HONOR THE EARTH
PO BOX 63, 607 MAIN AVE, CALLAWAY MN 56521
INFO@HONOREARTH.ORG | WWW.HONOREARTH.ORG

June 20, 2022

VIA EMAIL: publicadvisor.puc@state.mn.us

Public Advisor
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

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

To the Members of the Minnesota Public Utilities Commission:

Honor the Earth hereby provides reply comments to the Minnesota Public Utilities Commission ("Commission") in response to its Notice of Extended Comment Period of February 9, 2022, for the above captioned docket. These reply comments address a number of issues raised by other parties in their initial comments.

REPLY TO ENBRIDGE COMMENTS

I. Identification of Beneficiaries

Enbridge seeks to limit the beneficiary to "the entity that has the decommissioning obligations." Enbridge Initial Comments at 7 and 12. It argues that limiting the beneficiary to this single entity would "ensure[] that the Decommissioning Trust Fund would only be used to fund decommissioning obligations." *Id.* However, such assurance would not come primarily from narrowly defining the beneficiary, but rather from constraining the authority of the trustee to limit use of the funds only for post-abandonment mitigation.

Enbridge's proposal to limit the beneficiary to essentially the pipeline company fails to address the risk that such owner or operator will go bankrupt or simply refuse to undertake mitigation for Line 93 when it is eventually abandoned. In this case, the trustee should be given authority to provide funds to other entities, including the state, local governments, and private landowners, via a state-managed fund dispersal mechanism. While it makes sense to assign the obligation to mitigate the pipeline initially to the pipeline's owner/operator, the Commission should not assume that the pipeline company will fulfill this obligation. Therefore, the Commission should not make the pipeline company the only beneficiary.

A failure to address the absent-owner contingency could create a risk that use of the funds could be tied up in administrative and/or judicial process. To address this risk, the Commission should identify a state government entity as the trustee and create a mechanism whereby the pipeline company has the right to apply for or recover funds from the trust to pay for its mitigation costs, but if the pipeline company fails to undertake this duty, to allow other entities, such as a state agency, local governments, and private landowners, to seek access to the funds via a march-in mechanism. The Commission should require comments on how such march-in mechanism might work.

II. Collection Period

Enbridge proposes to collect funds from its shippers "over the expected 50-year life of Line 93." Enbridge Initial Comments at 9. In contradiction, Enbridge's initial comments note that, per agreement with its shippers, "the economic life of Line 93 is stipulated as 30 years." *Id*. In contrast, Enbridge itself has proposed that it recover the cost of almost all of its Mainline System infrastructure in just 20 years, as per its May 2021 Depreciation Study Update, which examined the economic life of the entire Mainline System. Attachment A at 11. In its 2021 Update, Enbridge found that despite the uncertainties related to the potential economic life of the Mainline System, it was "rational and prudent" to establish a truncation date for depreciation purposes of December 31, 2040, in part because Enbridge could adjust this date in future depreciation studies. *Id*. The same reasoning holds here.

The fact that Line 93 by itself could have a physical life of 50 years or a stipulated economic life of 30 years should not be the basis for the collection term. Instead, the ability of Enbridge to pass on the costs of the trust to its customers depends on the ongoing operation and revenue generating capacity of the Mainline System as a whole. Therefore, the collection term should be based on the estimated economic life of the Mainline System, and not on the potential physical life or the stipulated economic life of Line 93. Given that Line 93 cannot operate as a standalone pipeline and rather must operate in concert with other upstream and downstream pipelines and tank farms that comprise the Mainline System, it would be rational and prudent to require a collection period for the forecasted economic life of the Mainline System, which Enbridge has asserted is 20 years.

Although there is a risk that the trust funds could be entirely collected before the end of Line 93's economic life, this outcome would be preferable to overestimating the length of the collection period. Since Enbridge has suggested that the Commission review the trust terms every five years, Enbridge Initial Comments at 9, if it appeared that the initial collection term adopted by the Commission was too short or too long, the Commission could reserve the right to either extend or shorten the collection period. Moreover, given that this liability would ultimately be born by Enbridge's customers, it would be prudent to err on the side of an overestimation of this liability rather than underestimate it, as doing so would avoid possible shipper claims that the terms of the asset retirement obligation have become substantially more onerous than initially anticipated. A shorter collection period would provide the state with more security – and the shippers with more certainty – than attempting to decrease the term later during the Mainline System's economic life, potentially in the face of a general downturn in the oil industry. The Commission should err on the side of frontloading this asset retirement obligation.

III. Shipper Agreement to Fund the Trust

Enbridge notes that "Line 93 is subject to an agreement between Enbridge and its shippers, referred to as the Facilities Surcharge Mechanism ("FSM"), which is a component of the FERC-regulated tariff rates. . . Enbridge will calculate the amount that needs to be contributed to the Decommissioning Trust Fund each year, based on the decommissioning cost estimate, the expected inflation rate, earnings in the trust, and trust expenses. Enbridge will recover that amount through the FSM . . . ." Enbridge Initial Comments at 9-10. What Enbridge fails to discuss is that proposed new charges to the FSM are subject to shipper protest at FERC, such that the FSM mechanism should not be assumed to be an automatic funding mechanism. In fact, in FERC Docket No. Docket No. OR21-9-000, Enbridge's shippers moved to intervene to protest inclusion of the costs of constructing Line 93 (approximately $4.2 billion) beyond those of the original cost estimate of $2.585 billion, (Attachment B), which estimate was contained in the Issue Resolution Sheet ("IRS") (attached as Appendix D to Enbridge's Line 3 Replacement Project Application for Certificate of Need) (Attachment C).

The IRS essentially memorializes the contractual agreement between Enbridge and its shippers as to the costs that they agreed to bear as part of the Line 3 Replacement Project. Although the IRS discusses decommissioning costs, it appears that these costs include only the costs of decommission old Line 3, and not the costs of establishing a trust fund for Line 93. The proposed trust amount is approximately $1.2 billion, a significant liability that would be passed on to Enbridge's customers, beyond what they expected to pay as part of the Line 3 Replacement Project. Therefore, there is a risk that Enbridge's shippers will not meekly accept an additional $1.2 billion in liability.

Although Enbridge admits that it will need to "discuss" the trust obligation with its shippers, Enbridge Initial Comments at 10, it fails to describe what would happen if these discussions do not go well and the shippers object to the amount or other terms of the trust collection. Rather than assume that Enbridge will successfully be allowed to use the FSM to collect the trust amounts, Enbridge should disclose the current status of its discussions with shippers regarding their acceptance of the trust liability, because there is a risk that the Commission could establish the trust obligation only to have this obligation be subject to protest at FERC or possibly litigation.

To mitigate this risk, Honor the Earth suggest that inclusion of shippers in the Commission's Line 93 trust fund decision would provide additional certainty that trust liability will be successfully passed onto Enbridge's shippers via the FSM or possibly some other tariff mechanism. Offering to include the shippers as parties in interest in this docket could help defend against possible future collateral administrative or judicial attacks by shippers on the asset retirement obligation that would be created by establishment of the Line 93 decommissioning trust.

IV. Scope of Trust Fund Use

Enbridge states that the trust could be used only to "deactivate, monitor, and remove Line 93," as per the Commission's order. Enbridge Initial Comments at 10. While Honor the Earth agrees that the funds should be used to pay only Line 93 decommissioning expenses, Enbridge's description of the type of such expenses is overly narrow. As reflected in Attachment A to Enbridge's comments, there are other potential forms of mitigation beyond, deactivation, monitoring, and removal, including but not limited to filling the pipe with cement, as under rail and road crossings, abandonment in place with segmentation to prevent water movement, and hazardous waste removal in the event that undiscovered leaks are found after abandonment. Documents filed in Canada more fully describe the range of possible mitigation options.

REPLY TO DEPARTMENT OF COMMERCE COMMENTS

Honor the Earth agrees with the Department of Commerce ("Department") that "additional process is needed to create a robust trust with sufficient funds to deactivate, monitor, and remove the pipeline and remediate soil when the pipeline is removed from service." Department Initial Comments at 2 (footnote omitted). Honor the Earth also agrees with the Department's statement that "there is still work to be done to identify and draft terms and conditions that reflect the goals of the Commission and the State as well as the issues" identified by the Department. Honor the Earth notes that there is significant overlap between the

Department's list of tasks on its page 3, and Honor the Earth's list of issues on page 5 of its comments.

As a procedural mechanism, the Department recommends that the Commission:

- require Enbridge to "engage an independent firm to evaluate the decommissioning cost estimate and provide detailed estimates in the record;" Department Initial Comments at 4;
- require Enbridge to propose a draft trust document and provide an explanatory document that explains how it addresses the Department's concerns and the requirement of the 14-916 docket. Department Initial Comments at 5.

Frankly, Honor the Earth expected that Enbridge would file a decommissioning plan and proposed trust document, so that parties would have a more complete proposal on which to comment. Instead, Enbridge's Initial Comments are largely general and/or conceptual and provide very little additional factual information. Although Enbridge includes a revised cost estimate, it provided little detail about the methodology it used for this estimate.

Given the following issues identified by the Department and Honor the Earth, including but not limited to:

- the potential complexity of the trust's legal arrangements;
- factual issues related to cost estimates, collection periods, and trustee selection;
- identification of the legal and practical beneficiaries and the need to create a march-in mechanism in the event that the owner of Line 93 does not fulfill its abandonment mitigation obligations;
- development of investment policies;
- potential issues related to shipper concerns; and

- the need to provide a process in which tribes and private landowners may participate,

Honor the Earth does not agree that basing future process on providing a comment period on a trust document and an outside cost estimate will provide the Commission with sufficient information to craft a functional Line 93 trust fund order. Therefore, Honor the Earth again requests that the Commission refer this matter to the Office of Administrative Hearings so that it could benefit from ALJ findings and recommendations, and so that all stakeholders, including shippers and landowners, can formally participate in this groundbreaking process.

Honor the Earth agrees that the trustee should be "the state actor anticipated to handle the decommissioning." Department Initial Comments at 5 (footnote omitted). Honor the Earth also agrees that "determination of the appropriate beneficiary . . . is complicated," and that impacted Tribes should be included. Department Initial Comments at 5-6. However, the Department fails to recognize that (a) in practical effect, the largest class of potential beneficiaries of the proposed trust would be the owners of impacted private land, such that (b) the state simply cannot march in and dictate mitigation terms throughout the Line 93 route, possibly due to private easement terms between Enbridge and landowners. The state beneficiary would need a trust structure in which it could work with a wide range of landowners.

CONCLUSION

For the foregoing reasons, Honor the Earth renews its request that the Commission refer this matter to the Office of Administrative Hearings for a contested case hearing, and require that Enbridge provide written notice of this matter to all landowners subject to an easement or right-of-way agreement for new Line 3. In addition, Honor the Earth requests that the Commission direct Enbridge to provide a filing describing its discussions of this matter, if any, with its shippers, and direct that Enbridge also provide all of its shippers with notice of such hearing.

Dated: June 20, 2022

Respectfully submitted,

*/s Paul C. Blackburn*_______
Paul C. Blackburn
607 Main Avenue
Callaway MN 56521
612-599-5568
paul@honorearth.org
Attorney for Honor the Earth

ATTACHMENT A

1. Pipeline Overview CFR § 347.1 (e) (2)

An explanation of the organization, ownership, and operation of the pipeline.

The 2,047-mile Lakehead system, which is the United States portion of the world's longest liquid petroleum pipeline, has operated for more than 70 years and is the primary transporter of crude oil and natural gas liquids from western Canada to the United States. It is a common carrier pipeline that runs from the international border near Neche, North Dakota to the international border near Marysville, Michigan. As of April 2021, it consisted of approximately 4,547 miles of pipe with various loops having diameters ranging from 18 to 48 inches; 116 pump station locations; and 95 crude oil storage tanks with a capacity of about 17.0 million barrels.

The Lakehead system is owned by Enbridge Energy, Limited Partnership (Enbridge Energy) which is an operating subsidiary of Enbridge Energy Partners, L.P. Enbridge Energy Partners, L.P, headquartered in Houston, Texas, is a leader in energy transportation, delivering crude oil and natural gas liquids and operating crude oil storage terminals in the Mid-Continent region of the United States. Enbridge Energy Partners, L.P. owns and operates its crude oil and natural gas liquids transportation and crude oil storage terminals businesses through two subsidiaries: Enbridge Energy and North Dakota Pipeline Company LLC. North Dakota Pipeline Company LLC owns and operates the North Dakota crude oil pipeline system which transports crude oil from the Bakken region and interconnects with the Lakehead system and other pipelines. Enbridge Energy's liquids segment business is conducted principally through the ownership of the Lakehead system, which transports crude oil and natural gas liquids primarily from reserves in western Canada through its connection with its affiliated pipeline in Canada, Enbridge Pipelines Inc. (collectively, the Enbridge Mainline), and the Bakken formation in the Midwest to refining centers in the Midwest and eastern Canada and to connections with other pipelines serving those regions and the U.S. Gulf Coast. In 2020, Lakehead system deliveries averaged 2.3 million barrels per day, meeting approximately 76% of the refinery capacity in the greater Chicago area; 76% of the Minnesota refinery capacity; and 84% of Ontario refinery capacity.

From 1991 until December 20, 2018, Enbridge Energy Partners, L.P. was a publicly traded master limited partnership whose units traded on the New York Stock Exchange (NYSE) under the symbol EEP. On December 20, 2018, all of the publicly held units of Enbridge Energy Partners, L.P. along with those of Enbridge Energy Management, L.L.C., which managed the business and affairs of Enbridge Energy Partners, L.P. were acquired by Enbridge Inc. (Enbridge) based in Calgary, Alberta. Enbridge trades on the NYSE and Toronto Stock exchange under the symbol ENB.

2. General Principles Summary CFR § 347.1 (e) (1)

A brief summary relating to the general principles on which the proposed depreciation rates are based.

Enbridge is filing this 2020 Technical Update to the 2015 Depreciation Study (2020 Depreciation Study) to update its depreciation rates based on its assets in-service as at December 31, 2020. All material to support approval of the revised depreciation rates as required in Subpart P, Chapter 1, Title 18, Code of Federal Regulations (CFR), Part 347 is available in this filing.

Enbridge Energy is requesting approval for the Lakehead system's proposed depreciation rates based on a truncation date of December 31, 2040. Enbridge Energy is specifically requesting approval to use revised depreciation rates as of January 1, 2021 for ratemaking as well as FERC reporting purposes.

A single set of depreciation rates, applicable for both ratemaking and accounting and reporting purposes, was approved by the Federal Energy Regulatory Commission (Commission or FERC)[1] for the Lakehead system effective January 1, 2016 (2015 Depreciation Study). Further, Enbridge Energy has prepared and compiled the proposed update to depreciation rates on the same basis as the 2015 Depreciation Study.

The Lakehead system assets were acquired in December 1991 by Enbridge Energy Partners, L.P. For ratemaking purposes, the property, plant and equipment (PP&E) continues to be carried at historical cost (the prior owner's basis at the time of the acquisition plus subsequent net additions) and depreciated using rates previously approved by the Commission. Enbridge Energy continues to maintain historical cost PP&E records.

Since the 2015 Depreciation Study, the Lakehead system has continued to undergo significant expansion in addition to recurring maintenance and integrity capital expenditures. The aggregate net book value of PP&E at December 31, 2020 is virtually unchanged compared with the net book value of PP&E at December 31, 2015 despite the Lakehead system having recorded in excess of $1.9 billion in depreciation expense over that period.

The majority of additions to PP&E have been attributable to projects constructed and placed in service pursuant to the Facilities Surcharge Offer of Settlement (Facilities Surcharge) approved by the Commission[2], maintenance and integrity capital expenditures as well the recognition of an Asset Retirement Obligation in conjunction with Lakehead's Line 3 Replacement Project. The Facilities Surcharge allows Enbridge Energy to recover the costs associated with projects requested and supported by the Canadian Association of Petroleum Producers (CAPP), the counterparty to the Facilities Surcharge, through an incremental surcharge layered on top of the existing indexed base rates (the Base System). Several of the Facilities Surcharge projects have distinct commercial attributes, including depreciation terms, which differ from the depreciation terms of the assets that

---

1 Docket No. DO17-3-000. Letter Order dated January 17, 2017.

2 Enbridge Energy, Limited Partnership, 107 FERC 31,336 (June 30, 2004) Docket No. OR04-2-000.

are not tolled through the Facilities Surcharge. Due to this unique situation of having different depreciation terms and conditions, and consistent with the approach taken in the 2015 Depreciation Study, Enbridge Energy proposes to continue the segregation the Facilities Surcharge assets and the Base System assets for depreciation purposes.

For the Facilities Surcharge assets, the depreciation rates were determined based on the Commission-approved Facilities Surcharge agreements with CAPP, where applicable. As of December 31, 2020, there have been 26 shipper-supported projects approved by the Commission for inclusion in the Facilities Surcharge[3]. Five of these Facilities Surcharge projects include specific clauses stipulating the depreciation of the project's assets via either a fixed depreciation rate or a fixed period. Table 1 shows those Facilities Surcharge projects with stipulated depreciation terms and their respective composite remaining life at December 31, 2020.

Table 1: Facilities Surcharge Projects with fixed and stipulated depreciation terms

No.	Facilities Surcharge Project	FERC Docket No.	FERC Approval Date	Depreciation Start Date	Truncation Date	Composite Remaining Life at 12/31/15 (in years)
1	Project 5 - Southern Access Mainline Expansion Project	OR06-3-000	3/16/2006	4/1/2008	3/31/2038	N/A
2	Project 14 - Line 6B Integrity Project	OR11-5-000	3/31/2011	1/1/2011	12/31/2040	20.0
3	Project 15 - Line 6B Pipeline Replacement and Dig Program	OR12-8-000	3/29/2012	6/30/2013	6/29/2043	22.5
4	Project 21 - Line 14 2013 Additions	OR14-33-000	7/31/2014	1/1/2014	12/31/2035	20.0
5	Project 22 - Recoverable Legacy Integrity	OR14-33-000	7/31/2014	1/1/2014	12/31/2035	20.0

Project 5, Southern Access Mainline Expansion Project, has a fixed depreciation rate of 3.33% as stipulated in the terms of the agreement[4]. The other Facilities Surcharge projects noted in Table 1 have language in their respective agreements that prescribe a depreciation period or a truncation date. Even though certain Facilities Surcharge projects have specific truncation dates, the related physical assets may remain in-service beyond these dates.

[3] The following Facilities Surcharge projects are not included in this Depreciation Study as they have either been fully recovered or have no capital component: Projects 2, 4 (Docket No. OR04-2-000); Projects 9, 10, and 11 (Docket No. OR09-5-000); Project 21 – Legacy Line 14 (Docket No. OR14-33 and Project 21 – Line 14 Additions (Legacy) (Docket No. OR14-33). Project 25 (OR16-9-000) was approved by the FERC on February 1, 2016 and is not a capital project.

[4] FERC Docket No. OR06-3-000, at Page 9.

The remaining Facilities Surcharge projects[5] which either do not have stipulated depreciation terms, or stipulate the use of the later of the Facilities Surcharge project agreement stipulated truncation date or the truncation date applicable to the non-stipulated Facilities Surcharge projects and Base System assets, have been assessed using a truncation date of December 31, 2040.

For each individual Facilities Surcharge project, both stipulated and non-stipulated, Enbridge Energy applies a single depreciation rate for rate making and reporting purposes to all plant accounts within that Facilities Surcharge project for a given Facilities Surcharge project for ratemaking and reporting purposes.

The remaining balance of the Lakehead system PP&E is comprised of Base System assets. Depreciation rates for these assets are based on the remaining lives developed by Concentric Energy Advisors (Concentric) and are provided in Appendix "A" at page 2. An explanation of the depreciation rates for the Base system assets is discussed below in CFR § 347.1 (e) (4).

Summaries of current and proposed depreciation rates, remaining economic lives, gross plant and accrued depreciation for each Facilities Surcharge project and for the Base System assets by plant code are included in Appendix "A". Gross plant balances and accrued depreciation balances are as of December 31, 2020.

3. Average Remaining Life CFR § 347.1 (e) (4)

An explanation of the average remaining life on a physical basis and on an economic basis.

This depreciation study reflects the straight-line method of depreciation using a remaining service life basis. The remaining service life is primarily dependent on two factors: physical life and economic life. As discussed above, in order to best assess the service life of the Lakehead system, Enbridge Energy segregated the assets between Base System assets and Facilities Surcharge assets.[6]

For the Base System assets, Enbridge Energy engaged Concentric to undertake a technical update to the 2015 depreciation rate calculations incorporating the average service life estimates as approved in the 2015 Depreciation Study and to review the appropriateness of Enbridge Energy's proposed truncation date for the purpose of calculating depreciation rates for its pipeline assets as of December 31, 2020. The results of the technical update produced a detailed calculation of the remaining lives for each Lakehead Base System asset account. This study is included in Appendix "F". Accordingly, Enbridge Energy has utilized these remaining service lives (subject to the

---

[5] Project 12 – Alberta Clipper Project; Project 18 – Eastern Access Phase 1; Project 19 – Eastern Access Phase 2; Project 20 – 2014 US Mainline Expansions; Project 21 – Line 14 Additions; Project 23 – Recoverable Future Integrity; Project 24 – 2015/16 US Mainline Expansions. Projects 1, 3, 6, 7, 8, 13, 16 and 17 are categorized as Other FSM Projects for the purposes of this Depreciation Study.

[6] See Appendix A.

December 31, 2040 truncation date as described below) in calculating depreciation rates for the Base System assets.

For those Facilities Surcharge assets with either a stipulated depreciation rate or stipulated economic life and/or truncation date, Enbridge Energy proposes that the economic life, as determined by the Commission-approved Facilities Surcharge agreements with CAPP, be the sole factor in establishing the remaining life.

While this may result in certain Facilities Surcharge assets having an economic life somewhat longer or shorter than the December 31, 2040 truncation date proposed for the non-stipulated Facilities Surcharge assets and the Base System assets, these resulting economic lives reflect the outcome of negotiations between CAPP and Enbridge Energy and accordingly should continue to determine the depreciation rates applied to these projects.

These economic lives are reflected in the proposed depreciation rates as noted in Table 1 and Appendix “A”.

3.1 Physical Life

The physical life of the pipeline is continually extended through Enbridge Energy’s comprehensive program of maintenance and refurbishment. Enbridge Energy’s pipeline integrity program identifies sections of the pipeline needing repair or replacement and is designed to maintain the safe operating lifespan of the pipeline for an indefinite period of time.

Given this approach to integrity, the service life of the Lakehead system is not dependent solely upon physical forces such as deterioration but also to a large extent upon the economic exhaustion of supply and changes in the demand for crude oil.

3.2 Economic Life

The assessment of the economic life of the pipeline is as important as the estimation of the physical life in the calculation of appropriate depreciation rates given the long-lived nature of pipeline assets. Unless otherwise stipulated pursuant to the terms of a Facilities Surcharge project, the remaining lives of all asset groups reflect a truncation date of December 31, 2040, based on an economic life review of the Lakehead system.

There are several factors, considerations and uncertainties which support the use of a December 31, 2040 truncation date. These include current and anticipated competition to the Enbridge Mainline, actions by state and local governments and the uncertainty arising from the recent acceleration in the pace of Federal (United States and Canada), state/provincial and local governments passing decarbonization legislation or adopting policies that may influence the market demand for pipelines. An example of the latter is found in the recent issuance by President Biden of an Executive Order titled: "Tackling the Climate Crisis at Home and Abroad"[7], which unveiled detailed climate plans designed to meet his campaign promise that the United States achieves a 100% clean energy economy and net zero emissions no later than 2050.

The Enbridge Mainline, including the Lakehead System, is expected to face higher levels of competition for crude oil egress from the Western Canada Sedimentary Basin (WCSB) in the form of the TMEP pipeline expansion (owned by the Government of Canada). The TMEP pipeline, expected to come into service in late 2022, is anticipated to add approximately 590,000 barrels per day of egress from Edmonton, Alberta to tidewater on the Pacific coast. The incremental TMEP capacity is expected to be filled with barrels moving by rail today and by barrels from the Enbridge Mainline. Enbridge Energy expects that the diverted barrels will be made up as supply grows. Nevertheless, the introduction of additional competitive capacity introduces incremental uncertainty compared with the 2015 Depreciation Study.

The competitive position of the Enbridge Mainline is also impacted by the fact that its primary competitors for the transportation of WCSB volumes (Trans Mountain and Keystone) are, or will be, contracted crude oil pipelines with limited spot volumes. In contrast, the Lakehead system and Canadian Mainline provide only 100% spot service. Under most scenarios whereby crude oil supply or demand or both are reduced, spot volumes will likely be the first barrels to be cut, as they were during the Covid-19 pandemic when the Enbridge Mainline experienced an approximate 500,000 bpd drop in throughput during the second quarter of 2020 while Keystone experienced minor and short-lived volume reductions and Trans Mountain essentially no reductions. The Lakehead system and Canadian Mainline both currently have the highest exposure to spot barrels of the major pipelines provided egress out of the Western Canada Sedimentary Basin.

Unprecedented actions by state, local, and tribal governments to attempt to regulate, and ultimately shut down, existing pipeline infrastructure, such as experienced by Enbridge Energy in Michigan and Wisconsin with respect to Line 5, is a new, emerging risk not imagined at the time of Enbridge Energy's 2015 Depreciation Study. Despite having constructed Line 5 in 1953 and operating the pipeline in accordance with applicable federal safety standards, Enbridge is facing lawsuits filed in Michigan in 2019 and 2020 and in Wisconsin in 2019 that seek closure of Line 5 decades after the pipeline's construction. The lawsuits come despite the support of the Canadian government as well as most of the states and provinces that would be directly impacted by a shutdown of Line 5. In 2020, Enbridge also filed its own lawsuit against the State of Michigan to defend the continued, uninterrupted operation of Line 5. The fact that Enbridge must go to court to protect its operating assets is evidence of the emergence of a new risk not faced by Enbridge Energy at the time of the 2015 Depreciation Study.

Finally, the publicly stated goal of transitioning to a lower carbon economy of both the governments of the United States and Canada introduces additional uncertainty to the process of establishing depreciation rates. The timing of this transition is uncertain and unknowable. This uncertainty is

---

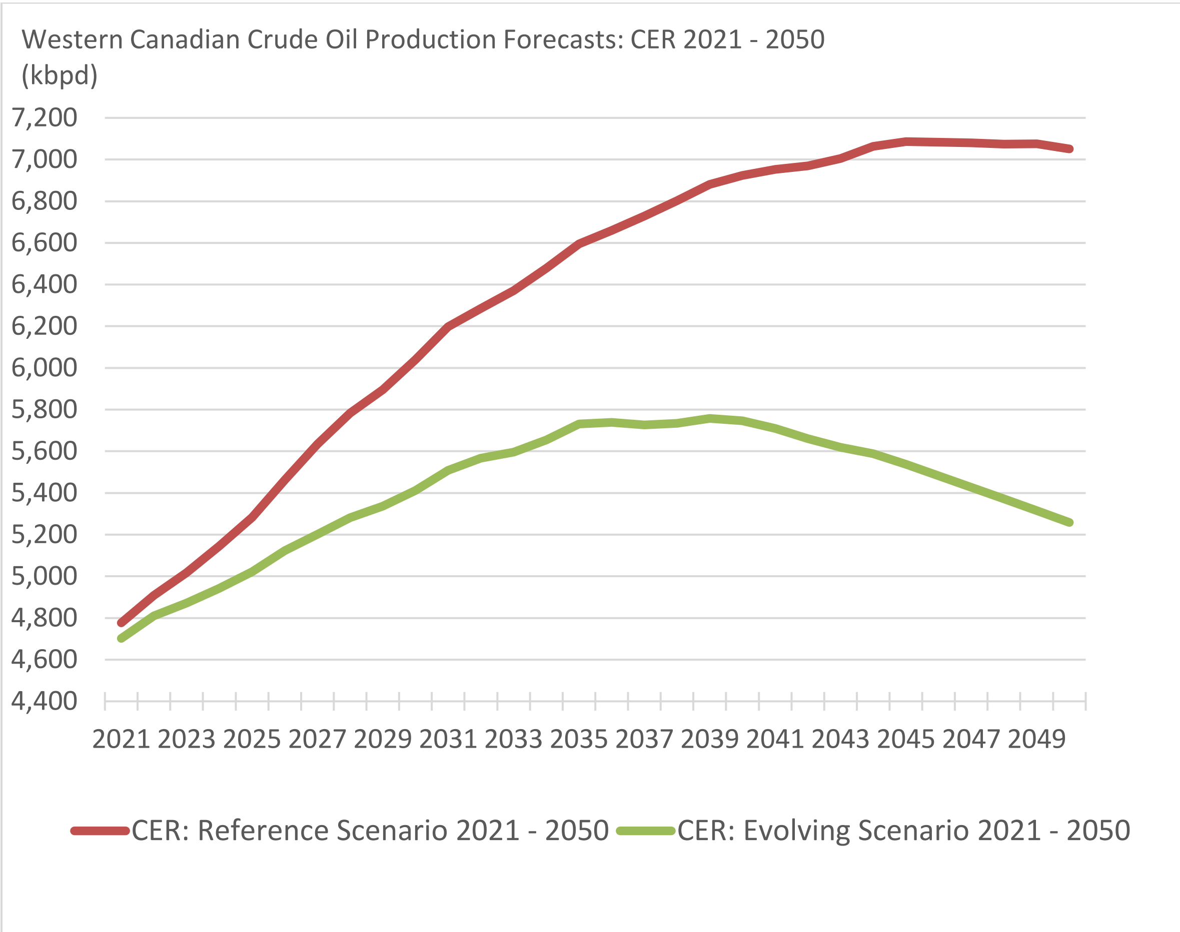
[7] Executive Order No. 14008 ("E.O. 14008"), 86 Fed. Reg. 7,619 (Jan. 27, 2021) (E.O. 14008).

significant as it is beginning to influence the forecasts Enbridge Energy has historically relied on to inform its process of establishing economic lives and truncation dates for setting depreciation rates for the Lakehead system and Canadian Mainline.

For example, Enbridge Energy has reviewed the recent forecast produced by the Canada Energy Regulator (CER) (formerly known as the National Energy Board of Canada) . While the CER's past forecasts have included alternate scenarios based on price and Triple E (a balancing of Economic, Environmental and Energy objectives), the CER is also now including alternative scenarios based on a societal transition away from carbon-based forms of energy.

The CER has issued two scenarios for WCSB production in its most recent forecast – a Reference Scenario and an Evolving Scenario (Figure 1). The Evolving Scenario assumes a lower demand for fossil fuels globally and advancements in low carbon technologies lead to improved efficiencies and lower costs while the latter scenario considers a future where action to reduce GHG emissions does not develop beyond measures currently in place. The Reference Scenario assumes stronger demand for fossil fuels and that, while low carbon technologies continue to improve, they do so at a slower rate than in the Evolving Scenario.

Figure 1[8]



Beyond 2040, as highlighted by the CER's alternate scenarios, there is uncertainty in determining when, and to the extent, supply may decline. It depends on how global and North American demand is impacted by any transition to alternative energy sources, often referred to as the energy transition. For example, as noted by the CER, future crude oil prices, access to market and market demand for Canadian crude oil will significantly influence the decisions producers will make regarding future production growth, competitiveness, and investments in new technologies.

Additionally, while CER's Evolving Scenario focuses on Western Canadian Sedimentary Basin production, the stated policy goals of a transition to a lower carbon economy may also have effects on the demand side of the ledger. The Canadian Government has recently announced its climate plan of which a centerpiece is to increase carbon taxes from the current level of CDN $40/ton to CDN$170/ton by 2030. The CDN$170/ton is equivalent to approximately CDN $0.40/liter of gasoline or about CDN $1.60/gallon of gasoline. According to one forecast, an IMF report entitled "Four Charts on Canada's Carbon Pollution Pricing System" dated March 18, 2021, the imposition of the carbon tax scheme as well as the escalation in the per unit carbon tax rate is forecasted to

[8] Canada Energy Regulator – Canada's Energy Future 2020 - Appendices

reduce Canada's expected carbon dioxide emissions by approximately one third by 2030. While the exact impact of Canada's carbon tax scheme on crude oil demand is currently not quantifiable it is clearly another uncertainty. The fact that the United States has not yet implemented such a scheme in an attempt to meet its commitment to the Paris Agreement, despite its stated intention to do so as evidenced by President Biden's Executive Orders, only adds to the level of uncertainty for pipelines as they attempt to forecast long term demand for crude oil transportation services.

In the face of all this uncertainty, new competitor pipelines, actions by state and local governments to attempt to regulate interstate and international pipelines and clearly divergent forecasts as to the level of WCSB production beyond 2040, the determination of a 2040 truncation date for purposes of establishing depreciation rates for the Lakehead system is both a necessary and prudent step at this time. As the future unfolds and these uncertainties are gradually resolved, Enbridge Energy should, and will, incorporate and reflect this additional clarity about the path forward in future depreciation studies.

Crude Oil Supply Capability

There is considerable uncertainty when attempting to forecast crude oil production, particularly for projection periods exceeding 20 years (Refer to discussion under 3.2 - Economic Life). Notwithstanding that inherent uncertainty, current supply forecasts for Canada and the United States support the conclusion that adequate crude oil supply will be available to the Lakehead system to support, at a minimum, a 20-year economic life.

Canadian Supply

In terms of oil reserves, where it is proven that oil can be economically recovered, Canada ranks third globally after Saudi Arabia and Venezuela with about 169.7 billion barrels[9]. Ninety-six percent of the current crude oil reserves are found in the oil sands formations in western Canada, with the balance located in conventional fields in western and eastern Canada.

The majority of the Lakehead system's crude oil supply comes from western Canada and especially the Alberta oil sands. Data gathered and analyzed by the Canada Energy Regulator suggests that the production of crude oil is anticipated to grow for the next two decades, which supports Enbridge Energy's position that there is a reliable supply of crude oil to be shipped on the Lakehead system. This is primarily because oil sands projects have very low decline rates, meaning that projects that are started can run at or near their initial production rates for 25-40 years. Many of the projects that are producing today are anticipated to continue to do so through 2040.[10]

---

[9] BP Statistical Review of World Energy 2020, at Page 14.
[10] CER Canada's Energy Futures 2019 Supplement: Oil Sands Production

Crude Oil Demand Outlook

Market demand for crude oil transported by the Lakehead system comes primarily from refineries in the Midwest United States and eastern Canada. Enbridge Energy expects that demand for western Canadian and Bakken crude oil production will continue to increase slowly in PADD II (the area that includes the Great Lakes and Midwest regions of the United States). PADD II refinery configurations and crude oil requirements continue to make it an attractive market for western Canadian supply.

United States Demand

Petroleum and other liquids continue to be the most-consumed fuel in the United States. In its AEO2021 reference case, the EIA forecasts that United States consumption of petroleum and other liquids, which include biofuels, will remain basically flat between 2019 and 2040, with an annual average increase 0.12%. The consumption of motor gasoline, a primary product of crude oil refining, is expected to decline from pre-pandemic levels of over 9 million barrels per day to approximately 8 million barrels per day by 2040.

Canadian Demand

According to the April 2018, Canadian Refinery Overview, Energy Market Assessment[11], Canada's total refining capacity is 1.9 mmbpd, with refining capacity in Ontario and Quebec (key markets for the Lakehead system) at 792 mbpd, and western Canada at 686 mbpd. Canadian refineries operate mostly to meet domestic needs. There was a 30-year period where no new refineries were built; this changed in 2017 when a refinery located in central Alberta began operations. There are no new refineries being proposed or in construction at this time.

Refineries in western Canada receive the majority of their crude oil requirements via pipeline, with smaller volumes transported by rail. As stated within Canadian Refinery Overview, Energy Market Assessment, "Crude oil receipts at Canadian refineries have not grown since 2000…Canadian refinery production peaked in 2004. Between 2004 and 2015, refinery production dropped nearly 15%."

3.4 Conclusion

The goal of depreciation policy and the establishment of oil pipeline depreciation rates is to provide the pipeline with a reasonable opportunity to recover its investment in property, plant and equipment. For the Lakehead System, that investment stood at just over $9 billion at December 31, 2020. Further that investment is expected to grow a further $4 billion later in 2021 with the in-

[11] Source: https://www.cer-rec.gc.ca/en/data-analysis/energy-commodities/crude-oil-petroleum-products/report/2018-refinery-report/2018cndnrfnrvrvw-eng.pdf

service of the U.S. portion of Enbridge Energy's Line 3 Replacement project[12].

The risk of recovery of a pipeline's investment in its property, plant and equipment, which Enbridge Energy views as its fundamental risk, ultimately rests with the pipeline company. Depreciation studies and capitalization policies are important tools which the company has at its disposal to manage this fundamental risk and provide the pipeline company with a reasonable opportunity to recover its investment and mitigate this risk.

Managing this fundamental risk is inherently difficult and challenging at the best of times due to the requirement for long term forecasts and, often, the size of the pipeline investment at stake. It is not possible to know at the time the truncation date is estimated, and depreciation rates are established, what the "correct" truncation date will be.

Furthermore, there is a unique asymmetric nature to this risk that must also be considered. If depreciation rates were set based on a truncation date that ultimately turns out to be too early, rate-payers may pay more in the near term but would ultimately benefit from a lower rate base and lower rates in the long run. Conversely, setting depreciation rates based on a too long truncation date may mean that the pipeline company may be unable to charge the necessary rates in the future to permit the pipeline company to recover its investment. Correspondingly, pipeline companies should be afforded a degree of latitude to manage this risk through depreciation studies provided that the pipeline resulting rates remain just and reasonable.

Accordingly, it is Enbridge Energy's view that the use of a December 31, 2040 truncation date in setting depreciation rates effective January 1, 2021 is a rational and prudent approach at this time. As new and incremental information becomes available it is incumbent on Enbridge Energy to incorporate this new information in future depreciation studies and depreciation rates to ensure such depreciation rates remain appropriate and that Enbridge Energy continues to address its fundamental risk.

---

[12] As the U.S. portion of the Line 3 Replacement Project is expected to be in-service in Q4 of 2021 it is not included in this 2020 Technical Update to the 2015 Depreciation Study.

4. Proposed Depreciation Rates CFR § 347.1 (e) (3)
A table of the proposed depreciation rates by account.

Please see Appendix "A" which sets forth the proposed depreciation rates for Lakehead's Base System and the Facilities Surcharge assets. The proposed changes reflect an overall decrease in the economic lives of the Lakehead system assets due to a revision of the truncation date from 2045 to 2040. Gross plant balances and accrued depreciation balances are as of December 31, 2020.

5. System Maps CFR § 347.1 (e) (5) (i)
Up-to-date engineering maps of the pipeline including the location of all gathering facilities, trunkline facilities, terminals, interconnections with other pipeline systems, and interconnections with refineries/plants. Maps must indicate the direction of flow.

Please see Appendix "B".

6. Operations Summary CFR § 347.1 (e) (5) (ii)
A brief description of the carrier's operations and an estimate of any major near-term additions or retirements including the estimated costs, location, reason, and probable year of transaction.

For a description of the Lakehead system operations, please refer to information provided in response to CFR §347.1 (e) (2) and CFR §347.1 (e) (5) (i).

Significant near-term additions include the Line 3 Replacement Project. The Line 3 Replacement Project provides for a new 36" diameter pipeline from the United States border to Superior, Wisconsin, except for approximately 16 miles downstream of the United States border which is 34" pipeline diameter. It includes eight new pump stations and terminal connectivity at the Clearbrook, Minnesota and Superior, Wisconsin terminals.

Subject to regulatory and other approvals, the estimated in-service date for the Line 3 Replacement Project is Q4 2021. The total estimated cost, including costs for decommissioning and remediation of the original Line 3 pipeline, for the United States portion of the Line 3 Replacement Project is $4.2 billion.

7. Current Depreciation Rates CFR § 347.1 (e) (5) (iii)
The present depreciation rates being used by account.

Please see Appendix "A".

8. Volume Information CFR § 347.1 (e) (5) (iv) and (vi)
For the most current year available and for the two prior years, a breakdown of the throughput received with source at each receipt point and throughput delivered at each delivery point. A list of shipments and their associated receipt points, delivery points, and volumes by type of product for the most current year.

Please see Appendix “C”.

9. Capacity Information CFR § 347.1 (e) (5) (v)
The daily average capacity (in barrels per day) and the actual average capacity (in barrels per day) for the most current year, by line section.

Please see Appendix “D”.

10. Plant and Reserve Balances CFR § 347.1 (e) (5) (vii)
For each primary carrier account, the latest month's book balances for gross plant and for accumulated reserve for depreciation.

Please see Appendix “A”.

11. Remaining Life Estimate CFR § 347.1 (e) (5) (viii)
An estimate of the remaining life of the system including the basis for the estimate.

Please refer to information provided in response to CFR §347.1 (e) (4).

12. List of Crude Oil Areas CFR § 347.1 (e) (5) (ix)
For crude oil, a list of the fields or areas from which crude oil is obtained.

Please see Appendix “E”. For additional background please refer to information provided in response to CFR §347.1 (e) (4).

13. Service Life Data Form CFR § 347.1 (e) (5) (x)
If the proposed depreciation rate adjustment is based on the remaining physical life of the properties, a complete, or updated, if applicable, Service Life Data Form (FERC Form No. 73) through the most current year.

As the proposed depreciation rates are based primarily on economic life, updated Service Life Data Forms (FERC Form No. 73) are not required.

14. Estimated Salvage Value CFR § 347.1 (e) (5) (xi)
Estimated salvage value of properties by account.

For purposes of this depreciation study, Enbridge Energy estimates the salvage value to be zero. Please see Appendix “A”.

ATTACHMENT B

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Enbridge Energy, Limited Partnership | Docket No. OR21-9-000

MOTION TO INTERVENE AND COMMENTS OF THE CANADIAN ASSOCIATION OF PETROLEUM PRODUCERS

Pursuant to Rules 212, 214 and 602 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") Rules of Practice and Procedure, 18 C.F.R. § 385.212, § 385.214 and § 385.602 (2020), the Canadian Association of Petroleum Producers ("CAPP") hereby moves for leave to intervene in the above-captioned proceeding, and submits the following comments regarding the filing that initiated this docket, the Facilities Surcharge Filing Supplement ("FS Filing") made by Enbridge Energy, Limited Partnership ("Enbridge").

I. COMMUNICATIONS

Communications and correspondence concerning this motion should be directed to the following persons, and CAPP requests that all such persons be added to the official service list:

Nancy Bérard-Brown
Canadian Association of Petroleum Producers
1st Canadian Center
2100, 350 - 7th Avenue, SW
Calgary, Alberta, Canada T2P 3N9
Nancy.BerardBrown@capp.ca

James H. Holt
Betts & Holt LLP
1101 Connecticut Avenue, NW
Suite 450
Washington, DC 20036
jhh@bettsandholt.com

II. THE FS FILING

On April 14, 2021, Enbridge filed a Supplement to the Facilities Surcharge Settlement (FS or FSM) approved by the Commission on June 30, 2004, in Docket No. OR04-2-000, at 107 FERC ¶ 61,336 (2004). CAPP is the counterparty to the FSM. Enbridge cites the support of CAPP for the Supplement as set forth in correspondence engaged in in 2014. The Supplement requests approval of the proposal by June 30, 2021 or, in the alternative (page 8, footnote 4), that the FS Filing be accepted in the fourth quarter of 2021, subject to adjustments in the annual FS Filing made in April. The Commission issued its Notice of the FS Filing in the captioned docket and established a comment date of May 4, 2021. Reply comments may be submitted by May 14, 2021.

As Enbridge describes, the purpose of the FS Filing is to effectuate the rate aspects of a project to replace and restore crude-oil transportation capacity within the U.S. portion of the mainline, the so-called Line 3 Replacement Project.

> Enbridge Energy seeks Commission approval to supplement the Facilities Surcharge Settlement to permit Enbridge Energy to include Project 27, which involves the planned integrity and maintenance driven replacement and restoration of Enbridge Energy's Line 3 mainline capacity from the international border near Neche, North Dakota to Superior, Wisconsin.

(Filing at page 1) Like other FS projects, the Line 3 Replacement Project comprises a portion of the Lakehead portion of the Enbridge system, operating within the U.S. from a point near Neche, North Dakota to Superior, Wisconsin.

III. Motion to Intervene

CAPP, as the counterparty to the 2004 Settlement Agreement pursuant to which the FS Filing was made, has a direct and substantial interest in this proceeding. It has participated in a number of prior proceedings involving the annual FS filings made with the Commission by Enbridge pursuant to the Settlement Agreement. The FS mechanism has proved to be effective and beneficial to both CAPP and Enbridge. Commission review of the annual filings is instrumental and vital to preserving the integrity of that process. CAPP members include shippers on the Enbridge system and other connected pipelines. As noted above, CAPP's members also account for the bulk of crude oil supplies that are produced in Canada and transported by Enbridge.

CAPP thus has interests in this proceeding that cannot be represented by any other participant. As the counterparty to the FS Settlement, its interests are directly implicated here. Therefore, CAPP has direct interests in the outcome of this proceeding, interests that cannot and will not be adequately represented by any other party.

IV. COMMENTS

The design and structure of the FSM envisions that projects operating within its scope become subject to a surcharge, which is added to the base mainline rates otherwise applicable under Enbridge's FERC tariff. Shippers making use of facilities and services subject to the FSM thus pay the mainline base rate – which is subject to the Commission's annual index-adjustment rate mechanism for oil pipelines – as well as the applicable surcharge calculated and applied pursuant to the FS mechanism. The purpose of the surcharge is to recover costs attributed to new and incremental facilities that may be necessitated from time to time, and as agreed to between Enbridge and CAPP.

The instant filing, in which Enbridge seeks approval to implement an FS surcharge for "Project 27" – a replacement and restoration project designed to cover costs and services attributed to the replacement of Enbridge's so-called "Line 3" – presents an additional issue relating to the relationship between the base rate and the surcharge. This issue is similar to ones that have arisen in similar circumstances relating to prior FS filings, (for instance, Project Nos. 14 and 15) and is brought about because the facilities and costs that would be subject to the proposed surcharge supersede and replace certain facilities that have heretofore been subject to the base mainline rate, the "indexed" portion of the tariff. The surcharge, which is intended to recover costs not otherwise recovered through the base rates, thus requires evaluation to ensure that that purpose is effectuated by any rates approved under the FS structure.

Another attribute of this FS filing and the underlying Project 27 Line 3 Replacement Project is the lengthy time period over which the project has been conceived, agreed upon and is being brought to fruition. As is apparent from Attachment A to the Filing, CAPP furnished its approval of the project in a letter to Enbridge dated 2014, nearly seven years ago. The passage of time and the complex course of intervening events have conspired to render the original cost estimate inoperative and of little guidance. The "current capital cost estimate" of "approximately $4.2 billion" (page 5) represents an increase of approximately 63 percent over the original project capital cost estimate of $2.585 billion.

Similarly, the in-service date of the project, which had been forecasted for third quarter of the 2017, has been superseded as well, with Enbridge now projecting service to commence in the last quarter of this year. Regulatory delays are identified as the primary intervening factors.

CAPP remains supportive of the project, which is integral to the commercial functioning of the Enbridge mainline. The instant Filing, however, does not purport to address or resolve the final cost figures that would be applicable in deriving the specific surcharge applicable to the project. Moreover, as noted above, it does not resolve issues relating to the relationship between the base rate(s) and surcharge(s) that would be in effect once the project becomes operational. As Enbridge notes, at page 3, "The particular project costs to be recovered via the Facilities Surcharge are determined through negotiations between Enbridge Energy and CAPP."   Those negotiations are expected to gain focus as the costs, in-service date, and other material considerations transpire.

In sum, the Filing represents a request for conceptual approval of the project under the FS mechanism. CAPP supports this request. The scope and specifics of the surcharge remain subject to negotiation and further bi-lateral procedures.

WHEREFORE, for the reasons stated above, CAPP requests that it be permitted to intervene in the above-captioned proceeding. CAPP further submits the foregoing initial comments and respectfully requests that the Commission give them due consideration in its disposition of the Filing.

Respectfully submitted,

CANADIAN ASSOCIATION OF
PETROLEUM PRODUCERS

/s/ James H. Holt
James H. Holt
Betts & Holt LLP
1101 Connecticut Avenue, N.W.
Suite 450
Washington, D.C. 20036
(202) 530-3380
jhh@bettsandholt.com

Counsel for the Canadian Association of Petroleum Producers

Dated: May 4, 2021

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary of the Federal Energy Regulatory Commission.

Dated at Washington, D.C., this 4th day of May, 2021.

/s/ James H. Holt

James H. Holt
Betts & Holt LLP
1101 Connecticut Avenue, NW
Suite 450
Washington, D.C. 20036

Counsel for The Canadian Association of Petroleum Producers

ATTACHMENT C

LINE 3 REPLACEMENT PROJECT

Application for Certificate of Need

Minnesota Public Utilities Commission
Appendix D

Issue Resolution Sheet (US)

Representative Shipper Group (RSG)
Issue Resolution Sheet (IRS)
CONFIDENTIAL & WITHOUT PREJUDICE

Final IRS # 2013-02-B (U.S.) Line 3 Replacement
Enbridge Pipelines Inc. Enbridge Energy Limited Partnership

ISSUE: Line 3 Replacement (U.S.)

PROJECT SCOPE (See Appendix A for additional information)

- *Initial annual capacity of 760 kbpd assuming 65% heavy / 35% light*
- *New 36-inch pipeline between the U.S. border and Superior, except for approximately 16 miles downstream of the U.S. border which will be new 34-inch pipe*
- *8 new pump stations*
- *Clearbrook terminal connectivity*
- *Superior terminal connectivity*
- *Target in-service date: Q3 2017*
- *All scope will be updated to reflect the Class IV Cost Estimate to be completed in April 2014*
- *Total unclassified cost (including AFUDC; including Decommissioning)("Unclassified Total Capital Costs"): US$2.6B*

Operational

- *New Line 3 will be placed in mixed service from Hardisty to Superior,*
- *Existing Line 3 decommissioned from Hardisty to Superior*

Should the scope of the project, including any of the individual components, deviate materially from what is identified above, Enbridge commits to update the RSG in a timely manner and where reasonable may seek amendment of this IRS 2013-02-B (U.S.).

RSG MEMBER CONDITIONS PRECEDENT

Enbridge Pipelines Inc. ("Enbridge") will update the RSG Members early Q2, 2014 regarding the completed results of the Line 3 Class IV Cost Estimates. Should the Line 3 Class IV Cost Estimates result in total capital costs (including AFUDC and decommissioning) (U.S. and Canada) in excess of 15% above the Unclassified Total Capital Costs, then within 30 days of receipt of the Line 3 Class IV Cost Estimates from Enbridge the RSG will have the option to vote on not proceeding with IRS 2013-02-A (Canada) and IRS 2013-02-B (U.S.), and should the RSG through a two thirds majority vote elect not to proceed, the applicable clauses in IRS 2013-01-A and 2013-01-B regarding the Class IV cost estimate recovery will be applicable. A RSG termination notice will follow a RSG two thirds majority vote to not proceed, which

Representative Shipper Group (RSG)
Issue Resolution Sheet (IRS)
CONFIDENTIAL & WITHOUT PREJUDICE

Final IRS # 2013-02-B (U.S.) Line 3 Replacement
Enbridge Pipelines Inc. Enbridge Energy Limited Partnership

must be provided to Enbridge through written notice within 30 days of the Enbridge delivery of the Class IV Cost Estimate. Failure to provide written notice within such 30 day period will be deemed to be an election to waive the related termination right.

<u>ENBRIDGE and RSG MEMBER CONDITIONS PRECEDENT</u>

In the event that;

1) Enbridge does not receive regulatory approvals by July 2016; or,
2) Enbridge has received regulatory approvals but the approval is not satisfactory to Enbridge, acting reasonably; or
3) Enbridge has applied for regulatory approvals and at any time Enbridge believes, acting reasonably, such regulatory approvals are not likely to be received, then

Enbridge will provide the RSG with notice of such event the RSG (subject to a two thirds majority vote), will have the option to elect to terminate the Line 3 Replacement upon notice. Such notice must be given within 30 days of Enbridge's notice, failing which either party will be deemed to have waived its right to elect to terminate the Line 3 Replacement.

In addition, the following key milestones are provided to inform the RSG of the important checkpoints for updates. The dates listed are based on the unclassified cost estimate and will be revised with the Class IV Cost Estimate.

Representative Shipper Group (RSG)
Issue Resolution Sheet (IRS)
CONFIDENTIAL & WITHOUT PREJUDICE

Final IRS # 2013-02-B (U.S.) Line 3 Replacement
Enbridge Pipelines Inc. Enbridge Energy Limited Partnership

Milestone	Date	*% of Unclassified Total Capital Cost
Class IV Completion	31-Mar-14	1.7%
Submission of Regulatory Applications	1-Oct-14	5.4%
Ordering Long Lead Items (Pumps, Pipe)	31-Mar-15	13.3%
Regulatory Approvals / Construction Start	1-Jun-16	40.2%
Target In-service	Q3 2017	~100%

*Unclassified Total Capital Cost used for percentage calculation excludes AFUDC

Enbridge will provide quarterly updates to the RSG related to the key milestones above and impacts, if any, on the target in-service date.

ENBRIDGE CONDITIONS PRECEDENT

Enbridge will not be obligated to proceed with the Line 3 Replacement described in this IRS 2013-02-B (U.S.) unless IRS 2013-02-A (Canada) is also approved by the RSG.

Enbridge will not be obligated to proceed with the Line 3 Replacement described in this IRS 2013-02-B (U.S.) unless it has received all necessary Enbridge Board approvals including any of its affiliates by the end of March 2014.

TERMINATION

Should the RSG vote to terminate the Line 3 Replacement, the RSG will support recovery of all costs incurred as a result of terminating the Line 3 Replacement through cost recovery to be negotiated and agreed to by Enbridge and the RSG.

Representative Shipper Group (RSG)
Issue Resolution Sheet (IRS)
CONFIDENTIAL & WITHOUT PREJUDICE

Final IRS # 2013-02-B (U.S.) Line 3 Replacement
Enbridge Pipelines Inc. Enbridge Energy Limited Partnership

RECOVERY OF LINE 3 REPLACEMENT

- Term
  - 15-years from the in-service date of the Line 3 Replacement. Upon expiry of this 15-year term, Enbridge will be entitled to recovery of any undepreciated Line 3 Replacement rate base, the terms of which will be negotiated with the appropriate counterparty at that time.
- The forecasted Line 3 transmission toll surcharge for Canada and the U.S., the total surcharge herein referred to as the "Line 3 Surcharge", which will be adjusted to reflect the capital cost risk sharing agreed to herein, is as follows:
  - For all barrels transported on the Enbridge Mainline a Line 3 Surcharge of
    - US$0.80/bbl (based on a Hardisty to Flanagan movement) will be applied to the Mainline base rate for the first 10 years of the 15-year term; and
    - US$0.75/bbl (based on a Hardisty to Flanagan movement) will be applied to the Mainline base rate for the remaining 5 years of the 15-year term.
  - Should the RSG and CAPP support proceeding with the Line 61 Twin project, the Line 3 Surcharge will be reduced by US$0.10/bbl once both the Line 3 Replacement and Line 61 Twin are in-service such that during the first 10 years, the Line 3 Surcharge will be reduced to US$0.70/bbl and during the last 5 years, the Line 3 Surcharge will be reduced to US$0.65/bbl.
  - Each year, the Line 3 Surcharge will be further adjusted to reflect the volume transported on Enbridge's pipeline system ex-Gretna as follows:
    - For every 50 kbpd below a lower threshold of 2,350 kbpd the Line 3 Surcharge will increase by US$0.04/bbl; and
    - For every 50 kbpd above an upper threshold of 2,835 kbpd, the Line 3 Surcharge will be reduced by US$0.035/bbl.
    - The measurement of the volume at Gretna will be based on a monthly average and any adjustment to the Line 3 Surcharge will be based on a 9 month moving average to align with the current Competitive Toll Settlement ("CTS").
  - In the event that the nine month moving average falls below the lower threshold, Enbridge and the RSG will determine if the cause of the shortfall was due to capacity loss on the Mainline system below the stated lower threshold of 2,350 kbpd. If it is determined that the shortfall was due to capacity loss on the Enbridge Mainline for reasons other than force majeure, the lower threshold will be reduced by the corresponding shortfall amount. For purposes of determining the applicable capacity

Representative Shipper Group (RSG)
Issue Resolution Sheet (IRS)
CONFIDENTIAL & WITHOUT PREJUDICE

Final IRS # 2013-02-B (U.S.) Line 3 Replacement
Enbridge Pipelines Inc. Enbridge Energy Limited Partnership

loss, Enbridge will use the historical nine month moving average of volumes from Canadian receipt points through Gretna. Appendix D sets forth capacity amounts anticipated by the in-service date of Line 3 Replacement.

- The transmission toll surcharge will be applied to the International Joint Toll ("IJT") and the Canadian Local Toll ("CLT"), will be distance adjusted with no commodity adjustment and will not be subject to annual escalation.
- During the remaining term of the (the "CTS") the CLT will be adjusted as required to ensure that the IJTis equal to or less than the sum of the CLT and the Lakehead tolls on file and in effect, including recovery of the surcharges. During the term following the completion of the current CTS term, the RSG agrees that the CLT will be adjusted to ensure recovery of the Line 3 Surcharge.

- Receipt toll Surcharge
  - A receipt toll surcharge of US$0.04/bbl will be charged on all volumes received at the Edmonton and Hardisty terminals with no commodity adjustment and will not be subject to annual escalation.
- Capital Cost Risk Sharing
  - The actual Line 3 Surcharge will be adjusted based on the Class IV Cost Estimate including AFUDC. This adjustment is based on an agreed capital cost risk sharing of 75% to the shipper and 25% to Enbridge for any costs in the Class IV Cost Estimate including AFUDC, which are in excess of the Unclassified Total Capital Costs. Following completion of the Class IV Cost Estimate, 100% of any capital costs that exceed the Class IV Cost Estimate including AFUDC will be borne by Enbridge.
  - The maximum adjustment will be capped at 15% above the Unclassified Total Capital Costs.
    - For reference the surcharge impact based on a Hardisty to Flanagan movement is shown below for 5%, 10% and 15% increases in the Class IV Cost Estimate over the Unclassified Total Capital Costs:
      - 5% = +US$0.04/bbl
      - 10% = +US$0.09/bbl
      - 15% = +US$0.14/bbl
      - Should the Class IV Cost Estimate be below the Unclassified Total Capital Costs, a similar adjustment would occur as follows:
      - 5% = -US$0.04/bbl
      - 10% = -US$0.09/bbl
      - 15% = -US$0.14/bbl

Representative Shipper Group (RSG)
Issue Resolution Sheet (IRS)
CONFIDENTIAL & WITHOUT PREJUDICE

Final IRS # 2013-02-B (U.S.) Line 3 Replacement
Enbridge Pipelines Inc. Enbridge Energy Limited Partnership

    - The Class IV Cost Estimate adjustment will be applied linearly between these intervals.
- Key Economic Parameters
  - 30-year depreciation
  - ROE consistent with FERC methodology
- Volume includes all forecast volume on the Enbridge Mainline which is expected to be between 2,350 kbpd and 2,685 kbpd as measured at Gretna.
- Post CTS Treatment of Enbridge Mainline Rate Base
  - The RSG agrees that the US$0.80/bbl Line 3 Surcharge includes the integrity capital of approximately $1.8 billion used to calculate the credit during the CTS term. Subsequent to the expiry of the CTS, the depreciated integrity capital in the amount of C$1.3 billion will continue to be included (based on 30-year depreciation) as part of the Enbridge Mainline rate base.
  - Enbridge will maintain a separate rate base for the proposed Line 3 Replacement for the 15-year term of this IRS 2013-02-B.
  - For the purpose of calculating the Enbridge Mainline base toll, power costs will be calculated based on the infrastructure in place without the Line 3 Replacement (See Appendix D).
  - It is also agreed that the estimated remaining rate base at 2013 of US$ 103 million for the existing Line 3, regardless of whether it is being decommissioned, will also be included as part of the Enbridge Mainline rate base for the Enbridge Mainline toll calculation and will be recovered as part of the Enbridge Mainline toll.
  - Enbridge Mainline Tankage principles, once finalized, will apply to any new tanks that are approved as a part of this project. Any future requirements imposed by a regulator, including those under the Land Matters Consultation Initiative, are outside the scope of this IRS.

<u>BACKGROUND</u>

At the January 31, 2013 RSG Meeting, Enbridge presented the Enbridge Mainline Expansions (2016-2017) project to the RSG and proposed that the RSG adopt this proposal as IRS 2013-01 and that pending further discussions, Enbridge would seek a RSG vote to recover the associated costs of the expansions at a subsequent RSG meeting.

Representative Shipper Group (RSG)
Issue Resolution Sheet (IRS)
CONFIDENTIAL & WITHOUT PREJUDICE

Final IRS # 2013-02-B (U.S.) Line 3 Replacement
Enbridge Pipelines Inc. Enbridge Energy Limited Partnership

At the same RSG meeting, Enbridge suggested that a new RSG Sub-Committee be formed to address IRS 2013-01. The new RSG Sub-Committee was to be called the "RSG Expansions Sub-Committee 2013". Enbridge requested volunteers for the RSG Expansions Sub-Committee 2013, and it was formed to address IRS 2013-01 in early February, 2013.

At the May 2, 2013 and June 6, 2013 RSG meetings, Enbridge provided an update on the commercial proposal that Enbridge made to the RSG Expansions Sub-Committee 2013 related to IRS 2013-01.

On August 13, 2013, CAPP, on behalf of its Executive Policy Group ("EPG"), provided written support for Enbridge to proceed with an expenditure of up to $37,000,000 to prepare a total Class IV estimate for the U.S. portion of the Line 3 Replacement Project and the Line 61 Twin Project.

On September 13, 2013, the RSG conducted an email vote for approval of expenditure and recovery of the Line 3 Replacement Class IV Cost Estimate for the Canadian portion (Final IRS 2013-01-A) for a maximum of $63,000,000, and the U.S. portion (Final IRS 2013-01-B) for a maximum of $20,000,000. When combined with the Line 61 Twin Class IV Cost Estimate of $17,000,000 (Final IRS 2013-01-C), the aggregate total of the three cost estimates is $100,000,000.

Subsequent to the Class IV funding approvals by the RSG which was originally designated as IRS 2013-01, the Line 3 Replacement project has been assigned IRS 2013-02-A (Canada) and IRS 2013-02-B (U.S.). Upon approval of the Line 3 Replacement Project (Final IRS 2013-02-A and Final IRS 2013-02-B), the $63,000,000 approved for the Canadian portion and $20,000,000 approved for the U.S. portion of the Line 3 Replacement Class IV Cost Estimate will be included in the overall capitalized project costs.

On October 8, 2013 Enbridge provided the RSG Expansions Sub-Committee 2013 with an update on the proposed commercial terms setting out the two scope options for originating barrels: Edmonton or Hardisty. On October 10, 2013 Enbridge provided a commercial and project update on Line 3 Replacement project to the full RSG for the above mentioned scope options (Edmonton or Hardisty).

Enbridge's proposed Line 3 Pipeline Replacement Project assumes a 36-inch pipe diameter in Canada, 34-inch pipe diameter in 17-mile section around the border, and 36-inch diameter in the U.S. The existing 34-inch Line 3 pipe between Edmonton and Hardisty will remain in-service whereas the existing 34-inch pipe between Hardisty and Superior will be decommissioned.

Representative Shipper Group (RSG)
Issue Resolution Sheet (IRS)
CONFIDENTIAL & WITHOUT PREJUDICE

Final IRS # 2013-02-B (U.S.) Line 3 Replacement
Enbridge Pipelines Inc. Enbridge Energy Limited Partnership

On October 21, 2013, Enbridge emailed a commercial offer to the RSG Expansions Sub-Committee 2013 for the Line 3 Replacement project that (1) originates at Hardisty by keeping the existing 34-inch Line 3a in-service between Edmonton and Hardisty; (2) decommissions the existing Line 3 between Hardisty and Superior; and (3) replaces the existing Line 3 between Hardisty and approximately 1 mile upstream of the border with 36-inch pipe, from approximately 1 mile upstream of the border in Canada to a valve approximately 16 miles downstream with 34-inch pipe and from the first valve to Superior with 36-inch pipe.

Subsequent to October 21, 2013, Enbridge and the commercial negotiating team of the RSG met weekly to negotiate the final commercial terms presented herein.

On February 24, 2014 the Final IRS 2013-02-A and IRS 2013-02-B was sent out for an RSG vote to take place on February 26, 2014 at Calgary, Alberta.

REFERENCE TO CTS

The IRS 2013-02-B (U.S.) represents an expenditure of greater than $250MM on the Enbridge Mainline. As a result, pursuant to Section 16.3 of the CTS, Enbridge has concluded negotiations with the RSG. Enbridge and the RSG have agreed that a surcharge is required to support the recovery of the costs of the Line 3 Replacement project.

RSG RESOLUTION:

As agreed to with the RSG, on February 26, 2014, the RSG voted on IRS 2013-02-B (U.S.). The results of the vote are below.

The RSG authorizes Enbridge to implement a Line 3 Surcharge in accordance with the commercial terms herein, which will be charged in addition on the CLT and the IJT.

Voting Results – to be completed by Secretary of the RSG:

__X__Approved ____Not Approved

Representative Shipper Group (RSG)
Issue Resolution Sheet (IRS)
CONFIDENTIAL & WITHOUT PREJUDICE

Final IRS # 2013-02-B (U.S.) Line 3 Replacement
Enbridge Pipelines Inc. Enbridge Energy Limited Partnership

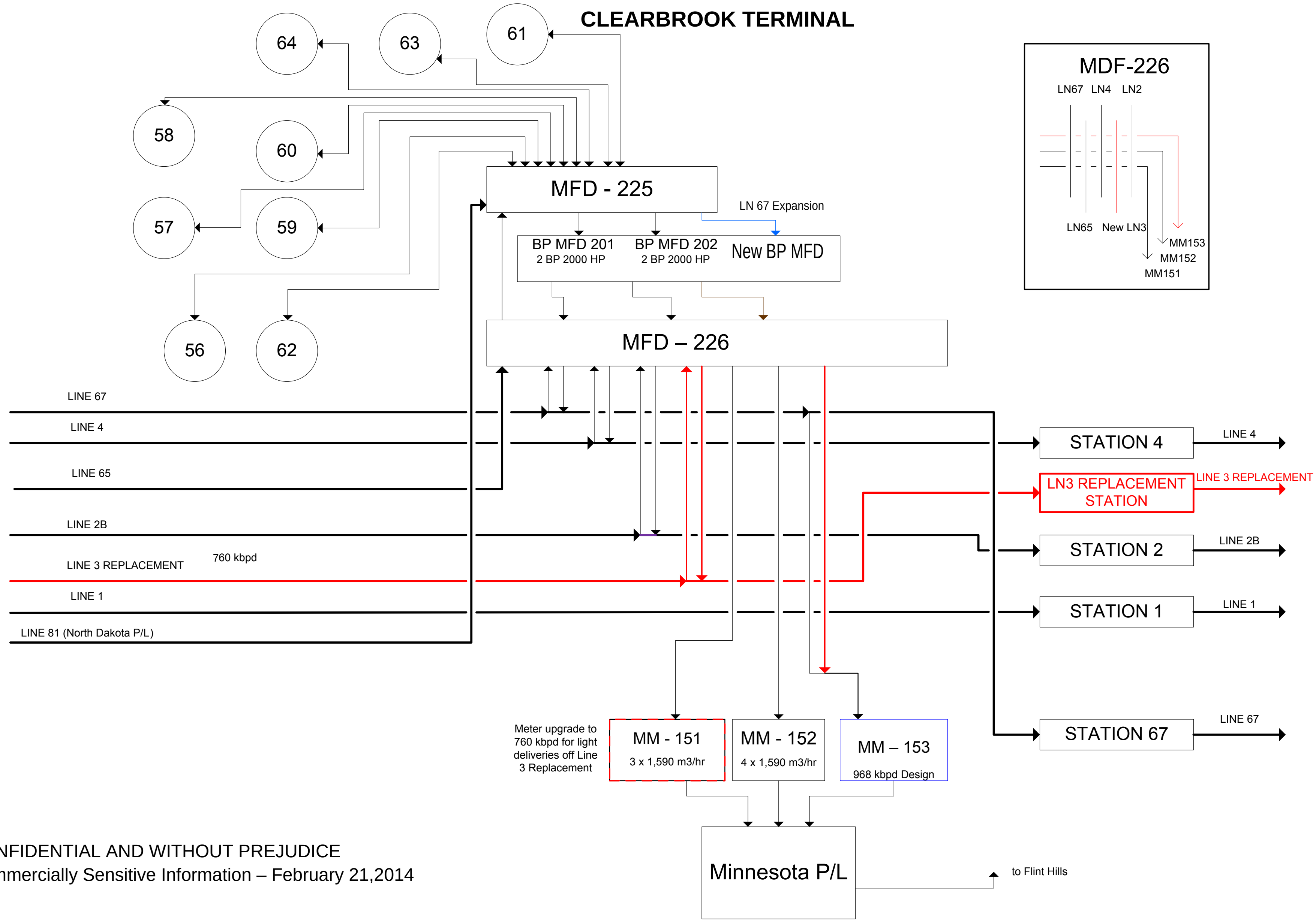
APPENDIX A

Line 3 Scope (US):

Project	US Capital
Line 3 Replacement (36")	$ 1,879
Line 3 Decommissioning	$ 25
Clearbrook Connectivity	$ 57
Superior - L3 / L61T Connectivity	$ 25
Re-Route	$ 300
***TOTAL**	**$ 2,286**

***Excludes AFUDC**

CLEARBROOK TERMINAL



CONFIDENTIAL AND WITHOUT PREJUDICE
Commercially Sensitive Information – February 21,2014

LEGEND:
- EXISTING In-Service Facilities
- Approved Facilities (2014/15/16)
- Facilities Required for Line 3 Replacement 2017

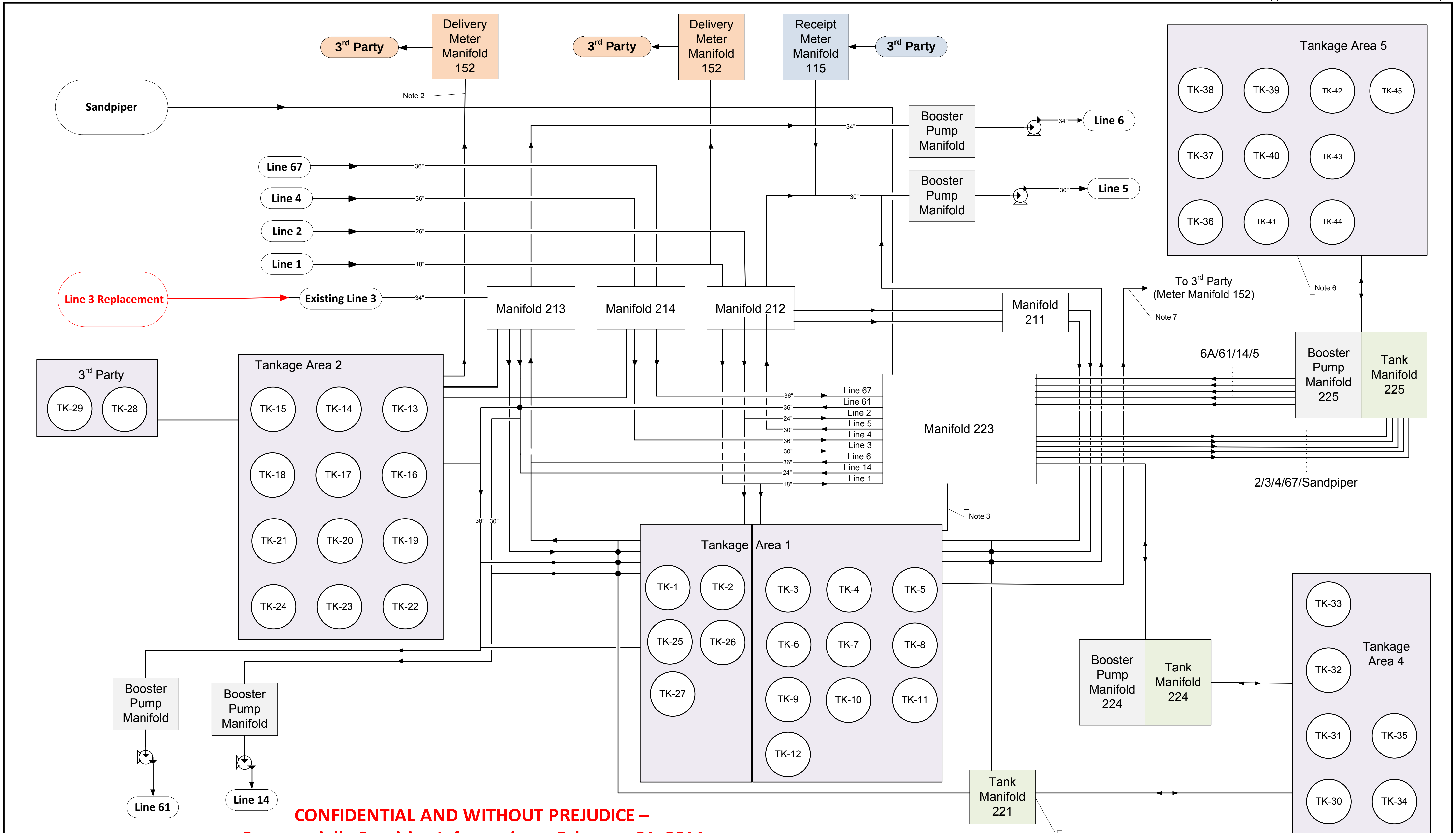
NO	REVISION	DATE	BY
	36-36 Case	07/2013	JY
	Preliminary		

Clearbrook Terminal Schematic

PROJECT	Line 3 Replacement
DRAWN BY	Jodi Yaworski
DATE January 8, 13	SCALE NTS
CHECK	APPROVE

ENBRIDGE
Enbridge Pipelines Inc.
10201 Jasper Avenue
Edmonton Alberta Canada

Drawing number SHT



CONFIDENTIAL AND WITHOUT PREJUDICE – Commercially Sensitive Information – February 21, 2014

ENBRIDGE
ENBRIDGE INC.

SUPERIOR TERMINAL
Line 3 Replacement DOU

Legend
Existing Facility
Line 3 Replacement

Notes:
1. 3rd Party transfer volume to tank 15 prior to inject onto Mainline.
2. Tanks 13 & 14 are the only heavies connected to 3rd Party.
3. Tanks 9 & 5 have independent connections to Manifold 223.
4. Manifold 221 is exclusively dedicated to tank 30.
5. Manifolds 224 & 223 are connected by five 36" lines.
6. Manifolds 225 & 223 are connected by ten 36" lines.
7. Tanks 2, 3, 4, 5, 6, 7, 8, 11 & 12 are the light tanks connected to 3rd Party.

DRAWN BY	B.A.P.
DATE	Feb. 20, 2014
CLASS LEVEL	UNCLASSIFIED
PAGE	1 OF 1

Representative Shipper Group (RSG)
Issue Resolution Sheet (IRS)
CONFIDENTIAL & WITHOUT PREJUDICE

Final IRS # 2013-02-B (U.S.) Line 3 Replacement
Enbridge Pipelines Inc. Enbridge Energy Limited Partnership

Appendix B

Distance Based Line 3 Surcharge Adjustment Prior to any Class IV Cost Estimate Adjustment for the First 10-years of the 15-year Term (Based on a Hardisty to Flanagan Movement)

9-month Rolling Average Volume (kbpd)	**Line 3 Only Surcharge [1] US$ /bbl**	**Line 3 Surcharge [1,2] Line 3 and Line 61 Twin in Mainline service US$ /bbl**
3,036 to 3,085	0.625	0.525
2,986 to 3,035	0.660	0.560
2,936 to 2,985	0.695	0.595
2,886 to 2,935	0.730	0.630
2,836 to 2,885	0.765	0.665
2,350 to 2,835	0.800	0.700
2,300 to 2,349	0.840	0.740
2,250 to 2,299	0.880	0.780
2,200 to 2,249	0.920	0.820
2,150 to 2,199	0.960	0.860
2,100 to 2,149	1.000	0.900
2,050 to 2,099	1.040	0.940

[1] The Line 3 Surcharge is reduced by US$ 0.05/bbl for the last 5-years of the 15-year term

[2] A separate Line 61 Twin surcharge will apply

ENBRIDGE

Representative Shipper Group (RSG)
Issue Resolution Sheet (IRS)
CONFIDENTIAL & WITHOUT PREJUDICE

Final IRS # 2013-02-B (U.S.) Line 3 Replacement
Enbridge Pipelines Inc. Enbridge Energy Limited Partnership

Illustrative Example of Line 3 Surcharge Adjustment

Month	9	10	11	12
Volume (kbpd) 9-month Moving Average	2,400	2,325	2,290	2,350
Surcharge US$ / bbl	$0.80	$0.84	$0.88	$0.80

Representative Shipper Group (RSG)
Issue Resolution Sheet (IRS)
CONFIDENTIAL & WITHOUT PREJUDICE

Final IRS # 2013-02-B (U.S.) Line 3 Replacement
Enbridge Pipelines Inc. Enbridge Energy Limited Partnership

Appendix C

Line 3 Class IV Capital Cost Over-run Table for the Line 3 Surcharge Adjustment

Class IV Capital Cost Over-run	**Line 3 Only Surcharge** **US$ /bbl**	**Line 3 Surcharge with Line 61 Twin** **US$ /bbl**
+15%	$0.940	$0.840
+10%	$0.890	$0.790
+5%	$0.840	$0.740
0	$0.800	$0.700
-5%	$0.760	$0.660
-10%	$0.710	$0.610
-15%	$0.660	$0.560

Representative Shipper Group (RSG)
Issue Resolution Sheet (IRS)
CONFIDENTIAL & WITHOUT PREJUDICE

Final IRS # 2013-02-B (U.S.) Line 3 Replacement
Enbridge Pipelines Inc. Enbridge Energy Limited Partnership

Appendix D

Anticipated Enbridge Mainline Reference Capacities at Gretna with a Line 3 Replacement

Line 1 = 240 kbpd

Line 2 = 440 kbpd

Line 3 = 760 kbpd

Line 4 = 800 kbpd

Line 67 = 800 kbpd

Line 65 = 185 kbpd

Anticipated Enbridge Mainline Reference Capacities at Gretna without a Line 3 Replacement

Line 1 = 240 kbpd

Line 2 = 440 kbpd

Line 3 = 390 kbpd

Line 4 = 800 kbpd

Line 67 = 800 kbpd

Line 65 = 185 kbpd

ENBRIDGE

Representative Shipper Group (RSG)
Issue Resolution Sheet (IRS)
CONFIDENTIAL & WITHOUT PREJUDICE

Final IRS # 2013-02-B (U.S.) Line 3 Replacement
Enbridge Pipelines Inc. Enbridge Energy Limited Partnership

Appendix E

Estimated Distance Adjusted Line 3 Surcharge prior to any Class IV Cost Estimate Adjustment

1) Edmonton to Hardisty US$ 0.06/bbl
2) Hardisty to Clearbrook US$ 0.44/bbl
3) Hardisty to Flanagan US$ 0.80/bbl
4) Hardisty to Sarnia US$ 0.90/bbl