Final Report

Diluted Bitumen-Derived Crude Oil: Relative Pipeline Impacts

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Executive Summary

This report evaluated the claim made that dilbit is more corrosive than other crudes. This evaluation was benchmarked against conventional and/or sour crude, and was based on the existing literature on crude and dilbit properties and characteristics, data on pipeline integrity and results of engineering assays of pipe that has been transporting dilbit, with such outcomes supplemented by interviews of industry engineering experts from operators with pipelines transporting dilbit.

It was found that the literature on this topic concludes that "the characteristics of dilbit are not unique and are comparable to conventional crude oils." The relative measure of similarity developed in this project did not indicate that crude oil derived from diluted bitumen is significantly more corrosive than any other oil, and that the dilbit oils likely have corrosivities close to the heavy sour conventional oils. In addition to this relative outcome, the experience of operators transporting dilbit does not indicate it behaves differently from typical crudes. That view can be supported with images of the inside of such pipelines, which appear no different after many years of service than those shipping conventional crude and data reported to PHMSA that no releases from pipelines transporting Canadian crudes and caused by internal corrosion occurred from 2002 to early 2011.

Similarity of Dilbit Relative to Conventional Crude Oils

Introduction

Following a brief discussion of factors that affect internal corrosion independent of the type of crude involved, this section evaluates the first of the above-noted claims that dilbit is more corrosive as compared to conventional crude oil. This evaluation is based on available data and a review of published literature: no laboratory experiments were conducted as part of this evaluation. This section draws extensively from one of the most comprehensive yet concise reviews of the corrosivity of dilbit as compared to conventional crude oil, which was developed by Alberta Innovates Energy and Environmental Solutions.[iii][1] Use is also made of the references cited in that report, with the related analysis developed as part of this project founded on basic corrosion science and electrochemistry.

Some Generic Factors that Affect Internal Corrosion

While the focus of this section is to evaluate dilbit relative to other crudes transported by pipeline, for the sake of completeness it is appropriate to briefly note that other factors more strongly influence if and where internal corrosion can occur, and its rate. Among some of the more important factors are the presence of solids like sand, and the design of the line as it influences the flow regime, which depends on the speed of flow and the "dropout" of liquid-phase water and its transport in the line along with solids. The presence of abrasive solids like sand in crude depends on the source of the crude and any prior processing, with sand being found in many sources of crude. As such solids are not unique to dilbit, they are not addressed as part of this comparison. Moreover, existing tariffs include limits on the water and solids content, where the combined total is usually limited to 0.5 weight percent. In regard to factors that are controlled by pipeline design it is important to note that pipelines transporting products that have the potential to cause internal corrosion are designed for turbulent flow, which limits liquid water and its dropout from the product stream. Because this and related aspects are design issues, and common to transported crudes rather than unique to dilbit, these and other such aspects that are not unique to dilbit are not addressed in the comparison that follows.

Approach to Compare and Contrast Crude Types

The approach used to compare the corrosivity of dilbit to conventional crude oil was to examine the factors that would most affect the corrosivity of oil in pipelines. These factors, based on fundamental electrochemical considerations, include oxygen content, water content, effect of Microbiologically Influenced Corrosion (MIC), underdeposit corrosion, and temperature. In addition to the relative outcomes of this analytical approach, input from operators that transport dilbit was assessed to determine an absolute metric of corrosion susceptibility.

Regarding the analytical assessment, other pipeline oil parameters such as total sulfur, sediment, and salt contents were used to derive a relative index of oil similarity. The "average" similarity of conventional oil was defined as a value of 1.0. Based on a consideration of how the common factors varied for dilbit and other oils compared to a conventional crude oil, a similarity index was defined as the ratio of the similarity of dilbit to a conventional Canadian heavy sour crude. A similarity index greater than 1.0 indicated that the oil was may be more corrosive than conventional crude, whereas an index value less than 1.0 indicated that the oil was likely less

[1] Superscript Roman numerals refer to the list of references compiled at the end of this report.

corrosive than conventional crude. The properties of the Canadian oils that were used for comparison were obtained from the on-line data available from Crude Quality Inc. (CQI)[iv] and Enbridge 2010 Crude Characteristics.[v] Data from crude oils from Colombia[vi] and Mexico[vii] were also included.

Results

Almost all corrosion processes in metals are electrochemical in nature. When electrochemical processes occur, there is only one anodic reaction that occurs on metals, namely

$$M \rightarrow M^{+n} + ne \qquad [1]$$

where M stands for a metal and n is the number of valence electrons. In the case of pipeline steel, the predominant metal in the steel alloy is iron. For most anodic reactions in steel exposed to an aqueous phase at ambient temperature, Eqn. 1 becomes,

$$Fe \rightarrow Fe^{+2} + 2e \qquad [2]$$

For every anodic reaction there must be at least one cathodic reaction, otherwise the corrosion process cannot proceed. Corrosion inhibitors are used to interfere with either the anodic or cathodic reaction or both in the attempt to minimize the corrosion reaction rate.

The following paragraphs review the role that water content, oxygen content, temperature, MIC, sulfur, underdeposit corrosion, total acid number (TAN), and salt concentration have on the interior corrosion of pipelines.

Water Content

For corrosion to occur, an electrolyte needs to be present. In oil pipelines, in the presence of sludge, the predominant electrolyte is water. While pure water is not a good electrolyte, the water in oil pipelines is sufficiently contaminated with dissolved solids and salts that it will serve as a good electrolyte. The amount of water that is typically present in any transmission oil pipeline will be quite low, as required by the basic sediment and water (BS&W) limitation of 0.5 volume percent[iii]. Moreover, this value is significantly less than what is considered the critical water concentration of greater than 10 percent,[viii] and water that is present must be the continuous phase of any water and oil emulsion.

The necessary condition for water to participate in the corrosion of the interior steel wall of a pipe is that water exists in the oil-in-water (O/W) condition rather than the non-corrosive water-in-oil (W/O) condition[ix]. The water layer on the surface of the pipe wall will be very thin. Unfortunately specific information on water-dropout for the examined crude oils was not available. Moreover, the pH of the water phase, which is an important parameter for determining the corrosivity of the water phase to steel, was also not available in the examined data.

Oxygen and other Gas Content

Oxygen content plays a major role in the corrosion reaction of steel. In neutral and alkaline pH solutions the predominant cathodic reaction involving reduction of oxygen is given by

$$O_2 + 2H_2O + 4e \rightarrow 4OH^- \qquad [3]$$

Combining the anodic reaction for iron given in Eqn. 2 with the cathodic reaction in Eqn. 3, yields,

$$Fe^{+2} + 2OH^- \rightarrow Fe(OH)_2\downarrow \qquad [4a]$$

The reaction product in this case is the relatively insoluble ferrous hydroxide. Ferrous hydroxide can also occur from the reaction of ferrous sulfate with hydroxide ions yielding sulfate ions.

$$FeSO_4 + 2OH^- \rightarrow Fe(OH)_2 + SO_4^{2-} \qquad [4b]$$

Sulfate ions, however, were experimentally found to not have an effect on pitting corrosion rate on steel.[ix]

In the absence of oxygen, ferrous hydroxide can be further oxidized by the hydrogen ions in water to form magnetite (Fe_3O_4), which is more stable than many other iron oxides and provides a protective coating to the underlying steel surface.

$$3\ Fe(OH)_2 \rightarrow Fe_3O_4 + H_2 + 2\ H_2O \qquad [5]$$

The corrosion of iron can also occur in acid solutions (pH below 7) in the absence of oxygen.

Other gases such as hydrogen sulfide (sour gas) can directly react with steel to form iron sulfide without the presence of oxygen and carbon dioxide (sweet gas) can also play a role in some corrosion reactions with pipeline steel. However, these presence or absence of these gases have not been reported in the evaluated crude oils and are therefore were not considered.

Temperature

It is not clear what the typical operating temperatures of the dilbit pipelines are compared to the conventional crude oil pipelines operating temperatures below 180 F are not expected to contribute to corrosivity of the oil. In addition, there are several factors that would temper the expected increase in corrosion rate as temperature increases. The major mitigating factor is the decrease in oxygen solubility in the water phase of the oil with increasing temperature. When additional constituents are in the water such as salts, the solubility will decrease further. On the other hand, the oxygen solubility increases with pressure. A higher pressure pipeline can have higher oxygen solubility in its water phase than a lower pressure pipeline.

Microbiologically Influenced Corrosion and Underdeposit Corrosion

MIC is most often associated with the presence of sludge, which plays a dominant role in underdeposit corrosion. Bacteria responsible for MIC in pipelines include sulfate reducing bacteria (SRB), heterotrophic aerobic bacteria (HAB), and acid producing bacteria (APB).[x] These bacteria are found in a wide variety of oil pipelines including those carrying conventional crude oil and dilbit.

Sulfur Content

The organic sulfur content of the oils at ambient temperature were found to either have no effect or actually decreased the corrosion rate of steel.[xi] The reported values for sulfur in oil, however, are the total sulfur concentrations that include both organic and inorganic forms of sulfur such as sulfates and sulfides. The presence of sulfate reducing bacteria can lead to pitting attack of the interior pipeline wall. Consequently, the sulfur parameter was included in the similarity index.

Sediment and Sludge

While the amount of sediment and sludge present in the oil may or may not be related to the amount of underdeposit corrosion, there are several variables associated with these parameters that need to be considered. These include the particulate size and distribution of sludge particles, the waxiness or oiliness of the deposits, and the velocity and turbulence of the deposits[xii]. The presence of MIC is also associated with sediments. For these reasons, the concentration of sediment was included in the similarity index.

Total Acid Number

The total acid numbers (TAN) for pipeline oils are associated with the presence of naphthenic acids. This parameter is important in determining the crude oils corrosivity at high temperatures encountered in crude oil distillation columns in refineries but not at ambient temperatures of 35 F to 75 F of oil transport in pipelines. The temperature range where the TAN is important is from 430 F to 750 F[xiii]. Because TAN is "not necessarily reflective of the corrosivity of crude oil,"[iii] it was excluded from the similarity index.

Salt Concentration

Chlorides and other halides are usually associated with the corrosive species in most salts but "it has been shown that high salinity brines in contact with oil did not affect the corrosion rate."[iii] However, this parameter was included in the similarity index because the ubiquitous nature of these constituents in the oils.

Nickel and Vanadium Content

The low-concentration presence of these metals in the pipeline oil will not play any role in the corrosion of steel pipelines and therefore was not included in the similarity index.

Pipeline Oil Similarity Index

There have been several attempts to arrive at a corrosivity index for pipelines with the most extensive one being based on a scoring method using points and a parameter weighting scheme.[xiv] However, because the common properties reported for pipeline oil have not been shown to be directly related to the interior corrosion of the pipeline steel, a similarity index scheme is used in this report that is based solely on published properties of the oil rather than the entire pipeline infrastructure and simply uses equal weighting for three oil parameters. These parameters include the sulfur content, sediment concentration, and the salt concentration. The selection of these parameters does not imply that they are responsible for any corrosion in the pipeline but are simply being used as a basis for comparison of one oil to another. The rationale for this approach is that if similar properties are found for dilbit oils compared to conventional crude that have not exhibited corrosivity, then the dilbit would also be expected to be equally non-corrosive. As a basis for comparison, the heavy sour conventional crude oil designated Western Canadian Blend (WCB) was chosen.

The pipeline oil similarity index (POSI) is calculated as follows:

$$POSI = \frac{\frac{Sulfur\ (wt\%)}{3.16} + \frac{Sediment\ (ppmw)}{294} + \frac{Salt\ (ptb)}{71.5}}{} \qquad [6]$$

where the values in the denominator for each factor is for WCB; the POSI for WCB, therefore would be 1.0.

Table 1 shows the POSI values calculated for a variety of heavy sour conventional, heavy sour dilbit, heavy sour synbit, heavy sour dilsynbit, medium sour, and light sour crude oils.

Table 1. List of Crude Oil Types and Their Associated Pipeline Similarity Index Based on Eqn. 6.

Country	Crude Type	Crude Name	Crude Code	POSI
Canada	Heavy Sour - Conventional	Bow River North	CAN A	0.82
		Bow River South	CAN B	0.62
		Fosterton	CAN C	0.63
		Lloyd Blend	CAN D	1.02
		Lloyd Kerrobert	CAN E	0.92
		Smiley-Coleville	CAN F	0.66
		Western Canadian Blend	Control (WCB)	1.00
	Heavy Sour - Dilbit	Access Western Blend	Dilbit A	0.69
		Cold Lake	Dilbit B	0.65
		Peace River Heavy	Dilbit C	0.81
		Seal Heavy	Dilbit D	0.79
		Statoil Cheecham Blend	Dilbit E	0.64
		Wabasca Heavy	Dilbit F	0.70
		Western Canadian Select	Dilbit G	1.01
	Heavy Sour - Synbit	Long Lake Heavy	Synbit A	0.59
		Surmount Heavy Blend	Synbit B	0.53
	Heavy Sour - Dilsynbit	Albian Heavy Synthetic	Dilsynbit	1.21
	Medium Sour	Midale	CAN Med Sour A	0.89
		Mixed Sour Blend	CAN Med Sour B	0.63
		Sour High Edmonton	CAN Med Sour C	0.55
	Light Sour	Light Sour Blend	Light Sour	1.09
Mexico	Heavy Sour	Maya	Maya	2.60
Mexico	Medium Sour	Isthmus	Isthmus	0.69
Colombia	Heavy Sour	Rubiales Oil Field	Rubiales	1.26

Figures 1 to 4 are bar charts of the data listed in Table 1. The red horizontal line in the charts at a POSI of 1.0 represents the similarity of the control oil, namely, the Western Canadian Blend conventional crude.

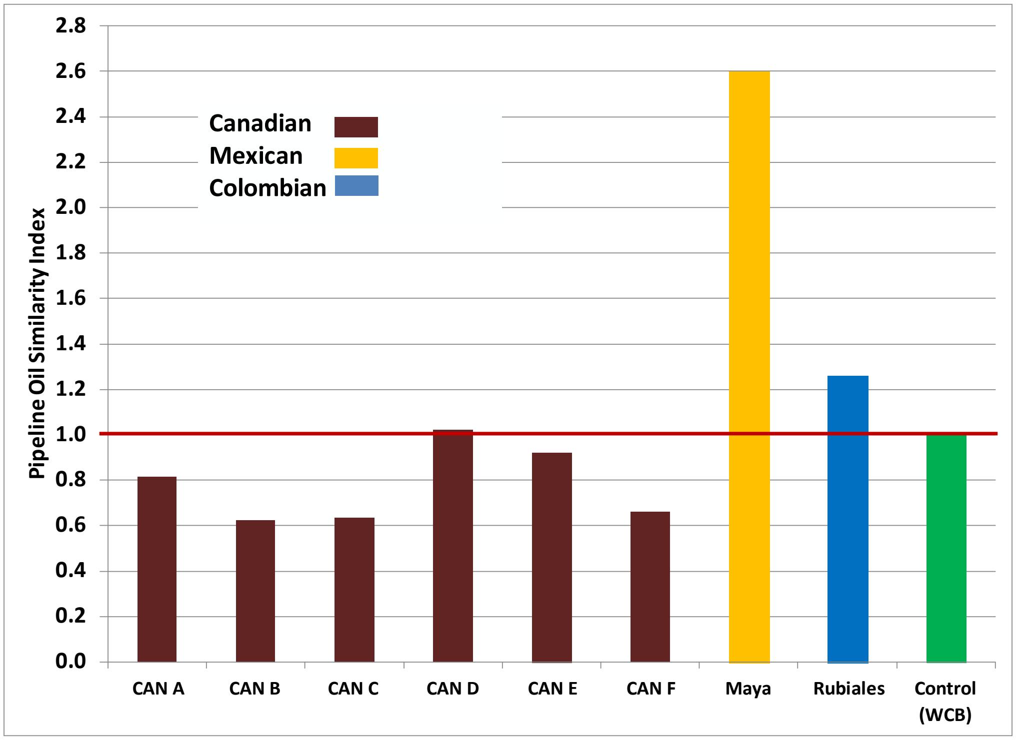

Figure 1. Pipeline oil similarity indices for heavy sour conventional crude oils.

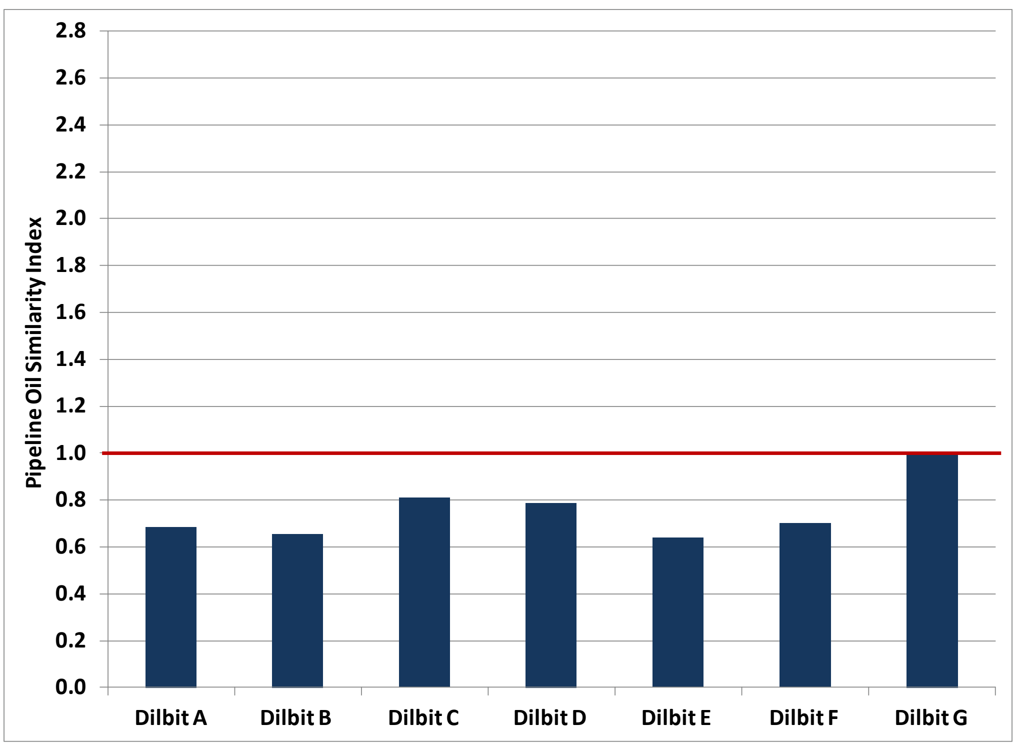

Figure 2. Pipeline oil similarity indices for Canadian heavy sour dilbit crude oils.

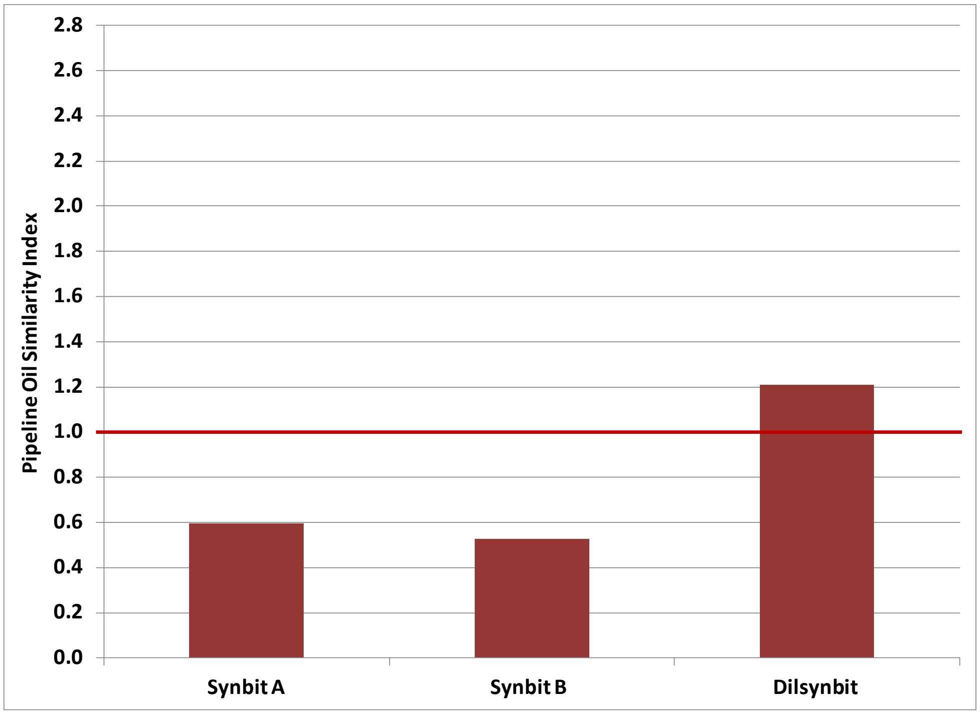

Figure 3. Pipeline oil similarity indices for Canadian heavy sour synbit and dilsynbit crude oils.

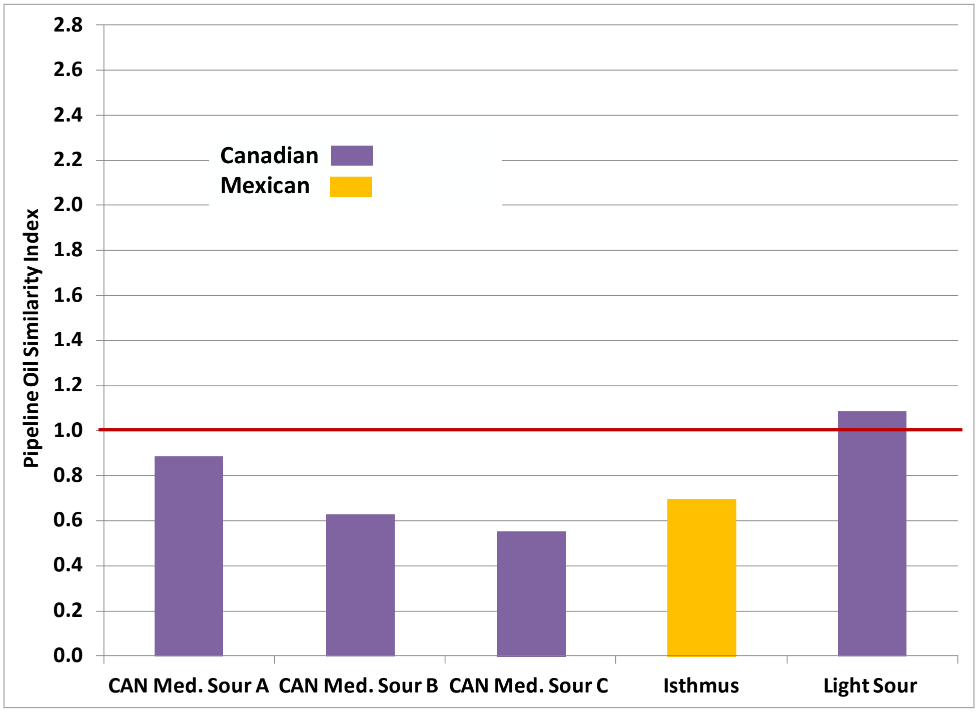

Figure 4. Pipeline oil similarity indices for medium and light sour crude oils.

In Figure 1, the POSI of the Mexican heavy sour conventional crude oil is significantly greater than the Canadian and Colombian crude oils, and the POSI values of all Canadian heavy sours are also less than the Colombian crude oil. Six of the seven heavy sour dilbit crude oils had POSI values less than the control and the seventh dilbit crude oil had the same value as the control (Figure 2). The POSI for the heavy sour synbit and dilsynbit crude oils were either slightly greater or less than the control (Figure 3). All of the medium sour crude oils had POSI values less than the control and the light sour Canadian oil was only slightly greater than the control (Figure 4).

Conclusions and Recommendations

The selection of a Pipeline Oil Similarity Index (POSI) to compare the similarities of various crude oils to one another revealed that the heavy sour dilbit crude oils were either less than or had the same similarity than a typical North American heavy sour conventional crude oil. More striking was the relatively high POSI value of the selected Mexican heavy sour crude, which was greater than any of the other oils randomly chosen for comparison. The key question that is left unanswered is what significance are the POSI values in terms of actual pipeline corrosion.

While choosing a different conventional crude oil as a control will yield different POSI values, the general approach is reasonable from a corrosion engineering consideration for calculating the relative corrosiveness of pipeline oils. While it is clear that the POSI approach does not indicate that crude oil derived by diluted bitumen is more corrosive than any other oil it also shows that the dilbit oils in particular likely have corrosivities close to or less than other heavy sour conventional oils commonly used in North America. In other words, based on the information available, diluted bitumen poses no more of a corrosion risk to pipelines than conventional crudes.

Further insight into similarity follows from absolute metrics of the extent of metal loss due to corrosion for pipelines that transport dilbit as well as conventional crudes. Dialog with operators clearly indicates operational experience with dilbit shows that it does not behave any differently than typical crudes. That dialog is supported by images of the inside of pipelines transporting dilbit, which appear no different than shipping conventional crude after many years of service. This observation is consistent with literature on this topic[i], which concludes that "the characteristics of dilbit are not unique and are comparable to conventional crude oils."

Should there be interest in corrosivity as quantified by the POSI approach, it is recommended that it be further refined to perhaps introduce additional weighting factors to capture the fact that some parameters are anticipated to have a greater affect on pipeline oil's corrosivity than others. Such refinement will likely require collection of additional field data specifically relevant to similarity of pipeline oil, and possibly also benchmark experiments.

Summary and Conclusions

This report evaluated the claim that dilbit is more corrosive than currently transported crudes. This evaluation was made benchmarked against conventional and/or sour crude, and based on the existing literature on crude and dilbit properties and characteristics, data on pipeline integrity and results of engineering assays of pipe that has been transporting dilbit, with such outcomes supplemented to a limited extent by interviews of industry engineering experts from operators with pipelines transporting dilbit.

Major conclusions at a high-level follow:

- Literature on this topic concludes that "the characteristics of dilbit are not unique and are comparable to conventional crude oils."
- The relative measure of similarity developed in this project did not indicate that one oil is significantly more corrosive than any other oil, and that the dilbit oils likely have corrosivities close to the heavy sour conventional oils.
- In addition to this relative outcome, the experience of operators transporting dilbit does not indicate it behaves differently from typical crudes. This view can be supported with images of the inside of such pipelines, which appear no different after many years of service than those shipping conventional crude.

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