INQUIRIES.

5.1. Inquiries or requests for clarifications regarding this RFI are to be sent by email to:

RFI Contact Person:	**Derek Stauber**
Title:	**Contracts Coordinator**
Email Address:	**ContractsUS@enbridge.com**
Subject Lines for Email Inquiries/Requests for Clarifications:	**Request for Clarification: WPX-1268889-18**
Submission Date for all Inquiries and Requests for Clarifications ("Inquiry Submission Date"):	**August 22, 2018**

5.2. Respondents must ensure that the above Subject Line is referenced in all inquiries or requests for clarifications regarding this RFI.

5.3. Respondents are requested to submit their inquiries or requests for clarifications regarding this RFI to the RFI Contact Person by the Inquiry Submission Date set out in Section 5.1 above. Inquiries or requests for clarifications received after the Inquiry Submission Date may be answered by Company, at its sole discretion.

5.4. Inquiries or requests for clarifications directed to Company personnel, other than the RFI Contact Person listed above, may result in Respondent's Response not being considered.

6. Response Errors and Omissions.

6.1. Respondent is responsible for all errors or omissions in its Response. Respondent may correct any errors and omissions in its Response by submitting a written request to do so which should be received by Company on or before the RFI Response Date.

6.2. Respondent shall be responsible for obtaining its own independent financial, tax, legal, accounting, engineering and technical advice with respect to this RFI and preparation of its Response, and any attachments or materials incorporated therein. Company will not be responsible for any claim, action, loss, damage, or liability arising from Respondent's reliance or use of this RFI or any other technical or historical appendices, data, materials, photographs, or documents provided by Company.

7. Post Response Information Requirements.

Company may request additional information about a Response by sending a written inquiry to Respondent. Company may require a site visit (at Company's expense) to evaluate Respondent's operation and clarify issues of methodology and experience.

8. Incurred Costs and Expenses.

Respondent participates in this RFI process at its sole risk, cost and expense; Respondent is solely responsible for all costs and expenses of preparing and submitting its Response and any activity associated with the RFI.

9. Ownership of RFI Documents.

All materials submitted by Respondent in response to this RFI shall become the property of Company without payment or liability for payment by Company and shall not be returned. Company reserves the right to, in its discretion, make a reasonable number of copies of Responses.

10. Disclosure of RFI Related Activities.

Respondent agrees not to refer to Company in relation to this RFI or any related activities in any public disclosure without prior written approval from Company.

11. Disposition of Response Material.

All material supplied, including supporting material and information disclosed during the RFI process and ensuing negotiation and award processes will become the property of Company and will be retained for internal use only. Materials submitted by Respondents as part of their Responses will not be returned by Company.

12. Confidentiality of Information.

This RFI and all associated communications and discussions constitute confidential and proprietary information of Company and may not be disclosed to a third party or used for any purpose other than preparing a Response to this RFI.

13. RFI Package & Submission Format.

13.1. Responses are to follow the outline described below and must address all requested information. Any additional information not specifically requested but that Respondent would like to be included, is to be included in Section 2 of the Response.

13.2. Responses must be submitted electronically to the email set out in Section 4.7 above. No other forms of submission will be accepted or considered.

13.3. Response submission format and content must consist of the following outline:

13.3.1 Section 1: Requested Information

Respondent shall supply the following information and submit as part of its Response:

A. Cost Breakdown per Attachment E

13.3.2 Section 2 – Additional Information

Any additional information that Respondents wish to include in their Responses shall be set out in this Section 2.

14. RFI Attachments.

14.1. Attachment A – Scope of Work

14.2. Attachment B – Drawings

14.3. Attachment C – Safety Requirements

14.4. Attachment D – Environmental Requirements

14.5. Attachment E – Pricing Worksheet

ATTACHMENT A

SCOPE OF WORK

1. GENERAL

Only such items as hereinafter specified or indicated on the Drawings to be furnished by others shall be considered to be furnished by others. All other items are to be considered part of the Request For Information ("RFI"). The omission of specific reference to any parts necessary to or reasonably incidental to a complete installation shall not be construed as releasing Contractor from furnishing and installing same as part of the RFI.

2. LOCATION OF WORK

The Work shall be performed along the Line 93 pipeline corridor and within the Line 93 terminal and pump stations located in Minnesota.

3. WORK DESCRIPTION

3.1 Contractor shall provide all services, supervision, labor, equipment, tools, testing devices, materials, supplies, warehousing, temporary facilities, and utilities necessary for the performance of the Work, unless otherwise specified herein in writing. Contractor shall do each and every act and thing necessary to perform the Work in strict accordance with all Specifications, Drawings, Exhibits, codes, standards, and attachments referenced or listed herein, all of which are expressly incorporated into the RFI.

Work shall include, but is not limited to the following:

3.1.1 Mainline removal of approximately three hundred and sixty (360) miles of thirty-six inch (36") pipeline

3.1.1.1 Removal and Backfilling

- Remove impediments;
- Topsoil stripping;
- Excavation;
- Cutting and capping of pipelines;
- Cutting of pipeline sections and removal to stockpile;
- Loading and hauling of removed lines;
- Disposal of lines;
- Coating and associated facilities; and
- Backfill trench compaction.

3.1.1.2 Land Restoration

- Restoration;
- Reclamation and remediation of contamination;
- Fencing and clean-up;
- Topsoil decompaction; and
- Revegetation.

3.1.1.3 Special Treatment

- Horizontal Directional Drills ("HDD's")/Bores: Cut, Cap, and fill with Company approved cementitious material (two hundred pound per square inch (200psi) compressive strength).

3.1.2 Facilities

3.1.2.1 Meter Manifold / Valve Manifold

- Excavation;
- Cutting and capping of pipelines;
- Cutting of pipeline sections and removal to stockpile;
- Loading and hauling of removed lines;
- Disposal of lines;
- Coating and associated facilities (damaged in removal process);
- Backfill trench compaction;
- Disconnecting of all associated equipment and instrumentation;
- Removal and disposal of equipment and instrumentation;
- Restoration;
- Reclamation and remediation of contamination;
- Fencing and clean-up;
- Topsoil decompaction; and
- Returning surface to pre-project conditions.

3.1.2.2 Electrical / Instrumentation Building

- Disconnecting of all associated equipment and instrumentation;
- Removal and disposal of equipment and instrumentation;
- Building demolition and disposal;
- Restoration;
- Reclamation and remediation of contamination;
- Fencing and clean-up;
- Topsoil decompaction; and
- Returning surface to pre-project conditions.

3.1.2.3 Booster Pump Station / Pump Stations

- Excavation;
- Cutting and capping of pipelines;
- Cutting of pipeline sections and removal to stockpile;
- Loading and hauling of removed lines and equipment;
- Below grade sump tank removal and disposal;
- Disposal of lines and equipment;
- Coating and associated facilities (damaged in removal process);
- Backfill trench compaction;
- Substation demolition and disposal;
- Electrical Switchgear Building ("ESB") demolition and disposal;
- Restoration;
- Reclamation and remediation of contamination;
- Fencing and clean-up;
- Topsoil decompaction; and
- Returning surface to pre-project conditions.

3.1.2.4 Below Grade Sump Tank

- Excavation;
- Cutting and capping of pipelines;
- Cutting of pipeline sections and removal to stockpile;
- Loading and hauling of removed valves;
- Disposal of valves;
- Coating and associated facilities (damaged in removal process);
- Backfill trench compaction;
- Restoration;
- Reclamation and remediation of contamination;
- Fencing and clean-up;
- Topsoil decompaction; and
- Returning surface to pre-project conditions

3.1.2.5 Mainline Valve Removals

- Excavation;
- Cutting and capping of pipelines;
- Cutting of pipeline sections and removal to stockpile;
- Loading and hauling of removed valves;
- Disposal of valves;
- Coating and associated facilities (damaged in removal process);
- Backfill trench compaction;
- Restoration;
- Reclamation and remediation of contamination;
- Fencing and clean-up;
- Topsoil decompaction; and
- Returning surface to pre-project conditions.

3.1.2.6 Pig Trap Assembly

- Excavation;
- Cutting and capping of pipelines;
- Cutting of pipeline sections and removal to stockpile;
- Loading and hauling of removed lines;
- Disposal of lines;
- Coating and associated facilities (damaged in removal process);
- Backfill trench compaction;
- Disconnecting of all associated equipment and instrumentation;
- Removal and disposal of equipment and instrumentation;
- Restoration;
- Reclamation and remediation of contamination;
- Fencing and clean-up;
- Topsoil decompaction; and
- Returning surface to pre-project conditions.

3.1.2.7 Terminals (includes manifold connections and booster pumps)

- Excavation;
- Cutting and capping of pipelines;
- Cutting of pipeline sections and removal to stockpile;
- Loading and hauling of removed lines and equipment;
- Disposal of lines and equipment;
- Coating and associated facilities;

- Backfill trench compaction;
- Instrument Shelter ("ISH") building demolition and disposal;
- Densitometer demo and disposal;
- Restoration;
- Reclamation and remediation of contamination;
- Fencing and clean-up;
- Topsoil decompaction; and
- Returning surface to pre-project conditions.

3.2 There are eight (8) facilities along the Line 93 corridor. They are of typical design, with the following pump station configuration:

3.2.1 4-pump configuration: one (1) station;
3.2.2 3-pump configuration: two (2) stations; and
3.2.3 2-pump configuration: five (5) stations.

4. MATERIALS, SERVICES AND EQUIPMENT TO BE PROVIDED BY COMPANY

Company shall not provide any materials, services or equipment.

5. MATERIALS, SERVICES AND EQUIPMENT TO BE PROVIDED BY CONTRACTOR

Contractor shall supply all material, consumables, and supplies necessary for completion of the Work in accordance with the Specifications, Drawings, and Exhibits unless specifically noted otherwise as being provided by Company.

Enbridge Energy, Limited Partnership
Line 3 Replacement Project
Removal

Revision: 0
Date: 17-Aug-2018

ATTACHMENT E
PRICING WORKSHEET

	DESCRIPTION OF WORK	AMOUNT	TOTALS
MAINLINE		**LUMP SUM**	
Spread 1			
3.1.1.1	Removal and Backfilling	$	
3.1.1.2	Land Restoration	$	
3.1.1.3	Special Treatment	$	
	Spread 1 Total		$0.00
Spread 2			
3.1.1.1	Removal and Backfilling	$	
3.1.1.2	Land Restoration	$	
3.1.1.3	Special Treatment	$	
	Spread 2 Total		$0.00
Spread 3			
3.1.1.1	Removal and Backfilling	$	
3.1.1.2	Land Restoration	$	
3.1.1.3	Special Treatment	$	
	Spread 3 Total		$0.00
Spread 4			
3.1.1.1	Removal and Backfilling	$	
3.1.1.2	Land Restoration	$	
3.1.1.3	Special Treatment	$	
	Spread 4 Total		$0.00
Spread 5 (RA-21 Option)			
3.1.1.1	Removal and Backfilling	$	
3.1.1.2	Land Restoration	$	
3.1.1.3	Special Treatment	$	
	Spread 5 (RA-21 Option) Total		$0.00
	MAINLINE 5 SPREADS WITH RA-21 SUB-TOTAL		**$0.00**
Spread 5 (RA-22 Option)			
3.1.1.1	Removal and Backfilling	$	
3.1.1.2	Land Restoration	$	
3.1.1.3	Special Treatment	$	
	Spread 5 (RA-22 Option) Total		$0.00
	MAINLINE 5 SPREADS WITH RA-22 SUB-TOTAL		**$0.00**
FACILITIES		**Unit Price (each)**	
3.1.2.1	Meter Manifold	$	
3.1.2.1	Valve Manifold	$	
3.1.2.2	Electrical Building	$	
3.1.2.2	Instrumentation Building	$	
3.1.2.3	Booster Pump Station	$	
3.1.2.3	Pump Station: 4-pump configuration	$	
	Pump Station: 3-pump configuration	$	
	Pump Station: 2-pump configuration	$	
3.1.2.4	Below Grade Sump Tank	$	
3.1.2.5	Mainline Valve	$	
3.1.2.6	Pig Trap Assembly	$	
	FACILITIES UNIT PRICE TOTAL		**$0.00**

In the Matter of the Decommissioning Trust Fund for the Enbridge Energy, Limited Partnership Line 3 Replacement Pipeline	**MPUC Docket No. PL-9/CN-21-823**

CERTIFICATE OF SERVICE

Breann L. Jurek certifies that on the 13th day of June 2022 she served a true and correct copy of Enbridge Energy, Limited Partnership's Responses to Information Requests 1 and 2, with attachments, upon the following individuals via email: Greg Merz; Katherine Hinderlie.

Dated this 13th day of June 2022

/s/ Breann L. Jurek

ENCLOSURE 4

ENBRIDGE ENERGY, LIMITED PARTNERSHIP'S INITIAL COMMENTS

STATE OF MINNESOTA
BEFORE THE
PUBLIC UTILITIES COMMISSION

Katie Sieben	Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

In the Matter of the Decommissioning Trust Fund for the Enbridge Energy, Limited Partnership Line 3 Replacement Pipeline	MPUC Docket No. PL-9/CN-21-823

ENBRIDGE ENERY, LIMITED PARTNERSHIP'S INITIAL COMMENTS

INTRODUCTION

Enbridge Energy, Limited Partnership ("Enbridge") submits these initial comments in response to the Minnesota Public Utilities Commission's ("Commission") December 20, 2021 Notice of Comment Period concerning the Decommissioning Trust Fund for the Line 3 Replacement Pipeline. Now that the replacement pipeline has been constructed and is operational, it is referred to as "Line 93" to distinguish it from the original Line 3 pipeline, which is no longer in service. Here, and going forward, Enbridge will refer to the replacement pipeline as "Line 93." In these comments, Enbridge responds to the issues identified in the Commission's Notice and proposes a framework for the establishment of a decommissioning trust fund for Line 93 that is consistent with the Commission's prior orders.

PROCEDURAL BACKGROUND

Enbridge applied for a certificate of need ("CN") and pipeline routing permit from the Commission for the Line 3 Replacement Project. In testimony related to the CN, the Department of Commerce, Division of Energy Resources ("DER") recommended that "the Commission require Enbridge to establish a decommissioning trust to pay for the costs of decommissioning the Project when it reached the end of its economic usefulness."[1] In its Order Granting Certificate of Need as Modified and Requiring Filings ("CN Order"), the Commission stated that it would "require Enbridge to propose the terms and conditions of a decommissioning trust fund for the Project based on the decommissioning trust required by the Canadian National Energy Board for Enbridge's Canadian pipelines."[2] Thus, the Commission approved the CN "contingent upon the creation and funding of a trust fund for decommissioning of the Project, including the costs of removal of the Project."[3] The Commission ordered Enbridge to submit a compliance filing "of the terms and conditions of the decommissioning trust fund based on the decommissioning trust that the Canadian National Energy Board directed Enbridge, Inc. to fund for the decommissioning of its pipelines in Canada" and requested that DER submit recommendations concerning Enbridge's compliance filing.[4]

On July 16, 2018, Enbridge submitted a compliance filing which provided a "discussion of the terms and conditions of the decommissioning trust fund based on the decommissioning trust that the NEB[5] directed Enbridge Inc. to fund for decommissioning of Enbridge pipelines in Canada."[6] In that filing, Enbridge explained that "the differences in regulatory structure and applicable law are such that Enbridge will mirror but is unable to wholly replicate the

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[1] Direct Testimony of Kate O'Connell, at 116 (Sept. 11, 2017). All docket references herein are to Docket No. PL-9/CN-14-916.

[2] CN Order, at 35 (Sept. 5, 2018) (reissued May 1, 2020).

[3] CN Order, at 38.

[4] CN Order, at 38.

[5] National Energy Board. The NEB is now the Canadian Energy Regulator ("CER").

[6] Enbridge Response to DOC-DER Comments regarding Enbridge Compliance Filing on the Decommissioning Trust Certificate of Need Modification ("Enbridge July 2018 Comments"), at 4 and Attachments 3A-C (July 16, 2018).

decommissioning trust structure used for NEB-regulated pipelines."[7] Enbridge further explained that "unless and until trust and/or tax laws applicable to L3R in Minnesota are changed, the decommissioning trust for L3R in Minnesota will be subject to potential legal risks, more difficult to achieve the goals of the Commission, and more costly."[8] Enbridge also identified issues related to creditor protections.[9]

In response, on July 20, 2018, DER recommended that the Commission require Enbridge to propose a revised decommissioning trust fund proposal that:

- Is consistent with, and requires no changes to, existing Minnesota and federal law;
- Includes collections over the expected 50-year life of Line 3 project in Minnesota at least to equal approximately $1.5 billion (USD), as adjusted for inflation;[10]
- Is not controlled by Enbridge Inc. or any present or future affiliated entity;
- Is established only for the purpose of deactivating, monitoring, and removing the pipeline together with remediation of the soil at the time Line 3 is taken out of service in Minnesota; and
- Includes other provisions as required by the Commission.[11]

---

[7] Enbridge July 2018 Comments, Attachment 3A, at 1.

[8] *Id.* at 2.

[9] Enbridge July 2018 Comments, Attachment 3B, at 3.

[10] In these comments, DER explained: "Enbridge witness Mr. Johnston confirmed the present cost of pipeline removal is about $855 per foot, and removal of the expected 337 miles of the proposed Line 3 in Minnesota would cost today about $1.5 billion (USD). The trust should be designed to collect this sum over the expected 50-year life of proposed Line 3, as adjusted for inflation." DER Comments, at 1-2 (July 20, 2018). DER cited Mr. Johnston's evidentiary hearing testimony, where he stated, among other things, "I guess if you want to think that's a reasonable proxy, fair enough," and "I would refer to the experts in that area." Evid. Hrg. Tr. Vol. 6A (Nov. 9, 2017) at 125-127 (Johnston).

[11] DER Comments, at 2 (July 20, 2018).

On October 16, 2018, Enbridge provided a detailed cost estimate for removal costs, following the methodology it uses in Canada. Based on that methodology, the removal cost for Line 93 was estimated to be approximately $983 million.[12]

After several additional comments from Enbridge and other parties, in its Order Approving Compliance Filings as Modified and Denying Motion, the Commission ordered:

> The Commission will accept Enbridge's July 16, 2018 compliance filing and Attachments 3A, 3B, and 3C as further modified by Enbridge's July 30, September 7, and October 16, 2018 filings relating to the Decommissioning Trust Fund. However, the Commission believes that additional work is needed to develop the Decommissioning Trust Fund. The Commission will open a docket with filing deadlines and comment periods set by the Executive Secretary for the purpose of establishing the terms and conditions of the Decommissioning Trust Fund. Enbridge shall consult with DER regarding its recommendations that the Decommissioning Trust Fund should:
>
> - Be consistent with, and require no changes to, existing Minnesota and federal law;
> - Include collections over the expected 50-year life of Line 3 project in Minnesota to equal approximately $1.5 billion (USD) at least, as adjusted for inflation;
> - Not be controlled by Enbridge Inc. or any present or future affiliated entity;
> - Be established only for the purpose of deactivating, monitoring, and removing the pipeline together with remediation of the soil at the time Line 3 is taken out of service in Minnesota.
>
> Enbridge shall analyze for Commission consideration the benefits of establishing the trust consistent with the Environmental Protection Agency and Bureau of Land Management rules for

---

[12] Certificate of Need Modifications – Compliance Filings, at 4 Attachment C—Line 3 Replacement Deactivation Cost Estimate (Oct. 16, 2018).

> financial assurances for decommissioning trust funds, as well as the Canadian National Energy Board's provisions.[13]

The Commission subsequently opened the above-captioned docket and, on December 20, 2021, issued a Notice of Comment Period requesting comments on three topics, each of which is addressed by Enbridge below.

DISCUSSION

I. WHAT ACTION SHOULD THE COMMISSION TAKE TO ESTABLISH THE DECOMMISSIONING TRUST FUND REQUIRED BY ITS ORDERS IN DOCKET 14-916?

Because of the lengthy record and prior Commission orders addressing issues related to the Decommissioning Trust Fund, and because the current Notice of Comment Period provides additional, multiple rounds of comments concerning the same, Enbridge suggests that, at the conclusion of the comment period, the Commission will be well-positioned to issue a decision concerning the Decommissioning Trust Fund. Specifically, after the conclusion of the supplemental comment period, the Commission should:

- Identify the basic terms and conditions of the Decommissioning Trust Fund. Enbridge discusses these terms and conditions in Section II, below.
- Authorize Enbridge to establish the Decommissioning Trust Fund, consistent with those terms and conditions.
- Require Enbridge to submit a compliance filing indicating that a decommissioning trust agreement, consistent with the Commission's Order, has been negotiated with a trustee, subject to final review by the Executive Secretary prior to execution.
- Delegate to the Executive Secretary authority to review the final Trust Agreement for consistency with the Commission's order.

[13] Order Approving Compliance Filings as Modified and Denying Motion, at 8 (Jan. 23, 2019) (reissued May 1, 2020).

- Following review by the Executive Secretary, require Enbridge to submit a compliance filing verifying that the Decommissioning Trust Fund has been established and file the final Trust Agreement after it is executed.
- Require Enbridge to submit annual reports from the Fund's trustee.
- Require Enbridge to update its decommissioning cost estimate every five years, consistent with the Commission's treatment of decommissioning obligations for other energy projects.

II. WHAT TERMS AND CONDITIONS SHOULD BE REQUIRED IN THE DECOMMISSIONING TRUST FUND?

In Section A, below, Enbridge addresses the general terms and conditions that should be part of the Decommissioning Trust Fund. In Section B, Enbridge addresses the categories identified by the Commission in its January 23, 2019 Order Approving Compliance Filings. The terms and conditions discussed herein are consistent with the Commission's previous direction and would accomplish the goal of setting aside funds for decommissioning of Line 93.

Enbridge notes that the specific terms and conditions and language in the Trust Agreement will need to be acceptable to and approved by the financial institution that will serve as the trustee for the Decommissioning Trust Fund. Because of this, neither Enbridge nor any other stakeholder can unilaterally dictate the terms of the Trust Agreement. This is particularly the case here, where the Decommissioning Trust Fund will be the first of its kind in Minnesota. That said, Enbridge believes these terms and conditions are achievable in that they are authorized under current law and are likely to be acceptable to a financial institution that will serve as the trustee.

A. **General terms and conditions**.

To ensure consistency with the terms and conditions of the decommissioning trusts required by the CER,[14] as modified to reflect U.S. law, Enbridge recommends that the Line 93 Decommissioning Trust Agreement include the following general terms and conditions:

Terms	Proposed Terms and Conditions
Purpose and Nature of Trust	Trust will be established and maintained for the sole purpose of decommissioning Line 93 in compliance with the Commission's Orders.
Settlor	Enbridge Energy, Limited Partnership
Beneficiaries	Enbridge Energy, Limited Partnership, or person or persons with obligation to decommission Line 93
Trustee(s)	A U.S. domestic corporate trustee not affiliated with Enbridge
Creditor Protection	The trust should be drafted to provide maximum protection of the trust assets from Enbridge's creditors.
Governing Law and Situs	Minnesota, subject to the ability of the trustee to change the situs and governing law of the trust (to another state within the U.S.)
Contributions	The trust will be funded with amounts collected from shippers as decommissioning charges.
Investment	Investment manager should be a U.S. domestic entity (to avoid foreign trust tax status), and will likely be an affiliate of the corporate trustee.
Distributions	• Trust expenses (trustee fees, costs, admin. expenses, etc.) • Taxes imposed on and payable by the trust, liability of the settlor • Distributions to settlor to pay any tax, resulting from trust income • To a beneficiary or third party for the purpose of decommissioning Line 93
Surplus Funds	After final decommissioning of Line 93, surplus funds may be distributed to a Minnesota abandoned pipeline fund that will be established and maintained for the purpose of funding reclamation of any other abandoned Enbridge pipelines in Minnesota.
Tax Obligations	If the trust is a non-grantor trust, to the extent it incurs tax, it will pay its tax obligations, and the trustee will prepare and file income tax returns. If the trust is a grantor trust, absent a law change, the tax obligations will fall on the grantor/settlor. The trust will make distributions to the grantor/settlor to pay tax resulting from the trust. Enbridge suggests the trust be drafted to allow for more favorable tax treatment, should it become available through private letter rulings or legislative changes.

[14] Under the CER, decommissioning trusts are called abandonment trusts.

Terms	Proposed Terms and Conditions
Reporting and Recordkeeping	Trustee will provide annual reports to Enbridge, which will file the report with Commission.
Term of Trust	The longest period that a trust under this instrument may continue under the laws of the jurisdiction that is the situs of the trust. Because Settlor's contributions to the Trust are not donative, but are required by the Commission, it is Enbridge's expectation and intention that the Trust may be perpetual under Minnesota law, and that the Perpetuities Period shall be indefinite. If for any reason the Trust cannot continue in perpetuity under the laws of the jurisdiction that is the situs of the Trust from time to time, the Term shall end on the last date on which such assets can validly remain in trust (likely 90 years under current Minnesota law). At that point, a successor trust could be created.
Irrevocable	Trust will be irrevocable.
Modification	Trust may be amended by agreement of Enbridge and the trustee.

B. Discussion of items identified in January 23, 2019 Order Approving Compliance Filings.

1. Be consistent with and require no changes to existing law.

As discussed above, it is possible to establish the Decommissioning Trust Fund and related Trust Agreement for Line 93 without changes to existing law. However, Enbridge continues to analyze potential legislative and legal efforts that will allow the Decommissioning Trust Fund to function more like the CER decommissioning trust funds; these efforts are not an impediment to establishing the Decommissioning Trust Fund, provided that, as discussed previously herein, the Trust Agreement is drafted in a manner that allows the trust to benefit from those future efforts, should they prove successful. Among other things, future changes in law could allow greater creditor protection and/or tax efficiency.[15]

[15] *See* Enbridge July 2018 Comments, at 3.

2. Include collections over the expected 50-year life of Line 93 to equal approximately $1.5 billion.

With this filing, Enbridge is submitting an updated decommissioning cost estimate (Attachment A); as identified in that estimate, Enbridge currently estimates that the cost of decommissioning Line 93—including removal, as required by the Commission—will be approximately $1.2 billion (USD). However, Enbridge respectfully submits that it would be prudent for the Commission to review this estimate every five years. Enbridge will, as it does under the CER-ordered trusts, continue to rigorously analyze and update the costs of complete removal in its estimate, incorporating lessons learned from the CER's years-long assessment of the issue and the costs of removal of the original Line 3 pipeline, over the life of Line 93's operation.

Enbridge proposes to file the Trustee's annual reports with the Commission each year (as it does with the CER in Canada). Further, similar to the Commission's decommissioning plan requirements for other energy projects in Minnesota, Enbridge proposes to submit updated decommissioning cost estimates to the Commission every five years.[16]

With respect to the term over which the Decommissioning Trust Fund will build, Enbridge will collect and contribute funds to the Decommissioning Trust Fund over the course of the economic life Line 93 to ensure the amount needed for decommissioning is available when the funds are needed. Line 93 is subject to an agreement between Enbridge and its shippers, referred to as the Facilities Surcharge Mechanism ("FSM"), which is a component of the FERC-regulated tariff rates. Per the terms of the FSM, the economic life of Line 93 is stipulated as 30 years. Enbridge will calculate the amount that needs to be contributed to the Decommissioning Trust

[16] The CER also revisits decommissioning estimates on a similar timeframe.

Fund each year, based on the decommissioning cost estimate, the expected inflation rate, earnings in the trust, and trust expenses. Enbridge will recover that amount through the FSM, which is collected through an annual Enbridge rate filing effective April 1 of each year. With this timeline in mind, and allowing for time to prepare the filing, discuss with shippers, have the new toll go into effect, and collect the trust funds through the new toll, Enbridge will begin funding the Decommissioning Trust Fund on May 10 of the first calendar year following the issuance of the Commission's final written order approving the establishment of the Fund. Because Line 93 went into service on October 1, 2021, Enbridge will prorate the recovery of the decommissioning cost estimate over the economic life of Line 93 that remains on May 10 of the year that Enbridge commences funding the Trust. For example, if Enbridge commences funding the Trust on May 10, 2023, the decommissioning costs will be collected over a period of approximately 27 years and 5 months to ensure that the Trust will be fully-funded by the end of the economic life of Line 93 (October 1, 2051).

3. Not be controlled by Enbridge Inc. or any present or future affiliated entity.

Enbridge has made this commitment. The Decommissioning Trust Fund would be controlled by the Trustee.

4. Be established only to deactivate, monitor, and remove Line 93.

Enbridge has made this commitment, and the scope of the Decommissioning Trust Fund would be reflected in the Trust Agreement, which would provide that funds would be disbursed only to pay decommissioning expenses.

5. Use of Environmental Protection Agency or Bureau of Land Management Trust Forms.

In response to comments from Friends of the Headwaters, the Commission's January 23, 2019 Order also directed Enbridge to analyze the potential benefits of establishing the trust consistent with the Environmental Protection Agency ("EPA") and Bureau of Land Management ("BLM") rules for financial assurances for decommissioning trust funds, in addition to those used by the Canadian National Energy Board's provisions.[17] Although Friends of Headwaters did not provide specific citations or examples of such rules or funds in their prior comments, Enbridge reviewed potentially relevant EPA and BLM regulations and sample agreements to determine if any could be relevant here.[18] However, as discussed below, Enbridge did not identify relevant EPA or BLM decommissioning trust forms that provided any identifiable benefits more favorable than the terms and conditions used by the CER as described above or which provide helpful guidance here.

With regard to the EPA, 40 C.F.R. §§ 264.140 - 264.151 contain the financial requirements for owners and operators of certain hazardous waste facilities. The regulations identify specific requirements and procedures for the financial assurances, as well as provide specific language that must be included in the trust agreement. 40 C.F.R. § 264.151. Among other things, the form trust agreement requires specifically that the EPA Regional Administrator direct payments from the fund. Of course, EPA has no role in the Line 93 Decommissioning Trust Fund. Further, the general structure is different than the structure contemplated by the Commission and, more generally, the EPA regulations do not provide helpful guidance because they are the result of a different, specific, regulatory regime that would be difficult to import into the Commission's process.

[17] Order Approving Compliance Filings as Modified and Denying Motion, at 8 (Jan. 23, 2019) (reissued May 1, 2020).

[18] Enbridge undertook good faith efforts to identify potentially relevant EPA and BLM regulations and trust agreements. However, as explained herein, the regulations and agreements identified by Enbridge thus far are not helpful to the Commission's establishment of a decommissioning trust fund for Line 93. To the extent other commenters identify additional, specific regulations and/or sample trust agreements, Enbridge can address those in further comments.

With respect to BLM trusts, Enbridge identified a BLM requirement that a financial guarantee be provided in some instances to cover estimated reclamation costs for mines. *See* 43 CFR 3809.500 *et seq.* Acceptable instruments for an individual financial guarantee include corporate surety bonds, cash, irrevocable letters of credit, certificates of deposit, government securities or bonds, investment-grade rated securities, or insurance. *See* 43 CFR § 3809.555. Enbridge has thus far not been able to locate an example of a BLM trust, and, like the EPA discussion above, it is unlikely that a different agreement designed to satisfy different regulatory requirements would provide a viable alternative here.

III. WHAT ENTITY SHOULD BE NAMED AS THE BENEFICIARY OF THE DECOMMISSIONING TRUST FUND?

Consistent with other decommissioning funds, Enbridge submits that the beneficiary of the Decommissioning Trust Fund should be the entity that has the decommissioning obligations. For example, the following is language from Enbridge's Canadian pipeline trust agreement:

> the Person or Persons, including the Company, acting on its own capacity or acting on behalf of a partnership, having Reclamation Obligations in respect of the Site.

This makes practical sense—the funds in the Decommissioning Trust Fund must be used to fund decommissioning activities, and the entity with the decommissioning obligations will be the entity undertaking those activities. The Trust Agreement, in turn, requires that any disbursements be used to pay decommissioning expenses. The beneficiary would not control the funds, however, because the funds would be disbursed to the beneficiary only with the approval of the Trustee. Thus, it would be ensured that the Decommissioning Trust Fund would only be used to fund decommissioning obligations.

CONCLUSION

Enbridge appreciates the opportunity to provide these comments and respectfully submits that the decommissioning trust framework and terms presented herein are consistent with and responsive to the Commission's prior orders on this issue.

Dated: May 19, 2022

Respectfully submitted,

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ATTACHMENT A

Basis of Estimate

Line 3 Replacement
Decommissioning Cost Estimate

Revised May 2022

ATTACHMENT A
TABLE OF CONTENTS

ATTACHMENT A

1.0 INTRODUCTION

1.1 SCOPE OF ESTIMATE

The scope of the project being estimated is decommissioning of Line 93 or L93 (formerly referred to as Line 3 Replacement), once the pipeline and related facilities are no longer transporting crude oil through the State of Minnesota. Enbridge's US Line 93 pipeline route begins at the Joliette Valve near Neche, North Dakota, and extends 343 miles across Minnesota to the Superior terminal at Superior, Wisconsin. Approximately 330 miles of the route is located in Minnesota. As part of the Line 93 project, there were new pump stations constructed adjacent to the existing Donaldson, Viking and Plummer pump stations and a permanent expansion of Clearbrook terminal, including a new pump station. New pump stations were also constructed at Two Inlets, Backus, Swatara and North Gowan.

1.2 DECOMMISSIONING COST ESTIMATE

The Minnesota Public Utilities Commission ("MPUC") directed Enbridge to provide a Decommissioning Cost Estimate ("DCE") for Line 93, similar to what is required by Canada Energy Regular ("CER", formerly the National Energy Board or NEB) in Canada for CER regulated pipelines. This estimate will be used to determine the amount of money that needs to be available in the Decommissioning Trust Fund being established for Line 93. The L93 DCE followed the CER methodology, where applicable.

2.0 ESTIMATE METHODOLOGY

Following a multi-year review process involving pipeline companies, associations representing pipeline companies, petroleum producers (shippers) and landowners, the CER set out a methodology for calculating decommissioning cost estimates. The CER held a technical conference and eventually established a base case including physical assumptions and unit costs. Pipeline companies are to apply the unit costs to their assets to calculate an estimate. Where a pipeline company has better unit cost information, such as from actual decommissioning experience, it may propose those unit costs in place of the base case and the CER would consider the reasonableness of the company specific unit costs.

Following the CER's methodology, Enbridge has estimated the costs for all activities required to permanently decommission (or in CER terms, abandon) L93 including engineering and project management, permanent decommissioning preparation, special treatment for crossings, pipeline removal, facilities removal, and contingency. Enbridge obtained L93 specific estimates from contractors or applied information on costs from the construction of L93, where it was determined that the CER's unit costs for Canada would likely not apply. The following sections provide a description of how the estimate was calculated.

2.1 ENGINEERING & PROJECT MANAGEMENT

The CER methodology uses a cost factor approach to the Engineering & Project Management costs for the DCE, which may include the following costs: regulatory, legal and finance support, external relations and land support, environment, health and safety support, operations support, stakeholder consultation, detailed cost estimates, planning, applications, detailed engineering and environmental studies, engineering and project management, construction management, and project and cost control.

The factors are based on the length of the pipeline project and apply the factor to the sum of the costs in the following categories: Decommissioning Preparation, Pipeline Decommissioning-in-place, Special Treatment areas, pipeline removal and facilities costs.

The factors are as follows:

If Pipeline Decommissioning project is:	Apply
<50 km (<31mi)	20%
50 to 500 km (31 to 311mi)	10%
>500 km (>311mi)	5%

For the purposes of the L93 DCE, the length of the pipeline removal in Minnesota is approximately 330 miles. This would result in the CER cost factor of 5%.

2.2 PERMANENT DECOMMISSIONING PREPARATION

Part 2 of the CER methodology, Abandonment (or Decommissioning) Preparation, is broken in to two sub-sections: “Land access and Clean up” and “Pipeline Purging and Cleaning”.

2.2a Land Access and Clean up

The scope of activities in the CER methodology in this section includes: access rights and permits, temporary work space, damages, re-establishing survey markers, as-built survey, updating GIS, and discharge rights. Additional costs factored into Land Access and Clean Up included geotechnical studies/reports and disbursements. These additional costs were based on L93 costs.

For the L93 DCE, the above costs were taken from the estimates of the construction phase of L93 and applied to the DCE, as they are expected to be similar for the removal and decommissioning as they would be for installation. Discrepancies between construction and decommissioning of L93 were accounted for by applying a numeric factor to the L93 construction costs.

2.2b Pipeline Purging and Cleaning

The scope of activities in the CER methodology in this section includes: pump or draw down gas; pipeline pigging, cleaning and purging, including pre-cleaning pig runs, isolating pipe sections, final cleaning pig runs, testing pipe for cleanliness, and waste storage and disposal.

For the L93 DCE, a request for proposal was sent to a cleaning contractor, to which a cost estimate was provided for the purging and cleaning scope. Additionally, actual costs from a recent project (cleaning the original Line 3) were used to estimate the costs for purging and cleaning support, including a lump sum cost associated with Enbridge support, cleanliness testing, pig tracking, nitrogen injection, consumables, matting, freight, and waste storage, hauling, and disposal.

2.3 PIPELINE DECOMMISSIONING-IN-PLACE

The CER methodology includes a section for Abandoning (or Decommissioning) a pipeline in place. For the purpose of the L93 DCE, this section is assumed to be not applicable as the estimate will include the removal of all existing L93 pipe, except for those sections of pipeline that required special treatment, which fall within Section 2.4, Special Treatment.

2.4 SPECIAL TREATMENT

The CER methodology includes an estimate for specific sections of the pipeline that require special treatment for abandonment (or decommissioning), such as horizontal direction drills ("HDD"), and major roadway crossings, railroad crossings or river crossings that are crossed by bore. For the L93 DCE, the assumption is that these sections will not be removed, but will be cut, capped and filled with a cementitious grout material.

For the L93 DCE, a request for proposal ("RFP") was sent out to a pipeline contractor for the removal of the pipeline, with a request for the sections of pipe that are installed via HDD or bore to be cut, capped and filled with a cementitious grout material. The contractor provided this estimate separate from the removal scope based on construction spreads used during the installation of L93 (each spread contains a unique quantity of pipe installed via HDD or bore), and the sum of these costs are documented in Section 3.0.

2.5 PIPELINE REMOVAL

Part 5 of the CER methodology, Pipeline Removal, is broken into two sub-sections: "Pipeline Removal and Backfilling" and "Pipeline Removal – Land Restoration".

2.5a Pipeline Removal and Backfilling

The scope of activities in the CER methodology in this section includes: removing impediments and topsoil stripping, excavation, cutting and capping of pipelines, cutting of pipeline sections and removal to stockpile, loading and hauling of removed lines, disposal of lines, coating and associated facilities, backfill, and compaction.

For the L93 DCE, the above costs were provided by a contractor in response to the RFP that was sent requesting removal costs. A contractor RFP response was selected rather than the CER factor in this instance as costs for these activities are heavily dependent on specific factors such as workforce, site-specific conditions, unique challenges and topographic conditions for equipment and personnel access, delineation between contractor and Enbridge provided services, and other varying factors; therefore the CER unit cost for these activities would not be appropriate to use in the L93 DCE.

2.5b Pipeline Removal – Land Restoration

The scope of activities in the CER methodology in this section includes: restoration, reclamation and remediation of contamination, fencing and clean-up, soil decompaction, re-vegetation, and inspection of removal activities.

For the L93 DCE, the above costs were provided by a contractor in response to an RFP that was sent requesting removal costs. Similar to section 2.5a above, contractor provided costs were selected as the basis for the land restoration estimate due to location-specific factors. Additionally, contractor responses were gathered from contractors who were familiar with the site-specific challenges for L93 across Minnesota, which also factored into the decision to use contractor provided costs instead of CER unit costs.

2.6 FACILITIES

Part 6 of the CER methodology, Above-Ground Facilities, is broken into thirteen sub-sections, based on separate parts of the facility. A cost estimate for each sub-section was provided by the contractor as part of the RFP response. The unit price removal costs were then applied to each of the 8 facilities and mainline valve sites along the route in Minnesota. The sub-sections break down the unit price removal costs into the following categories:

a. Meter Manifold
b. Valve Manifold
c. Electrical Building
d. Maintenance Building (not applicable – no maintenance buildings at stations)
e. Above Grade Tank (not applicable – no tanks installed for L93)
f. Booster Pump Station (not applicable – no booster pumps on L93)
g. Below Grade Sump Tank
h. Mainline Valve - Remote
i. Mainline Valve - Manual (not applicable – no manual mainline valves)
j. Mainline Instrument Building
k. Pig Trap Assembly
l. Pump Station (separated by pump configuration)
    - 2-pump configuration
    - 3-pump configuration
    - 4-pump configuration

m. Terminal Piping (not applicable – included in above estimates for L93 scope)

Additional costs were added to Contractor-provided facility costs to account for:

- Cleaning piping and components in each facility prior to removal
- Above and below-grade pipe removal and hauling
- Instrumentation, wire, and electrical component disconnect and removal
- Removal, hauling, and disposal of concrete
- Removal, hauling, and disposal of gravel and aggregate
- Restoration of facilities to pre-construction state.

Added costs were dispersed across the 13 subcategories to remain aligned with Part 6 of the CER methodology.

2.7 CONTINGENCY

The CER methodology provides for a contingency inclusion in the DCE calculation. Enbridge uses the CER approved factor of 13% of the entire cost estimate, with the exception of the Engineering & Project Management and provisions for post decommissioning activities.

2.8 INFLATION

To account for inflation, a 10.55% cumulative inflation cost was added to the original estimate total from 2018. This was done by using Consumer Price Index data published by the U.S. Bureau of Labor Statistics for inflation from 2018 to 2022. The inflation factor was added to the estimate prior to contingency.

ATTACHMENT A

3.0 Decommissioning Cost Estimate

	Category	Total
1	Engineering & Project Management	$56,000,000
2	Permanent Decommissioning Preparation	$68,000,000
a	Land Access and Clean Up	$61,000,000
i	Damages	$28,300,000
ii	Consultants	$9,500,000
iii	Easements	N/A – No new easements - $0
iv	Temp. Workspace + Ancillary Acquisitions	$7,400,000
v	Disbursements	$1,400,000
vi	Regulatory	$1,300,000
vii	Survey & Studies	$13,100,000
b	Pipeline Purging and Cleaning	$7,000,000
3	Pipeline Decommissioning-in-Place	N/A
4	Special Treatment (HDDs/Bores)	$7,000,000
5	Pipeline Removal	$829,000,000
a	Removal and Backfilling	$731,000,000
b	Land Restoration	$98,000,000
6	Facilities	$111,000,000
a	Meter Manifold	$100,000
b	Valve Manifold	$100,000
c	Electrical Building	$2,000,000
d	Maintenance Building	N/A - $0
e	Above Grade Tank	No Removal - $0
f	Booster Pump Station	No Removal - $0
g	Below Grade Sump Tank	$1,000,000
h	Mainline Valve (Remote)	$7,000,000
i	Mainline Valve (Manual)	N/A – No manual valves - $0
j	Mainline Instrument Building	$1,000,000
k	Pig Trap Assembly	$100,000
l	Pump Station	$100,000,000
i	2-pump configuration	$12,000,000
ii	3-pump configuration	$75,000,000
iii	4-pump configuration	$13,000,000
6m	Terminal Piping	N/A – Included Above - $0
7	Contingency	$132,000,000
	Total	**$1,203,000,000**

TABLE 1

WSP COMPARISON OF 2022 AND 2018 COST ESTIMATES FOR LINE 93 ABANDONMENT (DECOMMISSIONING)

Table 1
WSP Comparison of 2022 and 2018 Cost Estimates for Line 93 Abandonment (Decommissioning)

	COST CATEGORY	L93 DECOMMISSIONING COST ESTIMATE MAY 19, 2022			L93 DECOMMISSIONING COST ESTIMATE OCTOBER 16, 2018				UNITS	COST BASIS	COMMENTS
1	Engineering & Project Management	$56,000,000			$41,698,322					CER Factor	Assumed at 5%
2	Permanent Decommissioning Preparation	$68,000,000			$61,278,930					Enbridge	
a	Land Access and Clean Up		$61,000,000			$55,200,845				Enbridge	
i	Damages			$28,300,000			$25,566,735			Enbridge	
ii	Consultants			$9,500,000			$8,721,026			Enbridge	Assumed 33% of L 93
iii	Easements			$0			$0				
iv	Temp. Workspace + Ancillary Acquisitions			$7,400,000			$6,677,718			Enbridge	Assumed 50% of L93
v	Disbursements			$1,400,000			$1,225,913			Enbridge	
vi	Regulatory			$1,300,000			$1,201,920			Enbridge	
vii	Survey & Studies			$13,100,000			$11,807,533			Enbridge	
b	Pipeline Purging and Cleaning		$7,000,000			$6,078,085				Contractor	
3	Pipeline Decommissioning-in-Place	$0			$0						
4	Special Treatment (HDDs/Bores)	$7,000,000			$6,488,401					Contractor	
5	Pipeline Removal	$829,000,000			$750,240,800					Contractor	
a	Removal and Backfilling		$731,000,000			$661,332,513					
b	Land Restoration		$98,000,000			$88,908,287					
6	Facilities	$111,000,000			$15,958,300		L 93 Unit Cost (a)	L 3 Unit Cost (b)	Units (c)		
a	Meter Manifold		$100,000			$103,500		$158,000	1	Contractor	1 manifold; consistent with Enbridge assumptions
b	Valve Manifold		$100,000			$99,000		$73,000	1	Contractor	1 manifold; consistent with Enbridge assumptions
c	Electrical Building		$2,000,000			$1,739,200	$217,400	$190,000	8	Contractor	8 stations; consistent with Enbridge assumptions
d	Maintenance Building		$0			$0					
e	Above Grade Tank		$0			$0					
f	Booster Pump Station		$0			$0					
g	Below Grade Sump Tank		$1,000,000			$846,400	$105,800	$26,000	8	Contractor	8 stations; consistent with Enbridge assumptions
h	Mainline Valve (Remote)		$7,000,000			$5,943,600	$114,300	$150,000	52	Contractor	52 valves; consistent with Enbridge assumptions
i	Mainline Valve (Manual)		$0			$0		$50,000			
j	Mainline Instrument Building		$1,000,000			$474,000	$237,000	$76,000	2	Contractor	2 buildings; consistent with Enbridge assumptions
k	Pig Trap Assembly		$100,000			$133,600	$66,800	$88,000	2	Contractor	2 traps: consistent with Enbridge assumptions
l	Pump Station		$100,000,000								
i	2-pump configuration			$12,000,000		$745,000	$745,000		1	Enbridge	1 station; consistent with Enbridge assumptions
ii	3-pump configuration			$75,000,000		$4,956,000	$826,000		6	Enbridge	6 stations; consistent with Enbridge assumptions
iii	4-pump configuration			$13,000,000		$918,000	$918,000		1	Enbridge	1 station; consistent with Enbridge assumptions
m	Terminal Piping	$0			$0						
7	Contingency	$132,000,000			$108,415,636					CER Factor	Assumed at 13%
	Total	$1,203,000,000			$984,080,389						

a/ From L3R Attachment E.
b/ From L3 NEB approved unit costs (Table A-3) 2018.
c/ Units from Enbridge or estimated by WSP.
CER = Canadian Energy Regulator.
L93 = Line 93.
L3 = Line 3.