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In the Matter of the Application of Enbridge Energy, Limited Partnership for a Certificate of Need for the Line 3 Replacement Project in Minnesota from the North Dakota Border to the Wisconsin Border	MPUC Docket No. PL-9/CN-14-916 OAH Docket No. 65-2500-32764

INITIAL BRIEF OF THE MINNESOTA DEPARTMENT OF COMMERCE, DIVISION OF ENERGY RESOURCES

January 23, 2018

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INTRODUCTION

The Minnesota Department of Commerce, Division of Energy Resources (DOC DER) respectfully submits this Initial Brief to provide the Administrative Law Judge (ALJ) and the Minnesota Public Utilities Commission (Commission) with an analysis of the facts and law pertaining to the Application for a Certificate of Need (CN) (CN Application) for the Line 3 Replacement Project in Minnesota (Project), filed by Enbridge Energy, Limited Partnership (Enbridge or Applicant).[1]

SUMMARY OF DOC DER'S CONCLUSIONS AND RECOMMENDATIONS

After evaluation of the CN criteria under Minn. Stat. § 216B.243 and Minn. R. 7853.0130 in light of the record, DOC DER concludes that Enbridge has not demonstrated need for the proposed Project. In CN proceedings, an applicant bears the burden of proof to demonstrate need under the applicable criteria. DOC DER concludes that Enbridge has not demonstrated that the probable result of denial would adversely affect the future adequacy, reliability, or efficiency of energy supply to the applicant, to the applicant's customers, or to the people of Minnesota and neighboring states, and that the consequences to society of granting the CN are less favorable than the consequences of denying the CN. Thus, Enbridge has not demonstrated that it satisfied the CN factors. If, however, the Commission wishes to consider whether conditions might cure Enbridge's lack of a demonstrated need, DOC DER identifies conditions that together would be important to consider.

[1] To the extent DOC DER refers to an affiliated Enbridge entity other than the Applicant, the name of the Enbridge entity will be specifically provided and defined (e.g. Enbridge, Inc.). *See* Ex. DER-13, DER-14 (Enbridge Organizational Charts).

PROCEDURAL HISTORY

DOC DER provided edits to Enbridge's proposed procedural history on November 30, 2017. This document has been filed separately.[2]

THE PROJECT

Enbridge proposes to build a new, larger 36-inch crude oil pipeline in lieu of repairing its existing Line 3 crude oil pipeline, which is a 34-inch pipeline. Initially, the proposed Project would follow the same corridor of the existing Line 3 pipeline from the Minnesota border with North Dakota to Clearbrook, Minnesota. At that point, the proposed Project would be built using a new corridor from Clearbrook to Superior, Wisconsin; running parallel to the existing Minnesota Pipeline from Clearbrook to Park Rapids, then turning east and following utility or road rights-of-way where no crude oil pipeline currently exists.[3] If the Commission grants Enbridge a CN, Enbridge would then abandon-in-place its existing 34-inch Line 3 from Hardisty, Alberta, Canada to its terminal in Superior, Wisconsin after the new Line 3 is constructed.[4] While Enbridge refers to the proposed Project as a replacement of the existing Line 3, the facts indicate that it is an entirely new pipeline with different capacity in a new corridor where no crude oil pipeline exists.

THE APPLICANT AND ITS CUSTOMERS

The Applicant is Enbridge Energy, Limited Partnership (EELP, Enbridge, or Applicant), which is a wholly-owned subsidiary of Enbridge Energy Partners, Limited Partnership (EEP).

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[2] DOC DER Redlined Procedural History (eDocket No. 201711-137808-01).
[3] Ex. EERA-29 at ES-1 (FEIS Executive Summary).
[4] Ex. EN-1 at 1-1 (CN Application).

Both the Applicant and EEP are direct or indirect subsidiaries of Enbridge, Inc.[5] The Applicant's current Line 3 crude oil pipeline is part of the Enbridge Mainline System, which transports crude oil from western Canada to markets located in the United States (including Minnesota) and eastern Canada.[6] Enbridge described three typical kinds of shippers (or customers) of the Enbridge Mainline System, including Line 3:

> (1) producers who find, develop and extract oil from the field and look for markets in which to sell their oil supplies; (2) refiners who invest in developing their own production or acquire supply from third parties and then arrange for that supply to be delivered to their refinery as feedstock; and finally (3) marketers who either own their own production or else acquire it as an agent for a third party and ship it to the designated market.[7]

The Enbridge Mainline System is a common carrier pipeline system and does not have committed shippers with long-term contracts.[8] Generally, Enbridge's shippers use the Enbridge Mainline System, other pipelines, or alternative methods to ship crude oil.[9]

ISSUES

The main issues before the Commission are whether Enbridge has shown that the proposed Project meets the applicable statutory and rule criteria for a CN, or whether a more reasonable and prudent alternative to the proposed Project has been demonstrated by parties or

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[5] *Id.* at 2-2. How the Applicant and associated Enbridge entities are inter-related is described in more detail below. In this Initial Brief, the Applicant is generally referred to as Enbridge and particular entities are specifically referred to. "The Applicant is part of a family of companies that are primarily located in the U.S. and Canada (Enbridge Companies) which together make Enbridge one of the industry leaders in the transportation and distribution of energy in North America." *Id.* at 1-3.

[6] *See id.* at 1-1–1-7. For a map of the Enbridge crude oil pipelines in Minnesota, see Ex. EERA-29 at ES-2 (FEIS).

[7] Ex. EN-14 at 3 (Fleeton Direct).

[8] Ex. EN-1 at 3-22 (CN Application); *see also* Ex. DER-1 at 23 (O'Connell Direct).

[9] *Id.*

persons other than Enbridge.[10] In its August 12, 2015 Order, the Commission stated the issue to be addressed in this contested case proceeding as:

> [W]hether Enbridge's proposed pipeline meets the need criteria set forth in Minn. Stat. § 216B.243 and Minn. Rules Chapter 7853. This issue turns on numerous factors that are best developed in formal evidentiary proceedings.
>
> The Commission invites parties, participants, and the public to address whether the proposed project and any alternatives to the proposed project meet the selection criteria established in Minn. R. 7853.0130. The parties may also raise and address other issues relevant to the application.[11]

Further, the Commission initially noted the following issues regarding the potential environmental impacts of the proposed Project:

> In particular, because Enbridge proposed to locate its new Line 3 project in arguably environmentally sensitive terrain that is not currently a pipeline corridor, many parties emphasized the need to scrutinize the environmental consequences of Enbridge's proposal. The Commission's pipeline review process requires submission and analysis of environmental data on the proposed pipeline and on proposed system and routing alternatives throughout the certificate of need process for pipelines. But the Commission's rules governing the certificate of need process for pipelines, Minn. R. Ch. 7853, do not call for the preparation of a separate environmental document within that process.
>
> In this case, the Commission will authorize the Department's Energy Environmental Review and Analysis staff to prepare an environmental analysis of the Line 3 proposal. This analysis may further develop the record regarding the effect of building the proposed facility upon the natural environment compared to the effects of not building it, or of alternatives.[12]

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[10] *See* Minn. Stat. § 216B.243, subd. 3 (2016); Minn. R. 7853.0130 (A)–(D) (2015).

[11] *In re Application of Enbridge Energy, Ltd. P'ship for a Certificate of Need for the Line 3 Replacement Project in Minn. From the N.D. Border to the Wis. Border*, Docket No. PL-9/CN-14-916, Order Finding Application Substantially Complete and Varying Timelines; Notice and Order for Hearing at 6 (MPUC Aug. 12, 2015).

[12] *Id.*

Due to the Minnesota Court of Appeals' decision on September 14, 2015, which held that "[w]here routing permit proceedings follow certificate of need proceedings, the Minnesota Environmental Policy Act (MEPA) requires that an Environmental Impact Statement (EIS)[13] must be completed before a final decision is made on issuing a certificate of need,"[14] the Commission ordered the following:

> The Commission authorizes the preparation of a combined environmental impact statement that addresses issues related to the certificate of need and routing permit dockets in accordance with Minn. Stat. ch. 116D and Minn. R. ch. 4410. Specifically, the Commission does the following:
>
> a. Authorizes the Department to administer the EIS process in consultation with the Executive Secretary.
>
> b. Asks the Minnesota Department of Commerce to submit for Commission approval its proposed list of alternative routes or route segments to include in the EIS.
>
> c. Requires completion of the final EIS prior to the filing of intervenor direct testimony.
>
> d. Rescinds the December 8, 2015 notice requesting comments from parties on the *Line 3 Alternative Routes Report* filed by the Department.
>
> The Commission authorizes a combined environmental review that considers the cumulative impact of the Sandpiper Pipeline Project and the Line 3 Project.[15]

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[13] *See* Minn. Stat. § 116D.04 (2016); *see also* Minn. R. 4410.0200, subp. 26 (2015).
[14] *In re N.D. Pipeline Co. LLC*, 869 N.W.2d 693, 699 (Minn. Ct. App. Sept. 14, 2015).
[15] *In re Application of Enbridge Energy, Ltd. P'ship for a Certificate of Need for the Line 3 Replacement Project in Minn. From the N.D. Border to the Wis. Border*, Docket No. PL-9/CN-14-916, Order Joining Need and Routing Dockets at 9–10 (MPUC Feb. 1, 2016).

Thus, where relevant under the CN criteria, a formal EIS would further develop the record regarding the effect of building the proposed facility upon the natural and socioeconomic environments compared to the effects of not building it, or of alternatives.[16]

BURDEN OF PROOF

Enbridge bears the burden of proof by a preponderance of the evidence that it has satisfied Minnesota legal criteria for a CN.[17] Regarding alternatives to the proposed Project, however, if Enbridge has met the need criteria, other parties have the burden to demonstrate by a preponderance of the evidence that a more reasonable and prudent alternative exists.[18]

ANALYSIS

I. MINN. R. 7853.0130 A: ENBRIDGE HAS NOT DEMONSTRATED THAT THE PROBABLE RESULT OF DENIAL WOULD ADVERSELY AFFECT THE FUTURE ADEQUACY, RELIABILITY, OR EFFICIENCY OF ENERGY SUPPLY TO THE APPLICANT, TO THE APPLICANT'S CUSTOMERS, OR TO THE PEOPLE OF MINNESOTA AND NEIGHBORING STATES.

A. Summary

The principal requirements for a certificate of need are set forth in Minn. Stat. § 216B.243, subd. 3 and Minn. R. 7853.0130 A–D; this section examines the record as to Rule 7853.0130 A. Because Minnesota Rules are more detailed than corresponding statutory need criteria, DOC DER uses the rule criteria in Minn. R. 7853.0130 as a framework for evaluating Enbridge's compliance with the legal criteria. Enbridge has not demonstrated that the proposed Project satisfies the criteria in Minn. R. 7853.0130 A.

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[16] *See id.* at 9.
[17] Minn. Stat. § 243B.243, subd. 3 (2016).
[18] Minn. R. 7853.0130B0130 B (2015).

Minn. R. 7853.0130 A addresses the supply (and demand) impact of a denial of a proposed project. It includes five criteria to consider whether denial of a proposed project would adversely affect the future adequacy, reliability, or efficiency of energy supply to the applicant, to the applicant's customers, or the people of Minnesota and neighboring considering:[19]

i. The accuracy of the applicant's forecast of demand for the type of energy that would be supplied by the proposed facility;

ii. The effects of the applicant's existing or expected conservation programs and state and federal conservation programs;

iii. The effects of the applicant's promotional practices that may have given rise to the increase in the energy demand, particularly promotional practices that have occurred since 1974;

iv. The ability of current facilities and planned facilities not requiring certificates of need, and to which the applicant has access, to meet the future demand; and

v. The effect of the proposed facility, or a suitable modification of it, in making efficient use of resources.

To evaluate Enbridge's stated need for the proposed Project, DOC DER asked Dr. Marie Fagan of London Economics International (LEI) to provide an analysis of Enbridge's forecast of demand for the oil that would be supplied via a new Line 3. In this Initial Brief, DOC DER first presents Dr. Fagan's examination regarding primarily the testimony of Enbridge witnesses

[19] The Commission provided guidance in its recent Order Granting Certificate of Need (Phase 2 Order) in the Enbridge Alberta Clipper Phase 2 crude oil pipeline matter regarding the meaning of "region." *See In re Application of Enbridge Energy, Ltd. P'ship for a Certificate of Need for the Line 67 (Alberta Clipper) Station Upgrade Project - Phase 2 - in Marshall, Clearwater, Itasca, Kittson, Red Lake, Cass, and St. Louis Counties*, Docket No. PL-9/CN-13-153, Order Granting Certificate of Need at 7 (Nov. 7, 2014) (hereinafter "Phase 2 Order"). In the Phase 2 Order, the Commission adopted the meaning of "region" to be the 15-state Petroleum Area Defense District No. Two (PADD 2) as defined by the U.S. Energy Information Administration (EIA). As in the Phase 2 matter, DOC DER agrees in this case that focus on Minnesota and on EIA's PADD 2 region for analysis under Minn. R. 7853.0130 A is reasonable.

Mr. Earnest and Mr. Rennicke as to the criterion of "the accuracy of the applicant's forecast of demand for the type of energy that would be supplied by the proposed facility." Then, DOC DER presents Ms. Kate O'Connell's overall conclusions as to Enbridge's satisfaction of criteria under Minn. R. 7853.0130 A considering several aspects of Enbridge's proposal, including the Consent Decree reached with the federal government about Enbridge's Line 6B in Michigan and Line 3 in Minnesota, the size of the proposed Project, and its stated need for a pipeline interconnection at Clearbrook, Minnesota. DOC DER concludes, overall, that the Applicant has not demonstrated that the probable result of denial would adversely affect the future adequacy, reliability, or efficiency of energy supply to the applicant, to the applicant's customers, or to the people of Minnesota and neighboring states.

B. Minn. R. 7853.0130 A(1): Enbridge Has Not Demonstrated that Its Forecast of Demand for the Type of Energy that Would Be Supplied by the Proposed Facility is Accurate.

DOC DER witness Dr. Fagan reviewed Enbridge testimony submitted to address the Rule criterion of "the accuracy of the Applicant's forecast of demand for the type of energy that would be supplied by the proposed facility." Dr. Fagan concluded that the forecasts relied by Enbridge were unrealistic;[20] thus, Enbridge has not demonstrated that its forecast of demand of crude oil from Western Canada is accurate.[21] Supporting testimony by a party, the three companies making up the Shippers Group (two Canadian companies and a British company), as well as letters by non-party refiners such as Flint Hills and Andeavor did not cure Enbridge's failure to accurately forecasted demand.

[20] *See, e.g.*, Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 15–18, 72, 95–100 (Fagan).
[21] Minn. R. 7853.0130 A(1).

Dr. Fagan reviewed two expert reports, one by Mr. Neil Earnest and another by Mr. William Rennicke, filed in support of Enbridge's CN application[22] and reviewed them "with a focus on high-level issues related to supply and demand for oil and petroleum products in Minnesota and related regions."[23] The review of Dr. Fagan concentrated on topics within the two reports relating to supply and demand of crude oil and refined products (such as fuel) and pipeline infrastructure forecast assumptions.[24] Dr. Fagan previously worked at EIA on its extremely complex Annual Energy Outlook (AEO) model and forecasts.[25] This experience and expertise in complex modeling and forecasting is why DOC DER hired Dr. Fagan, through LEI, as an expert witness in this matter.

Unable to confirm the reasonableness of the reports' modeling results or their implications, Dr. Fagan testified: "LEI cannot conclude with confidence that the forecasts in the reports are realistic."[26] She reaffirmed her conclusion throughout this proceeding despite additional Enbridge testimony on these topics.[27]

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[22] Ex. DER-4, MF-1 at 1 (Fagan Direct). Mr. Earnest filed, "Enbridge Line 3 Replacement Program Market Analysis" (Muse Stancil Report or Earnest Report), Ex. EN-15, Sched. 2 (Earnest Direct); Mr. Rennicke filed, "Report on the Impact of Crude-by-Rail and the 'No-Action' Scenario for the Line 3 Project in Minnesota" (Oliver Wyman Report or Rennicke Report), Ex. EN-10, Sched. 2 (Rennicke Direct).

[23] Ex. DER-4, MF-1 at 9 (Fagan Direct).

[24] *Id.* Dr. Fagan was not asked to perform a stand-alone analysis of any Minnesota certificate of need legal criterion, but rather was asked to critique Mr. Earnest's and Mr. Rennicke's reports, (*see, e.g.*, Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 29, 82, 91 (Fagan), which were provided to satisfy or support legal criteria on behalf of Enbridge. Dr. Fagan also reviewed subsequent testimony of Mr. Earnest, Mr. Rennicke and relevant testimony of other witnesses.

[25] Tr. Vol. 9B at 77 (Fagan).

[26] Ex. DER-4, MF-1 at 39 (Fagan Direct).

[27] *Id.* at 8; Ex. DER-7 at 1, MF-1 at 4–12 (Fagan Surrebuttal); Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 15–18, 56–57, 95–100 (Fagan).

At trial, Dr. Fagan highlighted two particularly unrealistic assumptions used in Mr. Earnest's modeling to forecast use of the Enbridge Mainline System with and without the proposed Line 3 pipeline. Dr. Fagan testified that Mr. Earnest included input assumptions, "that didn't allow for the possibility of changes to global refined product demand over time."[28] This means that he "implicitly assumed that demand from refined products in Minnesota, in PADD 2,[29] in the United States and globally, would not change over time."[30] This assumption is unrealistic, as Dr. Fagan explained, because it runs counter to a basic principle of crude oil market economics that demand for refined products drives refineries' demand for crude oil:[31]

> [W]ith very few exceptions, nothing consumes crude oil directly except a refinery, and a refinery doesn't consume crude oil unless the refinery expects the refined products to be sold profitably. Weak demand for refined products can lead to low prices for refined products. Low prices of refined products can lead to lower refinery profitability. Lower profitability can lead to closure of refineries, which in turn, can lead to lower demand for crude oil and less need for pipeline capacity. This must be taken into consideration on a global basis, as it's not local to Minnesota or is it restricted to the United States. Crude oil and refined product markets are global.

Dr. Fagan further explained that Mr. Earnest's model is "driven by demand [for] crude oil by refineries, which is used as an input for the forecast."[32] The problem as identified by Dr. Fagan is that Mr. Earnest did not include as assumptions potential changes in the driver for refinery crude oil demand, which is the demand for refined products. For example, even if

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[28] Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 15–16 (Fagan).
[29] Identified in a previous footnote, PADD stands for Petroleum Area Defense Districts which are administrative areas in the United States from which information on refined products is collected. *See generally* DER-4, MF-1, Sched. 2 at 15–16 (Fagan Direct).
[30] *Id.*
[31] *Id.* at 16.
[32] Ex. DER-4, MF-1 at 18 (Fagan Direct).

demand for refined products is weak, Mr. Earnest's model results in a projection that crude oil still flows at high levels through the Enbridge Mainline System.[33] Therefore, Dr. Fagan concluded that Mr. Earnest's forecast or projection of crude oil pipeline flows is not realistic[34] and is a mistake[35] since it means that "any extra crude oil is automatically exported."[36] Dr. Fagan explained the significance of Mr. Earnest's omission of potential changes in demand for refined products on his resulting projections of crude oil flows:[37]

> [T]his is not an issue if in the real world we can assume that any extra crude oil that's not needed in the United States from the [forecast] period, 2019 to 2035, can be easily exported. But the real world has sometimes seen global gluts of refined products and these have led to reduced refinery operations. *It's a mistake to ignore global refined product demand.*

Dr. Fagan's second issue with Mr. Earnest's direct testimony report included the unrealistic assumption that there would be no future pipeline expansions after 2021 to transport oil from Western Canada. She testified, as follows:[38]

> The Muse Stancil report input assumptions did not allow for more than one possible realistic future for pipeline development. The Muse Stancil report assumed there would be no pipeline capacity growth for 14 years, from 2021 to 2035, from western Canada. That doesn't square with the historical record of pipeline expansions.

Dr. Fagan observed, "This is a long period - 14 years - to assume a complete lack of pipeline construction."[39] Further, actual experience in Canada is that pipelines have been expanded or

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[33] *Id.* at 16-17.
[34] Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 95-96 (Fagan).
[35] *Id.* at 17.
[36] *Id.* at 56–57, 95–96.
[37] *Id.* at 17 (emphasis added).
[38] *Id.*; *see also* Ex. DER-4, MF-1 at 18, 30–31 (Fagan Direct) (citing Ex. EN-15, Sched. 2 at 30–31, 61 (Earnest Direct)).

added every few years, as long as oil production is increasing.[40] In subsequent testimony responding to Dr. Fagan, Mr. Earnest included more than one modeling scenario, but Dr. Fagan found that those scenarios also used unrealistic assumptions regarding refined product demand, and included modeling scenarios that were not performed in a realistic way; thus, Mr. Earnest's forecast results showing that crude oil coming out of Western Canada would flow to the proposed Line 3 at high levels are unrealistic.[41] Dr. Fagan could not conclude from her review that Enbridge forecast results are realistic,[42] meaning that Enbridge witnesses Mr. Earnest and Mr. Rennicke did not show those forecasts to be realistic. Dr. Fagan explained, as follows:[43]

> Because of assumptions such as these, LEI can't conclude with confidence that the forecasts, the model outputs in the Muse Stancil [Earnest] report are realistic. And because the outputs of the Muse Stancil model are used as inputs into the Oliver Wyman analysis, the same critique applies to the Oliver Wyman [Rennicke] forecast.

Dr. Fagan's review of the subsequent testimony of Mr. Earnest and Mr. Rennicke as well as that of other witnesses, did not change Dr. Fagan's conclusions.[44] That is, Enbridge did not show that the results of Mr. Earnest's modeling are realistic.

Dr. Fagan also examined whether the impact of Enbridge Mainline apportionment on Minnesota District refineries could be objectively measured or quantified.[45] Apportionment occurs when the capacity of pipelines is not large enough at a particular time to deliver all of the

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(Footnote Continued from Previous Page)
[39] Ex. DER-4, MF-1 at 30–31 (Fagan Direct).
[40] *Id.* at 31.
[41] Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 18, 56-57, 70–72, 95–100 (Fagan).
[42] *Id.* at 17–18.
[43] Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 17-18 (Fagan);
[44] *Id.* at 18, 95–100; *see also* Ex. DER-7 at 2 (Fagan Surrebuttal).
[45] Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 83-85, 93-94 (Fagan); *see also* Ex. DER-9, MF-1 at 4 (Fagan Supp. Surrebuttal).

crude oil requested by shippers.[46] In such cases, each shipper's nomination (request) is reduced proportionately.[47] Enbridge claims that current apportionment on the Enbridge Mainline System necessarily results in harm to refineries. Specifically, it claims that refineries currently are harmed by current apportionment on its pipelines carrying heavy crude oil, and Mr. Earnest forecasts that apportionment will increase in the future, which will increase the harm to refineries.[48] Dr. Fagan testified that Minnesota district refineries appear to be operating efficiently and refining all the crude they possibly can;[49] her findings did not confirm Enbridge's claim that the refineries presently are significantly harmed by current levels of apportionment.[50] In particular, her review was inconclusive as to whether, based on the data from the present or recent past, Enbridge's Mainline System apportionment has effectively limited the supply of heavy crude to the Minnesota District refineries.[51] She also testified that she found no quantification of the costs of apportionment on shippers.[52] Dr. Fagan's examination compared historical monthly data reported by Minnesota district refineries to the EIA indicating the extent of heavy oil refinery use of heavy oil refining equipment called cokers with the historical monthly levels of apportionment of heavy crude oil provided in historical data from Enbridge.[53]

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[46] *See* Ex. EN-19 at 10 (Glanzer Direct).
[47] *See id.*
[48] *See* Evid. Hrg. Tr. Vol. 1B (Nov. 1, 2017) at 12-14, 36 (Earnest) (stating that refineries are hurt by present apportionment and if the CN is denied, then "my forecast indicates that apportionment will get worse.").
[49] Ex. DER-4, MF-1, Sched. 2 at 14 (Fagan Direct).
[50] *See* Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 18, 83-85, 95-100 (Fagan); *see also* Ex. DER-9, MF-1 at 4-10 (Fagan Supp. Surrebuttal).
[51] *See id.* at 18, 84–85, 93–94.
[52] Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 85 (Fagan).
[53] Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 18, 83-85, 93-94 (Fagan).

Dr. Fagan's inconclusive findings regarding the impact of recent Mainline System apportionment of heavy crude oil on Minnesota district refiners did not change after considering critique from Mr. Earnest.[54] Although she testified that she had many reasons why Mr. Earnest's criticisms did not alter her conclusions,[55] Dr. Fagan was not allowed to explain those reasons with specificity.[56] Nonetheless, her findings are important; they indicate that: 1) Enbridge did not show that current apportionment equates with material harm to Minnesota refineries; and 2) Enbridge did not show that a possible increase in apportionment in the future would necessarily harm them. Further, the record does not show any particular level of present or future apportionment that might materially harm such refiners.

Finally, the record provides no reasonable means by which the Commission might quantify a level of apportionment in the future that might significantly harm either of the two Minnesota refineries, Flint Hills or Andeavor, in the event that the Commission were to deny a CN for the proposed Project.

For reasons stated above, DOC DER concludes that Enbridge did not demonstrate that its supply and demand forecasts are realistic—or are likely to be accurate—as required by Minnesota Rule 7853.0130 A(1).[57]

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[54] *Id.* at 89, 100.
[55] *Id.* at 100.
[56] DOC DER appreciates the ALJ's ruling that allowed Dr. Fagan's Supplemental Surrebuttal into the record as well as her ruling that Mr. Earnest was allowed to respond.
[57] Whether Enbridge demonstrated the accuracy of its demand forecast is a legal conclusion concerning the requirements of Minnesota rules, and is not a topic upon which Dr. Fagan offered an opinion. Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 71-73 (Fagan). As a factual matter, Dr. Fagan noted that a forecast of the future cannot by definition be known to be accurate or inaccurate before that future occurs. One can, however, provide realistic assumptions and scenarios in modeling outlooks or projections. *Id.* DOC DER concludes that demonstrating the
(Footnote Continued on Next Page)

1. Crude Oil Markets: General Principles

Dr. Fagan, an experienced energy economist whose career has encompassed the oil and natural gas sectors and detailed modeling of pipeline flows,[58] provided key principles that are important to understanding her review of the direct testimony reports of Mr. Earnest and Mr. Rennicke.

a. Crude Oil Markets Are Global

Dr. Fagan emphasized that crude oil markets are global, not local. She explained that, "[c]ompared to its value, crude oil is cheap and easy to transport by tanker ships. Even if shipped thousands of miles, imported crude oil remains economically competitive."[59] She explained that the oil market is integrated globally,[60] meaning that products can flow freely from one location to another in response to price signals.[61] Dr. Fagan provided as a recent example of the global nature of the crude oil market, the global oil price collapse between 2014 - 2016, as follows:[62]

> Because the oil market is integrated globally, events that impact supply or demand in one part of the world impact crude oil prices all over the world. This was evident most recently in 2014/15, when surging oil production from the US caused global oil prices to collapse from about $100 per barrel ("bbl") in the summer of 2014 to below $40 per bbl in early 2016.

(Footnote Continued from Previous Page)
"accuracy" of forecasts of demand under Rule criterion 7853.0130 A(1) requires a showing that the forecasts relied on realistic assumptions and modeling scenarios.

[58] *Id.* at 14.

[59] Ex. DER-4, MF-1 at 10 (Fagan Direct) (also, Appendix 1 of MF-1 includes more discussion on drivers of global oil prices).

[60] *Id.*

[61] Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 54 (Fagan).

[62] Ex. DER-4, MF-1 at 10 (Fagan Direct) (Appendix 1 includes more discussion on drivers of global oil prices).

To illustrate the impact of that global price collapse on demand for pipeline capacity and rail transportation through Minnesota, she stated that global oil prices influence local oil production including crude oil production from Canada, and she provided:[63]

> Crude oil production from both the Bakken shale in North Dakota and from Canada is a significant component of the demand for pipeline and rail transportation through Minnesota. Both these regions have reacted to changes in global oil prices. . . . With lower oil prices, oil producers have lower cash flows and usually cut back investment in response. The Canadian Association of Petroleum Producers ("CAPP") reported that capital investment in the oil sands declined dramatically from . . . 2014 to . . . 2016[.] . . . If producers expect that prices will stay low, then fewer new wells or new mining development projects will be viewed as economically attractive, and future investment plans will be cut back, even if current cash flows might be adequate. This reduces the amount of oil that will be available in the future . . . .

b. Exports Increasingly Link the U.S. to Global Refined Products Markets

Dr. Fagan emphasized at trial that the refined products market is global.[64] In her initial report she explained that the U.S. demand for refined products has been flat (had "levelled off") since 2004/2005.[65] Dr. Fagan gave examples of the increasingly global nature of the market for refined products from what has been an already-integrated continental (North American) oil and refined products markets, with increasing demand from other countries.[66] The top ten destinations of U.S. refined products exports from the U.S. in 2016 include Brazil, Netherlands, Japan, China, Chile, Singapore, India and Colombia.[67]

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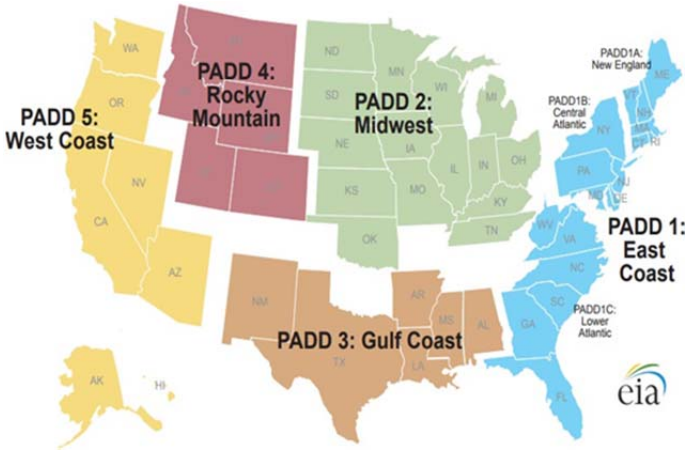
[63] Ex. DER-4, MF-1, Sched. 2 at 11-13 (Fagan Direct).
[64] Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 95 (Fagan).
[65] Ex. DER-4, MF-1, Sched. 2 at 15–16 (Fagan Direct).
[66] *Id.*
[67] *Id.* at 16.

Further, as noted, the refined product market is and has been integrated on a continental basis.[68] Dr. Fagan explained that in the U.S., reference to refined product regions commonly are called Petroleum Administration for Defense Districts, PADDs), as follows:[69]

> The markets for refined products are well-integrated across North America which means that, like crude oil, refined products can flow freely from one location to another in response to price signals. In the US, refined product regions commonly used are the "Petroleum Administration for Defense Districts" ("PADDs") (see Figure 6). [The Midwest, including Minnesota, is in PADD 2.] PADDs are an administrative concept, developed by the federal government during World War II to help manage fuel rationing. Thus, PADDs do not represent physical boundaries between markets, and the price data shows that, for the most part, the US is a single, integrated market for refined products such as gasoline. This is evident in looking at the price of refined products across US PAD [sic] Districts [with the exception of PADD 5 (California)] which has specific rules for gasoline that make it more expensive than other markets.
>
> The wholesale price of gasoline tracks closely within PADD 2, too, averaging only 4% lower in Minnesota than in Illinois. This close tracking of prices indicates that PADD 2 is internally a single, integrated market. In such markets, when a local price spike occurs – for example, if a refinery or pipeline is unavailable — the spike will be short-lived because supplies can be brought in from alternative refineries or using other transportation modes.

[68] *Id.* at 13–14.
[69] *Id.*

Fagan Direct Figure 6. United States Petroleum Administration for Defense Districts (PADD)



c. Minnesota Area Refineries Operate at High Levels of Utilization

Dr. Fagan's analysis concluded that Minnesota district refineries, including Flint Hills and Andeavor, currently are running efficiently and are processing nearly all the crude oil they possibly can. She explained:[70]

> Within PADD 2, the Energy Information Administration ("EIA") defines a refining district that includes Minnesota, North Dakota, South Dakota, and Wisconsin as the "Minnesota district." The Minnesota district tends to run at higher levels of refinery utilization – close to 100% for the past few years – than the rest of PADD 2 or the US on average[.] Capacity utilization levels near 100% demonstrate that refiners are not only operating efficiently, they are processing all the crude they possibly can (though there could be room to adjust the crude oil diet to change the mix [of] various grades of crude). This implies that crude oil for the Minnesota district has not been in short supply compared to refining capacity, though the mix of crude oil supplies might not be perfectly optimal.

[70] Ex. DER-4, MF-1, Sched. 2 at 14 (Fagan Direct).

Dr. Fagan also explained terms of art and basic modeling concepts underlying her analyses and conclusions. A clear understanding of terms is important because it helps understand her examination and findings as well as her criticisms of the testimony of Mr. Earnest and Mr. Rennicke.[71] For instance, because she reviewed Mr. Earnest's modeling of crude oil flows to the Enbridge Mainline System, Dr. Fagan explained the meaning of a "model". She testified that a model can be as simple as: 1X + 2Y = Z. In this model, X and Y are inputs or assumptions (by definition, assumptions come from outside the model) and Z is the output that results from running the model together with assumptions.[72] Note that while assumptions "X" and "Y" in this model might change, the relationship between those assumptions (1X + 2Y) will not change. To further illustrate these concepts, Dr. Fagan gave an example of using low assumptions and high assumptions to get a low and a high model scenario.[73] When an assumption is itself a forecast (something that is projected to occur in the future), then the modeling output or result may also be referred to as *outlook* or *forecast*.[74] Outlooks or forecasts are projections into the future.[75] While more complicated than Dr. Fagan's simple example of a model, Mr. Earnest's model also consists of assumptions, modeling equations, and the model's outputs or forecasts.[76]

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[71] Dr. Fagan's explanations of these terms of art helps one to understand the significance of her observation that in Mr. Earnest's "Analytical Conclusions" section of his Muse Stancil Report, he includes incorrectly a statement that is an assumption rather than a conclusion. Ex. DER-4, MF-1, at 22 (Fagan Direct) (the oil supply "outlook" or forecast used in his model is not a conclusion; it is an assumption which is an input to his analysis).
[72] Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 74-76 (Fagan). Assumptions also may be called variables. *Id.* at 91.
[73] *Id.* at 75-76.
[74] *Id.* at 91–92.
[75] *Id.*
[76] *See id.* at 76.

2. Mr. Earnest's Initial Report is Significantly Not Supported.

The purpose of Mr. Earnest's direct testimony Muse Stancil Report is to forecast the utilization of the Enbridge Mainline System in order to "to help determine if there is sufficient need for the restored pipeline capacity to support construction of the L3R (Enbridge Line 3) project."[77] His report, however, did not consider "more than one potential future for oil supply, demand, and pipeline infrastructure," as follows:

- It used only a single annual crude oil supply forecast prepared by the Canadian Association of Petroleum Producers (CAPP vintage 2016) for a 14-year period (2016-2035) as an assumption for his model output of forecasted utilization of the Mainline;[78]

- It included no assumptions that would allow demand for refined product like gasoline to increase or decrease, whether in Minnesota, PADD 2 "or at any other level of aggregation;"[79] and

- It did not allow for any future pipeline expansion after 2021.[80]

Dr. Fagan highlighted the significant limitations of the reports of Mr. Earnest and Mr. Rennicke,[81] as follows:[82]

> Both reports contain forecasts (also referred to as "outlooks" or "projections"), and both have limitations. *Neither* of the two reports *considers more than one potential future for oil supply, demand, or infrastructure.* Both reports rely on *a single outlook*

[77] Ex. DER-4, MF-1 at 17 (Fagan Direct) (quoting Ex. EN-15, Sched. 2 at 3 (Earnest Direct)).
[78] *Id.* (noting that Mr. Earnest calculated from the 2016 CAPP crude oil *production* forecast the resulting assumption for forecasted crude oil *supply* to the markets).
[79] Ex. DER-4, MF-1 at 17, 23, 25-26, 30 (Fagan Direct).
[80] Ex. DER-4, MF-1 at 17, 23, 30 (Fagan Direct).
[81] Mr. Rennicke wholly relied on Mr. Earnest's "outlook" or forecast of future crude oil supply and the impact of that supply on transporting crude oil by rail in the event the Commission were to deny Enbridge's Proposed Project. Ex. DER-4, MF-1 at 6 (Fagan Direct); Ex. EN-10, Sched. 2 at 10–11 (Rennicke Direct). Thus, the "limitations" of Mr. Earnest's report apply as well to Mr. Rennicke's projected transportation of crude oil by rail. Ex. DER-4, MF-1 at 36 (Fagan Direct); *see also* Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 17–18 (Fagan).
[82] Ex. DER-4, MF-1 at 6 (Fagan Direct) (emphasis added).

> *[forecast] for annual crude oil supply* and *no specific outlook [forecast] at all for refined product demand.* Neither report *allows for more than one potential future for infrastructure development*; for example, they both assume that there will be no pipeline expansions for 14 years (from 2021 to 2035) in Canada, which is inconsistent with historical records of expansions.
>
> *Neither report recognizes the potential for a dynamic relationship over time between transportation and supply, in spite of the lengthy time-frame (2019-2035) of the outlooks [forecasts]*. Adding more capacity (such as the Enbridge Line 3 project) could allow more oil supply to be developed profitably at any given global oil price. This means that oil production and supply from Canada could increase, and the projected reduction in rail transport of crude oil forecasted by both reports may not materialize. *Neither report allowed for this possibility.*

Given these limitations, Dr. Fagan could not confirm that Dr. Earnest's assumptions for supply, demand, pipeline capacity or his model's forecasted utilization of the proposed Project were realistic.[83] She did conclude, though, that Minnesota refineries and those of neighboring states have been operating at high levels of utilization such that they "have little room to increase total crude runs;" given that supplies of refined product like gasoline are not short or appear likely to be short in this area, the "whole" of the additional pipeline capacity that the proposed Project would provide would not be used to meet local refined product demand.[84]

a. Enbridge Did Not Show its Initial Reliance On a Single Crude Oil Supply Forecast Assumption To Be Reasonable.

A major limitation of Mr. Earnest's direct testimony report is his reliance on a single annual CAPP forecast for crude oil supply to refiners.[85] While he included additional supply

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[83] *Id.* at 5; *see also* Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 15–18 (Fagan).
[84] Ex. DER-4, MF-1 at 5 (Fagan Direct).
[85] *Id.* at 23. Dr. Fagan noted that, by definition, a forecast cannot be determined in advance to be accurate. *Id.* at 5. It can be evaluated, however, as to whether it accounts for key uncertainties and reflect important underlying trends. *Id.* Mr. Earnest's use of a single forecast does not (Footnote Continued on Next Page)

forecasts in his rebuttal testimony, they were not realistic or were not modeled realistically[86] and did not cause Dr. Fagan to change her conclusions.[87] DOC DER discusses this initial failing because of its significance to Mr. Earnest's modeling projection underlying Enbridge's stated need for the proposed Project.

The 2016 CAPP supply forecast is key to Mr. Earnest's ultimate determination that there is sufficient need for the pipeline capacity that the proposed Project would provide, both in terms of his model's forecasted use of the proposed Project and as to Mr. Rennicke's projected rail shipments that would occur if proposed Line 3 is not built. Dr. Fagan explained that the importance of the 2016 CAPP forecast assumption in Mr. Earnest's model is because that single CAPP supply forecast assumption "drives the need for crude oil transportation from Western Canada . . . ."[88] Also concerning is that the period of the CAPP supply forecast assumption is only 14 years (2016-2035) even though the proposed Project would be expected to be a much longer-lived asset.[89]

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account for key uncertainties such as changing demand for refined products over time or additions to pipeline capacity after 2021. *See, e.g.*, Ex. DER-4, MF-1 at 32, 38–39 (Fagan Direct).

[86] Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 18, 70-72, 95-100 (Fagan); *see also* Ex. DER-7 at 2 (Fagan Surrebuttal).

[87] *Id.*

[88] *Id.* Mr. Earnest's direct testimony report acknowledges the key role of using the CAPP forecast as a modeling assumption, "The June 2016 CAPP supply forecast is the fundamental basis for the Western Canadian crude supply outlook used in this analysis." Ex. DER-7, MF-1 at 8 (Fagan Surrebuttal) (citing Ex. EN-15, Sched. 2 at 43 (Earnest Direct)).

[89] *See* Ex. DER-7, MF-1 at 7 (Fagan Surrebuttal). Dr. Fagan testified that it is not clear why Mr. Earnest considers only the first years of service of long-lived infrastructure such as a pipeline to bear "on the overall merits of the L3R program . . . ." *Id.* (quoting Mr. Earnest) (citation omitted).

Forecasts used to make decisions regarding long-lived infrastructure assets such as the proposed Project must allow for a range of future projections or outcomes.[90] Dr. Fagan explained that relying only on one supply forecast can mask the potential for a wide variety of future outcomes, as shown by comparing 2015 and 2016 oil prices:[91]

> This can be seen by comparing CAPP's outlooks for Western Canadian production before and after the 2015 oil price collapse. After the collapse in oil prices in 2015, CAPP's outlooks have been about 5,000 thousand b/d for 2030, compared with about 6,500 thousand b/d before the price collapse [Figure 14 omitted].

She also explained that it is "widely recognized that current oil prices, as well as expectations for oil prices, drive future crude oil supply."[92] This is why energy forecasting organizations, such as the National Energy Board (NEB) in Canada and the EIA in the United States, provide forecasts for oil supply that are not based on a single assumption, but are based on a range of oil price assumptions.[93] Also, in NEB's and EIA's outlooks, crude oil prices are assumptions meaning that "they are not generated by the internal relationships of their model (in economics terms, crude oil prices are 'exogenous')."[94]

Dr. Fagan's direct testimony showed that the outlook for oil supply in the long term can vary widely, and will depend on expected global oil prices.[95] Global oil prices, in turn, depend on economic drivers such as refined product demand, but also on geopolitics, the decisions of key

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[90] *See* Ex. DER-4, MF-1 at 5, 23 (Fagan Direct).
[91] *Id.* at 23.
[92] *Id.*
[93] *Id.*
[94] *Id.*
[95] Ex. DER-4, MF-1 at 38 (Fagan Direct).

producing countries, and other policy drivers.[96] She testified that projections of future oil production can have a large impact on the projected need for new infrastructure.[97]

> For example, with the decline in Bakken production from 2014 to 2017, rail exports from North Dakota declined from about 800 thousand b/d in 2014 to 300 thousand b/d by the beginning of 2017— even before the Dakota Access pipeline went into service. Future production from the North Dakota Bakken region and Canada *will likely continue to vary with oil prices*, with implications for the need for rail and pipelines.

Dr. Fagan noted that by using the 2016 CAPP forecast, Mr. Earnest's model projections reflect lower prices and Canadian production than earlier CAPP forecasts that preceded the 2015 oil price collapse and, thus, may "have less chance of over-stating the need for pipeline capacity."[98] But she also noted that reliance on a single supply forecast as a modeling assumption also highlights the risk of doing so, given that just "two years earlier the CAPP outlook for 2035 would have been about 1.5 million b/d higher."[99] She explained that using a range of outlooks rather than a single outlook for supply would have provided the Commission with more insight to consider or test the range of potential utilization of a long-lived asset such as an oil pipeline.[100]

In his rebuttal testimony, Mr. Earnest included additional crude oil supply forecasts from NEB as assumptions for his model projections of crude oil pipeline flows.[101] While this addition addressed the simple flaw of having used only one supply forecast assumption, Dr. Fagan

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[96] *Id.* and Appendix 1.
[97] *Id.* (emphasis added).
[98] *Id.*
[99] *Id.*
[100] *Id.*
[101] Ex. EN-37, Sched. 1 at 18 (Earnest Rebuttal); Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 31 (Fagan).

testified that some of the additional forecasts were not realistic, and that her other concerns about Mr. Earnest's report remained.[102]

b. Enbridge Did Not Show its Failure to Allow for Changes in Demand for Refined Products Over Time To Be Reasonable

Mr. Earnest acknowledged in his direct testimony report that demand for refined products like gasoline "did not play a role in the forecasts leading to the conclusions about the use of crude-by-rail or the utilization of the Enbridge Line 3 project."[103] His subsequent testimony did not correct this mistake.[104] Thus, Dr. Fagan identified that the lack of any such role of refined product demand was a limitation of Mr. Earnest's modeling and the conclusions he reached from his modeling.[105]

Dr. Fagan emphasized that the economics of oil markets mean that demand for refined products drives refineries' demand for crude oil.[106] By giving no role to refined product demand, Mr. Earnest appears to assume that refinery demand for oil, in isolation, drives oil prices and oil supply. He gives no role to refined product demand by designing a model that essentially ignores the potential for changes in consumer demand for refined products; rather, he implicitly assumes that such demand will be unchanged for the entire forecast period, and assumes that

[102] Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 70-72, 95-100 (Fagan).
[103] Ex. DER-4, MF-1 at 26 (Fagan Direct) (quoting Ex. EN-15, Sched. 2 at 25–26 (Earnest Direct)); *see also* Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 15–18 (Fagan).
[104] Ex. DER-7, MF-1 at 5 (Fagan Surrebuttal); *see also* Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 15–17 (Fagan).
[105] Ex. DER-4, MF-1 at 23 (Fagan Direct); *see also* Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 15–16 (Fagan).
[106] Ex. DER-4, MF-1 at18 (Fagan Direct).

refiners and export countries "will automatically absorb any change in crude oil production."[107] That is, he assumes "any extra crude can be exported."[108]

Mr. Earnest's assumptions also exclude the possibility of crude oil gluts.[109] Dr. Fagan explained why exclusion of such a potential runs counter to oil market economics, specifically, the interplay between oversupply, demand for refined product, prices and, ultimately, demand for transportation of crude oil:[110]

> A larger problem [than the potential for PADD 2 refiners having to export refined product in order to increase their crude oil refining "runs"] would be *if demand for refined products was weak across the US and could not easily be exported, as might occur if there were a simultaneous glut of refined products globally.* This would result in lower prices for refined products and lower refinery profit margins, and perhaps result in the closure of less-efficient refineries, with potentially less need for crude oil from Canada and/or the Bakken region. This creates a problem for the Muse Stancil results if it reduces demand for transportation of crude oil from Canada on the Enbridge system.

Global oil oversupply clearly could reduce demand for transportation of crude oil on the Enbridge Mainline which, in turn, could reduce Mr. Earnest's modeling projection of the use of that system. Dr. Fagan concluded in her direct testimony that providing a range of forecasts for refined product demand could help demonstrate whether expanded pipeline capacity is needed:[111]

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[107] Ex. DER-4, MF-1 at 26 (Fagan Direct).
[108] *Id.*; *see also* Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 56-57 (Fagan).
[109] Ex. DER-4, MF-1 at 30 (Fagan Direct).
[110] *Id.* (emphasis added).
[111] *Id.* at 38. In a footnote, Dr. Fagan also stated:

> However, expanded capacity could still be attractive for the refineries in Minnesota in that it might provide crude to Minnesota refiners (and to other PADD 2 refineries) at a lower transport cost. Expanded crude pipeline capacity from Canada that can reach the

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> A low refined product demand outlook could imply that expanded crude pipeline capacity would not be needed to provide additional physical crude oil to refineries in the Minnesota district for consumption by Minnesota residents.

Mr. Earnest's rebuttal testimony attempted to defend his modeling methodology that provides no role for changes in demand for refined products by end-users.[112] He also disagreed with Dr. Fagan that forecast assumptions should include the potential for crude oil oversupply or gluts. He dismissed as "apocalyptic" and very unlikely[113] Dr. Fagan's scenario in which there may be simultaneous global oversupply of crude oil and refined products. Specifically, Mr. Earnest stated:[114]

> Dr. Fagan does offer a rather apocalyptic scenario whereby U.S. refined product demand is weak, refined product cannot be easily exported, and there is a simultaneous glut of refined products globally, all of which may reduce demand for crude oil transportation via the Enbridge Mainline (Fagan pg. 30). Dr. Fagan offers no probability of such a scenario occurring. I believe that such a scenario persisting over an extended period of time is very unlikely, and it can be dismissed as a plausible scenario that warrants analysis.

Recent history, however, suggests otherwise. In addition to her earlier example of the 2015 oil price collapse,[115] Dr. Fagan disagreed with Mr. Earnest, responding that "low-demand scenarios have happened in the past, and on one occasion did closely resemble an 'apocalyptic

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> US Gulf Coast can add to global supplies of crude oil, which could reduce prices to refineries and ultimately to consumers, though it may not be needed to support crude oil availability in Minnesota itself.

Id. at 38 n.56.

[112] *See* Ex. DER-7, MF-1 at 5 (Fagan Surrebuttal) (citing Ex. EN-37, Sched. 2 at 47 (Earnest Rebuttal)).

[113] *Id.* (citing Ex. EN-37, Sched. 2 at 46 (Earnest Rebuttal)).

[114] *Id.*

[115] Ex. DER-4, MF-1 at 23 (Fagan Direct).

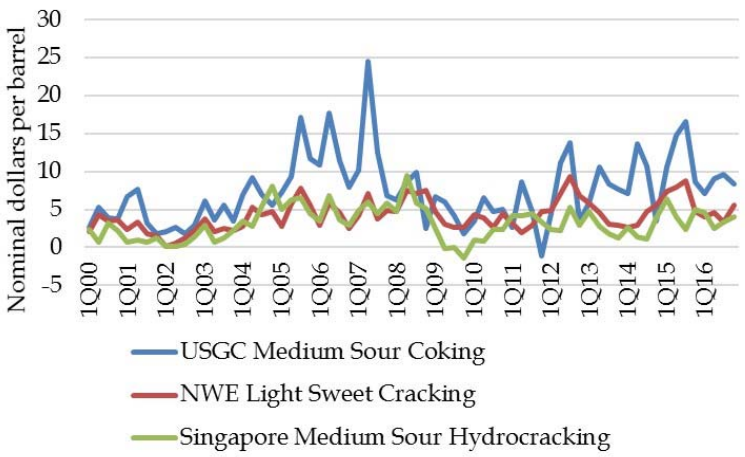
scenario' for the refining industry broadly."[116] She gave two examples of such known events together with descriptive graphs of those events, as shown in Figures 1 and 2, as follows:[117]

1) (O)il demand declined on a global basis in the wake of the global financial crisis, leading to a steep decline in refined product margins after 2007 that lasted several years (see Figure 1). In the United States, some refineries stopped operating; the number of operating refineries declined from 146 in 2008 to 134 in 2012.

2) An "apocalyptic" scenario played out for the refining industry in the 1980s and 1990s. Weak demand for refined products triggered by the global oil crises of the late 1970s and early 1980s resulted in a large overhang of refining capacity (see Figure 2). This oversupply took the industry decades to work off; refined product margins were badly squeezed globally for many years, even into the 1990s.

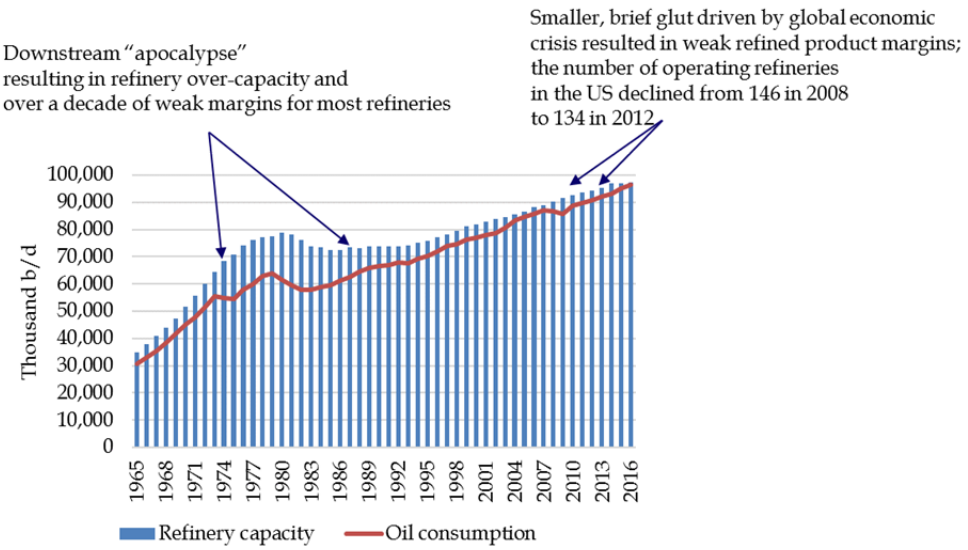
[116] Ex. DER-7, MF-1 at 5 (Fagan Surrebuttal) (footnotes omitted).
[117] *Id.* at 5–6 (footnotes omitted).

Fagan Surrebuttal Figure 1: Global Refining Margins



Source: BP Statistical Review of World Energy2017

Fagan Surrebuttal Figure 2: Global refinery capacity and global oil consumption



Data source: BP Statistical Review of World Energy2017

Figures 1 and 2 show how oversupply and weak demand for refined product have actually affected refinery demand for crude oil.

Mr. Earnest also claimed in rebuttal testimony that it was reasonable to exclude a refined product demand forecast assumption because, "there is no direct connection between Minnesota (and Midwestern and U.S.) crude oil runs and refined product demand . . . ."[118] Mr. Earnest is incorrect.

Dr. Fagan testified that the potential for weaker refined product demand is a global, not a local, issue.[119] Weak demand for refined product may impact prices of refined products, with consequences that clearly apply to Mr. Earnest's projections in this case, as Dr. Fagan explained:[120]

> With very few exceptions, *no one consumes crude oil except a refinery*; and a refinery does not consume crude oil unless refined products are expected to be sold profitably. Demand for refined products drives demand for crude oil, and is therefore a driver of the price of crude oil. *Weak demand for refined products can lead to low prices for refined products;* low prices of refined products can lead to lower refinery margins (lower profitability), *which impacts the viability of some refineries, which in turn can lead to lower refinery demand for crude oil.* This is not a local issue, but a global one.

Dr. Fagan made clear that it is a mistake to ignore global refined product demand.[121] Mr. Earnest ignored global refined product demand.

For these reasons, as well as Mr. Earnest's unrealistic pipeline expansion assumption to be discussed below, Dr. Fagan cannot confirm that Enbridge's assumed forecasts of use of the

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[118] Ex. DER-7, MF-1 at 5 (Fagan Surrebuttal) (citing Ex. EN-37, Sched. 2 at 47 (Earnest Rebuttal)).
[119] Ex. DER-7, MF-1 at 5 (Fagan Surrebuttal).
[120] *Id.*
[121] Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 17 (Fagan). Those model outputs include both Mr. Earnest's forecasted use of Enbridge's Mainline System, with and without the proposed Project, and forecasted use of rail.

Enbridge Mainline System and forecasted use of rail—the model outputs—in Mr. Earnest's Muse Stancil report are realistic.[122]

c. Enbridge Did Not Show its Assumption of No Future Pipeline Expansions or Additions after 2021 To Be Reasonable

Throughout this proceeding, Mr. Earnest assumed for modeling purposes that there will be no future pipeline expansions or additions after 2021, a period of 14 years.[123] This assumption is unrealistic.[124]

Dr. Fagan replicated in her Figure 22 (below), two of Mr. Earnest's direct testimony figures, Figures 11 and 46, to demonstrate that he indeed relies on such an assumption in his modeling that purports to forecast high use of the proposed Project, if constructed.[125]

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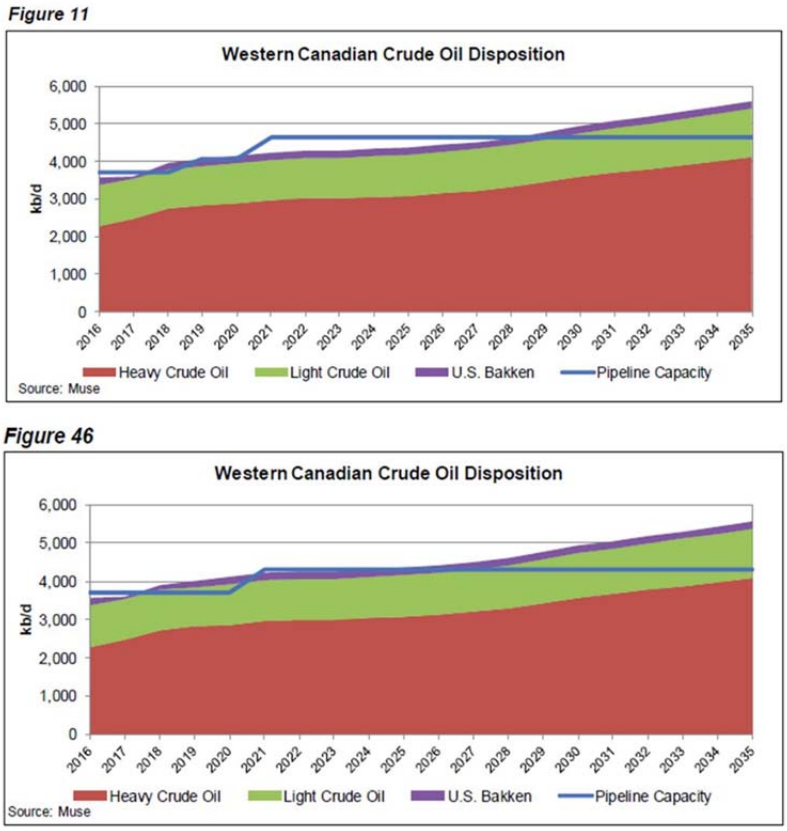
[122] *Id.*
[123] Ex. DER-4, MF-1 at 30–32 (Fagan Direct); *see also* Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 17 (Fagan).
[124] *Id.*
[125] Ex. DER-4, MF-1 at 30–32 (Fagan Direct). In his rebuttal testimony, Mr. Earnest took issue with Dr. Fagan's use of Figure 22, stating that Dr. Fagan's criticisms of his no new infrastructure assumption "would occur in the 2030+ time period." Meaning that her "criticism is only applicable roughly 12 years in the future, and has little bearing on the overall merits of the L3R Program." Ex. DER-7, MF-1 at 7 (Fagan Surrebuttal) (citing Ex. EN-37, Sched. 2 at 48 (Earnest Rebuttal)). Dr. Fagan testified that "it is not clear" why Mr. Earnest considers "only the first 12 years of service of a long-lived . . . pipeline" to bear on the overall merits of the proposed Line 3 project. Ex. DER-7, MF-1 at 7 (Fagan Surrebuttal).

Fagan Direct Figure 22: Crude Oil Pipeline Capacity Assumptions in Muse Stancil Report



Source: Muse Stancil P. 12, 75.

As Dr. Fagan testified, a period of 14 years is long time to assume a complete lack of pipeline construction."[126]

Actual experience in Canada, however, is that pipelines have been expanding every few years as long as oil production is increasing.[127] Dr. Fagan identified the following expansions or additions of pipelines flowing heavy crude from Canada: the installation of Line 4 in 2002, the addition of Line 67 in 2009, and TransCanada's Keystone Pipeline System that began operation

[126] Ex. DER-4, MF-1 at 31 (Fagan Direct).
[127] *Id.*

in 2010.[128] She also discussed Energy Transfer Partners' Dakota Access pipeline from North Dakota to Illinois as an example that, despite well-publicized opposition, and perhaps up to nine years of planning, went into service in June 2017.[129]

Not only is Mr. Earnest's assumption of no future pipeline expansions after 2021 unrealistic, Dr. Fagan explained that two assumptions underlying his exclusion of future pipeline expansions are unrealistic.[130] She testified that Mr. Earnest presented only one potential future to consider based on infrastructure assumptions that are inconsistent with historical trends and are inconsistent with oil producers' and pipeline companies' incentives.[131] First, his model implicitly assumes, based on the latest CAPP production forecast, a potential additional 1.5 million barrels per day of crude oil production by 2035; this means that, according to Mr. Earnest's assumption, Canadian crude oil producers looking forward to this additional oil supply would not be successful in supporting any future pipeline development after 2021. This assumption is unrealistic because, she explained, "These producers would presumably be aware that rail transport would likely be an expensive alternative to pipelines for most purposes."[132]

Second, is the unrealistic related assumption that Canadian pipeline companies would not be successful at moving forward with any proposed projects to take advantage of the opportunity to serve strong growth in oil supply.[133] Mr. Earnest did not demonstrate in subsequent testimony that his assumptions are realistic.[134]

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[128] *Id.* (footnotes omitted).
[129] Ex. DER-4, MF-1 at 32 (Fagan Direct).
[130] *Id.*
[131] *See id.* at 39.
[132] *Id.*
[133] *Id.*
[134] *See, e.g.*, Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 15–17 (Fagan).

Dr. Fagan stressed that infrastructure assumptions, just like assumptions of supply and of demand, should define ranges of potential futures.[135] Contrary to Mr. Earnest's assumption of no future pipeline expansions, "[a]t least one of the ranges should include assumptions that are consistent with historical trends and with oil producers' and pipeline companies' incentives."[136] Dr. Fagan testified that Mr. Earnest's assumption that no new pipeline capacity will be built for 14 years, while crude oil suppliers continue to increase production, guarantees a modeling result that overstates the actual future need for rail, if the proposed project is not constructed.[137]

d. Impact of Mr. Earnest's Unrealistic Assumptions and Modeling on His Projected Utilization of the Proposed Line 3

Based on the assumptions he uses, the output or projection of Mr. Earnest's model is the forecasted use of Enbridge Line 3 in Minnesota.[138] Mr. Earnest provides oil flows from Gretna, Canada to Clearbrook, MN; from Clearbrook, MN to Superior, WI; and on other pipelines. His forecasts show that the proposed Line 3 project "will be fully utilized through Minnesota, supplying both heavy and light crude oil."[139]

In her direct testimony, Dr. Fagan discussed the impacts of Mr. Earnest's assumptions as to oil supply (his use only of the 2016 CAPP forecast) and lack of refined product demand projections on his projected utilization of the proposed Line 3.[140] Certainly, Mr. Earnest's

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[135] Ex. DER-4, MF-1 at 39 (Fagan Direct).
[136] *See id.*
[137] *Id.* The impacts of Mr. Earnest's assumptions on Mr. Rennicke's conclusions regarding transportation of oil by rail in the event that the proposed Project is not constructed are discussed further, below.
[138] *Id.* at 22.
[139] Ex. DER-4, MF-1 at 22 (Fagan Direct).
[140] *Id.* at 38–39.

projected use of the proposed Line 3 could occur if his supply forecast assumption and static refined product demand assumption turn out to be accurate.

If, however, the future is inconsistent with his assumptions, then the impact on Mr. Earnest's projected use of proposed Line 3 is "more nuanced."[141] First, if there is lower refined product demand on a local level, it is possible that Minnesota's *own use* of refined products could decline rather than remain static.[142] "In that case, local refiners could still demand the same amount of crude oil, because refined products could be shipped to other PADD 2 states, other U.S. regions, or exported."[143] Thus, Minnesota refiners would not be harmed and consumers in other PADDs would have access to refined products.

Second, if demand for refined products falls across the U.S., "refined products prices would likely decline, and refinery profit margins would be squeezed."[144] Third, if demand falls globally for refined products and if refined products cannot easily be exported, then "some refineries could close." Mr. Earnest did not consider either the second or the third possibility in his report.[145]

Fourth, Dr. Fagan explained other possibilities. She suggested that "unless there were a global crude oil or refined product glut, and/or unless Canadian crude oil became un-economic to produce, it is *possible* that the increment of the proposed Enbridge Line 3 project would be use, though *the entire capacity would not be used to meet refined product demand in Minnesota*

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[141] *Id.*
[142] *Id.*
[143] *Id.*
[144] *Id.*
[145] Ex. DER-4, MF-1 at 38–39 (Fagan Direct).

directly."[146] Thus, Dr. Fagan criticized Mr. Earnest's report because it omitted a range of forecasts for the Commission to consider.[147]

Dr. Fagan maintained this opinion even after reviewing Mr. Earnest's rebuttal testimony.[148] In his rebuttal testimony, Mr. Earnest did not consider the potential for oil gluts or refined product gluts. He did, however, consider additional supply forecasts.[149] The results of his model, based on those additional supply forecasts, continued to show crude oil flowing at high levels of use to the proposed Line 3 rather than to other proposed pipeline projects.[150]

At trial, Dr. Fagan explained on cross-examination that she was unpersuaded by Mr. Earnest's rebuttal testimony because some of the forecast assumptions "didn't have a realistic view of the future."[151] In response to the question: "[W]hy is it then, when Mr. Earnest ran some different scenarios, different inputs, . . . to his model, that that didn't change your mind or your criticism that he had not looked at . . . sufficient scenarios," Dr. Fagan explained that some of Mr. Earnest's assumptions were not realistic or were not modeled in a realistic way.[152] She gave an example, Mr. Earnest's model run assuming low demand for refined product in the US. Although his model results show that inclusion of this assumption didn't affect his forecasted use of the Enbridge Mainline System, Dr. Fagan explained that the assumption is not realistic because the refined product market is global.[153] She testified that "it's not that a low

[146] *Id.* at 39.
[147] Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 70 (Fagan).
[148] *Id.*
[149] *Id.* at 31.
[150] Ex. EN-37 at 26–40 (Earnest Rebuttal).
[151] Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 70-71 (Fagan).
[152] Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 95-100 (Fagan).
[153] *Id.* at 95–96.

demand scenario didn't make sense. It's that it was just the U.S., but the real market's global."[154]

Dr. Fagan highlighted another example of unrealistic modeling, which concerned utilization results if the proposed Keystone XL pipeline is built, if the proposed Energy East pipeline is built and if the Ozarks pipeline expansion is completed. Regarding Keystone XL, she testified, "[I]f you're going to put Keystone in your model, you have to put it in realistically."[155] Because the proposed Keystone XL pipeline project depends on having enough committed shippers that contract to pay for capacity on that pipeline whether they need it or not, one would need to model that project as if there were sufficient committed shippers. Dr. Fagan theorized that while Keystone XL may want 90 percent of the capacity to be committed, the project may be viable with 50 or 60 percent of the pipeline committed.[156] Mr. Earnest, however, modeled the project with committed shippers shipping only a little over 100,000 barrels per day, which understates the crude oil that would be shipped on Keystone XL rather than a new Line 3. Dr. Fagan testified, "[I]f Keystone's going to get built, it's not going to flow at 100,000 barrels a day . . . it's not enough money to get the pipeline built."[157] She explained that realistic modeling would have to assume that the project would have sufficient shippers to ensure construction and, once built that "the committed shippers would use it because they already paid for it."[158] If Mr. Earnest had used realistic assumptions or modeled the proposed Keystone XL project in a realistic way, then if modeling results still showed the Enbridge Mainline System flowing at full

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[154] *Id.* at 96.
[155] *Id.* at 98.
[156] *See id.* at 97–99.
[157] Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 98 (Fagan).
[158] *Id.* at 99.

capacity, that information might show support for the proposed Project; Mr. Earnest's unrealistic modeling and modeling assumptions did not do so.[159]

Similarly, Mr. Earnest's modeling of the proposed expansion of the existing Ozark pipeline is an example of unrealistic scenarios. Although Dr. Fagan would not expect expansion of that pipeline to "have a big impact anyway"[160] because the Ozark pipeline does not start in Western Canada, its expansion would not lead one to conclude that it would affect flows on the Enbridge Mainline System that transports crude oil from Western Canada.[161] Also, and while according to Enbridge the Energy East project developers have announced that they will not go forward with that project,[162] Dr. Fagan observed that it is "a completely different animal," and "maybe there's not a big impact there."[163]

Mr. Earnest has not shown that his forecasted use of the proposed Line 3 is a realistic projection.

e. Impact of Mr. Earnest's Unrealistic Modeling on his Projected Avoidance of Rail Shipments from Canada if the Proposed Project is Constructed

Mr. Earnest used his model not only to project use of the proposed Line 3 for this matter, but also to project rail shipments from Canada that would be avoided if the Enbridge Line 3 project goes forward, and the number of those avoided rail shipments.[164] Assuming completion of proposed Line 3, Mr. Earnest forecasts that rail shipments from Canada ultimately destined for

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[159] *See* Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 99 (Fagan).
[160] *Id.* at 100.
[161] *See id.*
[162] *See* Ex. EN-39 at 6 (Fleeton Rebuttal).
[163] Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 100 (Fagan).
[164] Ex. DER-4, MF-1 at 20 (Fagan Direct).

PADD 2 "would be essentially nil,"[165] and that much of the avoided rail shipments would transit through Minnesota, if the proposed Project is not built.[166] Implicit from his forecast data, according to Dr. Fagan's calculations, is that approximately 7 loaded, 110-car trains from Canada are projected to be avoided if the proposed Line 3 is built.[167]

Mr. Earnest's forecasted oil shipments by rail, however, are affected by the same flawed assumptions and modeling discussed previously in this Initial Brief. Specifically, Dr. Fagan identified that Mr. Earnest's assumptions of 1) no future pipeline capacity after 2021, 2) limited capacity that would be transported on the Keystone XL pipeline, and 3) crude oil producers continuing to increase production, "guarantees a forecast in which the use of rail increases dramatically as oil production increases."[168] This means that Mr. Earnest's projections "will likely overstate the actual future need for rail in the case in which no new pipeline capacity is added"[169] or, stated, another way, understate the need for rail in the future if proposed Line 3 is added.

Dr. Fagan identified two additional assumptions that result in Mr. Earnest's overstatement of the future transportation of oil by rail if proposed Line 3 is not built.[170] First, Mr. Earnest (and also Mr. Rennicke) assumed that rail and pipelines are necessarily substitutes for each other[171] when, in reality, "additional pipeline capacity might not replace a perfectly

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[165] *Id.* at 20–21.
[166] *Id.* at 21.
[167] *Id.*
[168] Ex. DER-4, MF-1 at 39 (Fagan Direct).
[169] *Id.*
[170] *Id.*
[171] *Id.* at 36.

equivalent amount of crude by rail."[172] Dr. Fagan notes that Enbridge's reports assume that rail and pipelines are substitutes for each other, when in fact these two resources can work together as complements. While pipelines are generally a less expensive means to transport oil, shipping by rail is generally faster, can offer more flexible destinations, can respond quicker to short-term changes in market factors, and may offer shorter-term contracts than pipelines.[173] As one BNSF vice president noted: "You might think of pipelines as our competitor, and they are, but they're also becoming our customers."[174] Thus, the assumption in the reports that pipelines and rail would substitute for one another on a perfectly one-to-one basis is not realistic.[175]

Second, because shipping by pipeline is generally cheaper than rail, adding more pipeline capacity could allow marginally more expensive oil supplies to become profitable at any given global oil price.[176] As a result, the increase in marginally higher-cost production might take up the new pipeline capacity, leaving the previous production to use rail, as it had been before.[177] Dr. Fagan explained that because cheaper transport (more pipeline capacity) could increase the supply of crude that is economic to produce, the result could be a lower reduction in use of rail cars than Mr. Earnest projects if the proposed Project is built.[178]

Dr. Fagan stated as "the bottom line" impact of Mr. Earnest's and Mr. Rennicke's assumption of no new pipeline capacity after 2021 probably is, 1) significant over-forecasting of

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[172] *Id.* at 36, 39.
[173] *Id*. at 36.
[174] *Id*.
[175] *Id*.
[176] *Id.* at 36; *see also* Ex. DER-7, MF-1 at 8 (Fagan Surrebuttal).
[177] Ex. DER-4, MF-1 at 36, 39 (Fagan Direct).
[178] *Id.*

crude transportation by rail if the Enbridge Line 3 project is *not* completed, and 2) a smaller under-forecasting of the need for rail if it *is* completed.[179]

3. Mr. Rennicke's Analysis of the Amount of Rail That May Be Added if the Proposed Project is Denied is Similarly Unsupported

a. Mr. Rennicke Adopted Mr. Earnest's Unrealistic Supply, Demand and Infrastructure Assumptions

Mr. Rennicke's report wholly adopted Mr. Earnest's assumptions and modeling results.[180] Specifically, the outputs (projections) of the Earnest Report are input assumptions for Mr. Rennicke's transit-related testimony.[181] He relied solely on Mr. Earnest's assumed supply and demand for crude oil (that includes no consideration of potential global oil gluts or changes in refined product demand), and on Mr. Earnest's assumed lack of pipeline capacity additions after 2021 from Western Canada.[182] Thus, the same flaws underlying Mr. Earnest's projections apply to Mr. Rennicke's report.[183] As Dr. Fagan summarized:[184]

> Because of assumptions [by Mr. Earnest] such as these, LEI can't conclude with confidence that the forecasts, the model outputs in the Muse Stancil report are realistic. And because the outputs of the Muse Stancil model are used as inputs into the Oliver Wyman analysis, the same critique applies to the Oliver Wyman forecast.

The purpose of the Mr. Rennicke's report included describing the transportation network in Minnesota, assessing the implications of new federal rail regulations on crude oil transport, and assessing the impact on Minnesota rail users and Minnesota residents of the single

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[179] *Id.* at 39.
[180] Ex. DER-4, MF-1 at 36 (Fagan Direct).
[181] Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 17 (Fagan).
[182] Ex. DER-4, MF-1 at 36 (Fagan Direct).
[183] *Id.* at 17–18, 36.
[184] Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 17–18 (Fagan).

possibility of Commission denial of the proposed Line 3 project.[185] Mr. Rennicke, however, does not rely on any current or forward-looking assumptions about demand for refined products,[186] he includes no forward-looking assumptions, either quantitative or qualitative, about demand by other commodities for rail capacity,[187] he does not calculate or project total shipments for crude by rail (he relies on Mr. Earnest's projections),[188] he does not use a formal model of his own to project total future rail use[189] and does not use a formal model to projecting the detailed rail routes he includes in his report.[190]

b. Enbridge's Did Not Show its Projected Number of Additional Trains Through Minnesota if the CN is Denied To Be Reasonable.

Mr. Rennicke projected that by 2031 there would be about 16 more trains per day through Minnesota in the event that the Commission were to deny Enbridge's proposed CN, which is a significant number of additional trains.[191] In other words, he says that about 16 trains by 2031, each assumed to include 110 cars, would be avoided by approval of the CN.[192] Mr. Rennicke,

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[185] Ex. DER-4, MF-1 at 32 (Fagan Direct) (citing Ex. EN-10, Sched. 2 at 4-5 (Rennicke Rebuttal)).
[186] Ex. DER-4, MF-1 at 32-33 (Fagan Direct).
[187] *Id.* at 33.
[188] *Id.* at 36.
[189] *Id.* at 33 (citing Ex. EN-10, Sched. 2 at 10 (Rennicke Direct)).
[190] Ex. DER-4, MF-1 at 33 (Fagan Direct).
[191] *Id.* at 34–35.
[192] Ex. DER-4, MF-1 at 34 (Fagan Direct). Mr. Rennicke forecasts that shipments to Houston in PADD 3 will grow strongly and by 2029 will account for nearly all the crude moving by rail through Minnesota. *Id.* at 33. In the event that one out of four train routes went through Sweetgrass, Montana to Houston and, therefore, bypassed Minnesota, Dr. Fagan calculated (based on Mr. Rennicke's figures) that there would be a total of three to four fewer trains through Minnesota if the Sweetgrass route were used. *Id.* at 35–36.

however, did not demonstrate the reasonableness of his projections.[193] The key failing, though, is Mr. Rennicke's total reliance for his projections on Mr. Earnest's assumptions which, as discussed previously in this Initial Brief, were not shown to be reasonable.

Dr. Fagan could not confirm the reasonableness of Mr. Earnest's supply and demand assumptions or his assumed lack of pipeline capacity expansions after 2021, which in turn means that she was not able to confirm Mr. Rennicke's projections as to rail traffic through Minnesota that would be avoided if the Commission approves the proposed Line 3 project. These are the same conclusions noted previously in this Initial Brief regarding Mr. Earnest's report. Dr. Fagan concluded that Mr. Rennicke probably "significantly" over-forecasted the extent of rail transportation of crude oil if the CN is denied, and under-forecasted the extent of avoided rail traffic through Minnesota in the event that the CN is approved. Specifically she concluded that:

> The assumption that no new pipeline capacity will be built for 14 years, while crude oil suppliers continue to increase production, guarantees a forecast in which the use of rail increases dramatically as oil production increases. This will likely overstate the actual future need for rail in the case in which no new pipeline capacity is added.
>
> Two other assumptions lead to understatement of the future need for rail transport in the alternative case in which new pipeline capacity is added. First is the [sic] that additional pipeline capacity might not replace a perfectly equivalent amount of crude by rail. Second is the lack of any kind of feedback loop that recognizes that cheaper transport (more pipeline capacity) could increase the supply of crude that is economic to produce, with potentially less reduction in use of rail cars.
> The bottom line for the single assumption for future pipeline capacity employed by the two reports *is probably significant over-forecasting of crude transportation by rail if the Enbridge Line 3*

[193] Ex. DER-4, MF-1 at 34 (Fagan Direct); *see also* Ex. DER-7, MF-1 at 8–9 (Fagan Surrebuttal).

> *project is not completed, and a smaller under-forecasting of the need for rail if it is completed.* [194]

Mr. Rennicke's subsequent testimony did not address Dr. Fagan's substantive criticisms provided in her direct testimony, and did not change her conclusions.[195]

4. Electric Vehicles: Potential Impact on Gasoline Demand

DOC DER asked Dr. Fagan to consider the potential impact of hybrid electric vehicles and plug-in electric vehicles ("electric vehicles") on gasoline demand, which is a refined product,[196] since such vehicles might result in an overall reduction in gasoline use in the future. The purpose of the request was to examine whether, if demand for refined products were different from the level assumed by Mr. Earnest, there would be an impact on the need for pipeline capacity such as a new Line 3.[197] Dr. Fagan concluded that electric vehicles are not likely to affect the demand for refined products in the near term. Based on three different oil price scenarios contained in EIA's 2017 Annual Energy Outlook (AEO) for the five-state Minnesota district,[198] and as applied only to those markets,[199] "expansions of refined product supply, crude oil supply, and infrastructure such as pipelines" would not be required in order to meet growing demand for gasoline or other refined products "because demand would not be growing."[200]

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[194] Ex. DER-4, MF-1 at 39 (Fagan Direct) (emphasis added).
[195] *See, e.g.*, Ex. DER-7 at 2, MF-1 at 4–9 (Fagan Surrebuttal).
[196] Ex. DER-4, MF-1 at 26 (Fagan Direct).
[197] *Id.*
[198] EIA's Minnesota district is comprised of Minnesota, North Dakota, South Dakota and Wisconsin. Ex. DER-4, MF-1 at 14 (Fagan Direct).
[199] Ex. DER-7, MF-1 at 12–13 (Fagan Surrebuttal).
[200] Ex. DER-4, MF-1 at 29 (Fagan Direct).

That said, Dr. Fagan stressed that Minnesota, the Minnesota district as well as PADD 2 are not isolated markets; they would remain "integrated" with the larger U.S. market.[201] As discussed previously in this Initial Brief, events affecting the U.S. and global refined products market may affect Minnesota and vice versa.[202] This means that, for a Minnesota-centric analysis, even in a high oil price scenario implying low demand for gasoline in either Minnesota district or in Minnesota, events that impact the larger U.S. market, and vice versa, could affect the need for expansion of pipeline capacity.[203]

5. Current Apportionment: Dr. Fagan Could Not Confirm Current Harm to Minnesota Refiners at Present Levels of Heavy Crude Apportionment.

In her supplemental surrebuttal testimony, Dr. Fagan addressed whether the fact of current apportionment on the Enbridge Mainline System means that there is current material harm to refiners. Specifically, she examined whether or not there is evidence demonstrating that apportionment has effectively limited the supply of heavy crude to Minnesota district refiners in the recent past and present.[204] Her review was inconclusive—she could not confirm that Minnesota refineries currently are harmed during months of high apportionment of heavy crude oil on the Enbridge Mainline System.[205]

a. Present or Recent Past Level of Heavy Crude Oil Apportionment on the Enbridge Mainline System

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[201] *Id.*
[202] "It's a mistake to ignore global refined product demand." Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 17 (Fagan).
[203] *See id.*
[204] Ex. DER-9, MF-1 at 4 (Fagan Supp. Surrebuttal).
[205] Ex. DER-9, MF-1 at 9-10 (Fagan Supp. Surrebuttal); *see also* Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 18, 84-85, 93-94 (Fagan).

Apportionment of heavy crude oil on the Enbridge Mainline System has been in "almost constant apportionment since 2015,[206] with the average apportionment of heavy crude from August to December, 2016 at approximately 21 percent.[207] Apportionment varies by month and by pipeline.[208]

In a month when a pipeline system lacks capacity to accommodate all of the shippers' verified requests or verified "nominations", the pipeline operator apportions the available capacity among those shippers on a pro rata basis (nominations are cut back by an equal percentage amount).[209] According to Enbridge witness, John Glanzer, when a pipeline system is in apportionment, "refiners are not able to receive all the crude oil *required for their operations*, which would force them to source crude from other less economical sources, such as rail."[210] Similarly, he testified that when the Enbridge Mainline system is in apportionment, "[t]his means that shippers will not receive the volume of crude *they require*."[211]

Mr. Glanzer seems to suggest that the fact of apportionment evidences harm to Minnesota district refiners, as follows:[212]

> [A]pportionment on the Enbridge Mainline System forces the Minnesota refineries to *either reduce production of refined products from that feedstock, obtain crude oil from other sources, or transport Western Canadian crude oil using more expensive modes of transportation, such as rail or truck.* Any of these options in turn, increases direct cost to the Minnesota refineries, as

[206] Ex. EN-38 at 8 (Glanzer Rebuttal).
[207] *Id.* Mr. Glanzer further testified in his direct testimony that from June 2014 through February 2017, there has been apportionment on the Enbridge Mainline System in Minnesota every month, except October 2015 and April 2016. Ex. EN-19 at 11 (Glanzer Direct).
[208] *Id.*
[209] Ex. EN-19 at 10 (Glanzer Direct).
[210] Ex. EN-38 at 2 (Glanzer Rebuttal) (emphasis added).
[211] *Id.* at 3 (emphasis added).
[212] Ex. EN-38 at 13 (Glanzer Rebuttal) (emphasis added).

> acquiring crude feedstock from other sources is typically more expensive and shipping crude oil by rail is usually more expensive than by pipeline.

Somewhat similarly, perhaps, is Mr. Earnest's statement at trial that Minnesota refineries "*are* hurt" by apportionment, but he then said that supply alternatives "*may not* be able to supply adequate crude oil supply."[213]

In contrast, Dr. Fagan sought objective confirmation from historical data that Minnesota district refiners did not receive all of the heavy crude oil they reasonably could refine during months of high apportionment.[214] She found no such confirmation.

b. Dr. Fagan's Analysis of Coker Feeds in the Minnesota District During Months of High Apportionment

Dr. Fagan's analysis started with the assessment in her previous testimony that Minnesota area refineries are operating at refinery utilization of "close to 100%"; this fact shows that refiners "are not only operating efficiently, they are processing all the crude they possibly can (though there could be room to adjust the crude oil diet to change the mix [of] various grades of crude)."[215] She explained that while the level of refinery utilization does not allow one to determine a refinery's mix of oil (heavy, light, etc.), refineries with cokers likely are refining heavy crude oil.[216] Dr. Fagan explained that cokers, among other refinery equipment, allow for more efficient refining of heavy crude oil, and she provided a general description of the "high conversion" process that includes refining heavy oil with the use of cokers.[217] In the Minnesota

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[213] Evid. Hrg. Tr. Vol. 1A (Nov. 1, 2017) at 13 (Earnest) (emphasis added).
[214] Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 37-38 (Fagan) ("I would rather have been able to demonstrate that, rather than just take someone's word for it.").
[215] Ex. DER-9 at 5 (Fagan Supp. Surrebuttal).
[216] *See id.* at 6-7.
[217] *Id.*

district, only Flint Hills's Pine Band refinery has a coker,[218] and the refinery primarily refines heavy crude.[219] Flint Hills receives all of its crude oil by pipeline.[220] Dr. Fagan's focus on heavy rather than light crude is important because the Enbridge Mainline System pipelines that transport light crude have not generally been in apportionment.[221]

Significantly, Dr. Fagan explained that refineries report to the EIA their monthly inputs of heavy crude oil to cokers, and EIA makes the data publically available. Those inputs to cokers indicate the amount of heavy crude the refineries in a district are "consuming" in a given month relative to their potential consumption;[222] of course, for Minnesota district refineries that input data reflects only heavy crude refining at Flint Hills. If a coker is operating at far below capacity, Dr. Fagan explained that the refinery "is probably running less heavy crude than it could."[223] And, as a proxy to measure heavy crude oil runs, lower feeds to cokers in months of relatively higher apportionment could be an indication that apportionment may be a reason for lower heavy oil refining.[224]

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[218] Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 85 (Fagan).
[219] Ex. DER-1 at 77 (O'Connell Direct).
[220] Ex. DER-1, KO-17 at 3 (O'Connell Direct) (Flint Hill's letter dated August 16, 2017).
[221] Evid. Hrg. Tr. Vol. 1B (Nov. 1, 2017) at 66 (Glanzer) ("And the light system is currently not in apportionment, and that means that there is some, some space available on that."); *see also* Ex. DER-19 at 12 (Glanzer Direct) (light crude apportionment occurred in January and February of 2015 and the next year in January of 2016; during each of those three months over that year period, apportionment did not exceed 6 percent).
[222] Ex. DER-9 at 7 (Fagan Supp. Surrebuttal).
[223] *Id.*
[224] *See* Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 83-84 (Fagan).

Dr. Fagan examined apportionment data provided in Mr. Glanzer's direct testimony Figure 5, as reproduced in Dr. Fagan's supplemental surrebuttal testimony, below:[225]

Fagan Supp. Surrebuttal Figure 5: Enbridge Mainline Apportionment Within Minnesota

		Apportionment Percentage by Month (2017)											
Line	Service	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
2	Light	-	-										
3	Predominantly Light	-	-										
4	Predominantly Heavy	33.00	41.00										
67	Heavy	33.00	41.00										
		Apportionment Percentage by Month (2016)											
Line	Service	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
2	Light	3.00	-	-	-	-	-	-	-	-	-	-	-
3	Predominantly Light	3.00	-	-	-	-	-	-	-	-	-	-	-
4	Predominantly Heavy	16.00	14.00	2.00	-	6.00	7.00	4.00	22.00	22.00	23.00	17.00	23.00
67	Heavy	16.00	14.00	2.00	-	6.00	7.00	4.00	22.00	22.00	23.00	17.00	23.00
		Apportionment Percentage by Month (2015)											
Line	Service	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
2	Light	5.00	6.00	-	-	-	-	-	-	-	-	-	-
3	Predominantly Light	5.00	6.00	-	-	-	-	-	-	-	-	-	-
4	Predominantly Heavy	30.00	36.00	33.00	42.00	42.00	42.00	31.00	34.00	16.00	-	16.00	19.00
67	Heavy	30.00	36.00	33.00	42.00	42.00	42.00	31.00	34.00	16.00	-	16.00	19.00
65	Light, Medium	-	6.00	-	-	-	-	-	-	-	-	-	-

Source: Glanzer Direct. P. 12.

She then examined the historical monthly inputs to cokers that she plotted on a graph, her Figure 4 (omitted). Dr. Fagan calculated the average annual apportionment for 2015 as 28 percent and the average annual apportionment for 2016 as 11 percent.[226]

On an annual average basis, Dr. Fagan compared historical apportionment data with the EIA data on input to cokers, and saw lower annual average utilization of cokers, corresponding with higher annual average apportionment, as described in her Figure 6, below:[227]

[225] Ex. DER-9 at 7–9 (Fagan Supp. Surrebuttal). In his rebuttal testimony, Mr. Glanzer's updated Figure 5 to include three more months of 2017. Ex. EN-38, Sched. 3 at 2 (Glanzer Rebuttal).
[226] *Id.* at 8.

Fagan Supp. Surrebuttal Figure 6. Capacity and annual average utilization of cokers, and annual average Enbridge Mainline apportionment

	2015	2016
Thermal craking, delayed coking (b/stream day)	67,000	67,000
Annual average utilization	80%	90%
Annual average apportionment	28%	11%

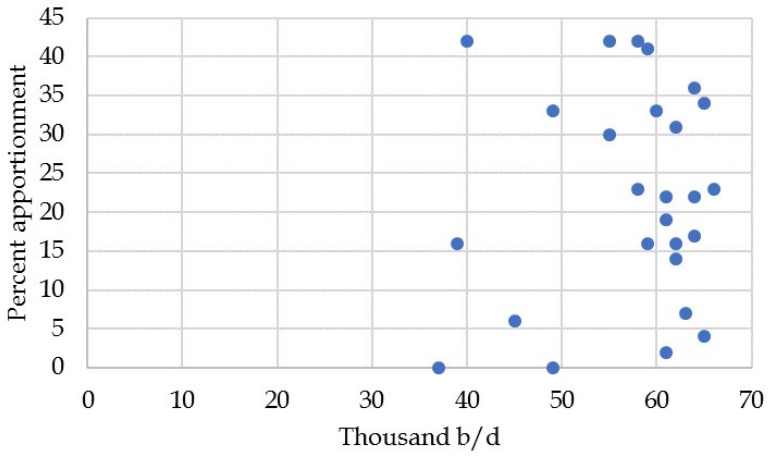
Source: EIA "Minnesota Downstream Charge Capacity of Operable Petroleum Refineries." http://www.eia.gov/dnav/pet/pet_pnp_capchg_dcu_smn_a.htm

Thus, on an *annual* average basis, Dr. Fagan questioned whether apportionment could be the cause of lower utilization of cokers shown in her Figure 6, above.[228] Examining the *monthly* data, though, Dr. Fagan saw no such relationship: no correlation between higher apportionment and lower utilization of cokers.[229] She explained:[230]

> To test this LEI combined the monthly apportionment data in Figure 5 with the fresh feed input data in Figure 4 [omitted], to examine whether lower feeds to cokers in the Minnesota district occurred during months when apportionment was relatively high. LEI found that there was no correlation. In months *when apportionment was relatively high, often so were feeds to cokers* (see Figure 7). In months when apportionment was low, often so were feeds to cokers.

(Footnote Continued from Previous Page)
[227] Ex. DER-9 at 8 (Fagan Supp. Surrebuttal).
[228] *Id.*
[229] Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 83-84 (Fagan).
[230] Ex. DER-9 at 8 (Fagan Supp. Surrebuttal) (emphasis added).

Fagan Supp. Surrebuttal Figure 7: Minnesota Refining District Fresh Feed to Cokers, and Apportionment on Enbridge Mainline January 2015-February 2017



Source: EIA, "Delayed and fluid coking downstream processing of fresh feed input." http://www.eia.gov/dnav/pet/pet_pnp_dwns_a_(na)_ydf_mbblpd_m. htm , and Glanzer Direct. P. 12.

Although she theorized as to some possible explanations for why Minnesota refiners (i.e., Flint Hills) do not appear to be harmed by present or recently past levels of apportionment,[231] the record simply does not show why. The record does show that Dr. Fagan's analysis found no correlation on a monthly basis between high apportionment and low refining of heavy crude.[232]

Dr. Fagan concluded that the results of her examination of whether or not apportionment has effectively limited the supply of heavy crude to Minnesota district refiners in the recent past and present are inconclusive.[233] That is, Enbridge did not demonstrate harm to Minnesota refineries.

[231] Ex. DER-9 at 9-10 (Fagan Supp. Surrebuttal).
[232] Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 84 (Fagan).
[233] *Id.*; Ex. DER-9 at 10 (Fagan Supp. Surrebuttal).

c. Dr. Fagan's Disagrees with Mr. Earnest's Criticisms

Mr. Earnest provided supplemental surrebuttal testimony claiming that Dr. Fagan's apportionment analysis is materially incorrect.[234] He also testified that the most credible evidence on whether there has been a negative impact from apportionment on Minnesota refiners are statements of those Minnesota refiners.[235] Letters from the two Minnesota refiners did not show that there has been a negative impact from apportionment (or any quantification of harm), as is discussed in detail in the section I.B.5.e., below.

Dr. Fagan disagreed with Mr. Earnest's criticisms of her apportionment analysis and of her conclusions as "inconclusive" whether recent Mainline apportionment of heavy crude oil on Minnesota district refiners limited the supply of heavy crude to Minnesota district refiners in the recent past and present.[236] She testified that she disagreed for many reasons with Mr. Earnest's criticisms,[237] but was not allowed to explain.[238] Dr. Fagan, though, was clear that Mr. Earnest's supplemental surrebuttal testimony was unpersuasive and did not cause her to change her conclusions.[239]

Further, Mr. Earnest did not undertake to "correct" the apportionment analysis of Dr. Fagan showing harm from current apportionment or otherwise offer any means by which to

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[234] Ex. EN-94 at 1–8 (Earnest Supp. Surrebuttal).
[235] *Id.* at 1–2. Similarly, Mr. Earnest stated at trial in response to a question a statement by Flint Hills in its letter dated October 11, 2017, "[Y]ou would have to ask Flint Hills for clarification." Evid. Hrg. Tr. Vol. 1B (Nov. 1, 2017) at 29-30 (Earnest) (Flint Hills October 11 letter is attached as Schedule 1 to Ex. EN-56 (Earnest Surrebuttal)). Neither Minnesota refinery is a party and, thus, neither agreed to file testimony, to be subject to discovery or to be questioned under oath by parties.
[236] Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 89, 100 (Fagan).
[237] *Id.* at 100.
[238] DOC DER appreciates the ALJ's ruling that allowed Dr. Fagan's Supplemental Surrebuttal into the record as well as her ruling that Mr. Earnest was allowed to respond.
[239] Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 89, 100 (Fagan).

quantify or confirm the extent to which present apportionment is causing Minnesota refiners material present harm, if that is the case.

d. Apportionment Conclusion: Enbridge Did Not Demonstrate Harm to Minnesota Refineries at Present Levels of Heavy Crude Apportionment on the Enbridge Mainline System

As discussed above, and including her review of Mr. Earnest's criticisms, Dr. Fagan concluded that the results of her examination of whether or not apportionment has effectively limited the supply of heavy crude to Minnesota district refiners in the recent past and present are inconclusive.[240] Thus, Enbridge did not show that when there is apportionment there is harm. This lack of showing is important because it also means that even if apportionment were to increase in the future, Enbridge did not demonstrate a level of future apportionment that may or likely would cause material harm to refiners in Minnesota, the Minnesota district or in PADD 2.

e. Letters of Flint Hills and Andeavor Do Not Claim or Demonstrate Current Harm from Apportionment

Minnesota refiners, Flint Hills and Andeavor are not parties to this case and, even if they were, they do not bear the ultimate burden of proof to demonstrate need for the proposed Project. Again, Enbridge carries that burden of demonstrating its claim of need. Before addressing the substance of the letters regarding apportionment on the Enbridge Mainline System, some observations are in order.

i. Observations

In addition to Flint Hills and Andeavor not being parties in this matter, neither is a member of the three-member Shippers Group, which is a party. Two letters from Flint Hills and one letter from Andeavor were filed as public comments, and because they were included as

[240] *Id.*; *see also* Ex. DER-9 at 10 (Fagan Supp. Surrebuttal).

attachments to parties' testimony, those letters are part of the evidentiary record in this matter.[241] While they are not required to become parties in order to participate in this case through public comment, and while DOC DER appreciates their efforts to provide public comments, the fact is that both refiners chose not to become parties -- to provide sworn testimony, subject to discovery and cross-examination. Therefore, their letters are of limited value on the issue of whether or to what extent current or recently past apportionment of heavy crude (Flint Hills) or of light crude (Andeavor) on the Enbridge Mainline objectively harms either refiner.

ii. Flint Hills's letters do not appear to claim specific current harm from apportionment.

Flint Hills's two letters generated significant testimony and conjecture from parties. The letters at best can be read to note generalized concerns about impacts of apportionment to shippers as a whole without providing any specific claimed harm of current apportionment or any way to allow the Commission to assess the magnitude of such harm, if any. Like the testimony of Enbridge and the Shippers Group (to be discussed in the next section of this Initial Brief), these letters appear to be general assertions regarding the impact of present apportionment, and concern about the potential for future apportionment, but without specific claimed harm or any means of objective confirmation that during months of high heavy crude apportionment, Flint Hills does not currently receive all or nearly all of the heavy crude oil it reasonably can refine.[242]

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[241] *See, e.g.*, Ex. DER-1, KO-17 at 3–4 (O'Connell Direct) (Flint Hills letter dated August 16, 2017); *see also* Ex. EN-56, Sched. 1 (Earnest Surrebuttal) (Flint Hills letter dated October 11, 2017); Ex. EN-94, Sched. 1 (Earnest Supp. Surrebuttal) (Andeavor letter dated October 26, 2017).

[242] Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 37-38 (Fagan) ("I would rather have been able to demonstrate that, rather than just take someone's word for it."). *See also, id.*at 84-85, 93-94.

The August 16, 2017 letter provides the following language in italics that appears intended to address the impact of apportionment on Enbridge's Mainline System, present and future, which, for convenience, is provided as follows:[243]

> [C]ompetition for line space on the Enbridge system continues to increase. In the last 10 years, more than one million barrels per day of pipeline capacity have been added downstream of Clearbrook while upstream pipeline capacity has not kept pace. *This has led to greater apportionment or "rationing" of shipments* because the upstream portion of the system cannot accommodate all the volumes for which it has received nominations. *This imbalance creates inefficiencies that hinder a refinery's ability to access its most preferred or economic crude slate. Apportionment also can make it more difficult for refineries to respond to spikes in demand, make up for supply outages or unplanned events, and it can create operational inefficiencies, including underutilization of equipment. These inefficiencies and supply constraints ultimately harm consumers.*
>
> Enbridge Line 3, which is currently operating at reduced capacity, is a critical piece of the Enbridge system on which Minnesota relies. Flint Hills Resources expects to be a shipper on Line 3, if the pipeline is replaced at the proposed capacity of 760 barrels per day. *Replacing Line 3 will help alleviate apportionment and improve the overall reliability* of the Enbridge system, and by extension, the Minnesota Pipeline system. *Failing to replace the pipeline at its proposed capacity or shutting it down will increase apportionment and reduce reliability to the detriment of Minnesota refineries and Minnesota consumers.*

Although it states that there is now greater apportionment, Flint Hills's August 16 letter speaks only generally about its impact and does not do so specifically as to itself. For example, the refiner states that there has been increased "rationing" of nominated volumes, but does not say whether apportionment has effectively prevented it from economically refining all or nearly all of the crude oil it is able to refine.

[243] Ex. DER-1, KO-17 at 4 (O'Connell Direct) (Flint Hills letter dated August 16, 2017) (emphasis added).

Flint Hills certainly prefers that apportionment be limited and not increase, but unfortunately the August 16 letter gives the Commission no realistic basis from which to assess a level of present harm from present apportionment of heavy crude, if any, and it would not assist the Commission in meaningfully considering how much greater potential future apportionment would need to be in order to significantly harm the refiner or Minnesota consumers. Flints Hills simply does not say or attempt to demonstrate that current apportionment prevents it from receiving all the crude oil required for its operations or that it results in costs that are too high to refine that oil.[244]

Flint Hills's letter dated October 11, 2017, is similarly general as to whether material harm is actually caused by current or potentially future apportionment. The letter responds to DER's direct testimony, and for convenience is provided in relevant part with italics, as follows:

> The Department mischaracterized Flint Hills Resources' August 16, 2017 letter concerning recent upgrades to the Minnesota Pipeline system, including the Clearbrook terminal, which were recently approved by the state of Minnesota to help improve the reliability of crude oil deliveries to Minnesota refineries. The Department mistakenly asserts that these projects lessen the need for Enbridge's existing Line 3 pipeline. These projects, which improved the intrastate reliability of the Minnesota Pipeline system downstream of Clearbrook, in fact, would be rendered less capable of serving their purpose if Line 3 were shut down and not replaced as the Department recommends.

[244] For example, Enbridge witness Mr. Glanzer testified: "When a pipeline system is in apportionment, refiners are not able to receive all the crude oil required for their operations, which would force them to source crude from other less economical sources, such as rail." Ex. EN-38 at 2 (Glanzer Rebuttal). Flint Hills, however, does not receive crude oil by rail. Ex. DER-1, KO-17 at 3 of 5 (O'Connell Direct) (Flint Hill's August 16, 2017 letter stating, "The Pine Bend refinery relies exclusively on the Enbridge pipeline system to provide the crude oil it needs . . . ."). Mr. Glanzer did not testify as to whether current apportionment on the Enbridge Mainline System results in current material economic harm to Flint Hills. *See* Ex. EN-38 *supra* at 2.

The Minnesota Pipeline system, no matter how robust, is inadequate without the Enbridge Mainline System operating at full capacity. *The lack of sufficient capacity presently upstream of Clearbrook contributes to greater apportionment and lesser reliability of the pipeline system overall. If the upstream capacity of the Enbridge Mainline System isn't allowed to keep up with available downstream capacity and downstream demand, apportionment will continue to worsen. In addition, Minnesotans will likely pay more for the fuels they need, and the entire pipeline system Minnesota depends on for fuel and other refined products, including the Minnesota Pipeline system and the refineries it supplies, will be less reliable.*

Flint Hills Resources also disagrees with critical aspects of the Department's analysis of its refinery utilization, market reach, and market demand.

For instance, *the Department's analysis incorrectly concludes that the Flint Hills Resources Pine Bend refinery is at or near full utilization.* Neither the Department nor its expert consulted directly with Flint Hills Resources prior to formulating this opinion.

The Pine Bend refinery is not at full utilization. Last year the refinery reported a barrel per day rate of 290,000 out of a nameplate capacity of 339,000 barrels per day. This is up from 2012 when the refinery reported a rate of 270,000 but still well below full utilization.

The refinery also recently received a permit to implement several projects that will eventually give it the ability to consistently operate near its nameplate, while also reducing key emissions. These and other projects that have come online since 2012 have led to a step change in the refinery's overall efficiency and utilization. This, in turn, has led to growing demand for crude oil supplied by the Enbridge Mainline System.

* * *

Finally, *if Line 3 is not replaced or is shut down* permanently as the Department recommends, which is an outcome not previously contemplated, *Flint Hills Resources would likely be compelled to explore other alternatives for meeting its crude oil needs, including the possibility of receiving crude by rail, river vessel, or perhaps other pipeline projects.* In our view, among these and other

> alternatives, replacing Line 3 is by far the best option with respect to public safety, environmental protection, and cost-effectiveness.

Counsel for Enbridge pressed Dr. Fagan about particular statements in the Flint Hills letters (and Enbridge testimony). As to reliability of the Enbridge Mainline System, with or without the proposed Project, she explained the type of analysis that would be required presumably by the Applicant but, in any event, not by Dr. Fagan would be, as follows:[245]

> So when you think about reliability, if you have more stuff to back you up on anything, if you have an extra car, whatever it is, your system's more reliable.
>
> So at a high level, if you have more of something, you might have a more reliable system. But how much do you want to pay for reliability, how often are you going to use it? Those are the specifics you'd want to examine, but we did not do that.

As to Flint Hills's claim or expectation that "the Pine Bend refinery will remain vitally important to Minnesota and the region," Dr. Fagan clarified that her apportionment analysis focused on the present, or "now," while Flint Hills addressed the future: they "are talking about the future, and lots of different things can happen. So they could be right. But I don't know."[246]

Dr. Fagan did not assume that the presence of apportionment at, say 20 percent, in a particular month necessarily means that refineries aren't getting 20 percent of the oil that they require in that month.[247] Instead, she sought to confirm whether or to what extent a correlation exists between current apportionment levels and whether Minnesota refiners are receiving all or

[245] Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 33 (Fagan).
[246] *Id.* at 40–41.
[247] *Id.* at 85.

nearly all of the heavy crude oil they reasonably could refine during months of high apportionment.[248]

Dr. Fagan summarized the reason why, in her view, the two Flint Hills letters as well as the Andeavor letter were insufficient, that they were missing key statements, about being hurt by apportionment (and, thus, missing any statement showing the magnitude of such an impact). She could see from the letters that the refiners simply, "didn't say that."[249] She testified, as follows:[250]

> Q. Did you review both Flint Hill letters and Andeavor letters in this proceeding?
> A. I did.
>
> Q. Why weren't they good enough for you to conclude that either of those refineries has been hurt by apportionment?
> A. They didn't say that. They didn't come out and say that. They said other things, and they said, generally, this hurts refineries, or we're concerned about this for the future. But they didn't come out and say, we -- we're running 20,000 barrels a day less than we could because of apportionment. No one came out and said that. So it just seemed to be missing.
>
> Q. When you indicated, with respect to Flint Hills, at least one of the letters, it would be nice to have numbers around a Flint Hills statement, what do you mean?
> A. Just like what I said. They had -- in one of their letters, they said, well, we have a stream day capacity that's higher. We are running below that. When we upgrade our coking facilities, et cetera, we'll run more. But they didn't say, oh, and by the way, we would have really been happy to run 20 percent more heavy crude but we were apportioned. But -- so that's what I mean. There wasn't a number behind it. It seemed to be missing.

[248] *Id.* at 37–38.
[249] *Id.* at 93–94.
[250] *Id.*

In conclusion, Dr. Fagan sought objective confirmation or support from historical data that demonstrated present harm from present apportionment rather than "taking someone's word for it."[251] She did not find such confirmation in Flint Hills's letters. Those letters, and that of Andeavor, did not assert or show a material present harm from apportionment on the Enbridge Mainline System. That is, Flint Hills did not show that it is not able to receive all of the heavy crude oil they reasonably could refine during months of high apportionment,[252] or, perhaps, that procuring that crude oil is too high to refine. Again, Dr. Fagan's findings did not suggest that Flint Hills is refining less heavy crude oil during months of high apportionment of heavy crude oil.[253]

iii. Andeavor's letter does not appear to claim material current harm from apportionment.

Like the Flint Hills letters, the Andeavor letter simply "didn't say" that it presently is materially harmed by present or recent past apportionment. The letter includes the following language possibly relevant to the impact of apportionment on the refiner:[254]

> Enbridge Line 3, which is currently operating at a significantly reduced capacity, is an important part of the Enbridge Mainline System upon which Minnesota and the region rely. The replacement of Line 3 with a modern, state of the art pipeline that renews the 760,000 barrels per day capacity of Line 3 *will help reduce apportionment on the Enbridge Mainline System and improve the Refinery's access to needed crude oil supply.* If Line 3 were shut down and not replaced, this would exacerbate the

[251] Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 37-38 (Fagan) ("I would rather have been able to demonstrate that, rather than just take someone's word for it.").
[252] *Id.*
[253] *See* Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 89, 100 (Fagan); *see also* Ex. DER-9 at 10 (Fagan Supp. Surrebuttal).
[254] Ex. EN-94, Sched. 1 at 1–2 (Earnest Supp. Surrebuttal) (Andeavor letter dated October 26, 2017).

> already increasing apportionment problem on the Enbridge Mainline System and negatively impact the Refinery.
>
> As a customer of the Enbridge system, Andeavor believes that the failure to approve the Project will adversely affect the adequacy, reliability and efficiency of energy supply, not only to Minnesota, but the region and all those downstream who rely on the Enbridge system.

Without repeating concerns that have been identified previously above as to both the Flint Hills and Andeavor letters, the plain language in Andeavor's letter addresses largely the future rather any present claim of current harm to Andeavor due to present or recently past apportionment.

Like the Flint Hills letters, the Andeavor language is broad, and unquantified[255] and provides no clear statement of significant harm at present nor does it provide an objective measure of possible present harm from present apportionment such that the Commission could consider how potential future apportionment might impact Andeavor, or not.

iv. Conclusion: The Minnesota refineries did not claim or demonstrate material current harm from apportionment.

For reasons stated above, and consistent with Dr. Fagan's assessment of their letters, DOC DER concludes that neither Minnesota refiner claimed or showed material harm from current apportionment on the Enbridge Mainline System. Dr. Fagan sought to confirm objectively whether or to what extent a correlation exists between current apportionment levels, and whether Minnesota refiners are receiving all or nearly all of the heavy crude oil they reasonably could refine during months of high apportionment.[256] She could not do so. Dr. Fagan found both letters omitted key statements as to whether they currently are hurt by

[255] *Id.*
[256] *Id.* at 37–38.

apportionment[257] and, thus, both letters also omitted any statement or demonstration of the magnitude of harm.

f. The Shippers Group Did Not Demonstrate Current or Future Harm from Apportionment

Three shippers make up the Shippers Group, which is a party to this case. The members, Cenovus Energy Inc. (Cenovus), Suncor Energy Marketing Inc. (Suncor) and BP Products North America Inc. (BP), are "Canadian crude oil producers, and/or American and/or Canadian refiners."[258] This party states that its represents "a cross-section of the overall community of Enbridge Mainline shippers"[259] and its three witnesses attached letters of support for the proposed Project from refiners such as Flint Hills, Calumet in Indiana, and Marathon Petroleum Company in Ohio.[260] Flint Hills's letters are the most detailed, and letters from both Minnesota refineries were discussed in the section of this Initial Brief, immediately above.

The Shippers Group does not have the burden of proof in this matter. Enbridge carries the burden of demonstrating its claim that the proposed Project is needed, under the statutory and rule criteria. It is important to note, though, that none of the three Shipper Group members or the refiners represented in their attached letters, quantify any level of harm from current apportionment or provide a means by which the Commission could objectively evaluate whether or to what extent present or recent past apportionment levels caused material harm. In fact, when questioned at trial, Mr. Van Heyst of Suncor confirmed that the three shippers did not provide in this matter an estimate of the financial impact of present or past apportionment on the Enbridge

[257] Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 93-94 (Fagan).
[258] Ex. SH-1 at 3 (Kahler Direct). Neither Minnesota refinery is a party in this matter and neither is among the three shippers that belong to the party called the Shippers Group.
[259] *Id.*
[260] Ex. SH-1, Sched. A (Refineries Letters).

Mainline.[261] This testimony is consistent with Dr. Fagan's testimony that she found no quantification of the costs of apportionment on shippers.[262] Unlike Dr. Fagan, however, the Shippers Group did not undertake the effort to try to demonstrate or confirm that current levels of apportionment, particularly of heavy crude on the Enbridge Mainline System, presently results in refiners such as Minnesota district refiners not receiving all or nearly all of the heavy crude oil they reasonably could refine during months of high apportionment or are otherwise harmed.

Rather, testimony by the Shippers Group stresses that the Enbridge Mainline System currently is in apportionment, which can create increased risks and increased costs. For example, Mr. Kahler of Cenovus testified that this current apportionment is "affecting shippers' ability to transport needed volumes of crude oil to downstream refineries and markets, including those in Minnesota and the Midwest where refiners and their customers depend upon the Enbridge Mainline."[263] He stated that the proposed Project would reduce apportionment and improve availability and reliability of the system.[264] Similarly, Mr. Shahady of BP testified that refineries "face increased risks associated with capacity apportionment and supply disruptions. Both have a negative impact on operations, including increased supply and transportation costs for the refineries, for producers in Canada, and for consumers of crude oil products in the United States."[265] Calumet stated generally that transportation of crude out of Western Canada is currently constrained, but specifically notes only that Calumet "*may be* faced with undue or

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[261] Evid. Hrg. Tr. Vol. 9A (Nov. 15, 2017) at 79-80 (Van Heyst).
[262] Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 85 (Fagan).
[263] Ex. SH-1 at 3 (Kahler Direct).
[264] *Id.*
[265] Ex. SH-1 at 17 (Shahady Direct); *see also id.* at Sched. A (Marathon Letter to Enbridge, Apr. 7, 2015) ("If reliable transportation capacity is not made available, we are faced with undue and unnecessary risks tied to increasing capacity apportionment and/or more frequent operational and supply disruptions, both of which have a negative impact on our operations.").

unnecessary risks tied to capacity apportionment and/or operational/supply disruptions, both of which would have a negative impact on our operations."[266]

While the Shippers Group is less specific than Enbridge witness Mr. Earnest who testified that refineries currently are harmed by current apportionment of heavy crude oil on the Enbridge Mainline System and that apportionment will increase in the future, which in turn will increase the harm to refineries,[267] it shares with Mr. Earnest the lack of a showing that refineries presently are harmed by current levels of apportionment.[268] As noted previously in section I.B.5.a.-d. of this Initial Brief, Dr. Fagan's review was inconclusive as to whether, based on the data from the present or recent past, Enbridge's Mainline System apportionment has effectively limited the supply of heavy crude to the Minnesota district refineries.[269]

For these reasons, DOC DER concludes that the Shippers Group did not demonstrate that present (or recently past) levels of apportionment on the Enbridge Mainline effectively limit the supply of heavy crude to them or to Minnesota district refiners.

g. Conclusion as to Harm from Current Apportionment: Enbridge Did Not Demonstrate that Present or Recent Apportionment on the Enbridge Mainline System has Effectively Limited the Supply of Heavy (or Light) Crude Oil to Minnesota District Refiners

Dr. Fagan, on behalf of DOC DER, attempted unsuccessfully to objectively confirm whether Enbridge current or recently past apportionment has effectively limited the supply of

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[266] *Id.* at Sched. A (Calumet Letter to Ann. C. O'Reilly, July 8, 2017) (emphasis added).
[267] *See* Evid. Hrg. Tr. Vol. 1B (Nov. 1, 2017) at 12-14, 36 (Earnest) (stating that refineries are hurt by present apportionment and if the CN is denied, then "my forecast indicates that apportionment will get worse.").
[268] *See* Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 18, 83-85, 95-100 (Fagan); *see also* Ex. DER-9, MF-1 at 4-10 (Fagan Supp. Surrebuttal).
[269] *See id.* at 18, 84–85, 93–94.

heavy crude to Minnesota district refiners in the recent past and present; her findings are inconclusive.[270] Enbridge did not show that when there is apportionment there is harm. Even if one were to assume that apportionment will increase in the future, Enbridge did not demonstrate a level of future apportionment that may or likely would cause material harm to refiners in Minnesota, the Minnesota district or in PADD 2.

C. Enbridge Has Not Demonstrated That the Proposed Project Satisfies the Criteria Under Minn. R. 7853.0130 A Even in Light of Consent Decree Obligations and Operational Concerns.

Enbridge stated that certain operational concerns and certain obligations under a May 23, 2017 Consent Decree with the U.S. Department of Justice support its need to replace Line 3.[271] First, the Consent Decree does not bind the Commission regarding the merits of Enbridge's CN Application: it states that "Enbridge shall replace the segment of the Lakehead System Line 3 oil transmission pipeline . . . provided that Enbridge receives all necessary approvals to do so."[272] Thus, by itself, the Consent Decree does not make a finding of need for the proposed Project under Minnesota law.[273] If, based on the facts in this proceeding, the Commission finds that Enbridge has not demonstrated a need for the proposed Project under Minnesota law, including the proposed increase in size of the crude oil pipeline (discussed further below), the Consent

[270] *Id.*; *see also* Ex. DER-9 at 10 (Fagan Supp. Surrebuttal).
[271] *See, e.g.*, Ex. EN-30 at 16–17 (Eberth Rebuttal).
[272] *See id.*, Sched. 1 at 25. The fully-executed May 23, 2017 Consent Decree is attached to Mr. Eberth's Rebuttal Testimony at Schedule 1.
[273] *Id.*; *see also* Ex. DER-1 at 11 (O'Connell Direct). Enbridge witness Mr. Eberth agreed that the "[Department of Justice (DOJ)] does not have the permitting authority to grant approvals for the replacement of Line 3." Ex. EN-30 at 16 (Eberth Rebuttal).

Decree does not require construction of a new pipeline.[274] That is, the Consent Decree appears to allow Enbridge to operate the existing Line 3 in perpetuity under certain operating conditions if it does not get approval for a replacement.[275]

What is clear is that while the Consent Decree requires Enbridge to seek a replacement of Line 3 from the "approval authorities," Enbridge has not officially committed as to when, or even if, it would discontinue operating the existing Line 3.[276] The Consent Decree places limits on Enbridge's use of existing Line 3, but does not prohibit the Company from using Line 3.[277] Moreover, Enbridge's testimony indicates that the Company is prepared to continue operating the existing Line 3:

> If the Project is not approved, Enbridge will continue to operate Line 3 in a safe and reliable manner; however, the worsening condition of the pipeline is causing an increasing amount of maintenance and repair that would not only inconvenience landowners and impact the environment, but would also be economically inefficient. Further, ongoing maintenance will not restore the operating capabilities of Line 3, leaving Enbridge's customers without adequate, reliable, and efficient transportation capacity to reduce apportionment.[278]

Thus, without knowing if or when operations of the existing Line 3 would discontinue, not only is the timing of need not known from the record, the fact of need for the proposed Project, or the

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[274] Ex. DER-1 at 11 (O'Connell Direct). Moreover, the Consent Decree does not "permanently enjoin" Enbridge "from operating, or allowing anyone else to operate" Line 3, as it did with Lines 6A and 6B. *Id.* at 11–12; *see also* Ex. EN-30, Sched. 1 at 25–26 (Eberth Rebuttal).
[275] *See id.*; *see also* Ex. EN-30, Sched. 1 at 25–27 (Eberth Rebuttal).
[276] *See* Ex. DER-1 at 12 (O'Connell Direct); Ex. EN-30, Sched. 1 at 25–26 (Eberth Rebuttal). At trial, counsel for Applicant would not state affirmatively that Applicant will construct a new Line 3 even if the Commission finds need conditions on terms that the company does not like. The AJL ordered Applicant to provide a detailed response to this question in its Initial Brief.
[277] Ex. DER-6 at 9 (O'Connell Surrebuttal).
[278] Ex. EN-24 at 10 (Eberth Direct).

level of necessity, also is unknown.[279] Enbridge's approach is in this proceeding is troubling because Enbridge is essentially asking the Commission to determine that Enbridge has met the legal requirements for a new facility before Enbridge itself makes the business decision that it will cease operating the existing Line 3.[280]

Despite Enbridge's reported concerns with continued operation of the existing Line 3, Enbridge testified that it could continue to operate existing Line 3 safely, as indicated above.[281] In fact, Enbridge claims "that Line 3 can continue to operate safely with timely maintenance."[282] Enbridge testified that there is no time limit after which it could not operate Line 3 safely:

> Q. So your testimony here today is that Enbridge can continue to operate the existing Line 3 for as long as necessary safely?
> A. Yes. Provided that we continue our timely maintenance.
> Q. Is there any specific time limit after which you could not operate Line 3 safely?
> A. Not that I'm aware of.
> Q. So just like my old car, if Enbridge chose to expend the money to maintain Line 3, it could do so; is that correct?
> A. Theoretically, yes.[283]

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[279] *See* Ex. DER-1 at 15 (O'Connell Direct).
[280] *See id.* at 15; *see also* Evid. Hrg. Tr. Vol. 12A (Nov. 20, 2017) at 88 (O'Connell).
[281] *Compare* Ex. EN-12 at 20 (Kennett Direct) ("Enbridge has been analyzing the need for replacement of Line 3 for several years because of increasing maintenance activities associated with external corrosion, SCC, and long-seam-fatigue cracking.") *with* Ex. EN-24 at 10 (Eberth Direct) ("If the Project is not approved, Enbridge will continue to operate Line 3 in a safe and reliable manner . . . ."); *see also* Ex. DER-6 at 8, 45 (O'Connell Surrebuttal).
[282] Ex. EN-32 at 4 (Reb. Test. Kennett); *see also* Evid. Hrg. Tr. Vol. 1A (Nov. 1, 2017) at 51 (Kennett). Even without timely maintenance, Enbridge testified that the Petroleum Technology Association Canada (PTAC) concluded in a study that it would take twenty-five to fifty years for the existing Line 3 to suffer a full corrosive wall breach at a particular place. In addition, PTAC concluded that it would take hundreds if not thousands of years for the existing Line 3 to fully corrode, even without protective coating. Evid. Hrg. Tr. Vol. 2B (Nov. 2, 2017) at 23 (Simonson).
[283] Evid. Hrg. Tr. Vol. 1A (Nov. 1, 2017) at 51–52 (Kennett).

In fact, Enbridge witness Ms. Kennett testified that "integrity threats" are not risks to the environment from Enbridge's perspective. Thus, Enbridge claims that integrity threats, such as corrosion, cracking, deformation and strain, and facility-related threats, do not present risks to the environment and can be mitigated by the integrity management program.[284]

In addition, Enbridge stated that existing Line 3 has been operating at an annual average capacity of 390,000 barrels per day (bpd), which is Line 3's lowest operable pressure, and has been shipping primarily light crude oil rather than mixed service (e.g. light and heavy), since 2010.[285] Enbridge stated that this "lowered pressure maintained a safety factor on the line, deferred some of the maintenance work on the anomalies, and still allowed the pipeline to function, albeit at a much reduced rate."[286] Building a new pipeline would purportedly allow Enbridge to ship different types of crude oil, rather than being limited to shipping light crude oil.[287]

Enbridge also stated that, while it was replacing the worst segments of the existing Line 3 in order to address integrity issues, maintenance costs have increased significantly and are expected to grow over time. "Dig and repair costs were forecasted to exceed $6 billion through the year 2026, and replacing the segments in the worst integrity condition would only lower the forecasted cost to $4.3 billion."[288] By contrast, the estimated cost of the entire proposed Project is approximately $7.5 billion.[289]

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[284] *See id.* at 54–56.
[285] Ex. EN-12 at 21 (Kennett Direct).
[286] *Id.*
[287] Ex. DER-1 at 8 (O'Connell Direct).
[288] *Id.*
[289] Ex. EN-24 at 6 (Eberth Direct).

As it stands, Enbridge's stated need is a study in contrasts: it claims that it can operate the existing Line 3 safely in perpetuity, while at the same time warns about integrity concerns of operating the existing Line 3 such that it needs to be replaced.[290] It embraces two seemingly contrary views. By effectively leaving it up to the Commission to decide whether Enbridge should continue to operate the existing Line 3 (which Enbridge has stated it could do) or should construct a new Line 3 (which it has proposed to do), Enbridge fails to demonstrate that it has met the criteria for the proposed Project under Minn. R. 7853.0130 A.

The Department testified that it is concerned that Enbridge will cease operating the existing Line 3 only if Enbridge receives a CN and that the CN aligns with Enbridge's proposed Project.[291] In other words, it is unclear whether Enbridge will cease operating the existing Line 3 if the Commission grants Enbridge a CN that includes certain conditions with which Enbridge does not agree. As an example to support this concern, Enbridge's agreement with the Representative Shipper Group (RSG), Issue Resolution Sheet, which states that Enbridge can terminate the proposed Project if it receives regulatory approval that is not satisfactory to Enbridge.[292] By contrast, the Consent Decree states that Enbridge shall complete a replacement for Line 3 if it receives regulatory approval.[293] Even when asked directly about this contradiction between the Consent Decree and the Issue Resolution Sheet, Enbridge was unable to provide any clarification.[294] Considering all of the evidence, it is still unclear whether Enbridge would be required to cease operations of the existing Line 3 under the Consent Decree

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[290] *See, e.g.*, Ex. EN-24 at 10 (Eberth Direct); Ex. EN-30 at 8 (Eberth Rebuttal); Ex. EN-12 at 20 (Kennett Direct).
[291] *See* Ex. DER-1 at 14–15 (O'Connell Direct).
[292] Ex. EN-1, App. D at 2 (CN Application).
[293] *See* Ex. EN-30, Sched. 1 at 26 (Eberth Rebuttal).
[294] Evid. Hrg. Tr. Vol. 12 B (Nov. 20, 2017) at 102.

if Enbridge received regulatory approval, but rejected the CN and instead sought to continue operating the existing Line 3 without constructing a new Line 3.[295] DOC DER understands that Enbridge will brief this issue in its Initial Brief, as noted previously in a footnote. Nevertheless, DOC DER concludes that the record does not support the Commission granting regulatory approval for the proposed Project.

To summarize, despite Enbridge's reported operational concerns with continued operation of Line 3, Enbridge testified that it could continue to operate the existing Line 3 safely.[296] Enbridge has not stated unequivocally that it will retire the existing Line 3, and the Consent Decree does not require such retirement.[297] The timing of such a shutdown of existing Line 3 may inform the analysis of whether alternatives to any new needed pipeline facility could meet such a need.[298] But, if Enbridge does not demonstrate a need, then there is no reason to consider alternatives to meet the claimed need.[299] Thus, the alternatives analysis below should be considered only if Enbridge meets its burden of proof to show that a need for any new Line 3 or Line 3 segment exists.[300]

D. Size of the Proposed Line 3: The Commission Should Only Approve a 34-Inch Pipeline.

DOC DER concluded that Enbridge has not demonstrated that a larger, 36-inch pipeline is needed.[301] Instead, if the Commission approves a CN for the proposed Project, it should be

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[295] *Id.* at 7–20, 102–103.
[296] *Compare* Ex. EN-12 at 20 (Kennett Direct) *with* Ex. EN-24 at 10 (Eberth Direct); *see also* Ex. DER-6 at 8, 45 (O'Connell Surrebuttal); *see also* Ex. EN-30 at 5, 8 (Eberth Rebuttal).
[297] Ex. DER-1 at 14 (O'Connell Direct); *see also* Ex. DER-6 at 46 (O'Connell Surrebuttal).
[298] *Id.* at 15
[299] *Id.* at 15–16.
[300] *Id.* at 16.
[301] Ex. DER-1 at 21 (O'Connell Direct).

based on Enbridge's stated need to replace the original 34-inch diameter Line 3. Therefore, if the Commission grants a CN, a new Line 3 should be no larger than a 34-inch pipeline.

Enbridge stated that the 36-inch pipeline in the proposed Project would have an "ultimate design capacity" of 1,016,000 bpd, compared to 836,000 bpd for a 34-inch pipeline.[302] As to its full design capacity, Enbridge stated:

> The predicted maximum daily throughput, also referred to as full design capacity, for the project is 844 kbpd without planned or unplanned outages at the design mixed crude slate. The maximum daily throughput would be lower in 100% heavy service or greater in 100% light service. The pipeline will operate at flow rates up to the maximum daily throughput, in order to recover from operational outages (planned and/or unplanned), and still arrive at the annual average capacity of 760 kbpd. In addition, if there is excess supply to be pumped (for example from additional production of crude, or from an outage on another pipeline), the Project could operate at its maximum daily throughput (844 kbpd) to accommodate this excess supply, but only to the extent that excess capacity is available (i.e., the Project is not already full).[303]

Enbridge maintained that the need to be met by the proposed Project is to "[restore] the capacity of the pipeline to its original operating capacity of 760,000 bpd."[304] But the Commission would be approving a full design capacity of 844,000 bpd for a 36-inch pipeline because that is what Enbridge has proposed.[305] Enbridge has the burden of proving that this additional capacity is needed.[306] This greater amount would not only replace the capacity of the existing Line 3, but the Commission would also approve an increase to the capacity of the Enbridge Mainline System by about 84,000 bpd.

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[302] *Id.*, KO-2.
[303] *Id.*
[304] Ex. EN-24 at 10 (Eberth Direct).
[305] Ex. DER-1 at 19 (O'Connell Direct).
[306] *See* Minn. Stat. § 243B.243, subd. 3 (2016).

While Enbridge could not demonstrate that it could deny shippers access to the full 844,000 bpd, it stated that it could operate the new Line 3 at that larger capacity.[307] Enbridge appeared to acknowledge that it is, in fact, asking the Commission to certify this higher capacity.[308] Thus, it is reasonable to conclude that the new Line 3 would be more than a replacement: it would increase the capacity of the Enbridge Mainline System.

In addition, a larger, 36-inch Line 3 would pose a greater risk to the environment than a 34-inch pipeline in the case of an oil spill, which is discussed in more detail below in Section III.[309] This higher risk is especially concerning given that smaller Enbridge pipelines have done significant harm to the environment, such as Enbridge's 30-inch Line 6B, which was involved in the large 2010 oil spill near Marshall, Michigan.[310]

E. Enbridge's Stated Need to Interconnect at Clearbrook Demonstrates that the Proposed Project is Primarily Based on Efficiency, and Not Reliability or Adequacy of Oil Supply, Under Minn. R. 7853.0130 A.

After evaluating Enbridge's claims that the proposed Project must interconnect at Clearbrook, Minnesota with existing pipeline assets, DOC DER concluded that that the proposed Project is primarily designed to address the efficiency of the Enbridge Mainline System.[311] Enbridge proposed three limitations to construction of the proposed Project: 1) the proposed Project must cross into Minnesota in Kittson County; 2) the proposed Project must interconnect with other Enbridge pipelines at and make deliveries to Clearbrook; and 3) the proposed Project

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[307] *Id.* at 20.
[308] Ex. DER-6 at 51 (O'Connell Surrebuttal); *see also* Evid. Hrg. Tr. Vol. 1B (Nov. 1, 2017) at 58–60 (Glanzer).
[309] Ex. EN-51 at 15–16 (Mittelstadt Rebuttal).
[310] Ex. EN-1, Sched. C at 44 (CN Application); Evid. Hrg. Tr. Vol. 4A (Nov. 6, 2017) at 40 Mittelstadt); Evid. Hrg. Tr. Vol. 7B (Nov. 13, 2017) at 105 (Eberth); Ex. EERA-29 at 10-33 (FEIS).
[311] Ex. DER-1 at 29 (O'Connell Direct).

must exit Minnesota in Carlton County.[312] By focusing on these restrictions, Enbridge appears to focus on using existing Enbridge infrastructure to the greatest extent possible.[313]

The interconnection at Clearbrook is important because all deliveries of crude oil to Clearbrook (that do not pass through) are destined for the Minnesota Pipe Line (MPL) system, which transports crude oil to the two refineries located near St. Paul (the Flint Hills Resources Pine Bend Refinery and the St. Paul Park Refinery).[314] While Line 3 currently delivers mostly light crude oil to Clearbrook, other pipelines on Enbridge's Mainline System can deliver heavy and other kinds of crude oil.[315] Moreover, the Commission granted two CNs to Enbridge to expand the capacity of the Enbridge Mainline System that goes through both Clearbrook and Superior.[316] Specifically, in Docket No. PL9/CN-12-590, on August 12, 2013 the Commission granted Enbridge a CN to increase the capacity of Line 67 by 120,000 bpd.[317] On November 7, 2014, in Docket No. PL9/CN-13-153, the Commission granted Enbridge a second CN to increase the capacity of Line 67 by an additional 230,000 bpd.[318] O'Connell direct testimony Chart 1, below, which contains highly sensitive trade secret (HSTS) information based on information from Enbridge witness Mr. Glanzer's HSTS Appendix G, indicates the amounts of light and heavy crude oil that have been shipped through Clearbrook, including the supplies that are

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[312] *See* Ex. EN-1 at 10-1 (CN Application).
[313] *See* Ex. DER-1 at 22 (O'Connell Direct).
[314] *See id.* at 25.
[315] *Id.*; *see also* Evid. Hrg. Tr. Vol. 1B (Nov. 1, 2017) at 66 (Glanzer).
[316] Ex. DER-1 at 27 (O'Connell Direct).
[317] *In re Application of Enbridge Energy, Ltd. P'ship for a Certificate of Need for the Line 67 Station Upgrade Project in Marshall, Clearwater, and Itasca Counties*, Docket No. PL-9/CN-12-590, Order Granting Certificate of Need at 8 (MPUC Aug. 12, 2013).
[318] Phase 2 Order at 32.

delivered to Clearbrook.[319] O'Connell direct testimony Chart 2, which also contains HSTS information, indicates how much heavy and light crude oil is delivered to Clearbrook for transportation on the MPL.[320]

[HIGHLY SENSITIVE TRADE SECRET DATA BEGINS

[319] *Id.*
[320] Ex. DER-3 at 26 (O'Connell Direct).

HIGHLY SENSITIVE TRADE SECRET DATA ENDS][321]

Thus, DOC DER concluded that Enbridge Mainline System (all pipelines, including the existing Line 3) has been delivering increasing amounts of supplies to Clearbrook and Superior even with Line 3 capable of delivering predominantly light crude.[322] Second, DOC DER concluded that **[HIGHLY SENSITIVE TRADE SECRET DATA BEGINS**

HIGHLY SENSITIVE TRADE SECRET DATA ENDS]. Third, DOC DER concluded that, since 2014, **[HIGHLY SENSITIVE TRADE SECRET DATA BEGINS**

[321] These charts present deliveries in kilobarrels.
[322] Ex. DER-3 at 27 (O'Connell Direct).

HIGHLY SENSITIVE TRADE SECRET DATA ENDS].[323]

Despite this recent increase to overall capacity, Enbridge witness Mr. Glanzer stated that, if approved, the proposed Project would allow Enbridge to operate its Mainline system in Minnesota more efficiently and with less apportionment.[324] Further, Enbridge stated the following in response to a question about the incremental need for increased capacity on Line 3:

> The 350,000 bpd of incremental Line 67 capacity is not solely for Minnesota destined volumes. The Enbridge mainline system is operated as an integrated system. The allocation of incremental capacity varies month to month based on Shipper nominations and crude disposition.
>
> Additionally, if the Project does not include a connection at Clearbrook, the Minnesota refineries will lose connectivity to one of the Enbridge Mainlines they currently have access to, which will reduce operational flexibility and eliminate their access to volumes on Line 3 Replacement.[325]

Here, Enbridge makes an argument for need based on efficiency, which DOC DER agreed is a valid aspect of a need under Minn. R. 7853.0130 A.[326] Nevertheless, DOC DER concludes that Enbridge has not satisfied the criteria under Minn. R. 7853.0130 A.

F. Minn. R. 7853.0130 A(2): The Effects of the Applicant's Existing or Expected Conservation Programs and State and Federal Conservation Programs

The Commission must consider the effects of Enbridge's existing or expected conservation programs and state and federal conservation programs.[327] As a shipper of crude oil on a common-carrier pipeline system, Enbridge's conservation programs, while admirable,

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[323] *Id.*
[324] Ex. EN-19 at 11 (Glanzer Direct).
[325] Ex. DER-1, KO-5 (O'Connell Direct).
[326] *Id.* at 29.
[327] Minn. R. 7853.0130 A(2) (2015).

appear to be generally applicable to its business and likely do not have a significant impact on crude oil supplies or demand for refined products.[328] As stated in the CN Application, the proposed Project is designed "to better meet the petroleum supply needs of PADD II, including Minnesota," and thus, is designed to address the purported needs of third party shippers.[329] Enbridge does, however, have several in-house conservation programs, which it highlighted in the CN Application.[330] Nevertheless, DOC DER recommends that the Commission require Enbridge to apply the Commission-approved neutral footprint program to increased energy use implemented in the CN matter regarding the Phase 2 Upgrade to Line 67 crude oil pipeline (Docket No. EL9/CN-13-153), which Enbridge has not offered for the proposed Project.[331] As discussed further below in the CN conditions section, application of the neutral footprint program would limit the proposed Project's impacts to the natural and socioeconomic environments in a more meaningful, project-specific way.

Finally, DOC DER discusses below certain state environmental policies that are affected by the proposed Project, but otherwise relies on the FEIS to address the state and federal regulatory framework applicable to the proposed Project.[332]

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[328] *See* Ex. EN-1 at 5-1 (CN Application) ("As a common carrier, Enbridge does not buy or sell crude oil or petroleum products. Rather, Enbridge serves as a transportation company that ships crude oil to market where it can be refined. Thus, Enbridge's conservation efforts do not have any impact on crude oil supply or demand.").
[329] Ex. EN-1 at 3-1, 5-1–5-7 (CN Application).
[330] *Id.* at 5-1–5-7.
[331] *See* Phase 2 Order at 32; Ex. EN-30 at 25 (Eberth Rebuttal).
[332] *See* Ex. EERA-29 at 3-1 (FEIS).

G. Minn. R. 7853.0130 A(3): The Effects of the Applicant's Promotional Practices That May Have Given Rise to the Increase in the Energy Demand, Particularly Promotional Practices That Have Occurred Since 1974

The Commission granted Enbridge an exemption from identifying promotional activities that may have given rise to the increase in energy demand.[333]

H. Minn. R. 7853.0130 A(4): The Ability of Current Facilities and Planned Facilities Not Requiring Certificates of Need, and to Which The Applicant Has Access, to Meet Future Demand

Minn. R. 7853.0130 A(4) regards a scenario where the proposed Project would not be built. Enbridge did not demonstrate that current (such as the existing Line 3) and planned facilities do not have the ability to meet future demand for crude oil.[334] Furthermore, Enbridge's analysis of a no-action alternative does not accurately state the effect of denial of the certificate of need on Minnesota's refineries, given Dr. Fagan's analysis primarily of Mr. Earnest's testimony and Ms. O'Connell's analysis of Minn. R. 7853.0130 C criteria. As discussed in more detail below, the record shows how current pipeline facilities appear to be already meeting any stated need in Minnesota. Notably, as previously mentioned, Enbridge did not realistically model or consider the prospect that pipeline infrastructure other than a new Line 3 could come online in the future.

I. Minn. R. 7853.0130 A(5): The Effect of the Proposed Facility, or a Suitable Modification of It, In Making Efficient Use of Resources

This criterion considers the effect of the proposed Project, or a suitable modification of it, in making efficient use of resources for the future adequacy, reliability, or efficiency of energy supply to the applicant, to the applicant's customers, or to the people of Minnesota and

[333] Ex. EN-1 at 4-3 (CN Application).
[334] Above, DOC DER discussed how Enbridge did not demonstrate that its supply and demand forecasts regarding crude oil and crude oil products were accurate.

neighboring states.[335] DOC DER addressed this criterion as part of its underlying analyses regarding the economic need for the proposed Project and the reasonableness of alternatives to the proposed Project.

Under this criterion, DOC DER specifically addresses Enbridge's claim that a 36-inch pipeline would be more efficient than a 34-inch pipeline.[336] While this may be technically true, DOC DER discussed above that Enbridge has not demonstrated that it needs the extra capacity of a 36-inch pipeline compared to a 34-inch pipeline.[337] Moreover, if the Commission grants Enbridge a CN for the proposed Project conditioned on Enbridge applying a neutral-footprint program to the proposed Project's energy usage, assuming Enbridge's efficiency's claims are accurate, any increased energy usage by a 34-inch pipeline would be from renewable resources, which would limit the impact to the natural environment. Enbridge's neutral footprint program is discussed in more detail, below, in Section III.C.

J. Overall Conclusions Regarding Minn. R. 7853.0130 A

Based on the above analyses under Minn. R. 7853.0130 A, DOC DER concludes that Enbridge has not demonstrated that the probable result of denial would adversely affect the future adequacy, reliability, or efficiency of energy supply to the applicant, to the applicant's customers, or to the people of Minnesota and neighboring states, considering the applicable criteria. Despite Enbridge's reported operational concerns with continued operation of Line 3,

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[335] Minn. R. 7853.0130 A(5) (2015).
[336] *See* Ex. EN-1 at 5-2–5-3 (CN Application); *see also* Ex. EN-19 at 16 (Glanzer Direct); Ex. EN-38 at 4 (Glanzer Rebuttal).
[337] Ex. DER-1 at 18–21 (O'Connell Direct); *see also* Ex. DER-6 at 50–52 (O'Connell Surrebuttal).

Enbridge testified that it could continue to operate the existing Line 3 safely.[338] Enbridge has not stated unequivocally that it will retire the existing Line 3, and the Consent Decree does not require such retirement.[339] Under Dr. Fagan's analysis, DOC DER concluded that Enbridge has not shown that its supply and demand forecasts are realistic—or are likely to be accurate—as required by Minnesota Rule 7853.0130 A(1). Dr. Fagan also concluded that the results of her examination of whether or not apportionment has effectively limited the supply of heavy crude to Minnesota district refiners in the recent past and present are inconclusive.[340] This means that Enbridge did not show that when there is apportionment there is harm. Even if one were to assume that apportionment will increase in the future, Enbridge did not demonstrate a level of future apportionment that may or likely would cause material harm to refiners in Minnesota, the Minnesota district or in PADD 2.

Under Minn. R. 7853.0130 A(2), the Commission must consider the effects of Enbridge's existing or expected conservation programs and state and federal conservation programs.[341] Because the proposed Project is designed "to better meet the petroleum supply needs of PADD II, including Minnesota," and thus, is designed to address the purported needs of third party

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[338] *Compare* Ex. EN-12 at 20 (Kennett Direct) ("Enbridge has been analyzing the need for replacement of Line 3 for several years because of increasing maintenance activities associated with external corrosion, SCC, and long-seam-fatigue cracking.") *with* Ex. EN-24 at 10 (Eberth Direct) ("If the Project is not approved, Enbridge will continue to operate Line 3 in a safe and reliable manner . . . ."); *see also* Ex. DER-6 at 8, 45 (O'Connell Surrebuttal); *see also* Ex. EN-30 at 5, 8 (Eberth Rebuttal) ("Under the 'no action' alternative, Enbridge would continue to operate existing Line 3, addressing ongoing integrity issues with increasing dig and repair activities.").

[339] Ex. DER-1 at 14 (O'Connell Direct). The facts in this case are that no entity has required Enbridge to cease operations of existing Line 3 and Enbridge has stated its clear intention to continue operating existing Line 3 in a safe manner. Ex. DER-6 at 46 (O'Connell Surrebuttal).

[340] Evid. Hrg. Tr. Vol. 9B (Nov. 15, 2017) at 84 (Fagan); *see also* Ex. DER-9 at 10 (Fagan Supp. Surrebuttal).

[341] Minn. R. 7853.0130 A(2) (2015).

shippers,[342] Enbridge's conservation programs likely would not have a significant impact on crude oil supplies or demand for refined products.[343] Enbridge has several in-house conservation programs, which it highlighted in the CN Application.[344] DOC DER recommends that the Commission require Enbridge apply its neutral footprint program to the increased energy use implemented, which the Commission approved as to the Phase 2 Upgrade to the Line 67 crude oil pipeline (Docket No. EL9/CN-13-153), which would limit the proposed Project's impacts to the natural and socioeconomic environments in a more meaningful, project-specific way.[345]

Under Minn. R. 7853.0130 A(3), the Commission granted Enbridge an exemption from identifying promotional activities that may have given rise to the increase in energy demand.[346]

Under Minn. R. 7853.0130 A(4), which regards a scenario where the proposed Project would not be built, Enbridge did not demonstrate that current (such as the existing Line 3) and planned facilities do not have the ability to meet future demand for crude oil.[347]

Under Minn. R. 7853.0130 A(5), Enbridge claims that a 36-inch pipeline would be more efficient than a 34-inch pipeline.[348] While this may be technically true, Enbridge has not demonstrated that it needs the extra capacity of a 36-inch pipeline compared to a 34-inch pipeline.[349] Moreover, if the Commission grants Enbridge a CN for the proposed Project

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[342] Ex. EN-1 at 3-1, 5-1–5-7 (CN Application).
[343] *See* Ex. EN-1 at 5-1 (CN Application)
[344] *Id.* at 5-1–5-7.
[345] Ex. DER-1 at 85, 115 (O'Connell Direct).
[346] Ex. EN-1 at 4-3 (CN Application).
[347] Above, DOC DER discussed how Enbridge did not demonstrate that its supply and demand forecasts regarding crude oil and crude oil products were accurate.
[348] *See* Ex. EN-1 at 5-2–5-3 (CN Application); *see also* Ex. EN-19 at 16 (Glanzer Direct); Ex. EN-38 at 4 (Glanzer Rebuttal).
[349] Ex. DER-1 at 18–21 (O'Connell Direct); *see also* Ex. DER-6 at 50–52 (O'Connell Surrebuttal).

conditioned on Enbridge applying a neutral-footprint program to the proposed Project's energy usage, assuming Enbridge's efficiency's claims are accurate, any increased energy usage by a 34-inch pipeline would be from renewable resources, which would limit the impact to the natural environment.[350]

II. MINN. R. 7853.0130 B: WHETHER A MORE REASONABLE AND PRUDENT ALTERNATIVE TO THE PROPOSED PROJECT HAS BEEN DEMONSTRATED BY A PARTY OTHER THAN THE APPLICANT

Under Minn. R. 7853.0130 B, even if an applicant has demonstrated need for a project, other parties have an opportunity to demonstrate the existence of a more reasonable and prudent alternative. Specifically, in addition to criteria A, C-D, Minn. R. 7853.0130 B provides that a CN shall be granted if the Commission determines that:[351]

> B. a more reasonable and prudent alternative to the proposed facility *has not* been demonstrated by a preponderance of the evidence on the record by parties or persons other than the applicant, considering:
>
> (1) the appropriateness of the size, the type, and the timing of the proposed facility compared to those of reasonable alternatives;
>
> (2) the cost of the proposed facility and the cost of energy to be supplied by the proposed facility compared to the costs of reasonable alternatives and the cost of energy that would be supplied by reasonable alternatives;
>
> (3) the effect of the proposed facility upon the natural and socioeconomic environments compared to the effects of reasonable alternatives; and
>
> (4) the expected reliability of the proposed facility compared to the expected reliability of reasonable alternatives . . . .[352]

[350] Ex. DER-1 at 85, 115 (O'Connell Direct).
[351] Minn. R. 7853.0130 B.
[352] Minn. R. 7853.0130 B (emphasis added).

In this matter, among alternatives that parties might propose, the Commission directed that System Alternative SA-04 (SA-04) also be examined under the need criteria.[353]

A. Analysis of Alternatives to the Proposed Project

DOC DER witness Ms. O'Connell analyzed alternatives offered by the Applicant consistent with Minn. R. 7853.0540, together with system alternative SA-04 and additional pipeline systems.

1. The No-Action Alternative

The no-action alternative means that the proposed Project would not be constructed.[354] Enbridge evaluated the no-action alternative in the CN Application and determined that the proposed Project "is the best option."[355] Under this alternative, Enbridge would choose to continue operating the existing Line 3 if a CN is denied.[356]

Overall, DOC DER concludes that Enbridge has not satisfied the criteria under Minn. R. 7853.0130 A.[357] Enbridge could continue to operate the existing Line 3 under certain conditions and Enbridge has not committed to ceasing operations of the existing Line 3.[358] Enbridge's crude oil supply and demand forecasts were not shown to be realistic, and overall, Enbridge did

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[353] *In re Application of Enbridge Energy, Ltd. P'ship for a Certificate of Need for the Line 3 Replacement Project in Minn. from the N.D. Border to the Wisc. Border*, Docket No. PL-9/CN-14-916, Order Denying Motions, Approving Scoping Decision as Modified, and Requiring Expanded Notice at 10–12 (MPUC Nov. 30, 2016) (hereinafter "November 30, 2016 Order").
[354] Ex. DER-1 at 33 (O'Connell Direct).
[355] Ex. EN-1 at 10-3–10-12 (CN Application)
[356] *Id.*; *see also* Ex. EN-24 at 10 (Eberth Direct) ("If the Project is not approved, Enbridge will continue to operate Line 3 in a safe and reliable manner . . . ."); *see also* Ex. EN-30 at 5 (Eberth Rebuttal) ("Under the "no action" alternative, Enbridge would continue to operate existing Line 3, addressing ongoing integrity issues with increasing dig and repair activities.").
[357] *Id.* at Ex. DER-1 at 35 (O'Connell Direct); Ex. DER-6 at 71–74 (O'Connell Surrebuttal).
[358] *Id.* at 7–17, 35; *see also* Ex. EN-24 at 10 (Eberth Direct); Ex. EN-30, Sched. 1 at 25–27 (Eberth Rebuttal).

not demonstrate economic need for the proposed Project. Enbridge's analysis of the no-action alternative does not accurately state the effect of denial of the certificate of need on Minnesota's refineries, given Dr. Fagan's analysis primarily of Mr. Earnest's testimony and Ms. O'Connell's analysis pursuant to Minn. R. 7853.0130 C.[359] Below, DOC DER also discusses how little the proposed Project would likely address overall state energy needs.

Despite this conclusion, DOC DER testified regarding possible alternatives if the Commission determines that a need for crude oil capacity exists in this proceeding.

2. The Truck Alternative

DOC DER evaluated the truck alternative to the proposed Project (no new Line 3) largely based upon information provided in the FEIS.[360] That is, DOC DER evaluated whether it would be reasonable for trucks to transport a demonstrated need for additional crude oil capacity rather than the proposed Project. DOC DER concluded that a truck alternative would not present a reasonable alternative.[361]

The FEIS highlighted the following facts regarding a truck alternative:

- This alternative would require:
  - 1,920 loaded tanker trucks per day to ship crude oil from Gretna to Clearbrook;
  - 2,080 loaded trucks per day to ship crude from Gretna to Superior;
  - a total of 4,000 tanker trucks per day to travel from Gretna to Clearbrook and Superior, for a total of 12,200 new tanker trucks;
  - qualified drivers and support personnel to operate and maintain the trucks;

[359] *See* Ex. DER-1 at 34 (O'Connell Direct).
[360] *Id.* at 35–36.
[361] *Id.* at 38.

  - new loading facilities;
  - new or upgraded access to highways;
  - permanent conversion of agricultural land and some wetlands to industrial use for loading/off-loading;
  - truck off-loading facilities would be needed at Clearbrook and Superior.
- This alternative would result in more wear and tear on roads and more congestion in some areas; and
- The capital cost for new trucks is estimated at $2.4 billion every five years, compared to a one-time $7.5 billion capital cost of the proposed Project. Operational costs and labor would add to these costs.

A trucking alternative would also pose impacts to the natural and socio-economic environments. The FEIS indicated that trucks "are more likely than pipelines to have small to medium accidents and spills. . . . because the number of transits required to transport crude oil is large, which increases the risk of human error."[362] In addition, there would be higher vehicle emissions associated with the operation of the trucks on a daily basis.[363] In fact, the FEIS estimated that a Truck alternative would have the highest greenhouse gas emissions of any of the evaluated alternatives, including the proposed project.[364]

Regarding socio-economic effects, while a truck alternative would provide more trucking jobs (at least 12,200 assuming one driver for each truck), this alternative would also place a large

[362] Ex. EERA-29 at ES-14 (FEIS).
[363] *Id*. at ES-21.
[364] *Id.* (*see* Table ES-3).

number of trucks on public roads.[365] This increase would likely result in disruptions to local traffic, potential safety concerns during adverse weather, and higher road maintenance costs, which likely would be borne by local, county, and state agencies.[366]

Therefore, considering the ongoing capital, operation and maintenance costs for trucks, labor costs, and other costs, the economic costs for a truck alternative are significantly higher than the proposed Project.[367] DOC DER concluded that if a need for crude oil capacity is demonstrated, a trucking alternative would not be a reasonable alternative to meet that need.[368]

3. The Rail Alternative

e. Like Trucks, Rail Would Also Not Be a Reasonable Alternative to the Proposed Project.

Like the truck alternative, DOC DER similarly concluded that the rail alternative would not be reasonable should the Commission find a demonstrated need for additional crude oil capacity.[369] While a rail alternative may be somewhat more favorable than a trucking alternative, rail transportation suffers from many of the problems associated with moving oil by truck, including: a greater risk of accidents, higher probability of spills compared to a pipeline, potentially higher costs, and potential interference with shipping other products by rail.[370] Enbridge stated the following regarding a rail alternative:

> Because of the location of rail infrastructure and crude oil receipt and delivery points, much of the crude oil that would have been transported by the Project will nonetheless continue to travel to and across Minnesota. Utilizing rail would have significantly greater

[365] Ex. DER-1 at 38 (O'Connell Direct).
[366] *Id.*
[367] *Id.*
[368] *Id.*
[369] *Id.* at 42.
[370] *Id.*

> socioeconomic and environmental impacts compared to the Project.
>
> The 760 kbpd to be transported by the Project would be 17 percent of total rail tonnage in Minnesota. Estimated Project volume is 44 million tons per year; Minnesota total tonnage for 2012 is 253 million. Thus, it is uncertain that rail could actually deliver the entire capacity of the Project. In any event, sufficient rail tanker capacity does not currently exist to transport 760 kbpd. Transporting 760 kbpd via rail would require the construction by third parties of rail car loading and off-loading facilities. In addition, construction of new lateral above-ground rail service lines would be required. The increased traffic on current lines, as well as new rail lines, would pose additional risk and impact to landowners and the public.[371]

Enbridge's estimated costs of rail alternatives to pipelines are likely high.[372] Nonetheless, it would not be surprising if the cost of a rail alternative were higher than moving crude oil by pipelines.[373]

The FEIS also analyzed a rail alternative assuming, as with the trucking alternative above, that 360,000 bpd would be shipped to Clearbrook and that 400,000 bpd would be shipped to Superior, Wisconsin, for a total amount of 760,000 bpd.[374] This analysis assumed that at least 10 trains per day, with 110 specialized tank cars, would be needed to ship 760,000 bpd, with 5 trains delivering oil to Clearbrook and 5 to Superior.[375] This analysis also assumed that the

[371] Ex. EN-1 at 10–12 (CN Application).
[372] Ex. DER-1 at 40 (O'Connell Direct).
[373] *Id.* Further, it would not be reasonable to dismiss a rail alternative due to a potential need for an increase in labor, since that is often highlighted as a benefit, and due to timing since it is unclear in the record exactly when the proposed Project would be built. *Id.*
[374] Ex. EERA-29 at 4-9 (FEIS).
[375] *Id.*

existing rail lines would primarily be used.[376] The FEIS estimated that 7,200 new tank cars would be needed and that the capitalized cost would be $1 billion ($140,000 per car).[377]

Like trucks, a rail alternative would also similarly impact the natural and socio-economic environments.[378] It is also likely to have small to medium size accidents and spills.[379] And, while there would likely be an increase in employment to build and operate rail facilities, there would also be an increase in railroad congestion and accidents.[380] In addition to affecting general traffic, more frequent rail trains can interfere with emergency vehicles.[381] Moreover, it is unclear from the record whether BNSF and the Canadian Pacific railroads would have available capacity to handle such traffic, at least at present.[382]

Therefore, DOC DER concluded that if a need for crude oil capacity is demonstrated, a rail alternative would not be a reasonable alternative.[383] It would, though, be preferable to a trucking alternative.[384]

4. System Alternative SA-04 (SA-04)

a. SA-04 Could Satisfy the Need of Minnesota's Neighboring States.

A system alternative is defined as a pipeline proposal that has a different origin, destination, or intermediate point of delivery than the Applicant's proposed route.[385] One system

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[376] *Id.*
[377] *Id.* at 4-11–4-13. This estimate does not include that cost of constructing new rail spurs or other rail infrastructure, operation and maintenance costs, labor costs or costs of train terminal facilities to load and off-load.
[378] Ex. DER-1 at 41 (O'Connell Direct).
[379] *Id.*
[380] *Id.*
[381] *Id.*
[382] *Id.*
[383] Ex. DER-1 at 42 (O'Connell Direct).
[384] *Id.*

alternative, SA-04, is a conceptual alternative for pipeline service directly to the Chicago market.[386] The following map depicts SA-04 along the magenta line.[387]

The Commission ordered SA-04 to be evaluated during the CN contested case proceeding.[388] DOC DER witness Ms. O'Connell evaluated the reasonableness of SA-04 as a system alternative, which was presented in the FEIS.[389]

(Footnote Continued from Previous Page)
[385] November 30, 2016 Order at 10.
[386] Ex. DER-1 at 42 (O'Connell Direct).
[387] Ex. EERA-29 at 4-4 (FEIS).
[388] *See* November 30, 2016 Order at 14.
[389] Ex. DER-1 at 42–54 (O'Connell Direct); Ex. EERA-29 at 4-8 (FEIS).

DOC DER testified that SA-04 is a pipeline alternative of the same size and specification as the proposed Project (36-inch assuming an annual average capacity of 760,000 bpd), but would not interconnect at either Clearbrook or Superior.[390] Instead, SA-04 would deliver crude oil directly to the Chicago market.[391] SA-04 would follow the existing Enbridge Mainline System right-of-way from Alberta to the vicinity of Neche, North Dakota, where it would then intersect with the Alliance Pipeline right-of-way.[392] SA-04 would then follow the Alliance Pipeline right-of-way south through North Dakota and in a southeasterly direction, enter Minnesota in Big Stone County and would then exit the state in Freeborn County.[393] It would then continue along this right-of-way through Iowa and Illinois before terminating in Joliet, Illinois.[394] SA-04 would be expected to have similar economic impacts as the proposed Project in Minnesota.[395]

While SA-04 does not interconnect with the MPL at Clearbrook, it could still satisfy any demonstrated need for additional crude oil capacity as a system alternative for Minnesota's neighboring states.[396] SA-04 could serve the Chicago refinery market along with other markets in Minnesota's region and would be part of the integrated system of crude oil pipeline facilities in the United States.[397] While SA-04, as modified and discussed below, would not meet the Project Scope identified in the Issues Resolution Statement (IRS) between Enbridge and the

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[390] Ex. DER-1 at 43 (O'Connell Direct).
[391] *Id.*
[392] *Id.*
[393] *Id.*
[394] *Id.*
[395] *Id.* at 45.
[396] Ex. DER-1 at 43 (O'Connell Direct).; *see also* Minn. R. 7853.0130 A ("Minnesota and neighboring states").
[397] Ex. DER-1 at 43 (O'Connell Direct).

Representative Shipper Group, it would flow through Gretna and provide service to Flanagan, Illinois.[398]

Although Enbridge stated that SA-04 is not a reasonable alternative to the proposed Project because it does not have direct connections to existing Enbridge pipeline facilities and would require construction of significant storage and off-loading facilities, these claims were not shown to be credible.[399] While Enbridge does not have facilities in Joliet, Illinois, Enbridge has existing facilities and interconnections at Hartsdale/Griffith (located in the Chicago area along the Illinois/Indiana border) and also Flanagan, Illinois (located approximately 60 miles southwest of Chicago).[400] From these facilities, Enbridge would be able to serve the Chicago refinery market and all other refinery markets that it is currently able to serve, except the Twin Cities and Superior.[401] Development of this pipeline would provide a different way for crude oil supplies to move to Chicago, and would provide more geographical diversity for Enbridge's system.[402]

b. Enbridge Misrepresented the Crude Oil Market Analysis for SA-04.

DOC DER requested that Enbridge provide a cost analysis and a crude oil market analysis for a modified SA-04 that serves Flanagan and Hartsdale/Griffith, Illinois.[403] Enbridge provided these analyses, which are included in the record.[404] Enbridge's crude oil market analysis for SA-04 does not appear to be accurate.[405]

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[398] Ex. EN-1, App. D (CN Application).
[399] Ex. DER-1 at 45 (O'Connell Direct).
[400] *Id.* at 46.
[401] *Id.*
[402] *Id.*
[403] *Id.*
[404] *Id.*, KO-7, KO-8.

DOC DER identified issues with Enbridge's throughput graphs and apportionment estimates.[406] First, as to Enbridge's throughput graphs, the axis for "Enbridge Clearbrook to Superior Heavy Crude Oil" was modified to begin at 1,100 kbpd and not zero, as presented in the initial Muse Report and in several other market analyses.[407] Second, regarding the apportionment estimates in the charts, Enbridge used an incorrect capacity figure, which seems to suggest that Enbridge undersized SA-04 relative to shipper demand, creating greater estimates of apportionment in its analysis.[408] By changing the scale, Enbridge makes potential delivery shortfalls and system inefficiencies look worse than they would otherwise appear.[409] Charts 3 and 4 below compare the results of using a graph with a scale starting at 1,100 kb/d (as Enbridge used) to a scale that starts at 0 kb/d.[410]

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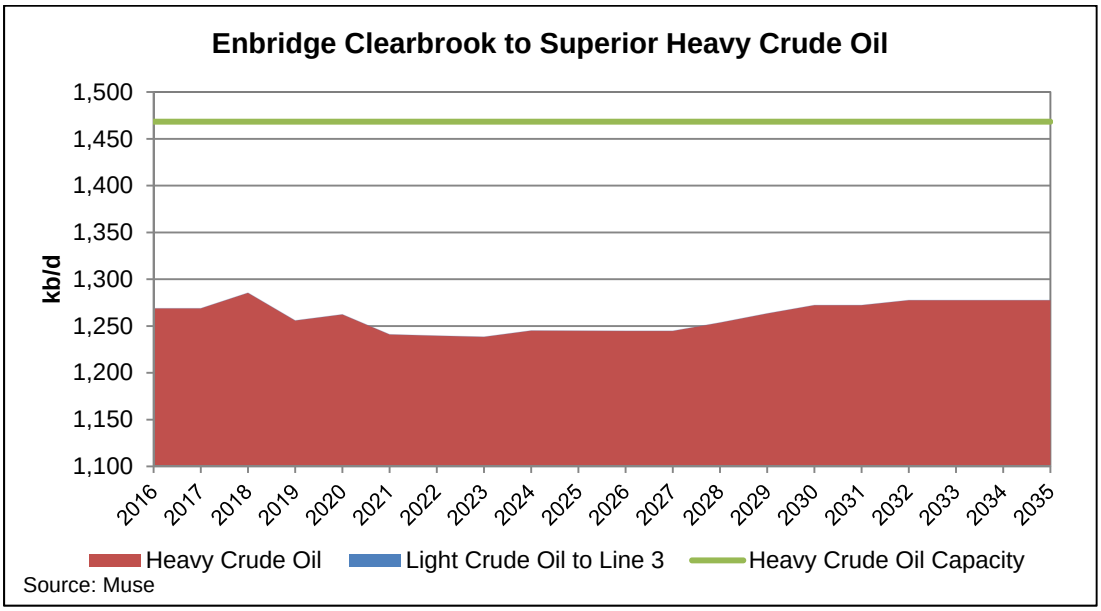
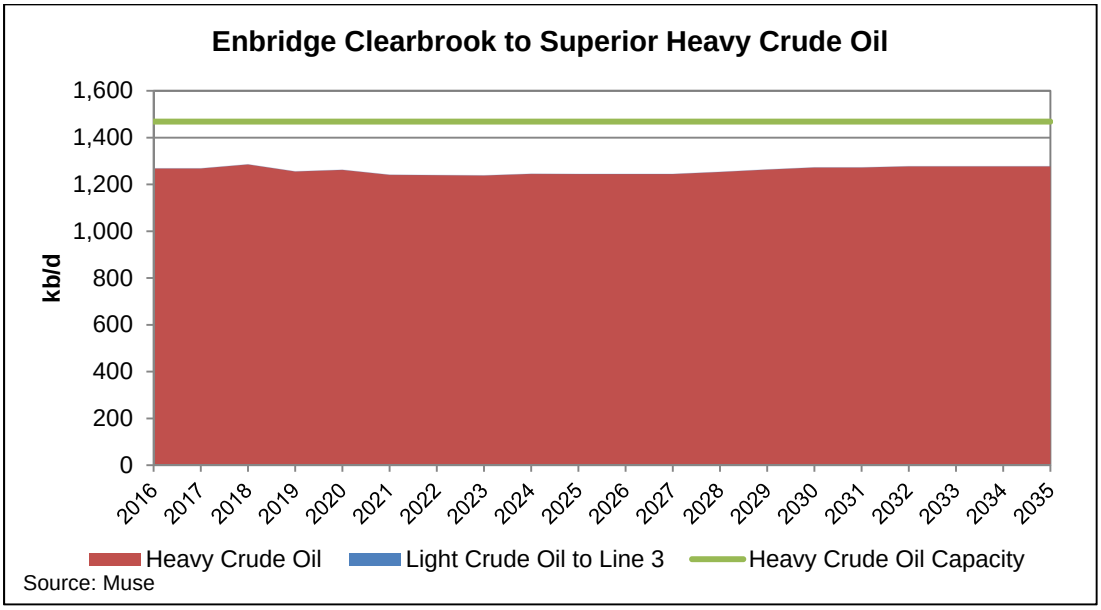
[406] *Id.*, KO-7 (Information Request No. 235).
[407] *Compare id.*, KO-7 at 6 *with* Ex. EN-15, Sched. 2 (Earnest Direct).
[408] *Id.*
[409] *Id.* at 47.
[410] *Id.* at 48–49.

O'Connell Direct Chart 3: Enbridge Representation of Enbridge Mainline System Use Under SA-04



By correcting the scale to start at 0, the chart should appear as follows:

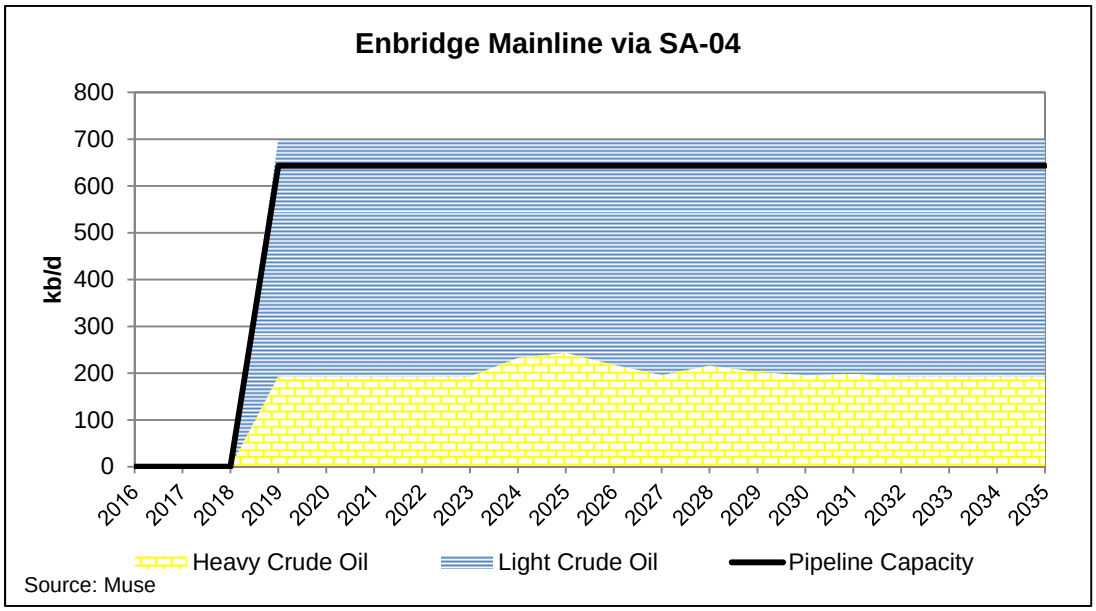
O'Connell Direct Chart 4: DOC DER Representation of Enbridge Mainline System Use Under SA-04



Although heavy oil use on the Enbridge Mainline System is below system capacity when considering SA-04 instead of the proposed Project, this differential appears to be less significant when the graph is presented correctly.[411] Further, apportionment does not appear to be as significant as indicated in Enbridge's response.[412]

In addition, Enbridge's analysis of the capacity of SA-04 was not correct.[413] Similar to the graph scaling issue above, Enbridge's graphical representation of SA-04 appeared to be inconsistent with assumptions for the proposed Project, namely 760,000 bpd in average capacity, as shown below.

O'Connell Direct Chart 5: Enbridge Initial Representation of Capacity of SA-04

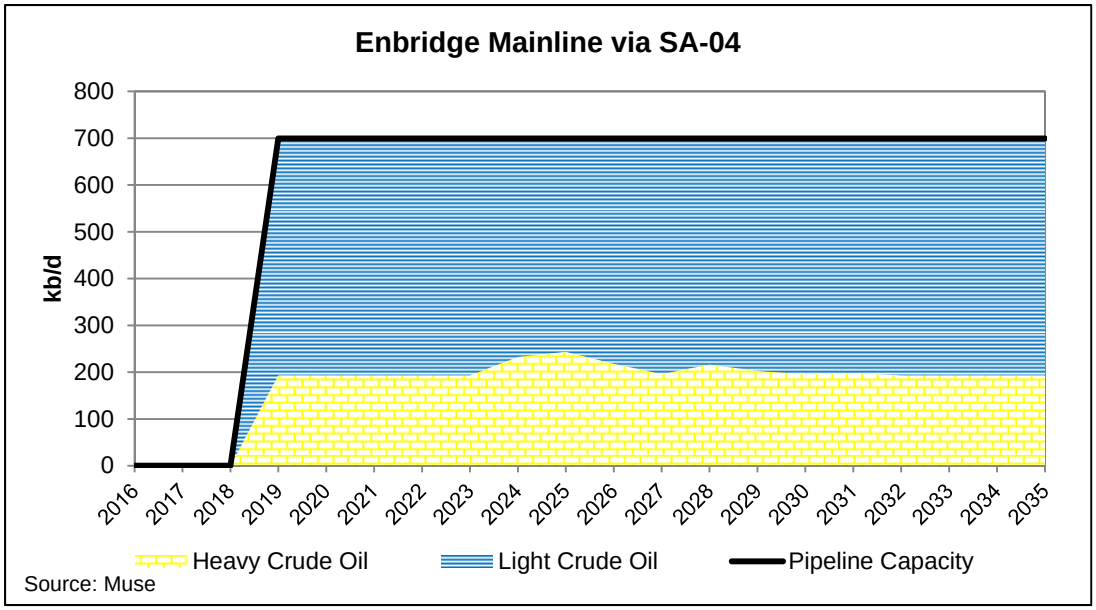


As can be seen, Enbridge understated capacity for SA-04 at 640,000 bpd even though its model calculated an effective demand of approximately 700,000 bpd.[414] Enbridge's inaccurate

[411] *Id.* at 49.
[412] *Id.*
[413] Ex. DER-1 at 49 (O'Connell Direct).
[414] *See* Ex. DER-1, KO-7 (O'Connell Direct).

graphical representation, however, based on incorrect input data, does not impact other conclusions in its response to DOC DER Information Request No. 235. Chart 6, below, shows the correct graphical representation using correct data.

O'Connell Direct Chart 6: Corrected SA-04 Capacity



These results suggest under-use of capacity to move light crude between Gretna, MB and Clearbrook, MN and under-use of heavy oil capacity between Clearbrook and Superior.[415] Enbridge's analysis indicates that Enbridge Mainline System usage during the forecast period, assuming construction of SA-04, would be between 172,600 bpd and 211,800 bpd less than the effective capacity (2.757 million bpd) with Enbridge's proposed Project.[416] These throughput figures are still greater than the current effective capacity on the Enbridge Mainline of 2.417 million bpd.[417]

[415] *Id.* at 51, KO-7, KO-8.
[416] *Id.*
[417] Ex. EN-15, Sched. 2 at 63 (Earnest Direct).

c. SA-04 Would Likely Impose Additional Costs for Shippers Compared to the Proposed Project.

SA-04 would likely impose additional costs for shippers compared to shipping crude oil through an Enbridge Mainline System with a new Line 3.[418] Enbridge testified that SA-04 would have increased capital expenditures, relative to the proposed Project, due to more piping, new terminal, and new downstream pipeline.[419] These additional costs are $3 billion in the United States, which would bring total costs in the United States to $5.5 billion.[420]

Further, Enbridge stated that SA-04, as modified to terminate at Griffith/Hartsdale, would cost an additional $0.47 per barrel relative to the proposed Project.[421] Enbridge also provided an estimate of the additional cost per barrel if SA-04 terminates at Flanagan, IL along with additional work to link Flanagan to Griffith/Hartsdale. In its response to Department Information Request No. 235, Enbridge estimated that this modification would increase the cost per barrel by $0.53.[422]

Finally, Enbridge stated that SA-04 would increase transportation costs for Minnesota refiners by $0.23 per barrel or approximately $28 million a year.[423] This cost increase may increase the prices of refined products.[424]

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[418] Ex. DER-1 at 52 (O'Connell Direct).
[419] Ex. EN-19 at 18 (Glanzer Direct); Ex. EN-14 at 11 (Fleeton Direct).
[420] *See id.*
[421] Ex. DER-1, KO-9 (O'Connell Direct).
[422] *Id.*, KO-7.
[423] *Id.*
[424] *See id.*

d. SA-04's Potential Impacts to the Natural and Socioeconomic Environments

i. Socioeconomic Benefits of SA-04 Would Generally Be Similar to Other Proposed Pipelines, Including the Proposed Project.

DOC DER concluded that the positive and negative benefits would be similar for the alternatives discussed above apart from the different construction costs, land use, and other factors associated with each individual alternative.[425] An in-depth comparative analysis of the socioeconomic costs and benefits of SA-04 and the various route alternatives can be found in the FEIS.[426] Because SA-04 and the route alternatives are pipelines, such alternatives could result in equivalent types of impacts to the rural and outstate economy based on an analysis similar to that conducted by Enbridge witness Dr. Lichty.[427] The locations of the local effects and amounts are likely to be somewhat different, however.[428] The positive and negative socioeconomic benefits would generally be the same for the system alternative apart from the different construction costs, land use, and other factors associated with each individual alternative.[429]

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[425] Ex. DER-1 at 71 (O'Connell Direct).
[426] *See generally* Ex. EERA-29 at ch. 5 (FEIS) (assessing potential construction and operation impacts of the proposed Project and alternatives).
[427] Ex. DER-1 at 70–71 (O'Connell Direct); *see also* Ex. EERA-29 at 5-470 (FEIS) ("The states and counties crossed by the Applicant's proposed project and CN alternatives contribute to regional and statewide economies through the production of a variety of goods and services.").
[428] *Id.* at 71.
[429] *Id.*

ii. The Problem of Karst Topography: SA-04's Present Route Poses Potential Serious Natural Environmental Impacts.

As the FEIS notes, SA-04 is the only alternative to the proposed Project that crosses karst topography.[430] The FEIS describes karst topography in the following way:

> A karst aquifer is a type of bedrock aquifer that usually consists of basic rock types that are prone to chemical weathering and dissolution from the slight acidity of precipitation and groundwater. This can result in the formation of fractures, joints, sinkholes, cavities, caves, and void spaces that allow the movement of large volumes of surface water into and through the aquifer. These characteristics also allow contamination to spread rapidly within the aquifer. Karst aquifers are susceptible to collapse of the aquifer matrix, which can be triggered by construction activities on the land surface. This can lead to the formation of sinkholes in unconsolidated sediments that overlie the bedrock.[431]

DOC DER testified that concerns about routing a crude oil pipeline through karst topography should be further addressed.[432] So, too, has the Commission, by order dated December 14, 2017, in which it ordered that DOC EERA supplement the FEIS by finding a different route for SA-04 that did not travel through karst topography.[433] As of the filing of this Initial Brief, that analysis has not been completed.

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[430] Ex. EERA-29 at ES-17 (FEIS).
[431] *Id.*
[432] Ex. DER-1 at 54 (O'Connell Direct).
[433] *In re Application of Enbridge Energy, Ltd. P'ship for a Certificate of Need for the Line 3 Replacement Project in Minn. From the N.D. Border to the Wisc. Border*, Docket No. PL-9/CN-14-916, Order Finding Environmental Impact Statement Inadequate at 3 (MPUC Dec. 14, 2017).

e. DOC DER Conclusions Regarding SA-04

The Commission may wish to consider SA-04 as an alternative to the proposed Project if a need is demonstrated for additional crude oil capacity in Minnesota and neighboring states.[434] DOC DER, however, attempted to analyze additional throughput data in order to determine whether SA-04 would be an adequate alternative to the proposed Project, but Enbridge did not provide sufficient data.[435] Since SA-04 deliveries would be made directly to the Chicago area, additional crude volumes could be available for shipment from Western Canada to the Midwest and the Gulf Coast because Enbridge has a tariff for shipment of oil on the Enbridge Mainline System to the Gulf Coast.[436] In addition, concerns regarding karst topography should be further addressed, and they will be, in the supplemented FEIS.[437]

5. The Keystone XL Pipeline Would Increase Pipeline Capacity for Western Canadian Crude.

DOC DER concluded that the Keystone XL pipeline could be a reasonable alternative to the proposed Project considering the factors under Minn. R. 7853.0130 B. The Keystone XL could increase export capacity of crude oil from Western Canada.[438] First, Keystone XL is a proposed pipeline project by TransCanada that would connect Hardisty, Alberta with existing facilities in Steel City, Nebraska via a direct route through Montana, South Dakota, and Nebraska.[439] From Steele City, Keystone XL would be able to deliver Canadian crude oil, via

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[434] *See* Ex. DER-1 at 54 (O'Connell Direct).
[435] *Id.* at 53.
[436] *See id.*
[437] *Id.*
[438] *See* Ex. DER-1 at 57 (O'Connell Direct).
[439] *Id.*

the existing Keystone system, to Wood River and Cushing.[440] Keystone XL is proposed to be 36 inches in diameter and ship up to 800,000 bpd on average, which is the same size pipe as the proposed Project.[441] Thus, it would increase pipeline capacity for Western Canadian crude oil shipments. In March 2017, the U.S. government issued a presidential permit allowing TransCanada to build the Keystone XL pipeline across the international border with Canada.[442] DOC DER understands that on November 20, 2017, the Nebraska Public Service Commission (PSC) approved an alternate route through Nebraska for the Keystone XL line and that TransCanada is still assessing the impact of this decision.[443]

Second, Keystone XL may be a lower cost or higher cost alternative, depending on shipper preferences.[444] Unlike the proposed Project, which is a common carrier pipeline, the Keystone XL pipeline is designed as a committed shipper pipeline that, if available, would also have uncommitted or open capacity.[445] In exchange for being a committed shipper, and signing a long-term contract to ship volumes on the pipeline, these shippers are given a lower transportation rate.[446] Thus, if the project is fully permitted, TransCanada would need to find

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[440] Ex. DER-1 at 54 (O'Connell Direct).
[441] *Id.* at 18, 54.
[442] *See id.* at 55.
[443] TransCanada, Keystone XL, http://www.keystone-xl.com/for-nebraska/approval-process-and-faqs/ (last visited Dec. 12, 2017). DOC DER notes that while this fact is now public knowledge, this fact was not included in any pre-filed testimony due to the timing of the NSC decision. DOC DER requests that the ALJ take administrative notice of the NSC's decision and TransCanada's apparent consideration of the impact of the decision.
[444] Ex. DER-1 at 54 (O'Connell Direct).
[445] *Id.* at 55.
[446] *Id.*

committed shippers to use the pipeline.[447] The following table highlights delivery costs per barrel to PADD 2 on the Enbridge Mainline System compared to the Keystone XL.

O'Connell Direct Table 1: PADD 2 Delivery Costs per barrel, Keystone XL—Heavy Oil[448]

Delivery Point	Enbridge Mainline (including Line 3 Surcharge)	Keystone XL Committed	Keystone XL Uncommitted
Chicago	$5.56	$4.88 to $5.84	$10.38 to $11.34
Patoka	$5.56	$4.89	$10.39
Detroit	$6.08	$5.94 to $6.44	$11.44 to $11.94
Wood River	$8.28	$4.43	$9.93

Third, regarding impact to the natural and socioeconomic environments, Keystone XL was originally proposed in 2008 and received its first regulatory approvals in 2010.[449] In 2012, however, the U.S. government rejected the original filing because of deficiencies in the environmental impact statement.[450] TransCanada submitted a revised environmental report in 2012 based on a revised route in Nebraska.[451] In November, 2015, DOC DER testified that the U.S. government initially rejected the revised petition.[452] In March, 2017, as indicated above, the U.S. government ultimately issued a Presidential Permit allowing TransCanada to build the Keystone XL pipeline into the U.S.[453]

[447] *Id.*
[448] *Id.* at 56.
[449] *Id.* at 54.
[450] Ex. DER-1 at 54 (O'Connell Direct).
[451] *Id.*
[452] *Id.* at 55.
[453] *Id.*

Finally, the Keystone XL may be a reliable way for shippers to transport Western Canadian crude oil. The Keystone XL would increase export capacity from Western Canada, in the same manner as the proposed Project.[454] While the Keystone XL project would not serve Minnesota refineries directly, to the extent that shippers would choose to use the Keystone XL pipeline instead of the Enbridge Mainline pipeline, this alternative may free up capacity on the Enbridge Mainline and decrease apportionment.[455]

6. The Energy East Pipeline Does Not Appear to be Capable of Being an Alternative to the Proposed Project.

DOC DER initially evaluated the reasonableness of TransCanada's proposed Energy East pipeline in its direct testimony.[456] Because TransCanada has apparently abandoned its proposal for this pipeline, it no longer appears to be capable of being a reasonable alternative to the proposed project.[457]

7. A New Spectra Pipeline Could Potentially Bring Additional Western Canadian Crude Oil to U.S. Refineries.

On February 27, 2017, Enbridge purchased Spectra Energy, including the Express and Platte crude oil pipelines (Spectra System), which makes these pipelines part of the greater Enbridge system.[458] Similar to the proposed Project, the Spectra pipeline alternative (Spectra) would involve construction of a new 36-inch pipeline, with a proposal to operate at 760,000 bpd of average capacity.[459] Alternatively, a smaller 370,000 bpd pipeline could be built.[460] Spectra

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[454] *Id.* at 57.
[455] Ex. DER-1 at 57 (O'Connell Direct).
[456] *Id.* at 57–59.
[457] Ex. EN-39 at 6 (Fleeton Rebuttal).
[458] Ex. DER-1 at 60 (O'Connell Direct).
[459] *Id.* at 59–60.
[460] *Id.* at 64.

would be located along the existing right-of-way for the Spectra Energy crude oil pipeline system.[461] The Spectra Energy pipeline system is made up of the Express and Platte crude oil pipelines.[462] The Express Pipeline originates in Alberta and travels southerly to Guernsey, Wyoming.[463] The Platte Pipeline originates in Guernsey, Wyoming and travels in an easterly direction to refineries in Wood River, Illinois.[464] While Spectra would not pass through Minnesota, it would reach the Illinois market and interconnect with other Enbridge pipelines.[465] While the Spectra alternative would deliver crude from Western Canada to Wood River, Illinois, similar to other pipelines, and to the extent that capacity is available, this pipeline would provide another option for shippers to use to ship products to PADD 2 and the Gulf Coast.[466] The following map shows the Spectra Energy and Enbridge pipeline systems.

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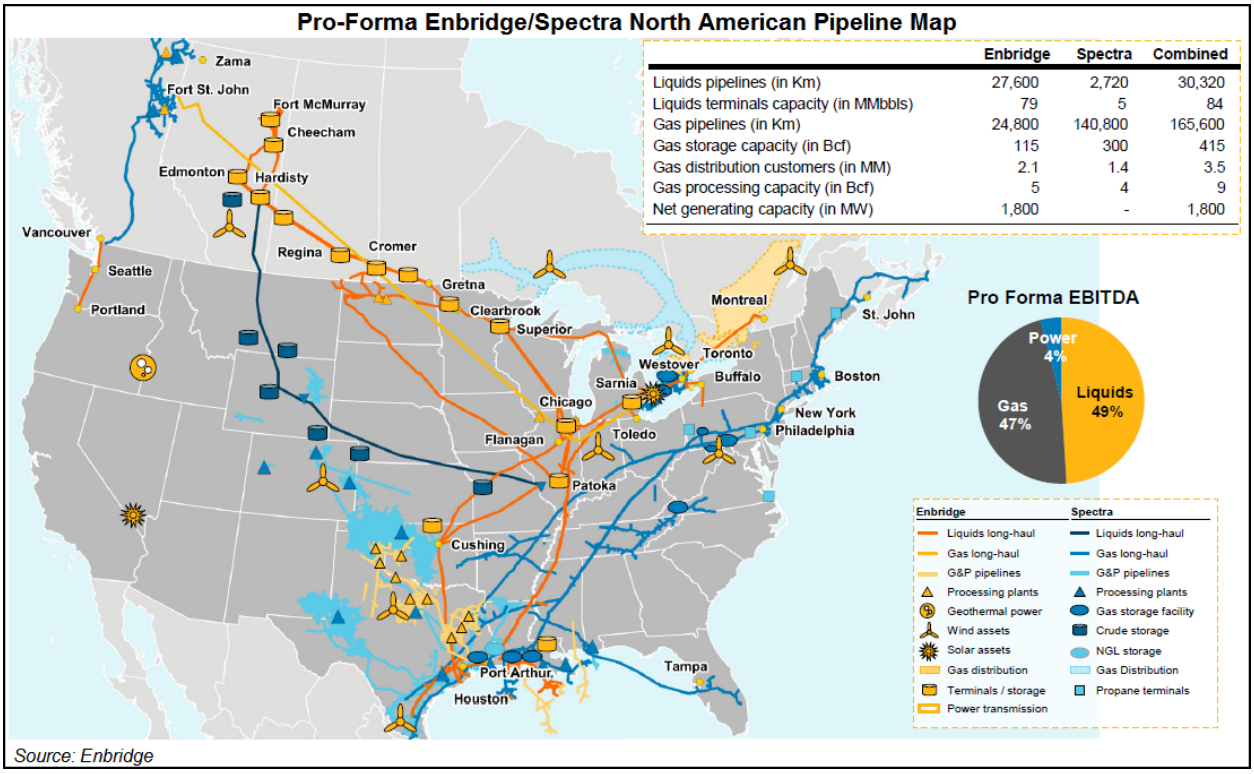
[461] *Id.*
[462] *Id.*
[463] *Id.*
[464] Ex. DER-1 at 64 (O'Connell Direct).
[465] *Id.*
[466] *Id.* at 63–64.

O'Connell Direct Map 1: Enbridge/Spectra North American Pipeline Map



	Enbridge	Spectra	Combined
Liquids pipelines (in Km)	27,600	2,720	30,320
Liquids terminals capacity (in MMbbls)	79	5	84
Gas pipelines (in Km)	24,800	140,800	165,600
Gas storage capacity (in Bcf)	115	300	415
Gas distribution customers (in MM)	2.1	1.4	3.5
Gas processing capacity (in Bcf)	5	4	9
Net generating capacity (in MW)	1,800	-	1,800

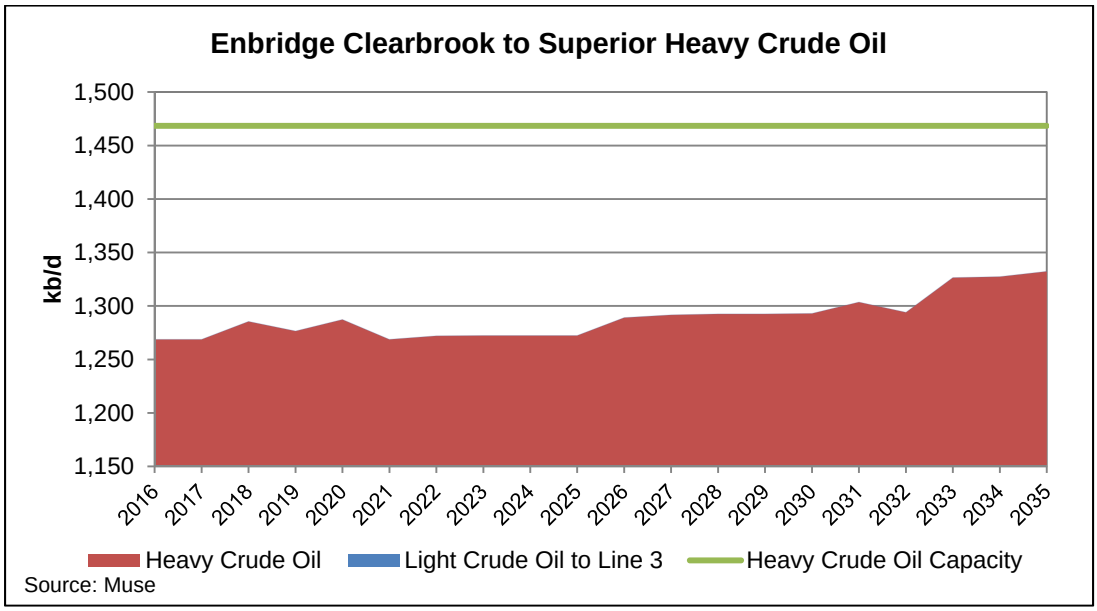
In addition, the Spectra System provides Enbridge with a secondary right-of-way out of Western Canada to the Midwest.[467] Enbridge will also have the ability to interconnect Spectra with Flanagan South, which would allow Enbridge to access Cushing, OK and Gulf Coast refiners without going through Chicago.[468]

DOC DER testified that Enbridge's reasons for dismissing Spectra as a reasonable alternative to the proposed Project were not credible.[469] First, Enbridge had conducted a crude oil market analysis for a new Spectra line, but again, like Enbridge's oil market analysis of SA-04, it had skewed its charts to misrepresent utilization of the Enbridge Mainline System with a

[467] *Id.*
[468] *Id.*, KO-13.
[469] *Id.* at 61–68.

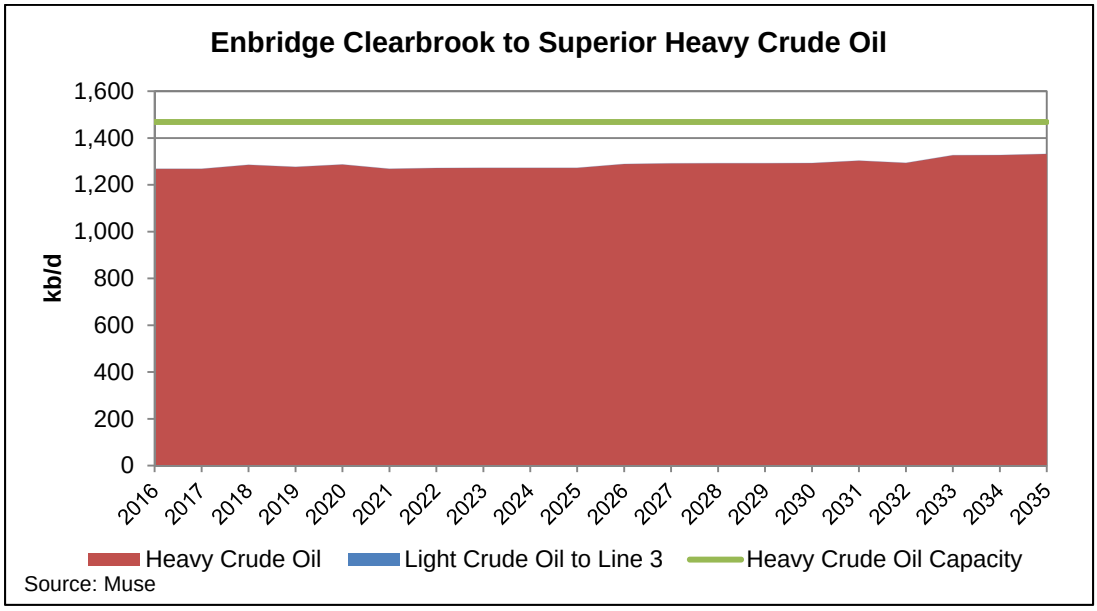
Spectra alternative in operation.[470] In much the same way as the SA-04 alternative, changing the scale of the graph makes potential delivery shortfalls and system inefficiencies look worse than they actually are, as indicated by the graphs below:

O'Connell Direct Chart 7: Enbridge Representation of Mainline Use under Spectra



[470] *Id.* at 64–66.

O'Connell Direct Chart 8: DOC DER Representation of Mainline Use under Spectra



As can be seen, while the Enbridge Mainline System may not be fully used, it does not appear as problematic when the graph is presented correctly.[471] But, issues with these graphs aside, Enbridge's analysis suggests that the Spectra System alternative may be under-used, across the entire forecasting period, relative to the effective demand of 700,000 bpd, for the 760,000 bpd option.[472] Enbridge's analysis for the 370,000 bpd option, on the other hand, assumes that it would be fully used during the forecasting period.[473] Enbridge's analysis, for both options, also suggests an under-use of the current Enbridge Mainline to ship light crude oil capacity from Gretna to Clearbrook and heavy crude oil capacity between Clearbrook and Superior.[474]

[471] Ex. DER-1 at 65–66 (O'Connell Direct).
[472] *Id.* at 66.
[473] *Id.*
[474] *Id.*

As for costs to construct the Spectra alternative and costs to shippers, Enbridge also provided these numbers.[475] Construction costs for a 760,000 bpd pipeline were estimated to be $11.72 billion ($2.24 per barrel), which is about $4.22 billion greater than the original project costs for the proposed Line 3.[476] Estimated project costs for a 370,000 bpd pipeline were estimated to be about $9.244 billion ($3.25 per barrel), which is approximately $1.744 billion greater than the original project costs for the proposed Project.[477] As for shipping costs, Enbridge estimated that a 760,000 bpd line would result in incremental transportation costs for Minnesota refiners of approximately $42 million per year, or $0.34 per barrel, and total Enbridge system throughput of approximately 2.45 million bpd throughout the forecasting period.[478] Enbridge estimated that a 370,000 bpd line (with the existing Line 3 continuing to operate) would result in incremental transportation costs for Minnesota refiners of approximately $35 million per year, or $0.28 per barrel, and total Enbridge system throughput of approximately 2.58 million bpd throughout the forecasting period.[479]

Enbridge also expressed a concern that a Spectra alternative is untimely.[480] Minnesota permits consideration of alternatives under the CN criteria before the close of public hearings and for which substantial evidence is present in the record to consider such an alternative.[481] This alternative has clearly been raised in the record prior to public hearings closing and the

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[475] *Id.* at 64, 67, KO-12.
[476] *Id.* at 64.
[477] Ex. DER-1 at 64 (O'Connell Direct).
[478] *Id.* at 67.
[479] *Id.*
[480] *Id.* at 62.
[481] Minn. R. 7853.0120 (2015).

DOC DER has sought to develop the record regarding prospective alternatives to the proposed Project as part of its evaluation of Enbridge's proposal under the applicable CN criteria.

Enbridge is also concerned that it would need to renegotiate shipping terms with shippers in its Issue Resolution Sheet (IRS) that it presently has with shippers for the proposed Project.[482] The IRS does not determine either whether there is a need for a new facility or where the facility would be located if there were such a need.[483] While terms of the IRS may require more negotiation by Enbridge and its shippers for a Spectra alternative compared to the proposed Project, that fact alone does not indicate that a pipeline alternative should be rejected.[484]

Regarding Enbridge's fourth concern that a Spectra alternative would be under-utilized because only refiners located in Wood River, Illinois would have access to Spectra does not appear to be accurate.[485] A pipeline connection exists between Wood River and Patoka via the Wood River-to-Patoka (Woodpat) Pipeline.[486] From Patoka, additional pipelines exist that can, if capacity is available, serve refiners in Chicago and the eastern portions of PADD 2, or the Gulf Coast through the Seaway pipeline.[487] In addition, on August 1, 2017, Marathon Pipeline, LLC issued a binding open season for a potential upgrade of the Woodpat Pipeline to 345,000 bpd.[488] Thus, it appears that more than Wood River shippers could use a Spectra pipeline. This

[482] Ex. DER-1 at 62–63 (O'Connell Direct).
[483] *Id.*
[484] *Id.*
[485] *Id.* at 63.
[486] *Id.*
[487] *Id.*
[488] Ex. DER-1, KO-14 (O'Connell Direct).

information is important because it would not only allow shippers access to PADD 2, but also would allow access to the Gulf Coast.[489]

Finally, as with SA-04, Enbridge failed to provide sufficient throughput data, when asked to do so by DOC DER, to adequately determine if Spectra would be a reasonable alternative.[490] Adequate data is not available to analyze the throughput that Enbridge ships on the Flanagan South and Spearhead pipelines.[491] Thus, it remains unclear whether sufficient capacity exists on these two pipelines to make a Spectra alternative viable.[492]

B. Conclusions Regarding Alternatives to the Proposed Project

While parties other than Enbridge have the burden of demonstrating the existence of a more reasonable and prudent alternative to the proposed Project, DOC DER's analysis indicates that Enbridge has not satisfied the criteria under Minn. R. 7853.0130 A.[493] First, the record shows that Enbridge could continue to operate the existing Line 3 if properly maintained, which is essentially the no-action alternative.[494]

Second, if there were the level of need asserted by Enbridge, DOC DER concluded that the truck and rail alternatives would not be reasonable compared to the proposed Project.[495]

Finally, if the Commission determines that a need exists, DOC DER concluded that the pipeline alternatives of Keystone XL or Spectra pipelines could reasonably meet a need for increased pipeline capacity for Western Canadian crude oil.

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[489] *See id.* at 67.
[490] *Id.* at 68.
[491] *Id.*
[492] *Id.*
[493] Minn. R. 7853.0130 B (2015); Ex. DER-1 at 71 (O'Connell Direct).
[494] *See* Ex. EN-24 at 10 (Eberth Direct).
[495] *Id.*

III. MINN. R. 7853.0130 C: WHETHER THE CONSEQUENCES TO SOCIETY OF GRANTING THE CERTIFICATE OF NEED ARE MORE FAVORABLE THAN THE CONSEQUENCES OF DENYING THE CERTIFICATE

The proposed Project's impact to the natural and socioeconomic environments could be significant. These potential impacts outweigh the consequences to society of granting the CN. Minn. R. 7853.0130 C states that a CN shall be granted if it is determined that "the consequences to society of granting the certificate of need are more favorable than the consequences of denying the certificate, considering:"

> (1) the relationship of the proposed facility, or a suitable modification of it, to overall state energy needs;
>
> (2) the effect of the proposed facility, or a suitable modification of it, upon the natural and socioeconomic environments compared to the effect of not building the facility;
>
> (3) the effects of the proposed facility or a suitable modification of it, in inducing future development; and
>
> (4) socially beneficial uses of the output of the proposed facility, or a suitable modification of it, including its uses to protect or enhance environmental quality . . . .

A. Analysis of Rule Criteria

DOC DER witness Ms. O'Connell analyzed whether the evidence showed that the consequences to society of granting the CN are more favorable than the consequences of denying the CN.[496] Ms. O'Connell concluded that the consequences to society of granting the CN are not more favorable than the consequences of denying the CN, and thus, Enbridge has not demonstrated that the CN factors have been satisfied.

[496] Ex. DER-1 at 72–94 (O'Connell Direct).

1. Minn. R. 7853.0130 C(1): Relationship of the Proposed Facility to Overall State Energy Needs

The Enbridge Mainline System's interconnection at Clearbrook, Minnesota is the only aspect of the proposed Project that provides service to Minnesota refineries.[497] Once at Clearbrook, crude oil supplies are transported through the MPL to the refineries in the Twin Cities.[498] Thus, DOC DER's analysis here focuses solely on the usefulness of the existing Line 3 to assist in delivering light crude supplies to Minnesota refineries at Clearbrook because this criterion focuses on state energy needs.[499]

The following HSTS charts highlight crude oil deliveries to Flint Hills and St. Paul Park:[500]

[HIGHLY SENSITIVE TRADE SECRET DATA BEGINS

[497] *Id.* at 73.
[498] *Id.* O'Connell Direct Charts 9 and 10, above, which contain highly sensitive trade secret information, indicate the amounts of crude oil by type that are identified as being shipped to either the Flint Hills Pine Bend refinery or the St. Paul Park refinery. In addition, while a pipeline connection exists between the Flint Hills refinery and Wood River, Illinois via the Wood River Pipeline, this pipeline was removed from service in 2013 and DOC DER is not aware of any plans to restart this pipeline.
[499] *Id.*; *see also* Minn. R. 7853.0130 C(1) (2015).
[500] Ex. DER-3 at 74 (O'Connell Direct).

HIGHLY SENSITIVE TRADE SECRET DATA ENDS]

This information indicates that considered together, Minnesota refineries are largely shipping heavy crude oil. Taken separately, in recent years Flint Hills mainly shipped heavy crude **[HIGHLY SENSITIVE TRADE SECRET DATA BEGINS**

HIGHLY SENSITIVE TRADE SECRET DATA ENDS] on the Enbridge Mainline System.[501] As a result, if it were a stand-alone system, since the existing Line 3 is capable of predominately delivering primarily light crude, Line 3 currently can contribute **[HIGHLY SENSITIVE TRADE SECRET DATA BEGINS**

HIGHLY SENSITIVE TRADE SECRET DATA ENDS] does not primarily contribute to meeting Flint Hills' needs to ship heavy crude.[502]

It does not, however, appear that Minnesota refineries have been harmed by Enbridge's reduced capacity on the existing Line 3.[503] Given the observations above, it has not been demonstrated that the proposed Project would contribute to state energy needs in a meaningful way.[504] Although Ms. O'Connell did not testify on this point, DOC DER notes Dr. Fagan's assessment that:

> Minnesota district (Minnesota, North Dakota, South Dakota, and Wisconsin) refineries as a group have been operating at high levels of utilization, which indicates both they are not short of physical supplies of crude oil, and that they have little room to increase total crude runs.[505]

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[501] Ex. DER-3 at 75 (O'Connell Direct).
[502] *Id.*
[503] *Id.*
[504] *See id.*
[505] Ex. DER-4, MF-1 at 5 (Fagan Direct).

As a result, it appears that Enbridge's Mainline System as a whole has been meeting those needs adequately and reliably without the proposed Project, especially with the recently-approved capacity expansions of Line 67.[506] Given that the St. Paul Park refinery **[HIGHLY SENSITIVE TRADE SECRET DATA BEGINS HIGHLY SENSITIVE TRADE SECRET DATA ENDS]**, there is no evidence that the existing Line 3 is unable to meet the expected or expressed needs of the St. Paul Park refinery.[507] The Flint Hills Pine Bend refinery has acknowledged recent capacity increases to the MPL and Enbridge Mainline System, specifically the approved capacity increases on Line 67, including the Clearbrook terminal, and that these "significant upgrades, approved by the State of Minnesota . . . help maintain the reliability of crude oil deliveries to Minnesota's two refineries."[508] Second, this letter acknowledges that these upgrades "improved the reliability and efficiency of a significant portion of the crude oil infrastructure that is critical to Minnesota and much of the region's transportation fuel needs."[509] These observations are consistent with the analyses of Ms. O'Connell, including Dr. Fagan's testimony that refineries in the Minnesota region have been operating at or near capacity.[510]

Notably, regarding the proposed Project, it appears that Flint Hills primarily welcomes the efficiencies that the proposed Project could bring to the Enbridge Mainline System because the record shows that the Minnesota refineries are already generally receiving adequate and

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[506] *See* Ex. DER-1 at 75 (O'Connell Direct); *see also* Ex. DER-6 at 35 (O'Connell Surrebuttal); *see generally* Phase 2 Order.
[507] Ex. DER-3 at 76 (O'Connell Direct).
[508] *Id.*, KO-17.
[509] *Id.*
[510] *Id.* at 77.

reliable supplies of crude oil.[511] Flint Hills's letters are discussed in detail above. Flint Hills has noted generalized, and largely potential, future impacts of apportionment as to creating inefficiencies for refineries.[512] Flint Hills focus on efficiency is certainly reasonable under the CN criteria, but as DOC DER shows in this Initial Brief, the Commission must balance efficiency concerns with all of the CN criteria.

Thus, it appears that the proposed Project would have a minimal effect on overall state energy needs. If it has any positive effect, it may contribute to crude oil supply to the state being more efficient.

2. Minn. R. 7853.0130 C(2): Effect of the Proposed Project on the Natural and Socioeconomic Environment

a. Effects on the Natural Environment

The Proposed Project could significantly affect the natural environment.[513] In DOC DER's view, the primary concern with any crude oil pipeline is the risk of accidental release.[514] Indeed, the FEIS states that: "Although the probability of a large or major oil release at any specific location is extremely low, the probability of a release of some kind along the entire pipeline during its lifetime is not low."[515] In addition, the consequences of a large release can be significant. Further, the FEIS makes it clear that transportation of oil by pipeline carries a lower probability of release than by truck or rail, but that the potential volume of oil spilled in an

[511] *Id.*
[512] *Id.*, KO-17.
[513] Ex. DER-1 at 80–85 (O'Connell Direct); *see* Ex. EERA-29 at ch. 5, 10 (FEIS).
[514] Ex. DER-1 at 80 (O'Connell Direct).
[515] Ex. EERA-29 at 10-1 (FEIS).

individual incident, and thus the consequences of an individual spill, are much larger for pipeline than for truck or rail.[516]

Regarding the costs of an accidental release via pipeline, it can be large—over $1.2 billion in the case of the Enbridge Line 6B spill near Marshall, Michigan.[517] It remains to be seen whether the long-term impacts on land and water resources that would be impacted by a spill would be sufficiently remediated.[518]

The number of water crossings along Enbridge's preferred route and other route alternatives that would exacerbate the impact of an accidental release.[519] Based on DOC DER's review, such concerns appear to be higher on the Clearbrook-to-Superior segment than on the Neche-to-Clearbrook segment.[520] If a need is found in this proceeding, the Neche-to-Clearbrook segment would involve work entirely in an existing crude oil pipeline corridor.[521] The FEIS identified risks to forests and wildlife habitats from construction on an existing or new pipeline; but notes that these risks can be partially mitigated by use of best management practices during construction, by restoration, and by corridor sharing wherever possible.[522] However, in the Clearbrook-to-Superior segment, significant sections of the applicant's preferred route would use a corridor in which no crude oil pipeline currently exists, resulting in potentially new impacts to these and other resources, as discussed in the FEIS.[523]

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[516] *See id.* at 10-141–10-167.
[517] Ex. DER-1 at 81 (O'Connell Direct).
[518] *Id.*
[519] *Id.*
[520] *Id.*
[521] *Id.*
[522] *See generally* Ex. EERA-29 at ch. 5 (providing existing conditions, impacts, and mitigation for the proposed project and certain alternatives).
[523] *Id.*

Enbridge's leak-detection system is only designed to automatically shut down an oil pipeline in the case of a full rupture.[524] Otherwise, Enbridge personnel have 10 minutes after a leak-detection system alarm indicates a leak might exist, to then shut down the affected line.[525] After 10 minutes of a leak-detection alarm, without human intervention, the line shuts down.[526] For detecting oil leaks in general, Enbridge employs a leak detection strategy, which employs "a different combination of people processes and technology . . . ."[527] With smaller leaks, Enbridge must often conduct flow measurements in order to detect any abnormalities.[528] Even then, Enbridge testified that part of its strategy is relying on the public to report leaks, in addition to other methods, like surveillance.[529] Enbridge runs drills for its leak-detection system for leaks that would set off alarms in the system, not for leaks that would not set off alarms.[530] Enbridge's reliance on the public to report certain smaller leaks, indicates there are leaks that evade Enbridge's own leak-detection system. Enbridge, however, testified that it will eventually find any leak: "It's just a matter of the amount of time."[531]

For leaks that occur, Enbridge's testimony regarding the proposed Project's potential impact to lakes and groundwater did not consider factors such as site-specific typical conditions, seasonality, crude oil type and volume, or oil spill response times.[532] Enbridge witness,

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[524] *See* Evid. Hrg. Tr. Vol. 4A (Nov. 6, 2017) at 116 (Philipenko).
[525] *Id.*
[526] *Id.*
[527] *Id.* at 90.
[528] *Id.*
[529] *Id.* at 91.
[530] Evid. Hrg. Tr. Vol. 4A (Nov. 6, 2017) at 119 (Philipenko).
[531] *Id.* at 90.
[532] *See* Evid. Hrg. Tr. Vol. 4B (Nov. 6, 2017) at 90–105 (Wuolo).

Mr. Wuolo, agreed that these factors could impact how spilled crude oil travels.[533] In addition, Enbridge did not evaluate any particular points along the preferred route that could have the greatest impacts to lakes or groundwater.[534] Its analysis only evaluated the potential impacts of the proposed Project to rivers and streams as they were connected to lakes.[535] Thus, the potential impact to the 192 surface water crossings were only evaluated to the extent "they provided a connection to a lake."[536] Enbridge's analysis also did not evaluate the impact to potential drinking water sources by the proposed Project.[537] The water source could be impacted by an oil spill, but as Enbridge's witness stated, it is only considered "toxic" if there is human exposure.[538] That aside, the potential impacts can be drastic: oil spilled into ground water can potentially still be in that water source 150 years after the spill.[539]

In addition to monetary costs of a pipeline leak, there are permanent costs to the natural and socioeconomic environments as a result of an oil spill, and there is a significant and meaningful concern for wild rice. Enbridge witness Ms. Tillquist testified that after an oil leak, regulatory agencies establish a remediation plan for recovery.[540] Recovery, however, does not necessarily mean returning the environment to the condition as it existed before the spill.[541] This

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[533] *Id.* at 95.
[534] *See id.* at 96.
[535] *Id.* at 97.
[536] *Id.* at 97–98; *see also* Ex. EERA-29 at 5-48 (FEIS) (surface waters crossed by the Applicant's proposed Project).
[537] Evid. Hrg. Tr. Vol. 4B (Nov. 6, 2017) at 99 (Wuolo).
[538] *Id.* at 115. *See also* Evid. Hrg. Tr. Vol. 5A (Nov. 8, 2017) at 111–12 (Stephenson) ("All crude oils would be potentially toxic to aquatic plants."); Evid. Hrg. Tr. Vol. 5B (Nov. 8, 2017) at 121 (Tillquist).
[539] *See* Evid. Hrg. Tr. Vol. 4B (Nov. 6, 2017) at 120 (Wuolo).
[540] Evid. Hrg. Tr. Vol. 5B (Nov. 8, 2017) at 135 (Tillquist).
[541] *Id.* at 135–136; *see also* Evid. Hrg. Tr. Vol. 6A (Nov. 9, 2017) at 21 (Tillquist) ("Again, recovery is not necessarily going back to it an—to the exact state it was before.").

is especially concerning with a natural resource like wild rice, which has significant cultural significance to the Anishinaabe people.[542] While Enbridge testified that after an oil spill, animals may switch from one food source to another, the record demonstrates serious concerns with re-establishing wild rice beds due to its culture significance to the Anishinaabe people and its sensitivity to environmental conditions.[543] DOC DER is concerned about the potential impact to the natural and socioeconomic environments for wild rice that the proposed Project could present.

There are also unique environmental concerns with establishing a new pipeline corridor.[544] Trees cut down to construct a new pipeline would be permanently cleared.[545] New water ways would be crossed by a crude oil pipeline where there was not one before, with all its appurtenant effects discussed herein.[546] Further, establishing a new corridor for crude oil pipelines would create a higher probability of using the corridor for other new or rerouted pipelines.[547] Moreover, a decision about whether to build new, long-lived infrastructure for the

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[542] *See, e.g.*, Ex. WE-1 (Goodwin Summary).

[543] Evid. Hrg. Tr. Vol. 5B (Nov. 8, 2017) at 139–140, 142 (Tillquist); *see also* Ex. WE-1 (Goodwin Witness Summary); Ex. FDL-2 at 4–8 (Schuldt Direct); Ex. EN-50 at 3 (Lee Rebuttal).

[544] *See* Ex. DER-1 at 82 (O'Connell Direct).

[545] Evid. Hrg. Tr. Vol. 2A (Nov. 2, 2017) at 69 (Simonson).

[546] Ex. DER-1 at 81 (O'Connell Direct). *See also* Evid. Hrg. Tr. Vol. 2B (Nov. 2, 2017) at 142 (Bergman):

> Q. Would it be your opinion that the presence of a crude oil pipeline poses a risk that would otherwise not be present if the line were not there?
>
> A. Phrased the way you phrased it, if there was nothing there at all, there would be no risk.

[547] *Id.*

transportation of oil comes at a time when oil use appears to be leveling off or declining, as indicated by DOC DER witness Dr. Fagan.[548]

Finally, DOC DER has concerns about statements Enbridge has made about its crude oil pipelines' potential impacts to the natural environment. For instance, Enbridge witness Ms. Kennett stated that it applies a protective coating to pipelines in order to prevent external corrosion, which it defines as an integrity threat.[549] Enbridge stated that under its integrity management program, it mitigates integrity threats before they become safety risks.[550] Nevertheless, Enbridge's integrity management department failed to disclose to Michigan authorities for three years that protective coating for Line 5, which spans the Straits of Mackinac, was damaged during the installation of pipeline anchors, and was just recently repaired.[551] Enbridge stated that the damage to the protective coating never presented a safety threat, but Ms. Kennett testified that Enbridge mitigates integrity threats before they become safety concerns.[552] Apparently that is not always the case, however, according to Enbridge's own

[548] *Id.*; Ex. DER-4, MF-1 at 5 (Fagan Direct).
[549] Ex. EN-12 at 5–8 (Kennett Direct). Enbridge stated that it does not believe that an integrity threat is a risk to the environment. *See* Evid. Hrg. Tr. Vol. 1A (Nov. 1, 2017) at 54–56 (Kennett).
[550] *Id.* at 8.
[551] Ex. DER-10 (News Article). DOC DER witness Mr. Dybdahl testified that an oil spill involving Line 5 through the Straits of Mackinac "could overwhelm the ability of Enbridge entities to pay for the loss costs associated with the spill." Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 55 (Dybdahl).
[552] *See* Ex. EN-12 at 8 (Kennett Direct). Enbridge statements in this regard are especially concerning in light of the National Transportation Safety Board (NTSB) investigation into the 2010 oil spill near Marshall, Michigan involving Line 6B, which Enbridge's own witness agreed was "critical" of Enbridge's safety practices. *See* Evid. Hrg. Tr. Vol. 3B (Nov. 3, 2017) at 89 (Gerard).

admissions about damage to Line 5's protective coating.[553] Finally, it is concerning that Enbridge only disclosed this information to Michigan authorities in response to information requests.[554]

b. Minnesota's Energy Policy

DOC DER also testified that the proposed Project is inconsistent with Minnesota's energy policy.[555] First, Minn. Stat. § 216C.05, subd. 3 states in relevant part that "[i]t is the energy policy of the state of Minnesota that 25 percent of the total energy used in the state be derived from renewable energy resources by the year 2025."

Second, Minnesota Statute 216H.02, subd. 1, states:

> It is the goal of the state of Minnesota to reduce statewide greenhouse gas emissions *across all sectors producing those emissions* to a level at least 15 percent below 2005 levels by 2015, to a level at least 30 percent below 2005 levels by 2025, and to at least 80 percent below 2005 levels by 2050.[556]

While these provisions are goals rather than requirements, it is important to consider how approval of the proposed Project could affect Minnesota's ability to meet that goal.[557] While Minnesota has made progress, it still has further to go to meet that goal.[558] The most recent information from the EIA is shown in Chart 11:[559]

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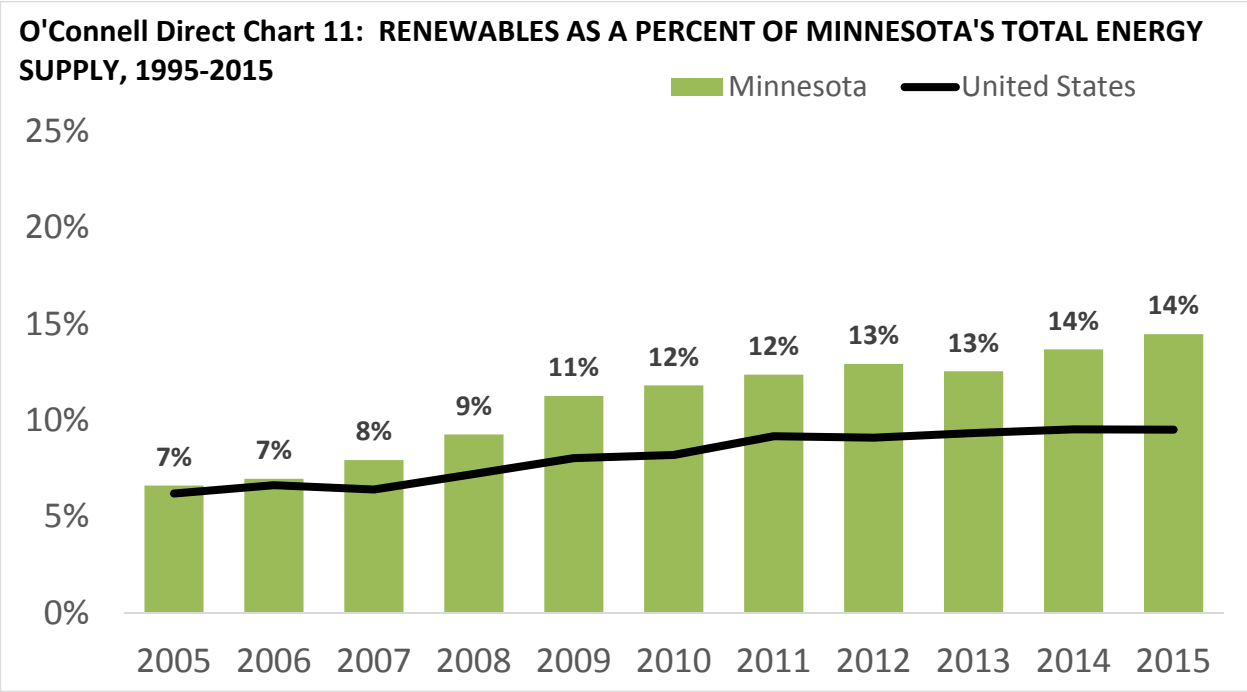
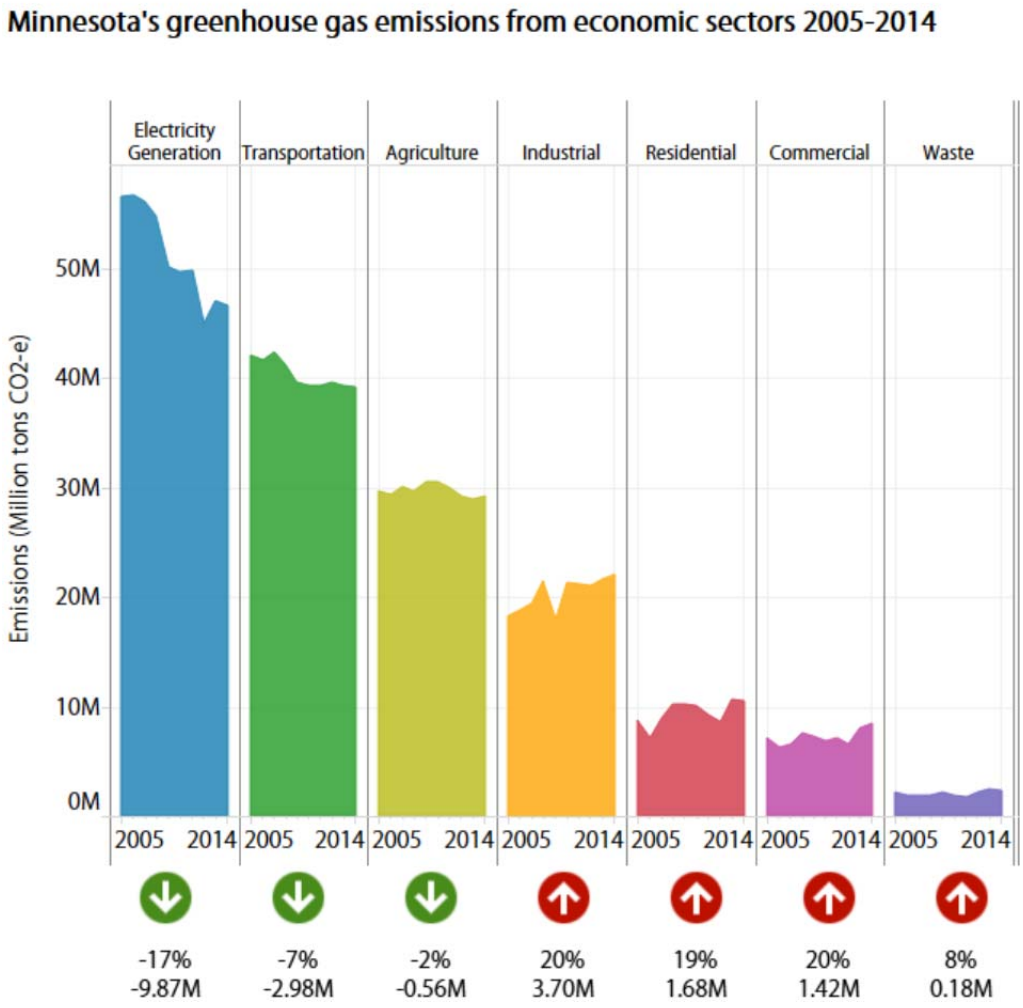
[553] Ex. DER-10 (News Article) ("Our pipeline integrity department continued to monitor these areas, and the coating damage was determined not to present any threat to the safety of the pipeline at any time.").
[554] *Id.*
[555] Ex. DER-1 at 82 (O'Connell Direct).
[556] Minn. Stat. § 216H.02, subd. 1 (2016).
[557] Ex. DER-1 at 82 (O'Connell Direct).
[558] *Id.*
[559] *Id.* at 83.



Regarding statewide greenhouse gas reductions, according to a report by the Minnesota Pollution Control Agency, Minnesota has made progress, but again, has further to go.[560] Based on data through 2014, as shown in Chart 12 below, while the electric generation, transportation and agriculture sectors made progress toward the 2015 goal, only the electric sector met that goal.[561] For the transportation sector, while GHG emissions have leveled off with usage, Minnesota is not close to the statutory reduction trajectory goal.[562]

[560] *Id.*
[561] *Id.*
[562] *Id.* Note that electric generation and transportation are the largest sectors.

O'Connell Direct Chart 12: Minnesota's Progress toward Greenhouse Gas Reduction Goals



Approval of the proposed Project would affect greenhouse gas emissions in Minnesota in multiple ways.[563] The FEIS evaluated potential lifecycle emissions associated with the proposed Project and alternatives to the proposed Project, including increases in upstream emissions associated with oil extraction and downstream emissions associated with oil consumption if the

[563] Ex. DER-1 at 84 (O'Connell Direct).

proposed Project induces new production and consumption or results in displacement of less greenhouse-gas intense alternative sources of oil.[564]

DOC DER concluded that a commitment to build Line 3 would likely result in a net increase in GHG emissions compared to not building the facility due to two factors: 1) increased throughput of crude oil through the state overall and 2) ability of the existing 390,000 bpd to ship heavy crude rather than solely light crude.[565] Shipments of heavy crude require more electricity from utilities in Minnesota than shipments of light crude, thus increasing Enbridge's electricity use.[566] Further, Enbridge indicated that it no longer offers its "neutral footprint program," which Enbridge, in the past, indicated would offset each kWh increase in electricity use with an increase in electricity produced by renewable power.[567]

c. Effects on the Socioeconomic Environment

In this section, DOC DER discusses the proposed Project's effects on local employment, local businesses, tribal resources, and effects on relocations and property. DOC DER appreciates that construction of the proposed Project would provide employment for potentially thousands of individuals in Minnesota. Nevertheless, DOC DER concluded that the proposed Project could present significant negative effects to the socioeconomic environment.

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[564] *Id.*; *see also* Ex. EERA-29 at ES-19–ES-23, 5-431–5-469, 12-42–12-51 (FEIS) (The FEIS "considers that collectively the proposed Project and other reasonably foreseeable actions across the world would contribute to global climate change."). *Id.* at 12-42.
[565] Ex. DER-1 at 85 (O'Connell Direct).
[566] *Id.*
[567] *Id.*, KO-18. Enbridge's past neutral footprint program is discussed further below in Section III.C. regarding conditions to a CN.

i. The Proposed Project Would Require a Significant Amount of Skilled Workers to Construct.

The proposed Project would have a positive effect on employment in Minnesota. Enbridge stated that the proposed Project would increase the number of local jobs, and that "[m]any of these will be union jobs":

> The Project will be a very large construction project. A few thousand workers will be required, and, per the current labor agreement in Minnesota, at least 50% of these workers will be expected to be employed from the local union halls.[568]

In addition, the FEIS noted the following regarding the potential for the proposed Project to be a job creator:

> Construction of the Applicant's proposed project is expected to require up to a maximum of 4,200 workers across 7 different construction spreads over a 12-month period. As noted above, it is expected that Enbridge would use some local workers – as referenced in the direct testimony of Barry Simonson (lines 505-513) current labor agreements in Minnesota require that at least 50% of workers would be expected to be employed from local union halls. As construction jobs are typically permanent in nature and spatially temporary in the sense that workers move from project to project, permanent jobs may result from said construction (this is also dependent on an unquantifiable backlog of other construction project demand). Based on this assumption, it is likely that direct construction-related employment would have a minor positive impact on county-level unemployment and per capita and/or median household income levels.[569]

Mr. Evan Whiteford, a representative of the Laborers International Union of North America, testified how union construction workers that work on pipeline projects are generally highly

[568] Ex. EN-22 at 18 (Simonson Direct); *see also* Evid. Hrg. Tr. Vol. 5A (Nov. 8, 2017) at 57–61 (Whiteford)
[569] Ex. EERA-29 at 5-572 (FEIS).

skilled and are mindful of environmental concerns in the community.[570] Mr. Whiteford attested to the versatility of union construction workers, not only for the proposed Project, but to other construction projects not presently proposed by Enbridge in this matter, such as removal of the existing Line 3 or the building of wind farms.[571] Enbridge also testified that the construction workers that build its pipelines are generally highly skilled, trained, and certified to do the work.[572] In addition, Enbridge testified that pursuant to its request for proposal (RFP) for construction of the proposed Project:

> [C]ontractors submit a socioeconomic plan where they demonstrate how they would meet—meet certain socioeconomic requirements, whether that's hiring tribal member-owned companies or diversity in their workforce. And then, as part of our evaluation of proposals, we give a certain weighting to the socioeconomic component of the contractor's proposal.[573]

Portions of Enbridge's RFP are in the record, which highlight the policies, procedures, and requirements governing contractors, and how Enbridge enforces those requirements.[574] The RFP, among other things, includes detailed sections about environmental plans governing contractors' performance, safety guidelines, and other policies and procedures governing contractors, such as compliance with Enbridge's business conduct policies and how those policies are enforced.[575]

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[570] Evid. Hrg. Tr. Vol. 5A (Nov. 8, 2017) at 57–61 (Whiteford).
[571] *Id.* at 62–64.
[572] Evid. Hrg. Tr. Vol. 8A (Nov. 14, 2017) at 66–62 (Eberth).
[573] *Id.* at 71.
[574] Ex. DER-20 (Enbridge Request for Proposal).
[575] *Id.*

ii. Enbridge's "Economic Impact" Analysis Fails to Reasonably Weigh Economic Costs.

Enbridge estimated the economic impacts to Minnesota through its witness Dr. Lichty.[576] DOC DER agrees with other intervenors that Dr. Lichty's economic impacts analysis is inadequate to reasonably assess a complete picture of socioeconomic benefits to Minnesota because it fails to compare costs (i.e. it is only an *impacts* analysis, not a *cost-benefits* analysis). Dr. Lichty's analysis fails to adequately evaluate the costs and benefits of the proposed Project when evaluating whether the "consequences to society of granting the certificate of need are more favorable than the consequences of denying the certificate . . . ."[577]

Enbridge estimated that, on a state level, the proposed Project would create over 13,600 full time equivalent (FTE) direct and indirect jobs during the construction phase and approximately 369 FTE jobs on an annual basis during the operation of the proposed Project. But the record is not clear whether these FTE jobs are new or whether these jobs are relocated from the existing Line 3.[578] Enbridge also estimated employment impacts by industry type.[579] In addition, Enbridge contended that the proposed Project would result in a positive impact to the State and regional economy through overall increased economic output, namely, it would increase labor income by $864,721,326, value added by $1,234,395,339, and total output by $2,253,696,670.[580] At the evidentiary hearing, Enbridge clarified that the amount of permanent

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[576] *See* Ex. EN-11, Sched. 2 (Lichty Direct).
[577] *See* Minn. R. 7853.0130 C (2015); *see also* Evid. Hrg. Tr. Vol. 1B (Nov. 1, 2017) at 164–179 (Lichty).
[578] Ex. EN-11 at 8–9 (Lichty Direct); *see also* Evid. Hrg. Tr. Vol. 1B (Nov. 1, 2017) at 178 (Lichty) ("JUDGE O'REILLY: So they're not really new jobs then? THE WITNESS: They could be, but we don't know. I did not study the—closing down the old line.").
[579] *Id.*
[580] *Id.*

jobs with Enbridge likely to be created by the proposed Project is actually between zero to twenty jobs.[581] Thus, the amount of permanent jobs created by the proposed Project appears to be quite small in number. Finally, the proposed Project would likely result in an increase in property tax revenue, but it is unclear, exactly, to what extent. Enbridge is currently in a dispute with the Minnesota Department of Revenue regarding its property tax obligation.[582]

DOC DER concluded that it is unclear whether the calculations provided by the Applicant represent an accurate estimate of potential benefits to Minnesota.[583] DOC DER does not dispute that some level of direct benefit, through construction jobs for example, will occur as a result of the Project. DOC DER appreciates that the proposed Project would create jobs in Minnesota. Nevertheless, DOC DER cannot confirm that Enbridge's benefit calculations are reasonable.

Moreover, like the proposed Project, it appears that Dr. Lichty's economic impact analysis would calculate a positive impact to the Minnesota economy for just about any large, high-cost construction project, without considering costs to society.[584] Dr. Lichty agreed that a wind farm project or even a project to clean up an oil spill could positively impact the Minnesota economy under his economic impact analysis.[585] While the economic impact project-to-project might change depending on what money is spent, an analysis that would always appear to calculate an economic "win" for Minnesota is an unreasonable method to weigh the effects to society of granting or denying the CN.

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[581] Evid. Hrg. Tr. Vol. 8A (Nov. 14, 2017) at 72 (Eberth).
[582] Ex. DER-1, KO-16 (O'Connell Direct).
[583] Ex. DER-1 at 70 (O'Connell Direct).
[584] Evid. Hrg. Tr. Vol. 1B (Nov. 1, 2017) at 165 (Lichty).
[585] *Id.* at 165, 176.

Nevertheless, positive benefits appear to exist for the local economy. Enbridge also claimed that the proposed Project would positively impact the local hospitality economy and local businesses.[586] While Enbridge did not commit to sourcing from local businesses, it stated that the proposed Project would "inevitably be sourcing various materials from local vendors":

> The contractors working on the Project and Enbridge will inevitably be sourcing various materials from local vendors. For example, gravel and washed rock will be needed for bag weights used for buoyancy control, and since these materials are prevalent in Minnesota, Enbridge anticipates our contractors will source them locally.[587]

Thus, in this regard, while the proposed Project is expected to have a positive impact to the local economy, Enbridge's analysis unreasonably measures the economic impacts without considering the costs.

iii. The Proposed Project Poses Significant Impacts to the Socioeconomic Environment.

On the other hand, the record shows that the proposed Project is expected to pose significant cultural impacts to Native Americans, in addition to the effects on wild rice, discussed above. The FEIS stated that each route option would impair tribal resources, tribal identity, and tribal health and that "any of the routes selected between North Dakota and Superior, Wisconsin, therefore, would have a disproportionate and adverse effect on tribal resources and tribal members, even if the route itself does not cross near residences."[588] That is, a new Line 3 would have disproportionate and adverse impacts on environmental justice communities, particularly

[586] *See* Ex. EN-22 at 18 (Simonson Direct).
[587] *Id.*
[588] Ex. EERA-20 at ES-29 (FEIS).

Native American communities in the project area.[589] EERA concluded that consultation with tribal leaders and membership during the preparation of the FEIS made it clear that these impacts are rooted in American Indian community values, uses, and attitudes toward natural and cultural resources.[590] Such impacts may not be able to be ameliorated financially.[591] The process of evaluating traditional cultural properties is also still ongoing.[592]

The continued operation of the existing Line 3 would also impact tribal resources, along with all other resources along its route.[593] Thus, in light of the serious risks of the existing Line 3 and the limited benefit that the existing Line 3 provides to Minnesota refineries, in order to avoid these impacts, Enbridge would need to cease operations of the existing Line 3, without any new pipeline being built.[594] That is, however, not what Enbridge proposed and is not what the DOC DER analyzed. Instead, despite the extensive testimony about risks of operating the existing Line 3, Enbridge has stated that it could continue to operate the existing Line 3.[595]

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[589] *Id.*; *see also* Evid. Hrg. Tr. Vol. 7A (Nov. 13, 2017) at 14–19 (Lamb) ("From an Indigenous perspective, this pipeline causes great concern. Not only for Indigenous medicines, but an ability to practice the Indigenous way of life to the fullest."). In fact, Ms. Lamb also testified that she did not believe that the FEIS adequately addressed tribal interests. *Id.* at 21. Thus, there is a concern that the facts in the record do not even adequately lay out tribal impacts from the proposed Project.

[590] Ex. EERA-20 at ES-29 (FEIS).

[591] *Id.*

[592] *See* Evid. Hrg. Tr. Vol. 2B (Nov. 2, 2017) at 116–17 (Bergland); *see also* Evid. Hrg. Tr. Vol. 3A (Nov. 3, 2017) at 46–47 (Bergman).

[593] Ex. DER-1 at 87 (O'Connell Direct).

[594] *Id.*

[595] *Id.* at 87–88. *Compare* Ex. EN-12 at 20 (Kennett Direct) ("Enbridge has been analyzing the need for replacement of Line 3 for several years because of increasing maintenance activities associated with external corrosion, SCC, and long-seam-fatigue cracking.") *with* Ex. EN-24 at 10 (Eberth Direct) ("If the Project is not approved, Enbridge will continue to operate Line 3 in a safe and reliable manner . . . .").

In addition, regarding relocations of people, DOC DER also evaluated the effects that the proposed Project would have on relocations of people and private property interests.[596] Enbridge stated that "[b]ecause construction and operation of the Project will require acquisition of additional property, the Project could result in relocation of people."[597] In addition, the FEIS stated the following regarding relocations and other effects on property:

> Residential structures were identified within the permanent right-of-way for the Applicant's preferred route. Because no barns, homes, or other structures would be allowed within the permanent right-of-way, Enbridge would need to remove or re-locate those structures, as negotiated with the landowner. Enbridge has identified 18 structures within the permanent right-of-way that would need to be removed and has reached an agreement with each of the affected landowners. Because Enbridge has negotiated agreements with each of the landowners, no unknown or unquantified impacts on structures in the permanent right-of-way would occur.
>
> For aboveground facilities, the Applicant's preferred route would require 27 MLVs, 4 new pump stations, and upgrades to 4 existing pump stations. Operation of the aboveground facilities would not affect an individual's ability to access their home; however, a landowner would no longer have access to the 0.1-acre MLV site on their property, which would be enclosed by a fence. Depending on the overall size of the parcel, this would be a minor to major permanent impact related to access. The expanded area of existing pump stations and any new pump stations would be enclosed by a fence to exclude access to all but Enbridge personnel. Enbridge would purchase the pump station sites from the landowner to eliminate any landowner access issues.[598]

[596] *Id.* at 88.
[597] Ex. EN-1 at 9–25 (CN Application).
[598] Ex. EERA-29 at 6-107 (FEIS).

Finally, the record shows that there may be increased traffic congestion in places in addition to impacts to cropland during construction of the proposed Project.[599]

3. Minn. R. 7853.0130 C(3): Effects of the Proposed Facility in Inducing Future Development

Enbridge testified that there would be a need for new electric transmission lines to serve the new pumping stations, along with increased water use.[600] The increase in electricity use is discussed above.

4. Minn. R. 7853.0130 C(4): Socially beneficial uses of the output of the Project to protect or enhance environmental quality

Under this criterion, Enbridge discussed the uses of refined crude oil products.[601] DOC DER agreed that the refined products created by crude oil have socially beneficial uses.[602] That being said, if refineries in the Minnesota district already are producing at or near capacity, there would not necessarily be an incremental benefit in Minnesota or the region.[603]

B. DOC DER Conclusions About Whether the Consequences to Society of Granting the Certificate of Need are More Favorable than the Consequences of Denying the Certificate

Because DOC DER concluded that Enbridge has not satisfied the criteria under Minn. R. 7853.0130 A, and given the significant concerns about effects of the proposed Project to the natural and socioeconomic environments, especially to Native Americans, DOC DER concluded that the Commission could determine that the high socioeconomic costs outweigh any benefits to

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[599] Ex. DER-1 at 89 (O'Connell Direct); *see also* Ex. EERA-29 at 2-25, 2-37, 5-527, 5-544 (FEIS).
[600] Ex. EN-1 at 9-23 (CN Application).
[601] *Id.* at 4-1.
[602] Ex. DER-1 at 91 (O'Connell Direct).
[603] *Id.*

Minnesota of the proposed Project.[604] First, considering the relationship of the proposed facility (or a suitable modification) to overall state energy needs, DOC DER concluded that Enbridge has not established a need for the proposed Project.[605] At a high level, in light of the serious potential environmental risks and economic costs of the existing Line 3 and the limited benefit that the existing Line 3 provides to Minnesota refineries, Enbridge does not propose to cease operation of the existing Line 3 in the event of approval of a CN with conditions it dislikes.[606] Instead, despite the extensive testimony about risks of operating the existing Line 3, Enbridge simply proposes to continue operating the existing Line 3 unless the Commission grants Enbridge a certificate for its proposed Project.[607]

Second, regarding the effect of the proposed facility on the natural and socioeconomic environments as to benefits, DOC DER concluded and appreciates that there would be economic benefits to those who would be employed in working on the proposed Project, on local businesses that would supply goods and services to the employees (and possibly to Enbridge), and to the counties in which the proposed Project would be built, at least to the extent that Enbridge pays a higher level of property taxes than it is attempting to do by its challenges in Minnesota Tax Court.[608] Nevertheless, Enbridge's economic benefits analysis is one one-sided and failed to weigh the economic benefits and costs of the proposed Project.

Third, regarding substantial costs to the natural and socioeconomic environments of the proposed Project, there would be risks to high-quality water resources, surface waters and

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[604] *Id.* at 93–94.
[605] *Id.* at 92.
[606] *Id.*
[607] *Id.*
[608] Ex. DER-1 at 92–93 (O'Connell Direct).

ground waters, wild rice, potential damage to forests, fish and wildlife habitats.[609] There is substantial testimony regarding the potential risk of the proposed Project to wild rice, a vital cultural resource to the Anishinaabe people.[610] These overall risks would be higher on the Clearbrook-to-Superior segment than on the Neche-to-Clearbrook segment.[611] Moreover, there would also be risks of contributions to climate change from direct and indirect project emissions, as well as lifecycle greenhouse gas emissions from any incremental oil usage facilitated by the project.[612] In addition, there would be disproportionate and adverse impacts to tribal communities if the project were built, no matter which route is used.[613] There would also be negative effects to people and businesses that would need to be relocated, but the effects would be higher on the Clearbrook-to-Superior segment than on the Neche-to-Clearbrook segment.[614] Finally, during construction of the proposed Project, there may be increased traffic congestion in places in addition to impacts to cropland.[615]

Thus, DOC DER concluded that the consequences to society of granting the CN would not be more favorable than denying the CN.

Based on its analyses of rule criteria 783.0130 A–C, DOC DER recommends that Commission deny Enbridge's CN Application.

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[609] *Id.* at 93.
[610] *See, e.g.*, Ex. WE-1 (Goodwin Witness Summary); Ex. ML-1 at 3–4, 6–7 (Kemper Direct); Ex. YC-20 at 5–6 (Paulson Direct). *See also* Ex. EERA-29 at 9-19–9-20, 9-30–9-31 (FEIS).
[611] Ex. DER-1 at 93 (O'Connell Direct).
[612] *Id.*
[613] *Id.*
[614] *Id.*
[615] *Id.*; *see also* Ex. EERA-29 at 2-25, 2-37, 5-527, 5-544 (FEIS).

C. If the Commission Determines that with Conditions, the Proposed Project Would Meet the CN Criteria, DOC DER Recommended Certain Conditions for the Commission's Consideration

Enbridge has not demonstrated that it has satisfied the CN factors. If, however, the Commission wishes to consider whether conditions might cure Enbridge's lack of a demonstrated need, DOC DER identifies conditions that together would be important to consider in this section. The Commission should ensure that conditions integral to any finding of need are also part of the Company's operating conditions of the route permit. DOC DER no longer recommends that the Commission condition any CN on construction of redundant control centers or to require Enbridge to use a thicker pipeline along the right-of-way in Minnesota.[616]

1. The Commission Should Only Grant a CN for a 34-Inch Pipeline, Not a 36-Inch Pipeline.

As presented above, Enbridge has not demonstrated need for a 36-inch pipeline. Thus, the Commission should allow Enbridge to install no more than a 34-inch pipeline to replace the existing 34-inch existing Line 3 pipeline.[617] If the proposed Project is truly a replacement project, then only a 34-inch line should be approved.

In addition, a 36-inch pipeline compared to a 34-inch pipeline could present significantly more risk to the natural environment. As Enbridge witness Benjamin Mittelstadt testified, a 34-inch pipeline could potentially release 11 percent less crude oil during a rupture compared to a 36-inch pipeline.[618] Thus, Enbridge testified that the diameter of the line is related to the consequences of a pipeline failure and that the consequences of a spill could be lower for a

[616] Ex. DER-6 at 30, 59 (O'Connell Surrebuttal).
[617] *See* Ex. DER-1 at 18–21 (O'Connell Direct).
[618] Ex. EN-51 at 15–16 (Mittelstadt Rebuttal).

smaller pipeline.[619] Real-life consequences of even small crude oil pipelines have had catastrophic effects to the natural environment. As an example, Enbridge's Line 6B, a smaller 30-inch crude oil pipeline, spilled approximately 20,000 barrels of oil near Marshall, Michigan in 2010, which Enbridge agreed caused environmental damage.[620] These environmental concerns, warrant the condition for a 34-inch pipeline.

2. The Commission Should Condition the CN on Enbridge Building Two Pipeline Maintenance Shops After Clearbrook.

Enbridge agreed with the DOC DER's proposal to add and maintain two pipeline maintenance shops, rather than only one, if any new pipeline segment, on any route, extends beyond Clearbook.[621] Given the significant number of new rights-of-way under the proposed Project, the addition of only one pipeline maintenance shop east of Clearbrook is insufficient.[622] Thus, if the Commission finds need for a pipeline and if that the need extends beyond Clearbrook, DOC DER recommended that, regardless of the route chosen, the Commission require Enbridge to add two pipeline maintenance shops.[623] Given the many miles of the proposed Project, an additional pipeline maintenance shop may help mitigate environmental risks to the natural and socioeconomic environments.[624]

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[619] Evid. Hrg. Tr. Vol. 4A (Nov. 6, 2017) at 39–40 (Mittelstadt).
[620] Ex. EN-1, Sched. C at 44 (CN Application); Evid. Hrg. Tr. Vol. 4A (Nov. 6, 2017) at 40 (Mittelstadt); Evid. Hrg. Tr. Vol. 7B (Nov. 13, 2017) at 105 (Eberth); Ex. EERA-29 at 10-33 (FEIS); Evid. Hrg. Tr. Vol. 5A (Nov. 8, 2017) at 81 (Stephenson).
[621] Ex. DER-1 at 99–101 (O'Connell Direct); Evid. Hrg. Tr. Vol. 4B (Nov. 6, 2017) at 140 (Haskins).
[622] Ex. DER-1 at 101 (O'Connell Direct).
[623] *Id.*
[624] *Id.*

3. The Commission Should Condition the CN By Requiring Enbridge to Remove All Exposed Segments of Existing Line 3 in Minnesota without Unnecessary Harm to the Natural Environment.

As a condition of finding need for a new Line 3, the Commission should require Enbridge to remove all exposed segments of existing Line 3 in Minnesota without unnecessary harm to the natural environment.[625] In addition, the Commission should require Enbridge to make a meaningful commitment to cease operations of existing Line 3 in a manner that assures Commission authority over enforcement of any such commitment (i.e., as an operating condition of the route permit or by submitting to the authority of the state regarding enforcement of the commitment).

Enbridge reported 223 instances of exposed pipe for the existing Line 3 totaling 8,496 feet in Minnesota.[626] Removing these exposed segments would limit effects to the natural and socioeconomic environments.[627] Thus, the Commission should require Enbridge to remove all exposed segments of existing Line 3 in Minnesota.[628]

4. The Commission Should Condition the CN By Requiring Enbridge to Report Annually to the Commission About Each Exposed Pipeline Segment.

As part of Enbridge's future monitoring of a decommissioned existing Line 3, including the removal of all exposed segments of the existing Line 3 once decommissioned, the Commission should require Enbridge to report annually about any exposed pipeline segments that are not yet removed and identify how and when Enbridge will meet federal requirements as

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[625] Ex. DER-1 at 113–115 (O'Connell Direct).
[626] *Id.*, KO-26.
[627] *See id.* at 114.
[628] *Id.*

to an exposed pipeline.[629] Granting a CN for an additional pipeline without requiring any current risk of harm to the environment posed by Enbridge's exposed pipe throughout the state would be adding to, rather than mitigating, risks of harm to Minnesota's natural and socioeconomic environments.[630] The Commission should ensure that Enbridge is meeting decommissioning requirements in this regard.

5. The Commission Should Condition the CN By Requiring Enbridge to Apply Its Former Neutral Footprint Policy to the Proposed Project, As it Did with the Line 67 Phase 2 Upgrade.

The Commission should require Enbridge to apply the Commission-approved neutral footprint policy to increased energy use implemented in the certificate of need matter regarding the Phase 2 Upgrade to Line 67 crude oil pipeline (Docket No. EL9/CN-13-153).[631] This would limit the proposed Project's impacts to the natural and socioeconomic environments. In the Line 67 matter, after Enbridge filed its compliance filings from implementation of the Phase 2 Upgrade, DOC DER became concerned that Enbridge's neutral footprint program was not truly "neutral" regarding Enbridge's promise to use or apply renewable resource credits to its consumption of nonrenewable energy to power its incremental operations from the Line 67 Phase 2 Upgrade, and that Enbridge was "double-counting" use of renewable resources.[632] Despite disagreeing with DOC DER and the Commission regarding the state's interpretation of its own program, Enbridge agreed to purchase renewable energy credits (RECs) to offset its

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[629] *Id.* at 115.
[630] *Id.* at 114.
[631] *See* Phase 2 Order at 32.
[632] *See In re Application of Enbridge Energy, Ltd. P'ship for a Certificate of Need for the Line 67 (Alberta Clipper) Station Upgrade Project - Phase 2 - in Marshall, Clearwater, Itasca, Kittson, Red Lake, Cass, and St. Louis Counties*, Docket No. PL-9/CN-13-153, Order Clarifying Neutral Footprint Objectives and Requiring Compliance Filing at 2–3 (MPUC Aug. 18, 2017).

incremental non-renewable energy use related to the Line 67 Phase 2 Upgrade based on a verifiable methodology.[633] The Commission allowed Enbridge until 2020 to comply.[634]

With the DOC DER's credible double-counting concerns and the Commission's clarifying order that its decision regarding implementation of Enbridge's neutral footprint program to Enbridge's incremental energy usage for the Line 67 Phase 2 Upgrade project, it is not surprising that Enbridge has discontinued this program for the proposed Project.[635] While DOC DER appreciates that Enbridge continues to engage in other environmental and conservation initiatives associated with its business activities, Enbridge's statements that it ended its neutral footprint program based on "stakeholder feedback" is simply not credible in light of its disagreement with the Commission's decision in Docket No. 13-153.[636] The Department encourages the Commission to similarly require Enbridge to offset all incremental nonrenewable energy usage associated with the proposed Project with renewable energy in a transparent, verifiable way.

6. Conditions Regarding the Control Center for the Enbridge Mainline System

DOC DER was initially concerned that Enbridge maintained its primary and redundant operation control centers in the same general vicinity.[637] Enbridge, however, stated in rebuttal testimony that:

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[633] *Id.* at 3.
[634] *Id.* at 5.
[635] *See* Ex. EN-30 at 25 (Eberth Rebuttal).
[636] *See id.*; *see also* Ex. DER-6 at 13–14 (O'Connell Surrebuttal).
[637] Ex. DER-1 at 102 (O'Connell Direct). By comparison, the Midcontinent Independent Service Operator (MISO) maintains its primary and secondary operating facilities in geographically disparate locations.

> [B]oth primary and back-up control centers operate on separate independent electrical grids, have multiple layers of redundancy relating to IT Networking Infrastructure, and have emergency back-up generators capable of providing power for extended periods of time.[638]

Given the physical differences between an electrical grid (such as MISO operates) and a crude oil system, DOC DER concluded that Enbridge's response fully addressed the concerns.[639]

a. Cyber Security

While DOC DER concluded that Enbridge had addressed its concerns regarding control center locations, DOC DER continued to recommend as a condition to a CN that Enbridge provide reasonable assurances to the Commission regarding the adequacy of its cyber security systems and to periodically provide updates.[640] Such a condition would help mitigate the risk of harm to Minnesotan's natural and socioeconomic environments by requiring Enbridge to demonstrate to the Commission that control of its pipeline operations in Minnesota are adequately protected against cyber security threats.[641] DOC DER appreciates Enbridge's description of its cyber security control framework and its treatment of details of its security measures as sensitive information.[642] Nevertheless, DOC DER believes that the Commission would benefit from periodic high-level assurances from Enbridge as to the nature of cyber security control measures it employs in order to protect pipeline systems in Minnesota from the cyber security threats.[643]

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[638] Ex. EN-34 at 1 (Baumgartner Rebuttal).
[639] Ex. DER-6 at 30 (O'Connell Surrebuttal).
[640] *Id.* at 103; Ex. DER-6 at 31 (O'Connell Surrebuttal).
[641] Ex. DER-6 at 31–32 (O'Connell Surrebuttal).
[642] Ex. EN-34 at 3–4 (Baumgartner Rebuttal).
[643] Ex. DER-6 at 32 (O'Connell Surrebuttal).

b. The Commission Should Condition the CN on Enbridge Providing an Updated Final Filed Emergency Response Plan for the Superior Region.

The Department recommended that the Commission require Enbridge to provide to the Commission an updated, final Field Emergency Response Plan for the Superior Region prior to commencing construction of the proposed Project.[644] The current Field Emergency Response Plan for the Superior Region does not include the proposed Project and will not be finalized until a final route and design work has been completed.[645] If the Commission determines that a need with conditions exists and ultimately approves the proposed Project, or a suitably modified version, DOC DER recommends that the Commission require Enbridge to provide an updated Field Emergency Response Plan for the Superior Region prior to commencement of construction, which is periodically updated according to the Commission's determination.[646]

7. The Commission Should Require Enbridge to Establish a Decommissioning Fund if it Grants a CN.

As discussed above, there are risks to the socioeconomic environment that exist with the proposed Project, including the future decommissioning of the Project. To help ensure that sufficient funding would be available to decommission any new pipeline, DOC DER recommended that the Commission require Enbridge to establish a decommissioning fund or trust to pay for the costs of decommissioning the proposed Project when it reaches the end of its economic usefulness.[647]

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[644] Ex. DER-1 at 97, 103 (O'Connell Direct).
[645] *Id.* at 103.
[646] *Id.*
[647] *Id.* at 116–120.

This is not a novel concept and Enbridge is familiar with it in Canada.[648] Enbridge's Canadian entities that are regulated by the National Energy Board (NEB) are already required to fund mechanisms related to future pipeline abandonment, based on an Abandonment Cost Estimate (ACE).[649] According to Enbridge, the NEB has confirmed that decommissioning and abandonment costs are legitimate costs of providing service.[650] While the Minnesota Commission does not regulate the rates that Enbridge charges to shippers, the Commission could consider requiring Enbridge to establish an escrow or trust fund to decommission the pipeline.[651]

The purpose of a decommissioning fund in the U.S. would be to have funds set aside to aid decommissioning and future monitoring of the proposed Project when it reaches its end of service.[652] Pipeline firms, including Enbridge, are required by federal law to deactivate and monitor pipelines when they are removed from service.[653] Although Enbridge and other Enbridge entities are currently financially viable and have, along with predecessor companies, operated continuously for decades, there are risks that the market for crude oil may diminish in the future.[654] If the market for crude oil erodes significantly, Enbridge may be unable to operate, in which case it is unclear what entity would be responsible for the decommissioning and monitoring of the proposed Project if it is no longer in service.[655] The creation of a

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[648] *Id.*
[649] *Id.* at 116, KO-28. In its response to DOC DER Information Request No. 155, Enbridge explained that the methodology to establish the ACE and the amount of funds to be set aside were created during a multi-year regulatory process including public hearings. Enbridge also included links to sample trusts that were created to collect the necessary funds.
[650] *Id.*, KO-28
[651] Ex. DER-1 at 116 (O'Connell Direct).
[652] *Id.*
[653] Ex. EN-22 at 21, Sched. 4 (Simonson Direct).
[654] Ex. DER-1 at 117 (O'Connell Direct); Ex. DER-6 at 57 (O'Connell Surrebuttal).
[655] Ex. DER-1 at 117 (O'Connell Direct).

decommissioning trust or fund would help insulate Minnesota taxpayers if Enbridge is no longer in business and would provide Enbridge with a pool of funds to aid in the future cost of removing the pipe from service.[656] This fund would also protect taxpayers from potentially unlimited expenses in relation to monitoring of the decommissioned Project if Enbridge, or a successor firm, ceases to be a going concern.[657]

DOC DER requested that Enbridge estimate the cost of decommissioning the proposed Project in Minnesota based upon the NEB's methodology. While Enbridge's response as to the specific costs is trade secret and can be found at KO-29, the total cost is public, which Enbridge projected to be $73,861,705.[658] The main advantage to a decommissioning trust is that Enbridge would be able to self-fund decommissioning of the proposed Project over time and during a period of relative financial strength.[659] By having this fund in place, Enbridge should have sufficient funds available to decommission the proposed Project without having to use future funds, which as indicated above, could be a risk to Minnesota taxpayers.[660] Finally, the Commission should require Enbridge to provide periodic updates to these costs.[661]

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[656] *Id.*
[657] *Id.*
[658] *Id.* at 119, KO-29.
[659] *Id.* at 119.
[660] *Id.* at 118–119.
[661] Ex. DER-1 at 120 (O'Connell Direct).

8. The Commission Should Not Find Need Without Requiring Enbridge to Implement the Conditions in DOC DER Witness David Dybdahl's Testimony Regarding Parental Guaranty and Insurance.

If it considers certain conditions as a means to support finding that need is established for Line 3,[662] DOC DER considers essential the financial assurance conditions recommended by Mr. David Dybdahl, an expert retained by DOC DER, with extensive experience and education in environmental risk management and insurance as well as placement of environmental insurance policies.[663] His recommendation is intended to protect the State of Minnesota in the event of future catastrophic losses from oil spills on Line 3 together with potential insolvency or financial inadequacy of the Applicant,[664] its parent,[665] or even Enbridge Inc.[666] His conditions attempt to ensure available funding for decades to come in case "the entire Enbridge organization" is not financially capable of paying for potential damages caused by crude oil spills from Line 3.[667]

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[662] Reference to "Line 3" in this Initial Brief discussion of Mr. Dybdahl's recommendations means a "new" or replacement Line 3, not the currently existing Line 3.
[663] Ex. DER-5 at 1, DD-1 at 6-7 (Dybdahl Direct).
[664] Enbridge Energy Limited Partnership, or EELP.
[665] Enbridge Energy Partners, L.P. or EEP.
[666] Enbridge Inc., is the overall parent company, domiciled in Calgary, Alberta (Canada), that effectively controls 17,511 miles of crude oil pipelines and ancillary equipment and property in North America through a series of divisions, subsidiaries, partnerships and affiliates in order to manage its operations, attract capital on favorable terms, minimize its tax liability and shield its assets. None of these downstream entities operate autonomously of the parent. Instead, they reflect to one degree or another the economic dynamics and financial imperatives operating on Enbridge Inc. Ex. DER-5, DD-1 at 11 (Dybdahl Direct) (as corrected). *See also* Ex. DER-13 and 14 (Enbridge Inc. organizational charts); Evid. Hrg. Tr. Vol. 6A (Nov. 9, 2017) at 13, 137 (Johnston) (Enbridge Inc. is the top Enbridge entity or "mother ship").
[667] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 52 (Dybdahl). *See, e.g.*, Ex. DER-5, DD-1 at 6-10 (Dybdahl Direct).

Given the massive $1.2 billion loss from the 2010 crude oil spill on Line 6B of the Enbridge Mainline System near Marshall, Michigan,[668] Mr. Dybdahl assumed for this matter a worse-case situation occurring some 60 years into the future that could result in similarly massive losses, although he also assumed financial insolvency or incapacity of Enbridge companies to pay the resulting future cleanup-related costs.[669]

Mr. Dybdahl recommends the Commission use a combination of financial assurance tools that, together, continues to equal at least the $1.2 billion loss resulting from the Enbridge Line 6B spill.[670] His three-part recommendation includes:[671]

1) A parental guaranty of Enbridge Inc. to indemnify the State of Minnesota; and

2) Insurance coverage (two types policies) totaling $1.2 billion, as offset by

3) Funding from the U.S. Oil Spill Liability Trust Fund, to the extent available.

His recommendation does not incorporate the possibility that the U.S. might require Enbridge in the future to remove its pipelines when abandoned, which would cost approximately $1.27 billion for a new Line 3 based on today's estimated removal cost of $855 per foot of pipe.[672]

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[668] Ex. DER-5, DD-1 at 8 (Dybdahl Direct). Later in 2010, another spill on an Enbridge pipeline, Line 6A near Romeoville, Illinois, caused additional losses of $38 million. *Id.* at 21.

[669] Ex. DER-5, DD-1 at 52-53, 109, 133 (Dybdahl Direct).

[670] *Id.* at 9. Mr. Dybdahl agreed that the term "financial assurance" is the notion that Enbridge needs to assure that funds are available to take care of something like a spill in case the operator can't do it or won't do it. Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 98-99 (Dybdahl).

[671] Ex. DER-5, DD-1 at 9 (Dybdahl Direct). Mr. Dybdahl's recommendation to protect the State of Minnesota reflect his education and experience, but are not exclusive. He acknowledged other mechanisms that may be available for the Commission's consideration such as surety bonds, payment or performance bonds, period financial assessments, and cash-funded trust funds with the State as a beneficiary. Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 99 (Dybdahl)

[672] Ex. DER-5, DD-1 at 124-125 (Dybdahl Direct). *See also*, Tr. Vol. 6A at 125-127 (Dybdahl); Evid. Hrg. Tr. Vol. 6A (Nov. 9, 2017) at 125-127 (Johnston) (confirms current pipeline removal costs equal approximately $855 per foot, and mileage in Minnesota of proposed Line 3 is 337 miles) (Calculation of removing new Line 3: 337 miles X 5280 fee/mile X $855/mile = over $1.5

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Mr. Dybdahl's insurance condition requires that Enbridge carry, at minimum, the following insurance: a general liability (GL) policy of $100 million having a reinstatement provision applicable to Line 3, and an environmental impairment liability (EIL) policy of $100 million that, by definition, provides coverage for pollution losses attributable to Line 3, together with a reinstatement provision.[673] The State of Minnesota must be named as an Additional Insured on both the GL and EIL policies,[674] and coverage under both types of liability insurance must increase by $10 million every five years until Line 3 is decommissioned.[675] If Line 3 becomes uninsurable at any time during its operating life, Mr. Dybdahl recommends that Enbridge be required to discontinue operation of Line 3 in Minnesota.[676]

a. Estimated future funding level: The $1.2 billion loss from the 2010 Enbridge Line 6B rupture near Marshall, Michigan frames Mr. Dybdahl's recommendation

DOC DER retained Mr. Dybdahl to provide information regarding the financial capacity of Applicant—Enbridge Energy, Limited Partnership or EELP—to address cleanup costs and other potential damages resulting from an oil spill over the operational life of the proposed Line

(Footnote Continued from Previous Page)
million); Evid. Hrg. Tr. Vol. 6B (Nov. 9, 2017) at 49 (Johnston) (confirms current mileage of Enbridge pipe in the U.S. is 5705 miles) (Calculation of removing existing Enbridge pipe in the U.S.: 5705 miles X 5280 feet/mile X $855/foot = over $25 billion). The cash value of an abandoned pipeline would be $0. *Id.* at 30.

[673] Ex. DER-5, DD-1 at 4, 36, and Appendix A (Dybdahl Direct); Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 55, 76-79, 100-01, 104-05, 125, 151-52, 154-62, 168 (Dybdahl).

[674] Ex. DER-5, DD-1 at 4, 36 (Dybdahl Direct); Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 163-164, 169 (Dybdahl).

[675] Ex. DER-5 at 36 (Dybdahl Direct).

[676] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 113-114 (Dybdahl).

3 pipeline, and to recommend means by which the State of Minnesota may be assured that, as to a future spill on Line 3:[677]

- Applicant EELP has the financial resources to ensure the timely remediation and restoration of the environment;
- Money will be available to compensate the stakeholders in Minnesota for damages that the citizens may incur; and
- There will be no unfunded potential liability or expense incurred by Minnesota arising from the operation of Line 3 within the State.

Mr. Dybdahl responded by filing as part of his direct testimony a report titled, *A Risk Financing and Insurance Report on the Proposed Enbridge Line 3 Replacement*,[678] as well as seeking and responding to discovery, providing surrebuttal testimony and appearing for cross-examination at trial. He summarized his role in this matter as making sure, in the event of future disastrous oil spills on Enbridge's Line 3, that the State of Minnesota doesn't "get left holding the bag."[679]

To estimate the potential size of future unfunded liabilities, he reviewed the historical risk of spills and cleanup costs related to crude oil pipelines both in the United States and in Minnesota.[680] He highlighted that, as recently as 2010, two of Enbridge's Mainline System pipelines caused the largest pipeline releases in U.S. history.[681] The worst spill on record is the $1.2 billion in losses stemming from the rupture near Marshall (and Kalamazoo), Michigan on

[677] Ex. DER-5, DD-1 at 7 (Dybdahl Direct). The report focuses on financing the cost of a spill from Line 3; indirect costs to third parties from a pipeline accident that affects unrelated, but interconnected activity and business, such as tourism, can be a significant loss exposure arising from a spill, but are not accounted for in the report. *Id.*
[678] Ex. DER-5, DD-1 (Dybdahl Direct).
[679] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 133 (Dybdahl). *See also id.* at 98, 100-101, 168.
[680] Ex. DER-5, DD-1 at 10-13 (Dybdahl Direct).
[681] Ex. DER-5, DD-1 at 22 (Dybdahl Direct).

Enbridge's Line 6B,[682] and the next worst is a loss of $38 million that occurred later the same year on a different Enbridge pipeline, Line 6A, near Romeoville, Illinois.[683] Mr. Dybdahl testified that Line 3, based on the conservative analysis of spill probability used in the Final EIS in this case, conceivably could release a volume of oil similar to that released on Enbridge's 2010 Line 6B spill, and such a potential release could occur into a waterway similar to the Line 6B spill.[684] The costliest oil spills to remediate are those involving water, and the proposed Project is proposed to cross hundreds of miles of land, wetlands and bodies of water in Minnesota:[685]

> Line 3 crosses over more than fifty waterways including the head waters of the Mississippi river. The environmental impact of a spill on an inland waterway in Minnesota could reasonably be expected to produce environment damages similar to the Enbridge Line 6B spill in Michigan. The costliest oil spill clean-ups on land are associated with pipelines near water. There is a significant amount of water along the proposed Line 3 alternative routes.

Thus, Mr. Dybdahl used the cost of the largest known loss, $1.2 billion from Enbridge Line 6B, as a benchmark – the Maximum Probable Loss - for estimating the potential funding needed to protect Minnesota over the life of the proposed Project,[686] noting that proposed Line 3 "has greater loss potential to spills into water" than Line 6B.[687] His recommendation hinges on the fact that crude oil pipelines are long-lived assets such that circumstances well into the future may

[682] *Id.*; Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 168 (Dybdahl).
[683] *See id.*; Ex. DER-5, DD-1 at 22 (Dybdahl Direct).
[684] *Id.* at 8-9 (citing FEIS Ch. 10.1.3.3.2).
[685] *Id.* at 8.
[686] Ex. DER-5, DD-1 at 16-20 (Dybdahl Direct).
[687] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 54 (Dybdahl).

be quite different from today.[688] Enbridge Line 5 is 64 year old and continues to transport crude oil under the Straits of Mackinac to Michigan.[689]

b. Potential future risks of operating Line 3

Significant emphasis in Mr. Dybdahl's report and other testimony concerns potential risks attendant to operating a crude oil pipeline like the proposed Line 3 for 60-plus years.[690] He focused on three main risk factors that could leave Enbridge entities unable to pay for cleanup costs resulting from a spill on Line 3. First, there is a potential for more than one catastrophic loss in a short period of time, thereby potentially leaving no financial resources available for the second loss (for instance, a subsequent spill on Line 3).[691] He noted the two record-setting spills on Enbridge Mainline System Lines 6B and 6A that occurred within the same year.[692] As to the future, Mr. Dybdahl testified that a future rupture on Line 5, the 64-year old Enbridge pipeline through the Straits of Mackinac could be of significant volume on "big water" with overwhelming financial consequences:[693]

> Based upon historical oil spills on big water costing tens of billions of dollars, a rupture of Line 5 could overwhelm the ability of Enbridge entities to pay for the loss costs associated with the spill.

In such a scenario, if another spill occurred within a short period of time, this time on Line 3 in Minnesota or anywhere on Enbridge's system, it is conceivable that no Enbridge entity –

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[688] Ex. DER-5, DD-1 at 1, 8-9 (Dybdahl Direct); Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 52-58 (Dybdahl).
[689] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 52 (Dybdahl). A rupture of Enbridge's Line 5 under the Straits of Mackinac, given the volume of water, depth and strong currents, could result in costs that are tens of billions of dollars more than those resulting from Line 6B. *Id.* at 55.
[690] *See generally* Ex. DER-5, DD-1 at 7-24 (Dybdahl Direct).
[691] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 55 (Dybdahl).
[692] *Id.*
[693] *Id.*; Ex. DER-5, DD-1 at 21 (Dybdahl Direct).

Applicant, EEP, or Enbridge Inc. – could pay for cleanup of that second spill if the first loss from Line 5 consumed all available funding resources.[694]

Second, a general downturn in the use of tar sand-sourced oil such as the heavy oil that Applicant seeks to transport from Western Canada on proposed Line 3, and assuming a potentially carbon-constrained economy, would impair the ability of EEP in its current business model to maintain profitable operations over time, and at the same time would significantly reduce the net asset value of the firm.[695] The result of such a general business downturn would be a reduction in Applicant's or EEP's ability to borrow funds to fund cleanup of such a loss event.[696]

Third, there are concerns with Enbridge Inc.'s historical practice of relying solely on general liability, GL, insurance and not also environmental impairment liability, EIL, insurance.[697] Mr. Dybdahl noted the proven difficulty, based on Enbridge's own history, of building reliable insurance coverage for pollution events based upon a series of pollution exclusions and exceptions to the exclusions in a general liability insurance policy.[698] Enbridge encountered this difficulty firsthand with the general liability (GL) insurance policy that covered all of its operations in 2010, and which contained exceptions to the universal GL exclusion for pollution losses for sudden and accidental pollution events. He explained that $85 million in coverage intended to reimburse Applicant for cleanup of the Marshall spill ultimately was denied following arbitration of a dispute between Enbridge Inc. and certain insurers that interpreted the

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[694] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 55-56 (Dybdahl).
[695] *Id.* at 56.
[696] *Id.*
[697] *See* Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 56 (Dybdahl).
[698] *Id.*

pollution exclusion language rather than the exceptions to exclusions to govern coverage.[699] Mr. Dybdahl recommends modest diversification of the type of liability insurance carried by Enbridge Inc. so that Line 3 is covered not only by GL insurance but also by environmental impairment liability or EIL insurance; unlike GL insurance, EIL insurance directly covers cleanup costs, restoration and costs for natural resources damages resulting from a pollution event, while both types of insurance cover bodily injury and property damage liability.[700]

The financial assurance tools proposed by Mr. Dybdahl, to address the above risks, are somewhat similar to those employed by Enbridge companies in response to the two 2010 spills: indemnity, insurance and the U.S. Oil Spill Liability Fund. That is, for the 2010 Line 6B spill, there was: 1) indemnity, then by Enbridge Energy Partnership or EEP—Once Applicant (EELP) exhausted its cash, EEP paid all cleanup costs including amounts that exceeded the amount ultimately recovered under insurance policies then in place;[701] 2) some insurance recovery of about $550 million;[702] and 3) state and federal agency responders received payment from the U.S. Oil Spill Liability Trust Fund,[703] which EEP apparently also repaid.[704]

c. A parental guaranty of Enbridge Inc. is an important financial assurance tool

To protect the State of Minnesota, Mr. Dybdahl recommends as one of his three financial assurance recommendations that indemnity through a parental guarantee of Enbridge Inc. be

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[699] *Id.* at 56-57.
[700] Ex. DER-5, DD-1 at 4, 30-31 (Dybdahl Direct); Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 76 (Dybdahl).
[701] Evid. Hrg. Tr. Vol. 6B (Nov. 9, 2017) at 14-15 (Johnston). Enbridge Inc. did not pay for the 2010 Marshall spill cleanup costs. *Id.*
[702] Evid. Hrg. Tr. Vol. 6A (Nov. 9, 2017) at 62 (Johnston).
[703] *See* Ex. DER-5, DD-1 at 8-9 (Dybdahl Direct).
[704] *Id.* at 8.

required.[705] Indemnification is "first dollar protection" for the State and renders the State eligible to be an Additional Insured on the liability insurance policies Mr. Dybdahl recommends.[706] Ensuring indemnity from an Enbridge entity potentially capable of paying extraordinary sums far into the future is particularly important in this case where Applicant and EEP do not, and will not, rely on insurance recovery to fund future cleanup costs stemming from pipeline spills.[707] According to both Enbridge witnesses Mr. Chris Johnston, Vice President of Finance,[708] and Ms. Selina Lim, Director of Insurance Risk Management,[709] insurance is simply supplemental to other funding.[710] Mr. Johnston testified that Applicant together with EEP have and will have the financial ability to pay for any cleanup costs from a future spill on Line 3.[711] DOC DER, however, disagrees that either entity, alone or together, made such a showing.

As discussed by Mr. Dybdahl, Applicant and EEP did not show that in the future they are likely to be able to pay all costs of spills on Line 3 in the event that Mr. Dybdahl's troubling risk scenarios occur, possibly many years from now. A key failing on the part of Applicant and EEP is that they do not or cannot envision a future in which together they will be unable to pay all

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[705] *See, e.g.*, Ex. DER-5, DD-1 at 8-9, 21 (Dybdahl Direct); Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 52-57 (Dybdahl).
[706] Ex. DER-5, DD-1 at 31 (Dybdahl Direct).
[707] Ex. EN-42 at 9 (Johnston Rebuttal) (insurance should not factor into assessing financial ability to fund cleanup efforts); Ex. EN-43 at 8 (Lim Rebuttal) (there is always a chance that insurance will not cover a loss).
[708] Ex. EN-42 at 1 (Johnston Rebuttal). Previously, Mr. Johnston was Vice President and Controller of Enbridge Inc. *Id.*
[709] Ex. EN-43 at 1 (Lim Rebuttal).
[710] Evid. Hrg. Tr. Vol. 6A (Nov. 9, 2017) at 50 (Johnston); Evid. Hrg. Tr. Vol. 6B (Nov. 9, 2017) at 111-112, 1331-132 (Lim) (Ms. Lim states that insurance recovery may occur many years after spill, and may not offset all costs of a spill); Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 126 (Dybdahl).
[711] Evid. Hrg. Tr. Vol. 6A (Nov. 9, 2017) at 51-53 (Johnston).

such costs.[712]Dybdahl's observed that Enbridge witnesses "assume a robust and profitable operating environment for Enbridge indefinitely into the future."[713] He expressed concern that neither Mr. Johnston nor Ms. Lim considers a future that includes significant oil spill-related losses or serious business adversity:[714]

> Neither one addresses a loss scenario that exceeds the recoverable insurance, sellable assets, cash, earning power or borrowing capacities of the Applicant, or EEP.
>
> Neither assumes the effect of a possible general downturn over time for the suppliers of unusually carbon-intensive fossil fuels in a carbon constrained economy or what a general business downturn would do to the ability of the Applicant, or EEP, to pay for the environmental legacy liabilities and loss costs on a pay-as-you-go basis.

Thus, a significant difference between DOC DER and Applicant or EEP is that DOC DER through Mr. Dybdahl looks to protect Minnesota against a worst-case financial future for Enbridge entities while Applicant and EEP rely heavily on continuation of their current financial condition.[715]

i. Present financial ability of Applicant and EEP to pay

Applicant EELP, together with EEP, rely on their current combined financial strength as assurance that together they will pay, and be able to pay, for any and all future losses that could

[712] *Id.* at 52-53.
[713] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 53 (Dybdahl).
[714] *Id.*; *see also* Evid. Hrg. Tr. Vol. 6A (Nov. 9, 2017) at 52-54, 56-60, 104, 106, 110-111, 115-117, 123 (Johnston); Evid. Hrg. Tr. Vol. 6B (Nov. 9, 2017) at 177-178 (Lim).
[714] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 53-54 (Dybdahl).
[715] *Id.*

occur on Line 3; if necessary, EEP offered to provide a parental guarantee in the event that EELP is unable to pay for such losses, and the guaranty is not dependent on insurance recovery.[716]

At present, EEP appears to be a profitable company. Mr. Dybdahl agreed not only that EELP and EEP together showed their past ability to pay for multiple record-setting spills within the same year to the extent that insurance proceeds were insufficient, he agreed that together they appear to have the present financial ability to do so.[717] The present financial capacity of the Applicant alone is not well developed in this record.[718] Enbridge witness Mr. Chris Johnston testified that EELP currently receives revenues from Enbridge Pipelines (Lakehead), LLC, which operates the Enbridge Mainline System, but the ability to borrow (i.e., lines of credit called credit facilities) resides with EEP.[719] He testified that 85 percent of EEP's business is Applicant's business.[720] He identified the present financial condition of EEP alone, as follows:

- Over $700 million in available cash (*i.e.*, net annual cash flow);[721]
- Ability to borrow up to $1.5 billion out of total committed lines of credit of $3.4 billion for the next three to four years;[722] and
- Total asset value of $ 15 billion (*i.e.*, the book value of pipeline in the ground less depreciation, etc.), with a net asset value of $7 billion (net of debt).[723]

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[716] Ex. EN-42 at 5 (Johnston Rebuttal); Evid. Hrg. Tr. Vol. 6A (Nov. 9, 2017) at 50, 62, 110 (Johnston); Ex. DER-5, DD-1 at 30 (Dybdahl Direct).
[717] Ex. DER-5, DD-1 at 9, 20 (Dybdahl Direct); *See* Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 53 (Dybdahl).
[718] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 106 (Dybdahl).
[719] *Id.* at 37.
[720] Tr. Vol. 6A at 140 (Johnston).
[721] Evid. Hrg. Tr. Vol. 6B (Nov. 9, 2017) at 38-39 (Johnston); Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 106, 109 (Dybdahl). Mr. Dybdahl testified at trial that his report identified the amount of cash currently available to EEP as $108 million in cash, but had not identified the higher present (net) annual cash flow of $700 million. *Id.* at 109.
[722] Evid. Hrg. Tr. Vol. 6B (Nov. 9, 2017) at 8-10, 15, 37-38, 41 (Johnston).

In Mr. Johnston's view, EEP's financial resources are "projected to be fairly stable",[724] but in response to questioning, he admitted that his outlook was limited to lenders' near-term commitments to lend for the next three to four years (commitments are for 5-year blocks of time),[725] and expected cash flow over perhaps the next 20 years,[726] but not over Mr. Dybdahl's timeline of perhaps 60 years of operating life for Line 3.[727]

Enbridge Inc., on the other hand, is the third largest Canadian company.[728] In contrast to EEP's current net cash flow of about $700 million, Enbridge Inc.'s current cash flow dwarfs that of EEP at, for 2016, about $4 to $5 billion.[729]. Mr. Johnston did not know Enbridge Inc.'s current available credit facilities, but testified that it they are "definitely larger" in that "Enbridge Inc. is a much larger company" than EEP.[730] The market capitalization of Enbridge Inc. (the quantity of shares owned by individual shareholders times the price) is about $95 billion in comparison with $6 billion in market capitalization for EEP.[731] While current financial conditions do not dictate future financial conditions, Enbridge Inc. is exponentially better positioned currently to fund cleanup of significant multiple pollution events.

(Footnote Continued from Previous Page)

[723] Evid. Hrg. Tr. Vol. 6B (Nov. 9, 2017) at 8, 10-11 (Johnston).

[724] Evid. Hrg. Tr. Vol. 6B (Nov. 9, 2017) at 47, 52 54, 64, 104 (Johnston).

[725] *Id.* at 9-10, 41.

[726] Evid. Hrg. Tr. Vol. 6A (Nov. 9, 2017) at 54 (Johnston).

[727] Evid. Hrg. Tr. Vol. 6B (Nov. 9, 2017) at 9-10 (Johnston).

[728] *Id.* at 131.

[729] Evid. Hrg. Tr. Vol. 6B (Nov. 9, 2017) at 130 (Johnston).

[730] *Id.* at 131.

[731] *Id.* at 131-132. The record does not appear to include evidence of the current financial condition of other Enbridge entities.

ii. Future lack of financial ability of Applicant and EEP to pay

Neither Applicant nor EEP showed that their *current* financial capacity is a reasonable proxy for their *future* financial capacity to fund $1.2 billion in pollution-related costs of cleanup, restoration and natural resources damages over the life of the proposed Project, particularly in light of the three risk factors and long asset life discussed by Mr. Dybdahl. He concluded that the current ability of the companies, EELP and EEP, to pay for major spills is unlikely to remain stable over time: "Changes in the business climate that Enbridge must operate in and the potential to have multiple large spill events over a short period of time, need to be accounted for in developing a risk financing strategy for the proposed Line 3."[732] As noted above, Mr. Dybdahl provided a future scenario with the potential for a single spill on another Enbridge pipeline to "overwhelm" all available funding resources and leave no funds available to pay for a subsequent spill on Line 3.[733]

As to EEP's future financial condition decades in the future, Mr. Dybdahl testified that only EEP's future cash should be regarded as a reliable means to fund future cleanup efforts.[734] He explained that EEP's net book value, currently at $7 billion, largely reflects accounting requirements and does not pay for cleanup costs.[735] Thus, future book value would not be helpful: "Assets [pipe in the ground], book value doesn't pay for cleanup cost. Cash pays for cleanup costs."[736] This fact is heightened by the fact that once a pipeline is abandoned, there is

[732] Ex. DER-5, DD-1 at 9 (Dybdahl Direct).
[733] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 55-56 (Dybdahl).
[734] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 106 (Dybdahl).
[735] *Id.* at 106-107.
[736] *Id.* at 105-108.

no value in that idled pipeline.[737] EEP's current available line of credit of $1.5 billion can only be counted on for the near term since current lines of credit are committed for the next three to four years,[738] and may be re-committed in five-year blocks of time.[739] Mr. Dybdahl explained the undependability of lines of credit in the event of a serious future general business turndown or in the event of a "really bad loss where nobody wants to do business with them."[740] In such future scenarios, EEP would have difficulty borrowing money to pay cleanup costs.[741] Further, in a future general business turndown, he concluded that even EEP's present annual available cash flow of $700 million could be insufficient for it to survive.[742]

Asked at trial why a parental guarantee of Enbridge Inc. is necessary to protect the State of Minnesota in addition to recommended conditions totaling $1.2 billion in insurance and other funding, Mr. Dybdahl testified that Enbridge Inc. not only (currently) has many times more available cash than does EEP, it also appears more likely to be able to survive a serious general business turndown:[743]

> So even in a general business downturn, Enbridge, the Company, the mothership, they're into renewable energy, they're diversified, where the U.S. operations look, to me, like pretty much exclusively tar sands derived crude.

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[737] *Id.* at 106-107. *See* Evid. Hrg. Tr. Vol. 6B (Nov. 9, 2017) at 30 (Johnston).
[738] Evid. Hrg. Tr. Vol. 6B (Nov. 9, 2017) at 9-10 (Johnston).
[739] *See* Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 41, 106-108 (Dybdahl).
[740] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 107-108 (Dybdahl).
[741] *Id.* Mr. Dybdahl did not consider the ability of Enbridge to use debt to pay for a pipeline spill. "The ability of any company to raise funds by borrowing is greatly impacted by the financial condition of the company at the time the funds are needed. Borrowing as a method to pay for uninsured losses is highly unreliable because lenders are always concerned about the financial health of the borrower when a loan is made. In the face of major uninsured cleanup liabilities, access to borrowed funds will certainly be impaired." Ex. DER-5, DD-1 at 20 (Dybdahl Direct).
[742] *Id.* at 109-110. *See also* Ex. DER-5, DD-1 at 6, 9, 22-23 (Dybdahl Direct).
[743] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 126-127 (Dybdahl).

> * * *
>
> Enbridge, the mothership, is much more survivable than the U.S. operations because of the diversity in the renewable energy sector and they've got the cash.
>
> So I like their indemnity better.

In addition, as discussed below, Enbridge Inc. is better able to ensure its longevity than is Applicant or EEP.

iii. Enbridge Inc.'s organizational structure appears to effectively insulate Enbridge entities from liability for future cleanup costs of a spill on proposed Line 3

According to Mr. Johnston, under no circumstances would Enbridge Inc. be responsible for cleanup or remediation of a future spill on proposed Line 3 nor would any Enbridge entity higher (closer to Enbridge Inc.) than EEP (which offers parental guarantee):[744] "You don't get above Enbridge Energy Partners, L.P."[745] The complex organizational charts of Enbridge Inc. appear to confirm Mr. Johnston's assessment.[746]

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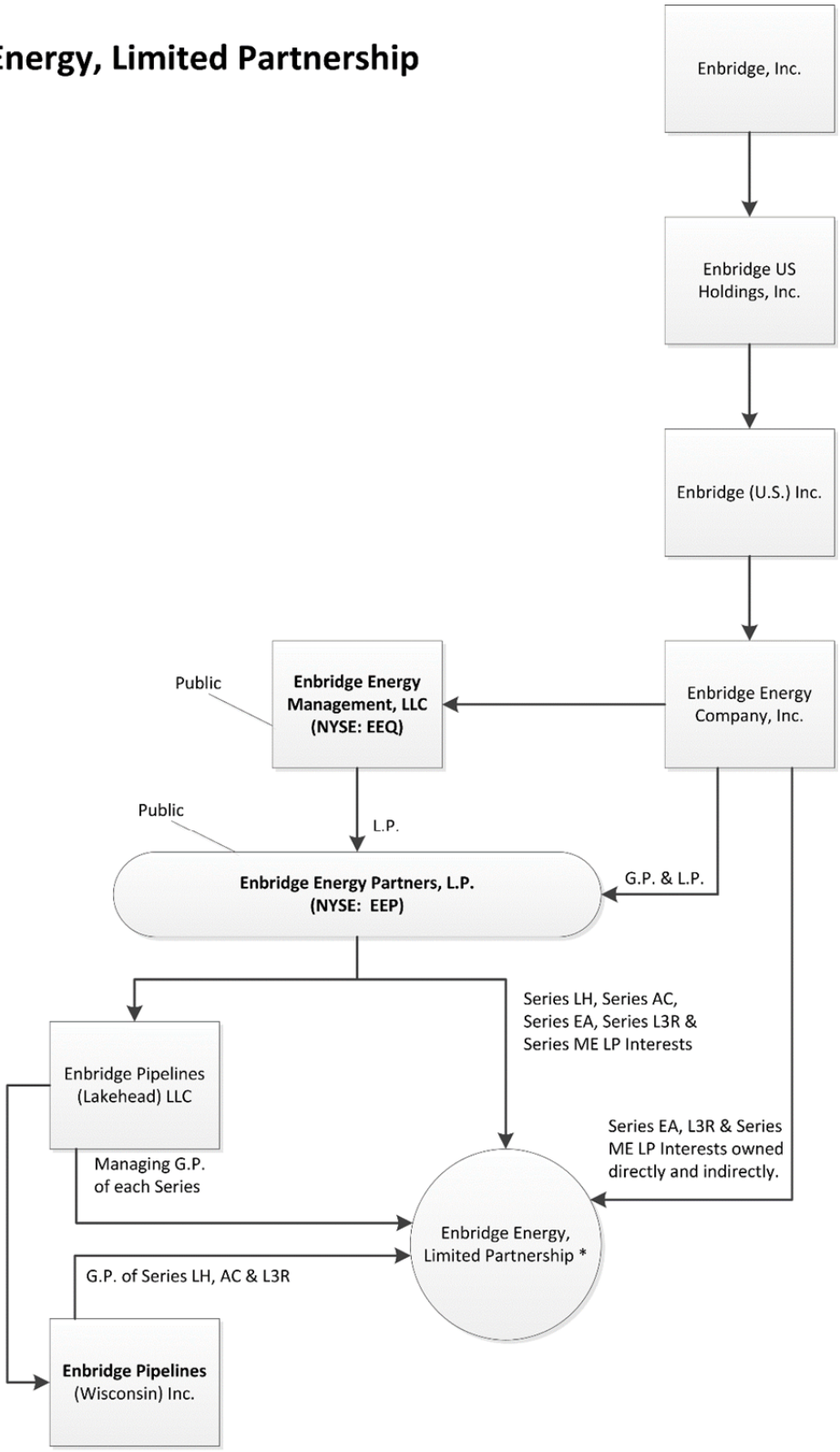
[744] Tr. Vol. 6A at 73, 76, 103, 115 (Johnston); Evid. Hrg. Tr. Vol. 6A (Nov. 9, 2017) at 73, 76, 103, 115 (Johnston).
[745] Evid. Hrg. Tr. Vol. 6A (Nov. 9, 2017) at 77 (Johnston).
[746] *See* DER-Ex. 13 (Enbridge Inc. U.S. operations), and DER-14 (Enbridge Inc. U.S. and Canadian operations, partial).

Enbridge Energy, Limited Partnership



* Existing joint funding arrangements in place for the Mainline Expansion, Eastern Access and Line 3 Replacement project.

DOC DER manually reproduced DER-Exhibit 13, above, which is a depiction of Enbridge Inc.'s U.S. operations.[747] This organizational structure of the U.S. operations of Enbridge companies appears designed to limit liability for potentially disastrous losses from spills on its pipelines. To see this effect, it is necessary to understand basic attributes of the various corporate boxes and partnership ovals or circles on DER-Ex. 13. In response to questioning, Mr. Johnston agreed generally that liabilities of a corporation are limited to the assets of the corporation.[748] Similarly, he agreed that for a "limited liability company" or LLC, its debts and liabilities are limited to the assets of the LLC; members are generally not responsible for debts and liabilities of an LLC.[749] As to a partnership, Mr. Johnston agreed at a high level that a general partner has liability for the obligations or liabilities of the partnership.[750] A general partner controls the significant operating, financing and investing decisions of the partnership while limited partners do not.[751] As to limited partners, Mr. Johnston generally agreed that they are not responsible for the partnership's debts and liabilities beyond their capital contribution to that partnership.[752] He emphasized, though, that while EEP is a limited partnership but is not a limited partner of Applicant (EEP holds a partnership investment in Applicant),[753] EEP's offer of a parental guaranty means that EEP would be responsible for Applicant's liabilities to the extent that EELP could not pay.[754]

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[747] DER-13 (Enbridge Inc. U.S. operations).
[748] Evid. Hrg. Tr. Vol. 6A (Nov. 9, 2017) at 136-137 (Johnston).
[749] *Id.* at 137.
[750] *Id.* at 138.
[751] Evid. Hrg. Tr. Vol. 6A (Nov. 9, 2017) at 91 (Johnston).
[752] Evid. Hrg. Tr. Vol. 6A (Nov. 9, 2017) at 138-139 (Johnston).
[753] *Id.* at 84-86.
[754] *Id.* at 139-140.

Exhibit DER-13 shows that Enbridge Inc. is a corporation which owns a corporation[755] which owns a corporation[756] which owns a corporation[757] which owns part of EEP, a limited partnership. According to Mr. Johnston, Enbridge Inc. owns "an effective 35 percent ownership interest" in EEP through its partial ownership of a management company,[758] which is another corporation. He explained that EEP is controlled by its general partner, Enbridge Energy Company, Inc.,[759] while Applicant is controlled by its two general partners, are Enbridge Pipelines (Lakehead) L.L.C. and Enbridge Pipelines (Wisconsin) Inc.[760] EEP owns 100 percent of Applicant,[761] which is a master limited partnership.[762] Further, Mr. Johnston testified that Applicant has access to the cash flow generated from the Lakehead system.[763] Applicant owns the pipeline assets of Enbridge's Mainline System[764] and would own the proposed Project.[765]

Significant time was spent at trial by parties trying to make sense of the organizational complexities of the U.S. family of Enbridge companies and their significance to this case. Although he claimed not to know why Enbridge Inc. chose such a complex organizational structure, Mr. Johnston was sure that Enbridge Inc.'s reason for doing so was not to intentionally

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[755] Enbridge US Holdings, Inc.
[756] Enbridge (U.S.) Inc.
[757] Enbridge Energy Company, Inc.; Enbridge Inc. effectively owns 100 percent of this company. Evid. Hrg. Tr. Vol. 6A (Nov. 9, 2017) at 68-69 (Johnston). Thus, Enbridge Inc. appears to own 100 percent of Enbridge US Holdings, Inc. and Enbridge (U.S.) Inc.
[758] Evid. Hrg. Tr. Vol. 6A (Nov. 9, 2017) at 71-72 (Johnston).
[759] Evid. Hrg. Tr. Vol. 6A (Nov. 9, 2017) at 82, 88-89 (Johnston).
[760] *Id.* at 82, 91.
[761] *Id.* at 71-72, 135-136.
[762] *Id.* at 60, 81.
[763] Evid. Hrg. Tr. Vol. 6A (Nov. 9, 2017) at 107-108 (Johnston).
[764] *Id.* at 133.
[765] *Id.* at 101.

limit liability of Enbridge entities.[766] Whether intentional or not, the effect of the Enbridge Inc. corporate structure surely insulates various Enbridge entities including Enbridge Inc. from responsibility for future spills on an Applicant-owned Line 3.

Also of concern regarding the future, Mr. Johnston confirmed that Enbridge Inc. could transfer (and has transferred in the past) ownership of assets from one Enbridge entity to another or could create a different operating company, subject to approval of applicable boards of directors.[767] This fact means that in addition to dire risk scenarios identified by Mr. Dybdahl, Applicant and EEP could be stripped in the future of significant cash or otherwise diminished financially by actions of Enbridge Inc.

For these reasons, Applicant and EEP did not demonstrate that the current organizational structure of the Enbridge family of companies is a reasonable proxy for the future structure or the future financial condition of Enbridge entities within that structure.

iv. Conclusion: A Parental Guarantee by Enbridge Inc. is Essential to a Need Determination

Enbridge did not show that a parental guarantee by any entity other than Enbridge Inc. reasonably could be assumed to protect the State of Minnesota from unfunded liabilities over the next 60-some years. DOC DER recommends that the Commission require a parental guarantee from Enbridge Inc. as an essential condition of receiving CN approval and of continuing to operate a new Line 3 in Minnesota.

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[766] Evid. Hrg. Tr. Vol. 6A (Nov. 9, 2017) at 140-142 (Johnston).
[767] *Id.* at 101-103; Evid. Hrg. Tr. Vol. 6B (Nov. 9, 2017) at 52-56 (Johnston). *See also id.* at 41-44 (restructured joint funding arrangements for the proposed Project).

d. Insurance is an important financial assurance tool

To protect the State of Minnesota against potential loss scenarios where the entire Enbridge organization may not be financially capable of paying substantial damages caused by Line 3, Mr. Dybdahl's recommendation includes insurance-specific conditions.[768] Critical to this recommendation is that Enbridge's current insurance policy is largely irrelevant to this case because insurance policies are negotiated annually and terms of future policies are likely to be different from today's terms.[769] Discussed below are Mr. Dybdahl's recommended insurance requirements, the value of insurance as a risk mitigation tool, typical GL and EIL policy terms and concerns, Enbridge Inc.'s current GL policy provisions, the importance of Mr. Dybdahl's insurance specifications, explanations satisfying Ms. Lim's concerns regarding potential stacking issues and EIL market availability, and discussion of the potential $1 billion in payment from the U.S. Oil Spill Liability Trust Fund in the event of a spill on Line 3.

i. Insurance requirements

Mr. Dybdahl's recommended insurance specifications in Appendix A of his report,[770] are summarized, as follows: Enbridge must procure and maintain the following liability insurance policies purchased from insurance companies with no controlling economic ownership ties to Enbridge over the course of the permit duration:[771]

1. GL insurance with a $100 million per loss limit including a "time element" exception to the pollution exclusion (currently in place);

[768] Ex. DER-5, DD-1 at 20-24 (Dybdahl Direct); Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 52-57 (Dybdahl).
[769] Ex. DER-5, DD-1 at 24 (Dybdahl Direct); Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 77, 132 (Dybdahl).
[770] Ex. DER-5, DD-1 at 35-36 (Dybdahl Direct) (pages 35-36 are entitled, "Appendix A").
[771] Ex. DER-5, DD-1 at 34 (Dybdahl Direct).

2. EIL insurance with a $100 million per loss limit of liability;

3. Both the GL and EIL policies should include one automatic reinstatement of limits provision (guaranteed for Line 3) or an annual aggregate of twice the per loss limit ($200 million);[772]

4. These amounts of insurance should be increased by $10 million for both GL and EIL policies every five years until Line 3 pipe line is decommissioned;

5. The State of Minnesota should be named as an Additional Insured under the GL and EIL policies; and

6. Enbridge should provide the State of Minnesota with a certificate of insurance on an annual basis that details all endorsements to the policy as they may appear.

The $200 million in insurance requirements assumes that $1 billion in payment is available from the U.S. Oil Spill Liability Fund; otherwise, Enbridge Inc. is required to increase its insurance requirements in order to meet the enduring $1.2 billion funding level Mr. Dybdahl recommends.[773] The reinstatement of limits provision is required only as to Line 3 and, particularly for the future GL policy, would guarantee continuing coverage of Line 3 under Enbridge Inc.'s GL policy in the event that initial limits are exhausted during the policy period by a spill elsewhere on Enbridge Inc.'s system.[774]

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[772] In case of exhaustion of limits during the policy period, the likely expense and potential capacity issues with the alternative of an annual aggregate of twice the per loss limit (the new policy would have to cover all of Enbridge operations), Mr. Dybdahl emphasized as his recommendation the easier and cheaper option of an automatic reinstatement of limits provision. Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 104, 158-160 (Dybdahl).

[773] Mr. Dybdahl's insurance condition assumes a solvent U.S. Oil Spill Liability Trust Fund with a $1 billion per loss cap that, when combined with his recommendation for total recoverable insurance coverage of $200 million, satisfies the $1.2 billion he recommends be required in order to protect the State of Minnesota for the Maximum Probable Loss from Line 3 in today's dollars. Ex. DER-5, DD-1 at 19-20 (Dybdahl Direct).

[774] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 104-105, 168 (Dybdahl).

ii. Value of including an insurance condition

Insurance is an important financial assurance tool. Access to insurance, however, is not guaranteed over time,[775] but neither is the profitability of Enbridge Inc. or the sustainability of the U.S. Oil Spill Liability Trust Fund.[776] Mr. Dybdahl emphasized the insurance industry's viability for over 400 years.[777] It remains an important risk management tool in part because "access to insurance operates as the *canary in the coal mine* to provide early warning to the stakeholders of unusually risky or uninsurable operations."[778] Incorporating his insurance recommendation as a condition of receiving CN approval and of continuing to operate a new Line 3 in Minnesota would protect the State of Minnesota by requiring operation to cease if or when Enbridge Inc. is unable to procure the required insurance, as Mr. Dybdahl explained:[779]

> So the insurance industry is extremely efficient at incorporating knowledge of risk. And if it's risky, insurance premiums will be high. If it's not risky, they'll be very low. If it's extremely risky, there won't be any insurance. And by requiring the environmental insurance, if Enbridge -- and we hope it never happens -- is unable to buy insurance, that's the canary in the coal mine for the State to say, well, maybe we shouldn't be using this pipeline, if it becomes uninsurable.

Also, general liability policies commonly include language dictating that coverage survives bankruptcy.[780] If Enbridge Inc. were to become insolvent in the future, it is possible that

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[775] Ex. DER-5, DD-1 at 22 (Dybdahl Direct).
[776] *See* Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 97-98 (Dybdahl).
[777] *Id.*
[778] *Id.*.
[779] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 113-114 (Dybdahl).
[780] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 92, 114-116 (Dybdahl). The insurance policy stays in effect and insurance company pays the claim "regardless of the insured's ability to pay the self-insured retention or deductible." *Id.* at 114-155. While other testimony was less clear whether an insolvent Enbridge Inc. must first pay its self-insured retention or deductible in order for the insurance company to honor the policy, *see id.* at 93, Mr. Dybdahl clarified this point in (Footnote Continued on Next Page)

insurance could be the only asset available to Minnesota to pay for costs associated with pollution from Line 3.[781] Mr. Dybdahl testified that "we don't even need the corporate entity of Enbridge to be there" because since there is "an obligation – there's a covered claim that survives."[782]

Like requiring a parental guaranty of indemnity from Enbridge Inc., Mr. Dybdahl's insurance-related conditions are intended to address the three major risk factors noted previously:[783]

- The potential for Enbridge entities to have more than one catastrophic loss in a short period of time, thereby potentially leaving no financial resources available for the second loss;

- A general downturn in the use of tar sand-sourced oil in a potentially carbon constrained economy would impair the ability of EEP, in its current business model, to maintain profitable operations over time, and at the same time, significantly reduce the net asset value of the firm, and therefore, its ability to borrow funds to fund a loss event; and

- The proven difficulty of building reliable insurance coverage for pollution events based upon a series of pollution exclusions and exceptions to the exclusions in a general liability policy.

Thus, as to the first bulleted loss scenario above, multiple large crude oil spills anywhere on Enbridge Inc.'s extensive North American pipeline system may result in insurance companies concluding that Enbridge Inc.'s pipeline system, including perhaps an aging Line 3, either is risky enough to charge high premiums or is too risky to insure, in which case Mr. Dybdahl's

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later testimony, Tr. Vol. 8B, *supra* at 114-116. Additionally, his conditions require the State of Minnesota to be an Additional Insured under the policy such that, conceivably as an insured, it could choose to pay monies needed to preserve availability of coverage under that policy.

[781] *Id.* at 57, 93.

[782] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 92, 115-116 (Dybdahl).

[783] *Id.* at 55-56;

recommendation would require Enbridge to cease operation of Line 3 in Minnesota. Requiring insurance coverage allows the State of Minnesota to benefit from the risk assessment of the insurance industry,[784] and to do so on an annual basis consistent with the practice of annual policy negotiation and renewal.[785] Also, because the insurance condition includes "one automatic reinstatement of limits provision" on both the GL and EIL insurance policies, as will be discussed further below, there would be insurance in place covering Line 3 even if a first spill on Enbridge Inc.'s system exhausted all coverage under the then-current policy.[786]

Under the second bulleted loss scenario, Enbridge Inc. in the future could be effectively insolvent and perhaps in bankruptcy. As noted, insurance generally survives bankruptcy,[787] and could be the only asset available to Minnesota to pay for pollution clean up the event of a spill from Line 3.[788]

The third bulleted loss scenario refers to Mr. Dybdahl's significant testimony on the importance of not relying solely on GL insurance given the superiority of EIL insurance policies for covering pollution-related costs; to date, Enbridge has completely relied on GL policies[789] that, typically, provide insurance coverage for pollution events based upon a series of pollution exclusions and exceptions to the exclusions.[790] Enbridge Inc.'s GL policy in effect at the time of the 2010 Marshall spill did not pay out in full; $85 million was denied in an arbitrated insurance

[784] Ex. DER-5, DD-1 at 15-16 (Dybdahl Direct).
[785] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 70, 77 (Dybdahl) (insurance policies typically are for a one-year term).
[786] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 104-105, 168 (Dybdahl).
[787] *Id.* at 92, 114-116.
[788] *Id.* at 57, 93.
[789] Evid. Hrg. Tr. Vol. 6B (Nov. 9, 2017) at 128 (Lim) (Enbridge has never used EIL insurance).
[790] Ex. DER-5, DD-1 at 24-31 (Dybdahl Direct).

coverage dispute.[791] Although he has no reason to dispute Ms. Lim's statement that Enbridge removed from its current GL policy the pollution exception or exclusion language that resulted in that denial of coverage for the Marshall spill,[792] Enbridge continues to purchase only GL insurance coverage.[793] Mr. Dybdahl recommends that $100 million of EIL insurance at minimum be purchased to cover Line 3.

Finally, in light of Enbridge's vast North American operations and its practice of insuring the entire operation under one general liability, GL policy,[794] it is important to tailor the insurance requirement in order to avoid the potential that a loss elsewhere on Enbridge Inc.'s extensive network of pipelines could wipe out insurance coverage for a subsequent spill on Line 3 in Minnesota. A look at Enbridge Inc.'s North American operations (U.S. and Canadian) shows how it is possible again, as occurred following the 2010 Marshall spill that was followed later the same year by the Romeoville spill, for pollution events anywhere on Enbridge's system to exhaust coverage limits. DOC DER manually reproduced DER Exhibit 14, below, which is a partial depiction of Enbridge Inc.'s U.S. and Canadian operations..[795]

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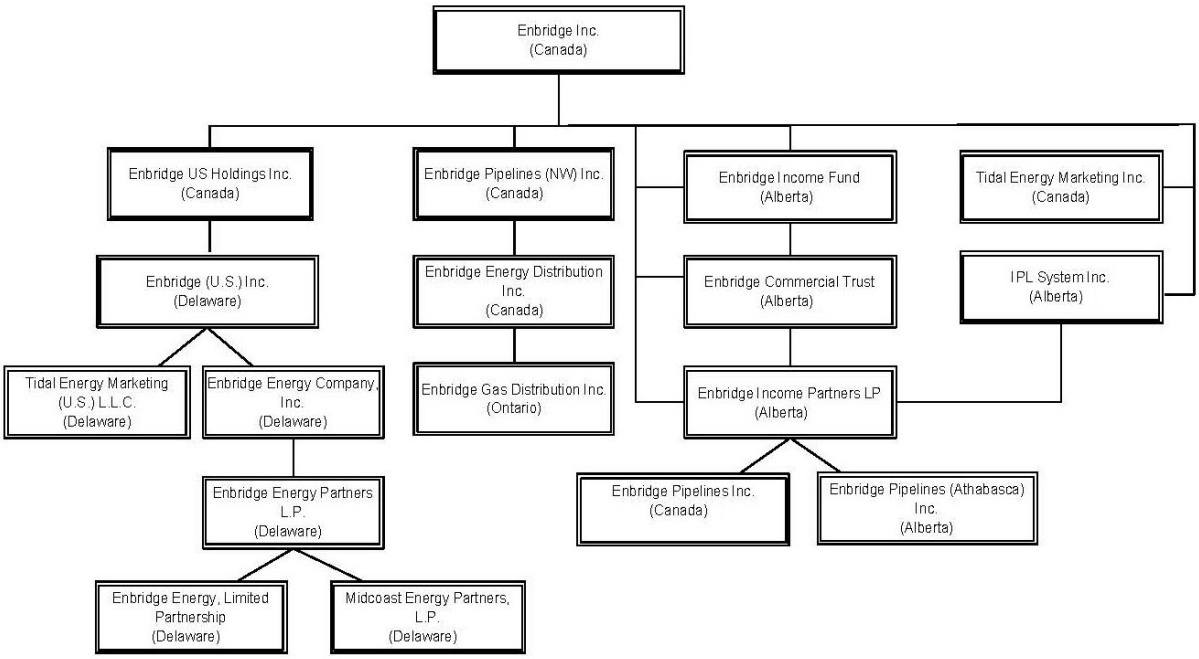
[791] *Id.* at 56-57.
[792] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 90 (Dybdahl).
[793] Evid. Hrg. Tr. Vol. 6B (Nov. 9, 2017) at 170 (Lim) (Enbridge Inc. has never purchased EIL insurance.).
[794] *See, e.g.*, Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 105 (Dybdahl).
[795] Ex. DER-14 (Enbridge Inc. U.S. and Canadian operations, partial). Ex. DER-14 is a partial organizational chart of Enbridge Inc.'s U.S. and Canadian companies, while Ex. DER-13 includes only its U.S. operations.



One can see from Exhibit DER-14 that a crushing loss resulting from rupture of any pipeline owned or perhaps operated by an Enbridge Canadian company could exceed the policy limits of Enbridge Inc.'s liability insurance. Ms. Lim agreed that a first spill could exceed the policy limits so that there would be no coverage for a second spill during the policy period.[796] She testified that Enbridge currently has a GL insurance policy with a limit of $940 million.[797] A $1.2 billion Marshall-sized spill would exceed today's policy limits, leaving no insurance coverage for the remainder of the policy period to cover losses caused by a spill on any other Enbridge pipeline including Line 3 in Minnesota.[798]

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[796] Evid. Hrg. Tr. Vol. 6B (Nov. 9, 2017) at 130-131 (Lim).
[797] *Id.* at 129.
[798] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 159 (Dybdahl). Mr. Dybdahl explained, "General liability policies are written with an aggregate, one million per occurrence, two million aggregate, so that you can have two $1 million dollar claims and still have coverage during the policy period. You can handle the second claim. But as the policies are currently structured, with the excess and all the subsequent layers, there's only enough insurance to deal with this -- it (Footnote Continued on Next Page)

iii. Importance of including EIL as well as GL insurance

Mr. Dybdahl provided detailed concerns about Enbridge Inc. depending in the future solely on general liability insurance policies for coverage of pollution-related losses.[799] In fact, the third of his three main risk factors that could leave Enbridge entities unable to pay for cleanup costs resulting from a future spill on Line 3 is the proven difficulty, based on Enbridge's own history, of building reliable insurance coverage for pollution events based upon GL policies alone; GL policies use a series of pollution exclusions and exceptions to the exclusions as a way to cover certain pollution events.[800] He explained that the meaning and effect of pollution exclusions in GL insurance policies, "has led to more litigated insurance coverage cases than any clause in the 400-year history of insurance."[801] The extent of litigation reveals design flaws in GL policies related coverage for pollution-related events. In contrast to GL policies, environmental impairment liability, EIL, policies use explicit language to describe coverage for pollution-related losses such as costs for cleanup, restoration and natural resources damages.[802]

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could cover multiple small claims, but this company has the potential to blast one all the way through to the policy limits." *Id.*

[799] *See, e.g.*, Ex. DER-5, DD-1 at 9-10, 24-31 (Dybdahl Direct); Ex. DER-8 at 5 (Dybdahl Surrebuttal).

[800] Ex. DER-5, DD-1 at 10 (Dybdahl Direct); Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 56 (Dybdahl).

[801] Ex. DER-5, DD-1 at 10 (Dybdahl Direct). Mr. Dybdahl has served as an expert witness in state and federal courts regarding over one billion dollars in litigated and arbitrated insurance coverage cases involving environmental damage losses. As an insurance broker, he has placed thousands of environmental insurance policies into the global insurance market place, and has worked with environmental insurance products on a day to day basis for 35 years. *Id.* at 7.

[802] Ex. DER-5, DD-1 at 9-10, 24-29, 31 (Dybdahl Direct); Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 76, 118-120 (Dybdahl).

(a) Typical GL policy coverage provisions, pollution exclusions, exceptions and concerns

Mr. Dybdahl identified typical GL policy coverage terms including typical pollution exclusions and exceptions to exclusions in policies commonly purchased by large companies in the energy sector.[803] He did not focus on Enbridge Inc.'s current, customized,[804] GL policy because his goal was to craft recommendations that would endure for 60 years: "[S]o I'm not going to design that based on what people crafted on a customized insurance policy" (like Enbridge Inc.'s current GL policy).[805]

Three provisions typically are found in GL policies, based on standard custom and practice, according to Mr. Dybdahl.[806] First, a GL policy insures claims being made against the insured party for:[807]

- Bodily Injury to non-employees;
- Property Damage, defined as physical injury to tangible property;

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[803] Small pipeline companies commonly purchase EIL insurance, in contrast to "big pipeline companies" which do not; large oil companies continue to "rely on GL policies with amended pollution exclusions in custom and practice. Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 70 (Dybdahl). The insurance sector that deals with the oil and gas business has its own policy forms and its own markets. *Id.* at 69.

[804] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 132 (Dybdahl).

[805] *Id.* at 132. Insurance requirements based on a customized policy are not likely to endure due to potential lack of industry support and because Enbridge might not be able to buy that policy for a long period of time." *Id.* Thus, Mr. Dybdahl designed his recommendation based on standard customer and practice rather than on "a specific type of individually purchased policy." *Id.* *See also*, Ex. DER-5, DD-1 at 24 (Dybdahl Direct) (the current Enbridge insurance coverage is largely irrelevant because almost all GL insurance policies only insure for a one-year coverage term and therefore must be renewed annually, and the marketplace changes over time).

[806] Ex. DER-5, DD-1 at 24-25 (Dybdahl Direct).

[807] *Id.*, DD-1 at 25; *see also* Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 131 (Dybdahl). "Advertising injury" regarding the running of advertisements also is commonly included in GL policies. *Id.* Contrary to good EIL policies, typical GL policies do not include explicit coverage for costs of cleanup, restoration, natural resource damages or emergency response. Ex. DER-5, DD-1 at 31 (Dybdahl Direct); Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 76 (Dybdahl).

- Personal Injury, including libel and slander; and
- Defense costs incurred by the insured in defending claims made by third parties for the above damages.

Key coverages for bodily injury and property damage in the GL insurance policy would come into play in the event of a spill from a pipeline together with the costs incurred to defend those claims.[808] Defense costs, though, currently are relatively insignificant in the event of a GL policy paying for cleanup costs because, as Mr. Dybdahl explained, cleanup obligations under environmental protection laws are based on strict liability for the polluter.[809]

He also testified that, like EIL policies,[810] GL policies sold to oil and gas companies typically pay on an "indemnity basis" such that the insured pays the immediate loss costs and later is reimbursed by the insurance company.[811] In the case of disputed coverage regarding the 2010 Marshall spill, it took over six years for the $85 million in disputed coverage to be resolved—denied—by binding arbitration in 2017.[812]

For a GL policy having very high limits such as Enbridge Inc.'s current GL policy limit of $940 million, the insured needs to buy policies from many insurers.[813] The common structure is for a "lead" or "primary" insurance company to sell a GL policy that establishes the scope of coverage for each of the insurance companies participating in a tower of insurance limits that are

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[808] *Id.*
[809] *Id.*
[810] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 94 (Dybdahl); Ex. DER-5, DD-1 at 25 (Dybdahl Direct).
[811] Ex. DER-5, DD-1 at 25 (Dybdahl Direct).
[812] *Id.*
[813] *Id.*, DD-1 at 24.

excess of the primary GL policy.[814] Then, the combination of the primary and excess layers of coverage are referred to as the insurance "program."[815] As Ms. Lim testified, Enbridge Inc.'s 2017 GL insurance program with limits of $940 million has many separate participating insurance companies.[816] The primary insurer will strive to build an insurance program where each participating excess insurance company agrees to "follow form"—agreeing to the same terms—with the primary policy and to each layer of coverage in the program.[817]

Second, "virtually all GL insurance policies" have a pollution exclusion.[818] Pollution exclusions "are the most litigated words in the history of insurance."[819] Typically, the concept of pollution involves contamination.[820] The pollution exclusion in a GL insurance policy applies to all claims arising from the emission, discharge, release, or escape of "Pollutants", and it eliminates coverage of third party bodily injury and property damage liability claims if the proximate cause of the loss is the release or escape of "Pollutants". Mr. Dybdahl explained that, essentially, the term "Pollutants" is defined in GL insurance policies to mean contamination. [821] If a material can contaminate something, it can be a "Pollutant" subject to the pollution exclusion in an insurance policy.[822] The damages caused by an oil spill will definitely fall within multiple parameters of commonly used pollution exclusions.[823]

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[814] *Id.*
[815] *Id.*
[816] Evid. Hrg. Tr. Vol. 6B (Nov. 9, 2017) at 129 (Lim); Ex. DER-5, DD-1 at 24 (Dybdahl Direct).
[817] Ex. DER-5, DD-1 at 24-25 (Dybdahl Direct).
[818] *Id.*, DD-1 at 25.
[819] *Id.* For a history of GL policy pollution exclusions and litigation, *see, id.*at 23-28.
[820] *Id.*
[821] Ex. DER-5, DD-1 at 25, 27 (Dybdahl Direct).
[822] *Id.* at 27.
[823] *Id.*

There are three basic pollution exclusions in a typical GL policy: 1) an absolute pollution exclusion for property damage arising from a contamination event, as noted above; 2) contamination that exceeds a "time elements" exception such that the contamination event was not discovered and reported within the time period of such an exception; and 3) contamination related to property owned or operated by the insured, which would apply to pollution contaminating a pipeline's corridor.[824] Mr. Dybdahl noted that the strict liability for cleanup costs does not clearly fit into the definition of Property Damage normally found in GL policies.[825] For this reason, liability for cleanup costs is an example of uncertainty regarding coverage of contamination of property under GL policies with pollution exclusions.[826] As Mr. Dybdahl explained:[827]

> One of the major areas of controversy over the past 40 years in the insurance business is does strict liability for clean-up costs constitute a liability claim by a 3rd party for "property damage" as defined in the GL insurance policy? No one can answer that question in a way that will apply to every case. The consentient answer to the question of; Are clean-up costs Property Damage under a GL policy; is "it depends".
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> * * *
>
> The take away for the purposes of this report is that no one can be certain if clean-up costs fit the definition of Property Damage in a standard GL insurance policy. This means an insurance program built solely on the basis of an exception to a pollution exclusion in a GL policy is unpredictable. Therefore, the GL policy provides unreliable coverage for pollution related claims.

[824] Ex. DER-5, DD-1 at 28-29 (Dybdahl Direct).
[825] *Id.* at 25.
[826] *Id.*, DD-1 at 27.
[827] *Id.*

Third, a typical GL policy includes a "time element" *exception* to pollution exclusions.[828] Mr. Dybdahl explained that the common practice today, for insurers that provide coverage for some pollution in GL policies, is to limit the effect of the comprehensive pollution exclusion in the policy as to those pollution events that take place within certain defined time frames.[829] Those defined time frames are accurately referred to as "time element" pollution events coverage.[830] Under "time element" pollution GL coverage commonly sold to companies in the oil and gas business, a claim for property damage or bodily injury arising from a pollution release event that begins and is discovered within 7-30 days and is reported to the insurance company within 30-90 days after the discovery of the pollution, is not excluded by the GL insurance policy.[831] The remnant or remaining GL coverage for pollution losses under this exception, however, "is still dependent upon an exception to an exclusion," as set forth in the time element pollution exception provision.[832]

Mr. Dybdahl points out the obvious gap in coverage under a "time element" exception to a pollution exclusion is pollution that is not discovered or reported within the time period of the exception.[833] This means, of course, that pollution discovered too late or that is reported too late will not be covered by the GL policy limits. For example, pollution that likely would be excluded from coverage under such GL policy terms would be a "buried pin hole leak leading to

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[828] *Id.*, DD-1 at 26, 28-29.
[829] *Id.*at 26.
[830] *Id.*
[831] Ex. DER-5, DD-1 at 24, 26 (Dybdahl Direct). Under a "time element" exception to a pollution exclusion, the "sudden and accidental" that were used some years ago no longer carry any weight in determining the effect of modern pollution exclusions on the coverage for a claim. *Id.*
[832] *Id.*
[833] Ex. DER-5, DD-1 at 29 (Dybdahl Direct).

oil migrating to and being transported by ground water [which] could take place over months or years in the remote regions of the Line 3 corridor before the damage is discovered."[834] In such a case, and despite suggestions by Enbridge witness Mr. Wuolo that contamination to ground water should not be a concern,[835] at trial Mr. Wuolo confirmed that crude oil contamination of ground water can be very expensive to clean up,[836] and could take well over 100 years to remediate.[837] In summary, given the uncertainty surrounding whether particular pollution may fall within a GL exclusion or an exception to an exclusion, together with the history of litigation over such issues (including Enbridge's own experience litigating disputes over insurance coverage relating to the 2010 Marshal spill), Mr. Dybdahl recommends that the State of Minnesota avoid being completely dependent on GL insurance purchased by Enbridge Inc. over the life of Line 3,[838] that contains "a modified pollution exclusion as a financial back stop for an oil spill from a pipeline."[839]

(b) Enbridge Inc.'s current GL policy provisions and exclusions

Mr. Dybdahl's review of Enbridge Inc.'s current $940 million limit GL policy did not alter his concerns or his recommendations.[840] A few public details of Enbridge's commercial

[834] Ex. DER-5, DD-1 at 29 (Dybdahl Direct)
[835] Evid. Hrg. Tr. Vol. 4B (Nov. 6, 2017) at 114-116 (Wuolo).
[836] Evid. Hrg. Tr. Vol. 4B (Nov. 6, 2017) at 132 (Wuolo).
[837] *Id.* at 120, 132.
[838] Ex. DER-5, DD-1 at 24 (Dybdahl Direct) (refers to the addition of EIL as a "partial hedge" against changing risk factors).
[839] Ex. DER-5, DD-1 at 26 (Dybdahl Direct).
[840] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 122, 131-132, 175-176 (Dybdahl). Upon objection of Enbridge counsel, Mr. Dybdahl did not provide testimony at trial concerning particular details of Enbridge Inc.'s current GL testimony. *See. e.g.*, Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 120-121 (Dybdahl).

and excess GL policy is provided in Schedule 2 of Ms. Lim's Rebuttal Testimony.[841] Contrary to Ms. Lim's testimony at trial suggesting the current GL policy did not contain pollution exclusions[842] Mr. Dybdahl counted seven such exclusions.[843] He explained that while it is uncommon to have so many pollution exclusions, it is not uncommon for GL policies to include pollution exclusions.[844]

Ms. Lim testified that the current Enbridge Inc. GL policy "covers Enbridge's legal liability for claims arising out of its operations and includes pollution liability coverage, again for recovery of moneys spent in responding to an accidental release, including costs related to cleanup, restoration, and damage to natural resources."[845] She also testified that Enbridge Inc.'s current GL policy has no absolute pollution exclusion:[846]

> Q. Does Enbridge, Inc.'s current general liability policy have what is termed in the industry an absolute pollution exclusion?
>
> A. No, it does not.

Ms. Lim described how the current Enbridge Inc. GL policy has a time elements provision for accidental releases—if pollution is discovered within 30 days and reported within 90 days—that renders certain pollution events to be covered under the GL policy.[847] She agreed that pollution

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[841] Ex. EN-43, Sch.2 at 1 of 4 (Lim); *see also* Ex. DER-16 (public version of Ex. DER-17, which is the current Enbridge Inc. commercial GL policy).
[842] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 173 (Dybdahl) (perhaps referring to Ms. Lim's testimony at trial, Evid. Hrg. Tr. Vol. 6B (Nov. 9, 2017) at 139-141 (Lim), in which she disagreed that are pollution exclusions because of the time element exception).
[843] Tr. Vol. 8B at 173 (Dybdahl).
[844] *Id.*
[845] Evid. Hrg. Tr. Vol. 6B (Nov. 9, 2017) at 112-113 (Lim). Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 114 (Dybdahl).
[846] Evid. Hrg. Tr. Vol. 6B (Nov. 9, 2017) at 139 (Lim). DOC DER assumes Ms. Lim meant that pollution that falls with the time element exception is covered by the policy.
[847] Evid. Hrg. Tr. Vol. 6B (Nov. 9, 2017) at 124-125 (Lim).

from a small crude oil leak that is not discovered within the 30-day time elements provision would be excluded from coverage under the current GL policy.[848] She explained that Enbridge expects to pay for cleanup and then to seek reimbursement from insurers, and to self-fund cleanup to the extent any costs ultimately exceed insurance recovery.[849]

Actual current GL policy provisions are found in Trade Secret Exhibit DER-17,[850] in part. This exhibit consists of two attachments, 262A and 262B, as being representative of the remaining layers of insurance provisions of the current Enbridge Inc. GL policy that Applicant provided in response to DOC DER discovery, IR 262. Note that the Trade Secret Exhibit DER-17 includes both attachments although compiled in reverse order, meaning that the document begins with 262B, not 262A. Provisions of Trade Secret DER-17 include language that is **[TRADE SECRET BEGINS**

TRADE SECRET ENDS], as follows:

[TRADE SECRET BEGINS

[848] *Id.* at 125.
[849] Evid. Hrg. Tr. Vol. 6B (Nov. 9, 2017) at 141-142, 152 (Lim).
[850] Ex. DER-17 (TS Attachments 262A and 262B) (compiled in reverse order).
[851] Ex. DER-17 at 5 (Attachment 262A).
[852] Ex. DER-17 at 6, 14 (Attachment 262A).
[853] Ex. DER-17 at 16 (Attachment 262A).

(Footnote Continued from Previous Page)
[854] Ex. DER-17 at 6 (Attachment 262A).
[855] Ex. DER-17 at 9-12 (Attachment 262A).

TRADE SECRET ENDS].

As to terms and definitions, DOC DER **[TRADE SECRET BEGINS**

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Finally, DOC DER notes with some concern inclusion of **[TRADE SECRET BEGINS**

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As a precaution, however, as part of its future reviews of Applicant's compliance with conditions (if so ordered), DOC DER recommends that the Commission inquire of Applicant and Enbridge Inc. each year as to the insurance policy language the company intends to use for the future year in order to be assured that crude oil spills on a future Line 3 in Minnesota are reasonably covered – not excluded - by those GL and EIL policies**.**

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[856] Ex. DER-17 at 10.

[857]Evid. Hrg. Tr. Vol. 4B (Nov. 6, 2017) at 42-43 (Horn) (discussing Ex. EN-66 at 367 (Horn Rebuttal)); Evid. Hrg. Tr. Vol. 5A (Nov. 8, 2017) at 19-21 (Haskins); Evid. Hrg. Tr. Vol. 5A (Nov. 8, 2017) at 74, 112-113 (Stephenson); Evid. Hrg. Tr. Vol. 11B (Nov.17, 2017) at 117 (White); *see, e.g.*, Ex. EERA-29 at 10-22, *et seq* (FEIS) (FEIS refers to "BTEX", a component of crude oil, to include benzene).

(c) Typical EIL policy provisions

The purpose of EIL insurance is to insure specifically against claims arising from pollution-events.[858] Like GL policies, EIL policies also cover bodily injury, property damage and defense costs, but its coverage generally is broader for environmental losses than are GL policies, as Mr. Dybdahl explained:[859]

> An EIL policy designed specifically to cover claims arising from pollutants provides broader coverage for environmental losses than a GL policy does. A good quality EIL insurance also specifically insures cleanup costs, emergency response costs, restoration costs and natural resources damages within the insuring obligations of the policy. GL polices do not reference these important elements of coverage which will always come into play as a source of damages in a pipeline spill.

Given EIL insurance's specific coverage for pollution-related losses, he testified that EIL is stronger coverage for pollution-related losses than is GL insurance.[860] He would recommend a condition of "$2 billion" in EIL policy coverage if it were available in the market,[861] which it is not at that level at this time. GL policies purport to cover pollution-related costs, but do not "do a very good job" in this regard due to a lack of definition and as to whether the terms used include cleanup, restoration or natural resources damages.[862] And, while there are not standardized definitions for terms like cleanup, restoration or natural resources damages, EIL

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[858] Ex. DER-5, DD-1 at 29 (Dybdahl Direct). EIL only insures against claims arising out of pollution events. *Id.*

[859] Ex. DER-5, DD-1 at 29 (Dybdahl Direct); Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 76 (Dybdahl). Like GL policies, EIL policies cover claims made against the insured for bodily injury, property damages and defense costs, and the definitions of those terms in EIL policies mirror the definitions commonly used in GL policies. Ex. DER-5, *supra*, at 29).

[860] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 150 (Dybdahl).

[861] *Id.* at 168.

[862] *Id.* at 76.

policies describe in greater detail the concepts of this coverage.[863] For example, Mr. Dybdahl explained common descriptions for terms like cleanup, restoration or natural resources damages in EIL policies:[864]

> By default, natural resource damages, since it's a regulatory driven cost, they refer back to the regulations. Otherwise, it doesn't make any sense.
>
> They use different words to describe the same thing. So it's usually cleanup costs as required under environmental regulations. They'll point back to that. The words they use to get there will vary from insurance company to insurance company.
>
> And then restoration costs, the concept there -- and that'll get to the concept, which is put it back to its preloss condition; put the property back to its preloss condition.

Also, in contrast to GL policies, an EIL policy by definition insures a specific project[865] such as Line 3.

Mr. Dybdahl described the design of EIL as "claims made and reported" such that under an EIL policy, as follows:[866]

> A. . . . . The way it works is there has to be a pollution -- a covered pollution event that – and then claims arising from that pollution event are covered by the policy in place when it was first reported.
>
> * * *
>
> Q. So if I was just going to use an example, to make sure we're really clear on this, the Company would report the incident to the insurer when they discover it and subsequent claims, even if they were years later, would be paid under that same initial policy, up to the policy limit that was in place at the time, right?
> A. Correct.

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[863] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 78-79 (Dybdahl).
[864] *Id.*
[865] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 161, 174 (Dybdahl).
[866] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 79-80 (Dybdahl).

> Q. And insureds, the Company who's buying the insurance, they can't stack multiple sets of policy limits year over year, right?
> A. Correct.
> Q. And so, again, it's just that original policy limit that would apply to all the subsequent claims from that initial –
> A. Yes.
> Q. Claims first made and reported?
> A. Correct.

He also testified that while some EIL carriers require continuous renewals into the future in order to have that first policy even respond to the claims, two-thirds of carriers do not include that provision (and their policies do not cost more), and some of those that do have the provision will remove it.[867]

iv. Importance of Mr. Dybdahl's insurance specifications: amount, reinstatement of limits, and Additional Insured

In addition to the two types of insurance discussed above, three other aspects of Mr. Dybdahl's insurance condition generated considerable questions at trial: $100 million for both GL and EIL insurance policies, reinstatement of limits as to Line 3 in Minnesota in the event policy limits are exhausted during the policy period elsewhere on Enbridge Inc.'s system, and addition of the State of Minnesota as an Additional Insured. To assess the importance of Mr. Dybdahl's insurance condition, it may be help to consider the following example:

> Example: Assume hypothetically that Enbridge Line 5 ruptures under the Straits of Mackinac during the first month of Enbridge Inc.'s 12-month GL insurance policy causing total losses of over $5 billion. Also assume that $1 billion in funding is available from the U.S. Oil Spill Trust Fund.

<u>Amount: $100 million in GL and $100 million in EIL coverage.</u> Under Mr. Dybdahl's condition, Enbridge Inc. would be required to have a GL policy of at least $100 million in

[867] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 80-81 (Dybdahl).

coverage (for all of Enbridge's operations), and $100 million in EIL coverage that by design covers only Line 3 in Minnesota. He acknowledged that $200 million is low in comparison with Enbridge Inc.'s current $940 million in GL policy limits because Mr. Dybdahl anticipated a scenario where the company could not procure its current level of insurance.[868]

Based on the Line 5 rupture example, the $100 million of GL coverage would be exhausted by a big loss anywhere on Enbridge Inc.'s system, including on Line 5 between Wisconsin and Michigan. No GL coverage would remain for the remaining eleven months of the policy period in the event of a spill in Line 3 in Minnesota. The Line 5 rupture would not affect the $100 million in EIL coverage for Line 3 in Minnesota. As discussed below, the reinstatement of limits provision on the GL policy would kick in, such that insurers would have to offer Enbridge another $100 million in GL coverage only as to Line 3 to be in effect for the last eleven months of the GL policy period.

The combined GL and EIL coverage of $200 million is small relative to the total $1.2 billion recommended by Mr. Dybdahl for continued funding. Coverage of $200 million per loss event on proposed Line 3 is only 17 percent of the $1.2 billion benchmark established by the 2010 Line 6B spill in Michigan;[869] 17 percent "is a very conservative amount designed to make the recommended insurance coverage on Line 3 procurable and affordable for Enbridge, while

[868] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 156 (Dybdahl). Again, Mr. Dybdahl's recommendation requires $200 million in insurance recovery plus $1 billion from the U.S. Oil Spill Liability Trust Fund so that there would be least $1.2 billion in funding cleanup of a spill on Line 3 in Minnesota. *See, e.g.*, at 101.
[869] Ex. DER-5, DD-1 at 19 (Dybdahl Direct).

creating a long-term risk management and financial backstop for the State of Minnesota," and which is unrelated to the future profitability of Enbridge Inc.[870]

One automatic reinstatement of limits for Line 3 in Minnesota. Under Mr. Dybdahl's condition, Enbridge Inc. would be required to have one automatic reinstatement of limits provision on both the GL and EIL insurance policies which will matter most as to the GL policy.

That is, if Line 5 were to rupture in month one, as in the example, the $100 million of GL coverage would be exhausted by that spill, but due to the reinstatement provision, Enbridge Inc. would be able to purchase another $100 million in GL coverage, at the price predetermined at the time it bought the initial GL policy,[871] that would provide coverage (only) for Line 3 in Minnesota for the remaining eleven months of the initial policy period.[872]

This reinstatement provision is important in light of Enbridge Inc.'s practice of insuring all of its operations under a single insurance policy[873] with a single limit of liability.[874] The GL reinstatement provision would be required only to cover Line 3, not Enbridge's entire North American operation, and would guarantee insurance coverage for a spill on Line 3 that is close in

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[870] *See* Ex. DER-5, DD-1 at 19 (Dybdahl Direct).
Although Mr. Dybdahl referred simply to "Enbridge" rather than to "Enbridge Inc.", the fact that Enbridge Inc. procures insurance for its entire organization "at the Enbridge Inc. level", Evid. Hrg. Tr. Vol. 6B (Nov. 9, 2017) at 121 (Lim), and that Mr. Dybdahl focused his recommendations in part on the potential insolvency of Enbridge Inc., DOC DER concludes that his references to "Enbridge" mean to include "Enbridge Inc."

[871] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 152 (Dybdahl). It is the custom and practice in the insurance industry for the premium related to a reinstatement provision to be negotiated with the insurer before purchase of the policy and at an agreed upon price. *Id.* The cost of reinstatement of the GL policy for coverage only of Line 3, and not the rest of Enbridge Inc.'s extensive operations, would be minimal, in Mr. Dybdahl's opinion. *Id.* at 154.
[872] *Id.* at 160.
[873] Evid. Hrg. Tr. Vol. 6B (Nov. 9, 2017) at 121 (Lim).
[874] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 157 (Dybdahl).

time to an earlier spill on any Enbridge pipeline that wipes out the company's policy limits for that policy period.[875] Without an automatic reinstatement provision, there would be no insurance remaining to cover losses from a subsequent spill on Line 3 that occurs soon after the first spill. With the reinstatement provision, a total of $200 million in coverage ($100 million of GL and $100 million of EIL) would exist for Line 3 in Minnesota for the entire 12-month policy period, as Mr. Dybdahl explained:[876]

> But in the insurance requirements, I said that a reinstatement of limits was acceptable [as an alternative to an annual aggregate requirement]. And the way that works -- and Ms. Lim would know – any insurance professional doing large accounts would know this -- when you buy the policy, you say, yeah, I'm going to buy this policy today, but if I get a loss that exhausts all the limits, you have to provide me another limit on Line 3 at a predetermined premium.
>
> So you don't even pay for it right away. You only pay for it if you use it, but they have to sell it to you.
>
> And because that's a tool, it's an insurance tool that doesn't stack limits. Because there's already been a loss. Could have been a loss in Canada; anywhere in their footprint, because they've got one insurance policy across all those entities.

Mr. Dybdahl's recommended one-time automatic reinstatement provision for the $200 million in coverage for GL and EIL policies would protect Minnesota for a spill on Line 3 in Minnesota during a policy period subsequent to a Marshall-sized spill that exhausted the initial policy's limits.[877] This is the purpose of the reinstatement provision:[878]

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[875] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 153–54, 157, 160 (Dybdahl).
[876] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 104 (Dybdahl).
[877] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 160 (Dybdahl) (as to GL reinstatement provision; if used, the premium probably would be prorated over the rest of the policy term).
[878] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 105 (Dybdahl).

> One loss anywhere can wipe out all of the insurance, and my design was to make sure there's always $1.2 billion of recoverable assets in Minnesota.

Mr. Dybdahl agreed with the ALJ's general summary of his EIL insurance condition, as follows:[879]

> Q. . . . Just so I understand, you are saying, as long as Enbridge has a general liability policy with $100 million per loss on it and an EIL insurance policy separately purchased, with $100 million limit specific to Line 3, that's the only dedicated one, and that they have one automatic reinstatement of limits provision related only to Line 3 that would protect the State of Minnesota?
>
> A. You described it perfectly. . . .

This one-time automatic reinstatement of limits provision would cover one, but not two, later spills on Line 3 within the policy period.[880] Reinstatement does not implicate stacking concerns, as discussed further in a later section of this Initial Brief.[881]

Additional Insured – the State of Minnesota. Mr. Dybdahl recommends that the State of Minnesota be added as "Additional Insured" to his recommended coverage under both the GL insurance and the EIL coverage of Enbridge Inc.'s insurance program."[882] Applicant agreed (as to its GL policy).[883] Being an Additional Insured under Enbridge Inc.'s policies benefits the State in the unlikely situation that, in the event of a spill on Line 3, a lawsuit against the State of Minnesota is filed claiming that the State is responsible for damages due to it allowing the

[879] *Id.*at 168.
[880] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 162 (Dybdahl).
[881] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 154 (Dybdahl).
[882] Ex. DER-5, DD-1 at 30 (Dybdahl Direct).
[883] Ex. EN-43 at 13 (Lim Rebuttal).

pipeline to exist; being an Additional Insured would allow Enbridge's insurance to pay for defending the State against that claim.[884]

v. Stacking and market availability are not implicated by Mr. Dybdahl's insurance condition

Contrary to Ms. Lim's testimony, Mr. Dybdahl's recommended insurance specification present no serious stacking issues (defined in the next paragraph, below) as to either GL or EIL policies, or EIL market availability issues. The insurance condition is subject to availability in the market,[885] and the insurance underwriters contacted by Mr. Dybdahl said they did not think that his GL and EIL condition would be a problem.[886] Nonetheless, Mr. Dybdahl anticipated stacking problems through the design of this condition.[887] Thus, DOC DER urges the Commission to adopt Mr. Dybdahl's recommendation together with some flexibility to address any insurer's actual limitations, and to rely on annual compliance reviews to identify any such insurers' responses.

Stacking: An insurer will avoid issuing multiple insurance policies covering the same loss, which is called "stacking" of policies.[888] Regarding the $100 million GL requirement, there is no potential stacking issue due to the reinstatement of limits provision (rather than the alternative of an annual aggregate),[889] since there would be only one GL policy at one time that would cover a loss on Line 3 in Minnesota.[890]

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[884] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 163-164, 169 (Dybdahl); *see also* Ex. DER-5, DD-1 at 30 (Dybdahl Direct).
[885] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 166, 170-171 (Dybdahl).
[886] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 166 (Dybdahl).
[887] *Id.*
[888] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 165-166 (Dybdahl).
[889] *See id.* at 153-154, 156-157, 165 (Dybdahl).
[890] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 153-154, 165-166 (Dybdahl).

Regarding the $100 million EIL requirement, because it applies only to Line 3 in Minnesota, there could be a stacking concern as to potential losses from a spill on Line 3 if the only insurers able and willing to provide $100 million in EIL insurance are all the same insurers that provide the $100 million in GL insurance.[891] If not, there would be no stacking concern for the EIL policy condition; insurers providing GL coverage would not also issue EIL policies and, thus, insurers would not be covering the same potential losses on Line 3. This appears to have been Mr. Dybdahl's expectation.[892]

If, however, in the future the only insurers able or willing to provide the GL and EIL policies are identical, then there could be insurers that would choose not to participate on both policies. In that event, Mr. Dybdahl proposed a solution.[893] He suggested that the amount of GL insurance covering all Enbridge Inc. operations could be reduced *only as to losses on Line 3*.[894] For example, under the current GL policy limits of $940 million, insurers also providing $100 million in EIL insurance for the policy period would not pay twice for Line 3 – those insurers would pay up to $840 million in GL coverage for Line 3 together with $100 million for

[891] *See* Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 164-165 (Dybdahl) (of the five insurers contacted by Mr. Dybdahl, four of them presently are insurers on Enbridge Inc.'s current GL policy).
[892] *See* Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 151-152, 169-171 (Dybdahl) (he put flexibility into the amount of required insurance in the event that Enbridge Inc. could not buy up to its current GL limits). *See also id.* at 151-152 (reference to Ms. Lim's incorrect view that Mr. Dybdahl's GL insurance recommendation would reduce the amount of available GL insurance).
[893] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 164-165 (Dybdahl).
[894] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 164-165 (Dybdahl) (emphasis added).

EIL coverage on Line 3, but would still be liable for up to $940 million for losses *not* on Line 3.[895]

Mr. Dybdahl wrote his insurance specifications to be easily met,[896] but in the future if Enbridge Inc. is only able to purchase a total of $200 million in insurance, then reducing the GL portion by $100 million only for insurers also providing $100 million in EIL coverage would avoid stacking concerns but would suggest other concerns. At that point, perhaps, if Enbridge Inc. is unable to purchase $100 million of GL and $100 million of EIL such that the $1.2 billion funding threshold is not met, then the "canary in the coal mine" may be indicating that Enbridge Inc. is too risky to insure.[897]

Market availability of EIL insurance: There is no shortage of capacity or availability in the EIL market; in Mr. Dybdahl's opinion, based on his discussion with five EIL insurers, there is about $250 million in available EIL insurance[898] which is more than adequate to allow Enbridge Inc. to purchase $100 million of EIL insurance on Line 3 in Minnesota.[899] Further, $100 million in EIL insurance in comparison to Enbridge Inc.'s present $940 million in GL coverage is a very small percentage; Mr. Dybdahl testified that his EIL recommendation should not pose a material increase in the risk exposure of underwriters.[900]

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[895] *See id.* In earlier trial testimony, Mr. Dybdahl agreed with Enbridge counsel that, if insurers faced stacking issues, one option would be a reduction of the current GL limits to $840 million together with a $100 million EIL policy (*id.* at 86, 163), but he later clarified that the GL reduction would be only as to losses on Line 3. *Id.* at 165-166.
[896] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 175 (Dybdahl).
[897] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 113-114 (Dybdahl).
[898] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 82-83 (Dybdahl) (based on his calls to five EIL insurers).
[899] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 171 (Dybdahl).
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[900] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 57-58 (Dybdahl).

While the insurance condition is subject to availability in the market,[901] Mr. Dybdahl was clear that there is no basis to conclude presently that there is constrained capacity. He testified that his EIL policy condition should be easy to satisfy as shown by the fact that it took him only 30 minutes to identify insurers willing to sell up to $250 million in EIL coverage.[902] His recommendation of $100 million in EIL coverage for a new Line 3 crude oil pipeline, and is not onerous, as he explained,[903]

> I didn't look at the world supply [of EIL availability]. That was an Enbridge idea. I looked at what's the possibility that this company could create a total-loss scenarios on the GL and not have any insurance left, or run into another coverage litigation buzz saw like they did in 2010, trying to get a general liability policy that has a series of pollution exclusions.

Mr. Dybdahl acknowledged that some years ago were only a handful of EIL insurers, but today there are over 40 companies selling EIL insurance.[904] Every EIL insurance carrier is profitable, and has been since 2006, although some companies like AIG ran into trouble for under-pricing policies issued prior to 2004.[905] If insurers in the future are not willing or able to provide $100 million in EIL insurance due solely to a lack of market capacity, then Enbridge Inc. would be required to purchase what it could obtain and, presumably, the Commission would require an increase in the amount of GL insurance in order to meet the $200 million insurance amount.

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[901] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 166, 170-171 (Dybdahl). *See also, id.* at 166.
[902] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 171 (Dybdahl). *See also, id.* at 82-83
[903] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 173 (Dybdahl).
[904] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 66 (Dybdahl).
[905] *Id.* at 67.

DOC DER recommends that the Commission adopt Mr. Dybdahl's insurance condition as part of his three-part recommendation, as provided in Appendix A of his report.[906]

e. U.S. Oil Spill Liability Trust Fund is an important financial assurance tool to extent it is available

The third condition of Mr. Dybdahl's risk mitigation recommendation recognizes as a possible future funding source the U.S. Oil Spill Liability Trust Fund,[907] which provides states with up to $1 billion per oil spill, assuming adequate trust funds are available.[908] To ensure future funding at the known loss level of $1.2 billion that occurred with the 2010 Marshall spill loss, Mr. Dybdahl recommends use of funding from the U.S. Oil Spill Liability Trust Fund together with a parental guarantee of Enbridge Inc., and insurance. To the extent that there was less than $1 billion available from the trust fund, Mr. Dybdahl recommends that the amount of insurance required by Enbridge Inc. be increased so as the total funding amount would continue to equal $1.2 billion over the life of Line 3.[909]

f. Summary: Mr. Dybdahl's three-part risk mitigation recommendation are essential to any need finding by the Commission

For the many reasons discussed above, DOC DER recommends that Mr. Dybdahl's three-part recommendation to mitigate risk to the State of Minnesota from a new Line be required if the Commission determines that, with conditions, need would be established and for continued

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[906] Ex. DER-5 at 32-32 and App. A at (Dybdahl Direct) (appended as Attachment 3). *See also id.* at App. B (general information regarding federal sources of funding for oil spill cleanup).
[907] 33 U.S.C. Sec. 2071, et seq. (Oil Pollution Act of 1990). Funded by a per barrel tax, the tax does not apply to tar sands heavy oil such that Enbridge would not pay into the Oil Spill Liability Trust Fund as to the heavy oil it intends to transport from Western Canada via the proposed Project. Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 97-98 (Dybdahl).
[908] Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 95-98 (Dybdahl).
[909] *Id.* at 98.

operation of a new Line 3. To that end, it is clear that neither Applicant nor EEP showed that a parental guarantee from EEP would adequately protect the State of Minnesota either from future conditions of general business unprofitability or from potentially huge losses from spills on its extensive system of pipelines in North America. It is reasonable to require, as Mr. Dybdahl recommends, a parental guarantee of Enbridge Inc. to indemnify the State of Minnesota for any loss the State may incur as a result of spills on Line 3.[910] The parental guarantee of Enbridge Inc. is particularly important in light of potential insurance coverage disputes that ultimately could reduce the amount of available insurance coverage for Line 3 in Minnesota, even if Mr. Dybdahl's insurance recommendation is met.

As to insurance, Mr. Dybdahl showed that it is unwise and unreliable for the Commission going forward to rely solely on an Enbridge Inc. GL insurance policy rather than also to include an EIL policy, as he described. Moreover, the U.S. Oil Spill Liability Fund is a current source of funding for crude oil spills and, to the extent it continues and is adequately funded, it is reasonable for the State of Minnesota to rely on this source of funding. In the event that this fund is not adequate, the amount of the insurance condition must be increased so as to ensure a total of $1.2 billion in funding for oil spills on Line 3.

Finally, DOC DER recommends that the Commission, as part of annual compliance reviews of Applicant's and Enbridge Inc.'s satisfaction of required conditions, review the insurance policies that are intended to meet the insurance recommendation of Mr. Dybdahl in order to be assured that damages caused by crude spills on Line 3 in Minnesota are reasonably covered—not excluded—by those GL and EIL policies.

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[910] *See, e.g.*, Ex. DER-5, DD-1 at 8-9, 30 (Dybdahl Direct); Evid. Hrg. Tr. Vol. 8B (Nov. 14, 2017) at 52-57 (Dybdahl).

IV. MINN. R. 7853.0130 D: COMPLIANCE WITH OTHER GOVERNMENTAL POLICIES, RULES, AND REGULATIONS

Minn. R. 7853.0130 D concerns whether Enbridge is likely to comply with policies, rules and regulations of other governmental entities.[911] Enbridge identified the polices, rules, and regulations relevant to the design, construction, and operation of the proposed project in Table 2.2-1 of the CN Application.[912] The information in the table includes the names of all agencies or authorities with whom Enbridge must file, the titles of the permits or certificates Enbridge must obtain for the proposed Project, and the filing and anticipated decision dates.[913] To date, the record in this proceeding provides no information that the final design, construction, or operation of the proposed Project would fail to comply with these relevant policies, rules, and regulations of other local, state, and federal governments.[914]

Finally, if the Commission concludes that, with conditions, the proposed Project should not be denied after evaluating the CN criteria, DOC DER recommended that the Commission require Enbridge to comply with the conditions as part of receiving a CN for the proposed Project in order to ensure that Minnesotans' natural and socioeconomic environments are

[911] Minn. R. 7853.0130 D (2015).
[912] Ex. EN-1 at 2-8–2-9 (CN Application).
[913] *Id.*
[914] Ex. DER-1 at 95 (O'Connell Direct). While Enbridge's preferred route for the proposed Project would not go through any tribal reservations in Minnesota, any route spanning a reservation would require tribal permits, as the existing Line 3 does for Leech Lake and Fond du Lac reservations. *See, e.g.*, Ex. LL-1 (Grant of Easement); Ex. FDL-7 (BIA Grant of Easement). From the record, it is unclear whether Enbridge would be required to obtain permits to construct a pipeline through certain off-reservation lands. *See, e.g.*, Evid. Hrg. Tr. Vol. 2B (Nov. 2, 2017) at 70–71 (Bergland). DOC DER appreciates these concerns and expects this issue to be addressed by the parties in post-hearing briefs.

reasonably protected.[915] This is particularly true since the proposed Project may potentially be in-service for decades and would present long-term environmental risks to Minnesota.

CONCLUSIONS AND RECOMMENDATIONS

After evaluation of the CN criteria under Minn. Stat. § 216B.243 and Minn. R. 7853.0130, Enbridge has not demonstrated need for the proposed Project. Enbridge has not demonstrated that the probable result of denial would adversely affect the future adequacy, reliability, or efficiency of energy supply to the applicant, to the applicant's customers, or to the people of Minnesota and neighboring states. The consequences to society of granting the CN are less favorable than the consequences of denying the CN, and thus, Enbridge has not demonstrated that the CN factors have been satisfied. Nevertheless, while DOC DER did not conclude that conditions would cure Enbridge's lack of a demonstrated need based on the record, at a minimum, the Commission could consider certain conditions in order to mitigate risk of harm to Minnesotans' natural and socioeconomic environments if, in its judgment, the Commission believed that such conditions would allow Enbridge to meet the CN criteria.

[915] *Id.* at 96.

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Respectfully submitted,

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