2.2 DESCRIPTION OF REASONABLE ALTERNATIVES

2.2.1 Rationale for Considering Alternatives

As noted in Section 1.4, Market Analysis, considerable changes in the crude oil market since the publication of the 2011 Final Environmental Impact Statement (Final EIS) have led to an evaluation of industry actions that have begun and may likely expand to adjust to ongoing constraints in trans-border pipeline capacity. In addition, comments received on the Final EIS regarding industry alternatives to the proposed Project have also led to an in-depth analysis of possible scenarios if the proposed Project is not built. These scenarios are analyzed under the No Action Alternative. Additionally, the Council on Environmental Quality (CEQ) guidelines also indicate that the choice of No Action by a federal agency would result in predictable actions by others, the consequences of the No Action Alternative should be included in the Environmental Impact Statement (EIS) (CEQ 1981).

The following is an overview of these scenarios under the No Action Alternative, including the development that would be necessary to accommodate transportation of crude oil from the Western Canadian Sedimentary Basin (WCSB) and Bakken Formation to replace the proposed Project's volumes if it is not built and if other additional pipeline capacity does not become available. This section also includes detailed discussions of major route variations and other alternatives considered in the Supplemental Environmental Impact Statement (Supplemental EIS).

2.2.2 Overview of Alternatives

In addition to the proposed Project, this Supplemental EIS considers alternatives to the proposed Project, consistent with the requirements of the National Environmental Policy Act (NEPA). Three broad categories of alternatives are considered:

- No Action Alternative (Section 2.2.3)—addresses the Status Quo scenario, as well as potential market responses that could result if the Presidential Permit is denied or the proposed Project is not otherwise implemented;
- Major Pipeline Route Alternatives (Section 2.2.4)—includes other potential pipeline routes for transporting WCSB and Bakken crude oil to Steele City, Nebraska; and
- Other Alternatives Considered (Section 2.2.5)—includes minor route variations, alternative pipeline designs, and alternative sites for aboveground facilities.

For each of these categories of alternatives, this section describes the process for identifying and screening alternatives; the reasonable alternatives identified, if any; and the rationale for eliminating other alternatives considered. This section concludes with the discussion from the Final EIS of the use of alternative forms of energy and energy conservation in the place of the proposed Project.

2.2.3 No Action Alternative

NEPA regulations (40 Code of Federal Regulations [CFR] Part 1502.14[d]) specify that the alternatives analysis in an EIS is to include the alternative of No Action. Under the No Action Alternative, the Department of State (the Department) would deny the Presidential Permit, the proposed Project would not be built (for that or other reasons), and the impacts relating to the proposed Project described in Chapter 4, Environmental Consequences, would not occur. This scenario focuses only on the specific impacts associated with construction and operation of the proposed Project that would not occur, and is referred to as the "Status Quo Scenario" under the No Action Alternative. Analysis of the Status Quo Scenario will serve as a benchmark against which other alternatives will be evaluated.

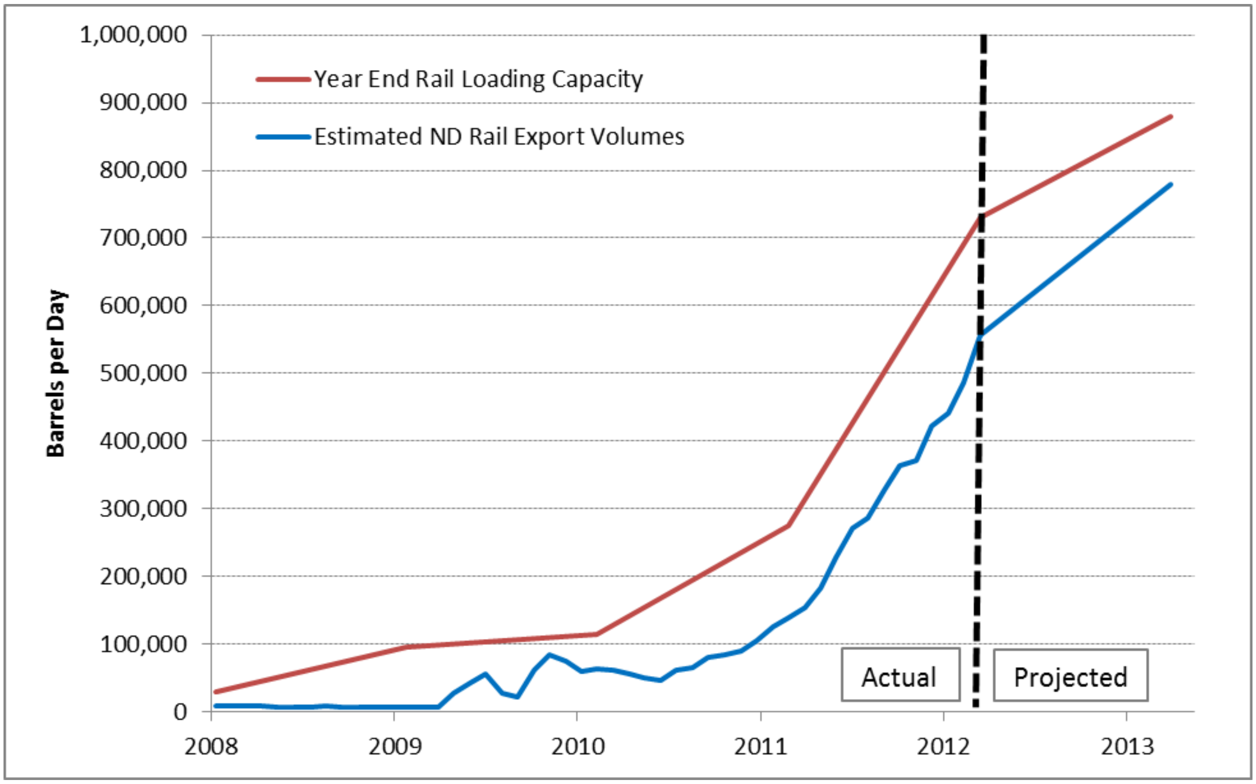
The No Action Alternative does not include consideration of the upstream (production of crude oil in the oil sands) or downstream (refining of crude oil and/or end-use of refined petroleum products). The upstream and downstream activities are not part of the proposed Project. To the extent that they would occur, the effects of those upstream and downstream activities that were affected by the proposed Project would be considered indirect effects, as effects that occur later in time or farther removed in distance (40 CFR 1508.8). However, as noted in Sections 1.4, Market Analysis, and 4.15, Cumulative Effects Assessment, because of broader market dynamics and options for crude oil transport in the North American logistics system, the upstream and downstream activities are unlikely to be substantially different whether or not the proposed Project is constructed.

To summarize, production and disposition of crude oil in North America (and throughout the world) is driven by market forces. There exists demand for heavy crude oil in PADD 3, particularly in the Gulf Coast area[1] refineries. In recent years, refiners in PADD 3 have consistently imported approximately 2.2 million barrels per day (mmbpd) of heavy crude oil (less than 25 degrees American Petroleum Institute [API] gravity). The proposed Project is supported by long-term contracts to deliver approximately 555,000 barrels per day (bpd) to the Gulf Coast area to meet part of that existing market demand. If the proposed Project is not approved, or is otherwise not constructed, the customers who signed those contracts would be expected to seek alternate transportation options to deliver the crude oil that had been committed to the proposed Project to the Gulf Coast area. Those customers would most likely seek other pipelines (if available) because they offer the most economic means of overland transportation of large volumes of crude oil. If other pipelines are not available, those customers would be expected to seek and utilize other modes of transportation, if the increased cost of such transportation does not render it uneconomic to produce and transport the crude oil to market. Section 1.4, Market Analysis, concludes that based on current market conditions and a range of future projected market conditions, it would be economic to ship crude oil by rail and other intermodal options to the Gulf Coast area.

The analysis in the Final EIS had not carried forward other modes of transportation for full analysis as reasonable alternatives largely because of economic practicability; however, developments since then clearly demonstrate that other modes of transportation can be economically utilized. Although the Final EIS noted the significant increase in capacity to transport crude oil using unit trains, particularly in the Bakken area, at that time the new capacity

[1] For the purposes of the Supplemental EIS, the Gulf Coast area includes refineries located in the Houston and Port Arthur area of southeastern Texas as well those in St. James, Louisiana.

was only beginning to be developed. Since the Final EIS was published, however, the volume of crude oil transported by rail out of the Bakken area has more than quadrupled to approximately 500,000 bpd (Figure 2.2.3-1) and could exceed 800,000 bpd by the end of 2013. This rail capacity has been developed because there is not sufficient pipeline capacity to transport the Bakken crude oil to market. The continuing rapid development of the Bakken resource does not appear to have been curtailed because of this lack of pipeline capacity.

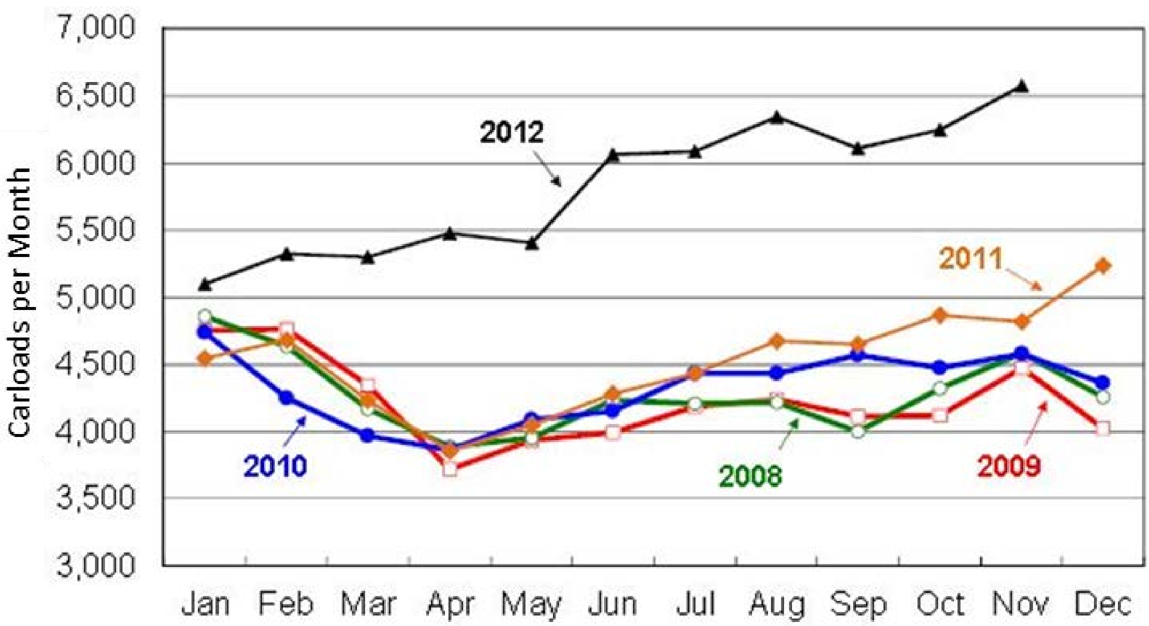


Source: North Dakota Pipeline Authority 2013; Company Reports.
Note: The 2013 estimate of volume of crude oil shipped from the Bakken is based on rail company statements.

Figure 2.2.3-1 Estimated North Dakota Rail Export Volumes, December 2012

The Bakken area has seen the most intensive development of rail transport capacity for crude oil, but this is a phenomenon that is occurring throughout North America, including in the WCSB. An analysis conducted by Hart Energy Consulting of existing, under construction, and announced crude-by-rail projects estimated that by 2016 companies will have constructed rail terminals throughout various United States production areas capable of loading 2.5 mmbpd; and terminals throughout various United States refining areas capable of off-loading 2 mmbpd (Hart 2012). These estimates are from summer 2012 and as indicated in Section 1.4.6.2, they are most likely low. For example, as of the end of 2013, there is an estimated 730,000 bpd of rail off-loading capacity in the Gulf Coast area, and almost 900,000 bpd on the East Coast (Figure 1.4.6-5).

As indicated in Section 1.4, this trend of increased rail transport is also beginning to occur in the WCSB area of Canada in response to pipeline constraints. There are two major rail operators in Canada – Canadian National (CN) and Canadian Pacific. Both of these rail operators are actively promoting crude-by-rail as an option for transporting crude oil out of the WCSB, including the transport of heavy crudes in the form of dilbit, railbit (similar to dilbit but with less diluent added), and raw bitumen without diluent (although this requires insulated rail cars with steam coils) (Figure 2.2.3-2). Current estimates are that more than 120,000 bpd were transported out of the WCSB by rail at the end of 2012. Projections for WCSB crude oil transport by rail to the U.S. Gulf Coast could reach 200,000 bpd or more in 2013 (Hart 2012, Peters and Co. Ltd 2013). Figure 2.2.3-2 shows the increase in carloads of petroleum and petroleum products transported by CN and Canadian Pacific. The increase is attributable almost entirely to crude oil and indicates that by the end of 2012 CN and Canadian Pacific were transporting as much as 200,000 bpd of crude oil.[2]



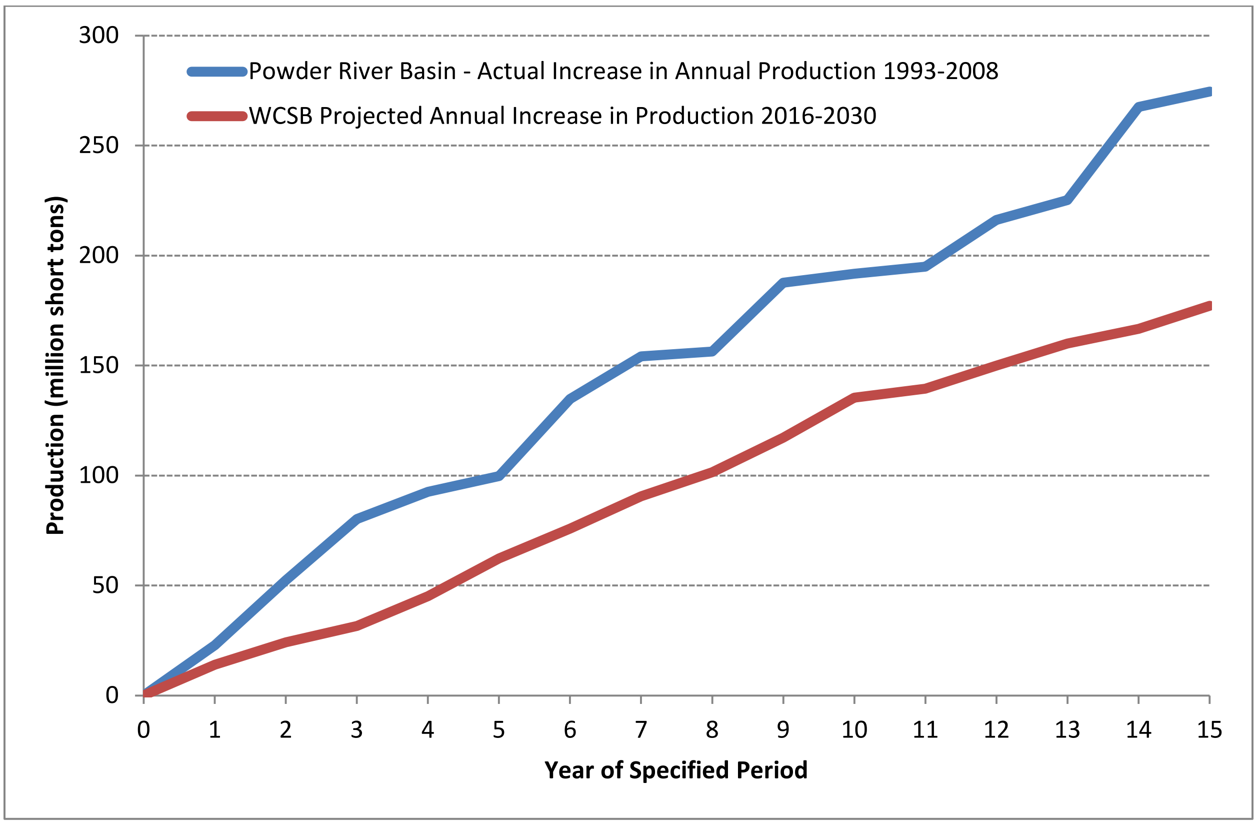
Source: AAR 2012

Figure 2.2.3-2 Actual CN and Canadian Pacific Petroleum Products Transported, Carloads per Month

There is no indication that the rail logistics system would not be able to continue to scale up at this rate over many years if the economics justified it. For example, the rail system was able to expand at an even greater rate, in terms of increased tons hauled per year, to accommodate coal production in the Powder River basin in Wyoming and Montana.3 The Powder River basin produces approximately 40 percent of the nation's coal, over 400 million tons per year, almost

[2] This 200,000 bpd includes the crude oil Canadian Pacific is transporting out of the Bakken in the United States.
[3] The increase in capacity was not without challenges or setbacks, but nonetheless, even with these challenges the described capacity increases were achieved (U.S. Department of Energy 2007).

all of which is transported by rail. The first truly large-scale surface mines in the area began operating in the 1970s. By 1980, approximately 99 tons per year of coal was transported out of the Powder River Basin. By 2008, this had increased to approximately 500 million tons, or an average increase of 14 million tons per year every year for 28 years. On a tonnage basis, this is equivalent to an increase of approximately 240,000 bpd per year, or 6.7 million bpd over 28 years. Figure 2.2.3-3 below compares the annual increase in rail transport of crude oil (expressed in short tons) that would be necessary to accommodate projected WCSB production from 2016 to 2030 to the annual increase in tons of coal hauled from the Powder River Basin from 1993-2008, when the most significant expansion in production occurred. This offers further evidence that the rail system (in terms of track improvements and loading facilities) would be capable of making any necessary capacity increases to accommodate all of the WCSB production, provided the economics justified it.



Source: CAPP 2012; Hellerworx, Inc. 2013

Figure 2.2.3-3 Annual Increases in Rail Transport to Accommodate WSCB Production Compared to Coal

As demonstrated above and in Section 1.4, rail, although still typically more expensive than pipelines for transporting crude oil, can be an attractive transport alternative, particularly where there is inadequate pipeline capacity. Rail also offers the benefits of lower capital costs (as most of the rail infrastructure already exists), shorter time to develop, quicker transit to market, greater flexibility with market destinations, and shorter contract terms (typically 0 to 5 years) (EnSys 2011; Hart 2012).

As other modes of transportation (e.g., tankers and barges) are also being economically utilized to transport such large and growing volumes of crude oil throughout North America, they are being further analyzed as alternatives to transport crude oil from the WCSB and Bakken basins to refinery markets, along with other potential proposed pipelines (e.g., Northern Gateway and Trans Mountain in British Columbia), modifications to existing pipelines (e.g., reversal of flow in the Seaway Pipeline), and construction of a new pipeline (e.g., Flanagan South).

Therefore, the development of alternative methods to transport WCSB and Bakken crude to refinery markets is considered a "predictable action" (CEQ 1981). The discussion below identifies and screens other predictable actions that should be included as scenarios under the No Action Alternative.

2.2.3.1 Identification and Screening of No Action Alternative Scenarios

Several technically feasible scenarios were identified for the transport of WCSB and Bakken crude oil to Gulf Coast area refineries based on existing and otherwise suggested transport measures:

- Rail to Vancouver or Kitimat, British Columbia and tanker to the Gulf Coast area refineries;
- Rail to Prince Rupert, British Columbia and tanker to the Gulf Coast area refineries;
- Rail directly to the Gulf Coast area refineries;
- Rail to the Cushing area and pipeline to the Gulf Coast area refineries;
- Rail to Wood River, Illinois or other Mississippi River ports and then barge to the Gulf Coast area refineries;
- Trucking;
- Existing pipeline system alternatives (i.e., use available capacity in existing pipelines); and
- Other recent crude oil transportation proposals.

In addition to these transport scenarios, other scenarios considered include:

- Use of alternative energy sources; and
- Implementation of energy conservation measures.

The screening of these scenarios took into consideration several factors including transport cost, timing (e.g., could it be implemented within the same general timeframe as the proposed Project), and whether it could transport approximately the same volume of crude oil as currently contracted to be shipped by the proposed Project, and could be scaled up to handle the maximum throughput of the Project. Three scenarios were included for further evaluation:

- The Status Quo Scenario, under which the direct impacts associated with construction and operation of the proposed Project would not occur; this Scenario provides a baseline for comparison with other alternatives;
- Rail/Pipeline Scenario, which could transport the equivalent capacity as the proposed pipeline (i.e., up to 730,000 barrels bpd of WCSB crude oil and up to 100,000 bpd of Bakken crude oil [see Section 2.2.3.2, Rail/Pipeline Scenario]); and
- Rail/Tanker Scenario, which could transport the equivalent capacity as the proposed pipeline (i.e., up to 730,000 bpd of WCSB crude oil and up to 100,000 bpd of Bakken crude oil [see Section 2.2.3.3, Rail/Tanker Scenario]).

The rationale for eliminating the other scenarios is provided in Section 2.2.3.4, Scenarios Considered but Eliminated from Detailed Analysis.

Rail Transport Assumptions

As noted in the market analysis in Section 1.4, in light of potential constraints on pipeline capacity, producers in the Canadian oil sands region and in the Bakken field have begun to use rail to transport crude oil to market. As noted above, approximately 500,000 bpd is currently being shipped out of the Bakken by rail. There are numerous reports of rail loading terminals being constructed in the WCSB, with CN now expected to have 14 operating loading terminals in 2013 (see Section 1.4.5, Crude Oil Transportation). Current estimates are that more than 120,000 bpd were transported out of the WCSB by rail at the end of 2012. Projections for WCSB crude oil transport by rail to the U.S. Gulf Coast could reach 200,000 bpd or more in 2013 (Hart 2012, Peters and Co Ltd. 2013).

For purposes of this analysis, assumptions were required regarding crude oil loading locations; whether the crude oil would be transported as dilbit, synbit, railbit, or bitumen; rail operations (e.g., unit trains); rail routes; and unloading locations. The basis for the assumptions used in this analysis is described below, but it is important to note that these are simplifying assumptions. In reality, and as current trends have indicated, the market is likely to develop multiple solutions (e.g., multiple loading locations, forms of crude oil shipped, train sizes, routes, and destinations). The scenarios presented here are intended to be a reasonable representation of likely rail transport of WCSB crude oil, but do not imply that these scenarios are the only, or necessarily the best, rail options.

Loading Locations

While Hardisty, Alberta is the starting point for the proposed Project, other potential crude-by-rail terminal locations were considered. Hardisty was not selected because it is only served by one of the Canadian Class I railroads in the WCSB region. Fort McMurray and Cold Lake, Alberta were eliminated because they were not as centrally located. It is possible that constraints in future pipeline capacity could make these locations more attractive to on-loading rail facility (so-called midstream) developers, and there are reports of facilities being expanded and new facilities being constructed in those areas.

Lloydminster, Saskatchewan and Edmonton are more central crude oil hubs and are served by both Canadian Class I railroads. Lloydminster was selected as the representative point of origin to develop this scenario because Canadian Pacific Railway System (CPRS) currently has a crude oil loading terminal at Lloydminster (CPRS 2012), and CN also serves Lloydminster. Lloydminster is relatively close to Hardisty (about 68 miles) and is about the same rail distance to the destination markets as Hardisty (Figure 2.2.3-2). Edmonton is approximately twice the distance from Hardisty. Epping, North Dakota was selected as a representative point of origin for transporting Bakken crude oil since it is one of the locations with an existing rail terminal is already servicing that location.

It is assumed that crude oil currently under contract through the proposed Project would be delivered to Lloydminster and Epping through similar means as it would have been to Hardisty and Baker, Montana. As a result, delivery to the points of origin is not included in the scope of this analysis. There are no Class I rail[4] routes that serve both Lloydminster and Epping, so two separate rail scenarios have been proposed.

Form of Crude Oil Transported

Crude oil from the WCSB can be transported by rail as dilbit, railbit, or undiluted bitumen. Dilbit can be transported in standard rail tank cars. The railbit and undiluted bitumen require insulated rail cars with steam coils for reheating the bitumen at the destination terminal. Recent announcements indicate that at least 60 percent of the rail tank cars now being manufactured are of the insulated/coiled type (Torq 2012). Based on that percentage, there are expected to be 28,000 new insulated/coiled rail cars capable of hauling approximately 800,000 bpd of bitumen/railbit/dilbit to the U.S. Gulf Coast available by the end of 2014. As noted in Section 1.4 there are at least 8 oil sands producers that are currently transporting WCSB heavy crude by rail and have publically announced plans to transport increasing amounts of it by rail in 2013 (see Table 1.4-9). This indicates that shippers should have a choice in the form they ship crude oil and that they are already making plans to utilize the rail option at scale.

While it is assumed to be more expensive to ship bitumen on a per barrel basis because it requires insulated/steam coiled railcars and less bitumen can be loaded into each rail car because of weight restrictions, the ultimate delivery to the refineries is 100 percent of the crude oil produced in the WCSB, rather than a blend with lighter hydrocarbon diluents that the WCSB producers have to purchase to make bitumen into dilbit. Removal of the need for diluent would reduce the volume required for transport by the roughly 30 percent of volume of diluent used in the dilbit production or 20 percent of volume of diluent used in railbit production. The benefit of transporting bitumen is that fewer barrels would be handled, and there would be no need to transport diluent into Canada for blending the volume of bitumen shipped by rail into dilbit. Based on this, the EnSys Energy and Systems, Inc. (EnSys) No Expansion Update (EnSys 2011) had calculated that the net shipping cost per barrel of bitumen by rail could be similar to the pipeline shipping costs for dilbit.

Even though the rail costs per barrel of bitumen may be much higher in some instances than those in EnSys (EnSys 2011), some producers may still be able to receive a better price per barrel by shipping bitumen by rail to the Gulf Coast rather than shipping it to Edmonton or Hardisty, where they are receiving significantly discounted prices. The producer can receive

[4] A Class I railroad in the United States is a large freight railroad company, as classified based on operating revenue. The Surface Transportation Board (STB) defines a Class I railroad in the United States as "having annual carrier operating revenues of $250 million or more.” (STB 2012)

much higher netback prices per barrel of bitumen by accessing better prices on the U.S. Gulf Coast, backhauling diluent from the U.S. Gulf Coast, and shipping fewer total barrels of product.

While shipping raw bitumen may have cost advantages, there are other logistical concerns that include the following:

- Rail congestion issues in the Gulf Coast area could cause delays and reduced reliability in the delivery of bitumen by rail directly to the refineries;
- Space constraints at refineries on the Gulf Coast area to accommodate large daily rail shipments of raw bitumen, including the necessary rail off-loading facilities on site.

One alternative to rail shipment of bitumen directly to the refineries would be to ship bitumen by rail to a U.S. Gulf Coast port facility for onward delivery by barge. There are several projects under construction that would implement this option. There can be some logistical challenges to scaling up to the full capacity of the proposed Project with this alternative as well. Most barges would require some modifications in order to keep raw bitumen liquid (e.g., insulation, modification of heating system and heating coils) and possibly retrofitting of vapor recovery equipment (EnSys 2011). Further, barge receipt of raw bitumen may constrain dock operations, especially if the refineries are still receiving crude oil shipments from other sources (e.g., Mexico, Venezuela).

Because of these logistical concerns associated with scaling up the bitumen or railbit by rail scenario to the full capacity of the proposed Project, it has been assumed for purposes of this analysis that the WCSB crude oil would be transported as dilbit, while recognizing that some portion of the crude oil would likely be transported as bitumen or railbit.

Rail Operations

All rail movements were assumed to occur in unit trains. A unit train transports all of its cargo from a single starting point to a single end point with no intermediate stops or storage, generally on one bill of lading. This provides shippers with an economy of scale, minimizes delays, and increases reliability. For the purposes of the analysis in this Supplemental EIS, the unit trains are assumed to be 100 railcars in length.[5] The railcars remain together as one unit train and cycle back and forth between the origin and destination, loaded and empty. Unit trains are delivered empty to the rail loading terminal, loaded and delivered back to the rail carrier within 24 hours. At destination, the loaded trains are delivered to the terminal and unloaded; the empty trains are delivered back to the rail carrier within 24 hours. Some crude oil unit train terminals can load or unload a 100 car unit train in 12 hours.

Rail Routes and Unloading Destinations

The rationale for the specific rail routes and unloading locations proposed for the Rail/Pipeline and Rail/Tanker scenarios are described below in the description of each scenario.

2.2.3.2 Rail/Pipeline Scenario

Under this scenario, the WCSB crude would be transported to Gulf Coast area refineries via the following modes and routes (see Figure 2.2.3-2):

[5] The number of rail cars in unit trains transporting crude oil may vary. BNSF recently announced that it was considering units trains of 118 cars. Coal unit trains can be up to 150 cars long.

- Loaded onto rail in Lloydminster, Saskatchewan, and transported approximately 1,900 miles (using CPRS and Burlington Northern Santa Fe [BNSF] Railway) or approximately 2,000 miles (using CN and Union Pacific [UP] routing) along existing rail lines via common carrier railroads to new rail terminals at Stroud, Oklahoma. Stroud was selected as the destination rail terminal because, currently, there are no railroads that go all the way to Cushing. These representative routes are used for analysis purposes only;
- Transferred to new oil storage facilities and pipeline at Stroud, Oklahoma, and transported via a new pipeline approximately 17 miles to the existing oil terminal at Cushing, Oklahoma. Crude oil is currently being shipped by this method, but it is assumed that additional pipeline capacity would be needed to accommodate the added volume of crude oil; and
- Transferred by existing pipelines from Cushing approximately 533 miles to the Gulf Coast area for refining.

The Bakken crude would be transported via the following modes and routes (see Figure 2.2.3-5):

- Loaded onto rail at Epping, North Dakota,[6] and transported approximately 1,347 miles to new rail terminals with storage tanks at Stroud, Oklahoma, via common carrier railroad (assumed to be the same terminals identified for the WCSB crude);
- Transferred to existing oil storage facilities at Stroud, Oklahoma, and transported via a new pipeline approximately 17 miles to the existing oil terminal at Cushing, Oklahoma; and
- Transferred by existing pipeline approximately 533 miles from Cushing, Oklahoma, to the Gulf Coast area for refining.

These proposed routes would use existing rail and pipeline infrastructure to the extent possible, but would require construction of the following new facilities, as shown in Table 2.2-1. The loading and unloading terminals would probably be sited near the railroad mainline. The terminals could be clustered near existing terminals, or spread out in the vicinity of Epping, Stroud, or Lloydminster. Representative sites were identified for these new terminals for purposes of this analysis.

Lloydminster Loading Terminal

Thirteen unit trains per day would be needed to transport up to 730,000 bpd throughput from Lloydminster to Stroud. A new rail terminal located near the mainline would have the capacity to load two 100-car unit trains per day. Based on the proposed throughput and the terminal capability, seven new terminal sites would need to be constructed at Lloydminster to load up to 730,000 bpd. Each terminal would occupy about 500 acres.[7] The terminal would include a loop track (25,000 to 30,000 feet per terminal); oil storage tanks (four 75,000 barrel tanks per site); and other infrastructure typically required for loading and unloading crude oil. Figure 2.2.3-6 is an example existing loading terminal in North Dakota representative of the type of facility that would be needed.

[6] The Epping area currently has one operating rail on-loading facility. For the purposes of analysis, because of future expected expansion of exports from the Bakken field, at least one addition terminal would be needed.
[7] This acreage was used for analysis purposes based on other typical facilities in the region. The exact dimensions of future facilities may differ.

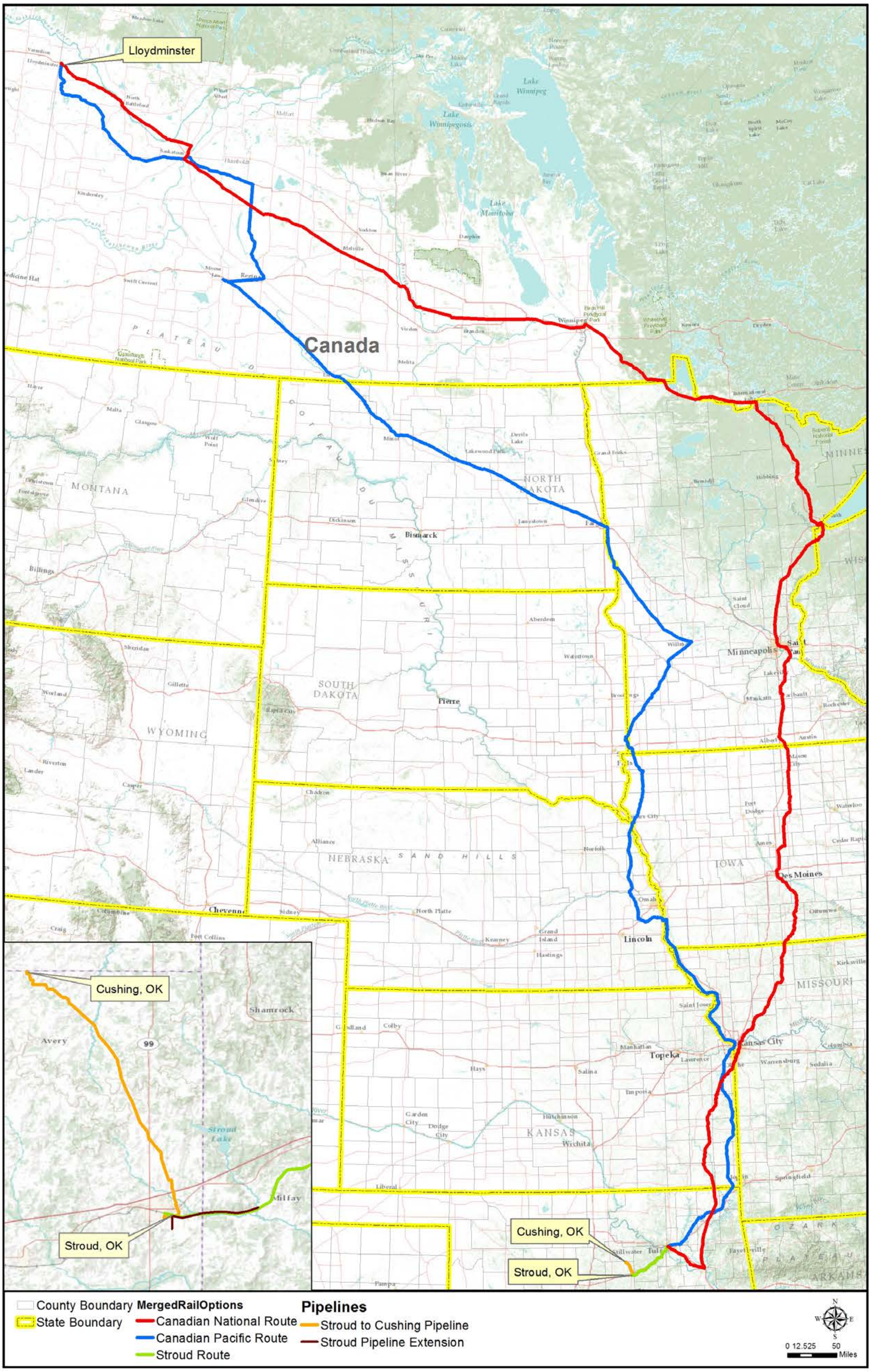


Figure 2.2.3-4 Rail Route Scenarios between Canada and the United States

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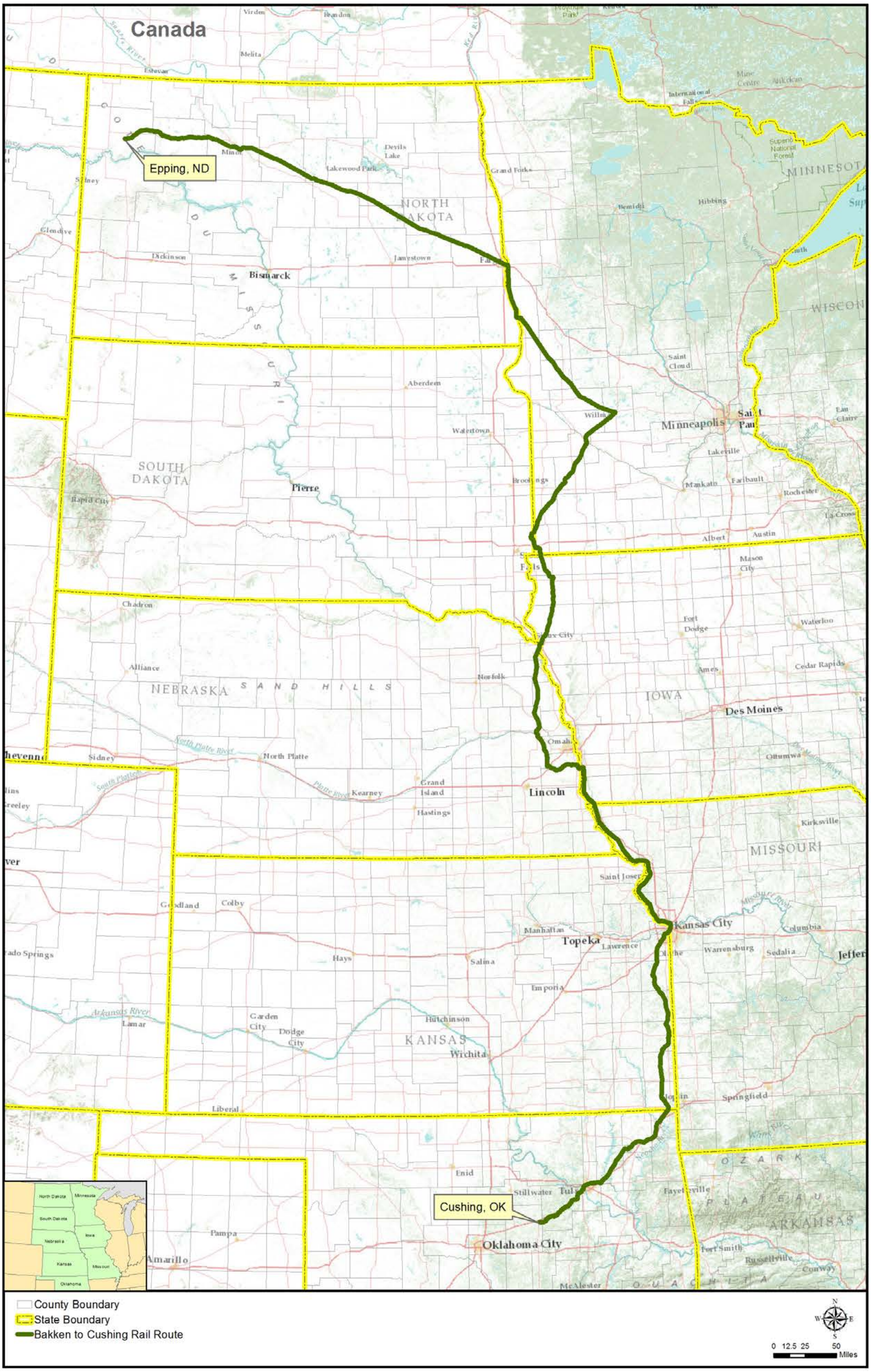

Figure 2.2.3-5 Bakken to Cushing Route

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Table 2.2-1 Crude Oil by Rail to Oklahoma/Pipeline to Gulf Coast Area Scenario: New Construction and Specifications

	Lloydminster, Saskatchewan	Epping, North Dakota	Stroud and Cushing, Oklahoma
Throughput (bpd)	up to 730,000 bpd WCSB	up to 100,000 bpd Bakken	up to 730,000 bpd WCSB; up to 100,000 bpd Bakken
Unit Train[a] Terminal Sites Needed	7 new sites; 2 unit train loadings per day/site	1 new site; 1-2 train loadings per day/site	7 new terminal sites; 2 train off-loadings per day/site for WCSB 1 off-loading/day for Bakken at existing site
Storage Needs	(4) 75,000 barrel tanks per site	(4) 75,000 barrel tanks	(4) 75,000 barrel tanks per site at Stroud (11) 75,000 barrel storage tanks at Cushing
Number of Trains	13 unit trains per day	1 to 2 unit trains per day	14-15 unit trains per day (WCSB + Bakken)
Total New Track (mainly within terminal)	175,000 to 210,000 feet for 7 terminals	25,000 to 30,000 feet	175,000 to 210,000 feet for 7 terminals
Terminal Acreage	3,500 (500 acres per terminal site x 7)	500 acres	3,500 acres
New Pipeline Needed	None	None	17-mile Stroud to Cushing pipeline
Total Acreage for New Terminals and Pipeline (approximate)	**Terminals: 3,500 acres**	**Terminal: 500 acres**	**Terminals: 3,500 acres** **Pipeline:103 acres (permanent) 227 acres (temporary)** **Total: 3,603 acres**
	Total Acres for Scenario	**7,603 acres**	

[a] A unit train transports all of its cargo from a single starting point to a single end point with no intermediate stops or storage. This provides shippers with an economy of scale. For the purposes of the analysis in this Supplemental EIS, the unit trains would be 100 railcars in length.

Source: Wilson & Company

Figure 2.2.3-6 Typical Rail Loading Facility in North Dakota

Loop track construction would include the following:

- Rail bed construction—a rail bed would be constructed upon which the ballast[8], rail ties, and rail would then be laid. Rail bed construction would require clearing, excavating earth and rock on potentially previously undisturbed land, and removing and stockpiling topsoil, where needed. Construction could require both cuts and fills.
- Track construction—in-place track construction would consist of placing ties, rail, and ballast on top of the rail bed. The track could be constructed on site or skeleton track panels could be constructed off-site and transported to the site.
- Construction staging areas—the proposed loop and terminal site could require construction staging areas to store material, weld sections of the rail line, and otherwise support construction activities. Staging areas would be identified before construction began.

Additional considerations for the Lloydminster Loading Terminal would include the following:

- Associated facilities—these would include buildings, maintenance equipment, security, and safety equipment.
- Associated pipelines—railcars would on-load from local storage tanks. A short pipeline from the temporary storage to the terminal would be needed at each new terminal location.
- Power requirements—it was assumed that each terminal would require 5 megawatts of electrical power. Power requirements would include new transmission lines to each new on-loading terminal.

[8] Ballast is the rock base used in railroad beds.

Epping Loading Terminal

Bakken crude currently moves in unit train quantities to both the Gulf Coast area and to Stroud, Oklahoma. There are multiple terminals in North Dakota that could load unit-train quantities of Bakken crude. Rangeland Energy's terminal at Epping, North Dakota, is representative of an origination terminal. This terminal loads 100-car unit trains of Bakken crude today. It is served by BNSF, one of the two largest Class I railroads serving the western United States (Rangeland Energy 2012). Under this scenario, a new loading terminal would be constructed in the Epping vicinity to transport up to 100,000 bpd of Bakken crude oil. Also, while the existing Stroud facility has the capacity to transport up to 100,000 bpd of Bakken crude to Cushing, it is assumed for analysis purposes that a new facility plus a 17-mile pipeline to Cushing would be needed to accommodate the anticipated increases in crude deliveries.

Stroud Off-loading and Storage Terminal

Cushing, Oklahoma does not have rail service, but rail service is available in Stroud, 17 miles away. WCSB crude would need to be transported by rail to Stroud, and then from Stroud by new and existing pipelines to Cushing (from Cushing it would be transported to the Gulf Coast area via existing pipelines). An existing Stroud pipeline operated by EOG Resources is connected to the Stillwater Central Railroad; however, its capacity is limited to 90,000 bpd. To accommodate WCSB crude, new off-loading terminals would need to be constructed in the Stroud vicinity, and new pipelines built to transfer the WCSB crude from Stroud into the existing storage infrastructure in Cushing. The off-loading facilities would need the same basic capacity as the on-loading terminals (seven new terminals with the capacity to off-load two 100-car unit trains per day) and would need the following terminal components:

- Sufficient track to hold three-plus unit trains at any time (loop track not necessary for off-loading terminals).
- Approximately 500-acres in land acquisition per terminal to handle unit trains, storage, and ancillary facilities. Seven terminals would require about 3,500 acres of land.
- Four 75,000-barrel tanks at each terminal to receive the crude from the railcars, and store crude for shipment into the pipeline to Cushing. For example, unit trains may be unloading WCSB into Tanks 1 and 3 while Tanks 2 and 4 are loading product into the pipeline to Cushing. The next unit trains would unload into Tanks 2 and 4 while Tanks 1 and 3 are switched to pump into the pipeline.
- Under this scenario, one new pipeline would be required from Stroud to Cushing. A number of midstream companies own storage tanks in Cushing, and they are the likely parties that may invest in rail off-loading terminals. These parties would presumably want the off-loading terminals connected to their own storage tanks in Cushing, and this could lead to more than one pipeline being built. However, for analysis purposes, only one pipeline has been considered. The pipeline would require a permanent right-of-way (ROW) of about 103 acres, with up to 227 acres needed during construction.
- Supporting infrastructure (buildings, maintenance equipment, security, and safety equipment).
- For the purposes of this analysis, it is assumed that the power requirements would include new transmission lines to each new off-loading terminal.

Rail and Pipeline Cost Assumptions

Capital costs were estimated based on cost information for terminals recently completed or currently under construction and on assumptions regarding storage and track unit costs (Table 2.2-2). Costs for individual terminals were multiplied by the number of terminals at each; costs for transmission lines and pipelines (Stroud) were added.

Table 2.2-2 Estimated Cost of New Facilities and Estimated Jobs Created for Crude by Rail/Pipeline Option

Estimates	Rail Terminal at Lloydminster	Rail Terminal at Stroud	Epping Facility (for Bakken crude)
Capital Costs	$650,000,000	$700,000,000	$110,000,000
Construction Jobs	1,900	2,240	320
Peak Employment	1,650	1,980	320
Construction Period (weeks)	106	106	52
Operations Costs (annual)	$49,000,000	$49,000,000	$7,000,000
Operations Jobs	50	50	15

Construction jobs were estimated using expenditure/direct job ratios obtained from other projects. The main reference was the Enbridge Northern Gateway project and adjustments were made for portions of expenditures with rail tracks (Alaska Department of Transportation and Public Facilities 2011), pipelines (as noted in the Final EIS), and transmission lines (Montana Department of Labor 2010). The base ratio used is 1.98 construction jobs per million dollars of capital expenditures, with up to 9.3 construction jobs per million dollars for rail track construction. Jobs would not be full-time equivalents and could be full- or part-time jobs. Peak employment and the length of the construction period were based on an assumed 52-week construction schedule for each terminal. For analysis purposes, a 9-week interval between the start of construction of each successive terminal was assumed at facilities with multiple terminals. Estimated delivery costs under this scenario are described in Table 2.2-3 below.

Table 2.2-3 Rail Costs from Lloydminster, SK to Stroud, OK, and Bakken Crude Oil from Epping, ND to Stroud, OK

	Cost $/barrel		
	CN-UP-SLWC[a]	**Canadian Pacific-BNSF-SLWC[b]**	**BNSF-SLWC**
Loading railcars	1.00	1.00	1.00
Rail Lloydminster, SK- Stroud, OK	10.00	10.75	--
Rail Epping, ND – Stroud, OK	--	--	4.75
Railcar lease	1.10	1.00	0.75
Transfer costs - railcars to storage tanks	1.00	1.00	1.00
Total	**13.00**	**13.75**	**7.50**

[a] Canadian Northern-Union Pacific-Stillwater Central Railroad
[b] Canadian Pacific-BNSF-Stillwater Central Railroad

2.2.3.3 Rail/Tanker Scenario

As noted above under the Rail/Pipeline Scenario and in Section 1.4, Market Analysis, producers in the Canadian oil sands and in the Bakken have begun to use alternative methods to transport their product to refineries. A second likely transportation method would include transporting crude oil by rail from Alberta to a western Canadian port. From there, the crude oil could be exported via tankers and delivered to various destinations.

Tankers are fully capable of carrying heavy WCSB crudes (as well as lighter crudes) in the form of dilbit and as undiluted bitumen. Transport of dilbit on a tanker is no different from transporting any conventional heavy crude oil and does not require special equipment. Tankers generally have steam heaters so they could carry dilbit with no modifications needed, but would require upgraded heating systems and tank insulation to transport bitumen. While not on a large scale, tanker movements of up to 15,000 bpd of WCSB crude have moved in recent years from the Westridge dock (Trans Mountain pipeline) in Vancouver via tanker to the U.S. Gulf Coast.

If cross-border pipeline capacity into the United States was constrained, moving WCSB crudes from Pacific ports in volume to the U.S. Gulf Coast could become attractive, but would require construction of new or expansion of existing port facilities.[9] Using heavy crude as a basis, a present day movement via Trans Mountain to Vancouver and thence on a Panamax tanker via the Panama Canal to Houston would have a total freight cost (pipeline tariff plus tanker freight and Panama toll) of around $8.50-9.50/barrel (bbl). Recognizing that Kinder Morgan plans to enable future shipment in larger Suezmax tankers, and that the Panama Canal Authority is expanding the Canal to take tankers of that size, the rate using a Suezmax would be approximately $1/bbl lower. These rates compare to approximately $8/bbl to move heavy crude via pipeline from Hardisty to Houston. Thus, while in normal markets, a tanker movement from Western Canada would be somewhat more costly than via pipeline, in a scenario where ability to move WCSB crudes by pipeline to the U.S. Gulf Coast were constrained, refiners in the U.S. Gulf Coast could opt for tanker transport.

There are several pipelines proposed for transporting WCSB crude oil to the Pacific, including Trans Mountain to Vancouver and Northern Gateway and Northern Leg to Kitimat. These pipelines have been controversial and are encountering significant opposition. It is uncertain whether such projects ultimately will be approved. The option of transporting WCSB crude oil to the Pacific via pipeline is described in more detail in Section 2.2.3.4. As discussed above, rail may offer a viable alternative for transporting crude oil to ports in Vancouver, Kitimat, and Prince Rupert in British Columbia, , as all of these ports are served by Class 1 rail carriers.[10]

There have also been proposals for the transport of WCSB crude oil to the Canadian east coast by converting existing natural gas pipelines to carry crude oil, rail, [11] and/or tankers via the St. Lawrence Seaway. These options appear to be a bit more speculative and would incur logistical challenges and potentially permitting issues. For example, the option of tanker transport would be constrained to a maximum tanker size of 45,000 ton capacity by size restrictions along the

[9] Nexen Inc. is exploring moving oil by rail to Prince Rupert, B.C. to export crude onto tankers for delivery to Asia markets (Vanderklippe 2013).
[10] There are also rail to marine tanker transloading facilities on the U.S. West Coast that are served by Class 1 railroads and that could receive Canadian crudes.
[11] The Irving oil refinery in Saint John, NB is reportedly receiving crude by rail from the Bakken and Western Canada.

St. Lawrence Seaway system. These options would clearly be more expensive, relative to the other scenarios discussed in this section, if the ultimate destination for the crude oil is the U.S. Gulf Coast.

Because of the uncertainty associated with whether these proposed pipelines will be approved, and when, rail transport of crude oil to Prince Rupert and onward transport via tanker to the Gulf Coast area refineries was selected for the Rail/Tanker Scenario. WCSB would be transported as follows (see Figure 2.2.3-7):

- Loaded onto rail in Lloydminster and transported to Prince Rupert, British Columbia;
- Transferred to a new/expanded marine terminal at Prince Rupert; and
- Shipped via Suezmax vessels to the Gulf Coast area (Houston/Port Arthur) through the Panama Canal.

It should be noted, however, that if WCSB crude oil reaches a Pacific port, regardless of whether by rail or by pipeline, the economics for movement via tanker would favor shipping the oil to Asia rather than the Gulf Coast area. The cost of transporting crude oil via tanker from Prince Rupert to Houston and Port Arthur is estimated to be approximately $4.70/bbl, whereas the transport cost via tanker from Prince Rupert to refinery ports in Asia (e.g., Ulsan, South Korea and Dalian, China), is estimated to be only approximately $1.70 and $2.00/bbl, respectively. The lower transport cost to Asia versus the Gulf Coast area is attributable to shorter trip duration (30 to 37 days to Asia versus about 45 days to the Gulf Coast area), avoiding the Panama Canal toll (about $0.70/bbl), and being able to use a larger tanker because it would not be constrained by the Panama Canal (a VLCC tanker to China would have a capacity of almost 2 million bbl versus a Suezmax tanker to the Gulf Coast area with a capacity of about 884,000 bbl). The EnSys (EnSys 2010) report indicated that if the option was available to export crude from the West Coast of Canada to Asia, it would be utilized.[12]

Although the main market for tanker shipments of crude oil from Pacific ports would likely be Asia, EnSys (EnSys 2011) notes that, especially if cross-border pipeline capacity into the United States were constrained, moving WCSB crudes in volume to the U.S. Gulf Coast could also become attractive. This analysis focuses on crude oil delivery via rail to Prince Rupert and tanker to the Gulf Coast area. This scenario is described below.

Crude Oil by Rail from Hardisty/Lloydminster to Prince Rupert, British Columbia

WCSB crude delivered to Lloydminster would be stored and loaded onto railcars at the new rail terminals and transported using existing rail to a new off-loading rail terminal and an expanded marine terminal in Prince Rupert, British Columbia (see Table 2.2-4 for an overview of new construction requirements for all facilities under this scenario).

[12] Further, Ensys (EnSys 2011) notes that it is evident that there are active efforts at the government level in Canada to access Asian markets, which are seen by the government as vital to Canada's ability to exploit its oil and gas resources.

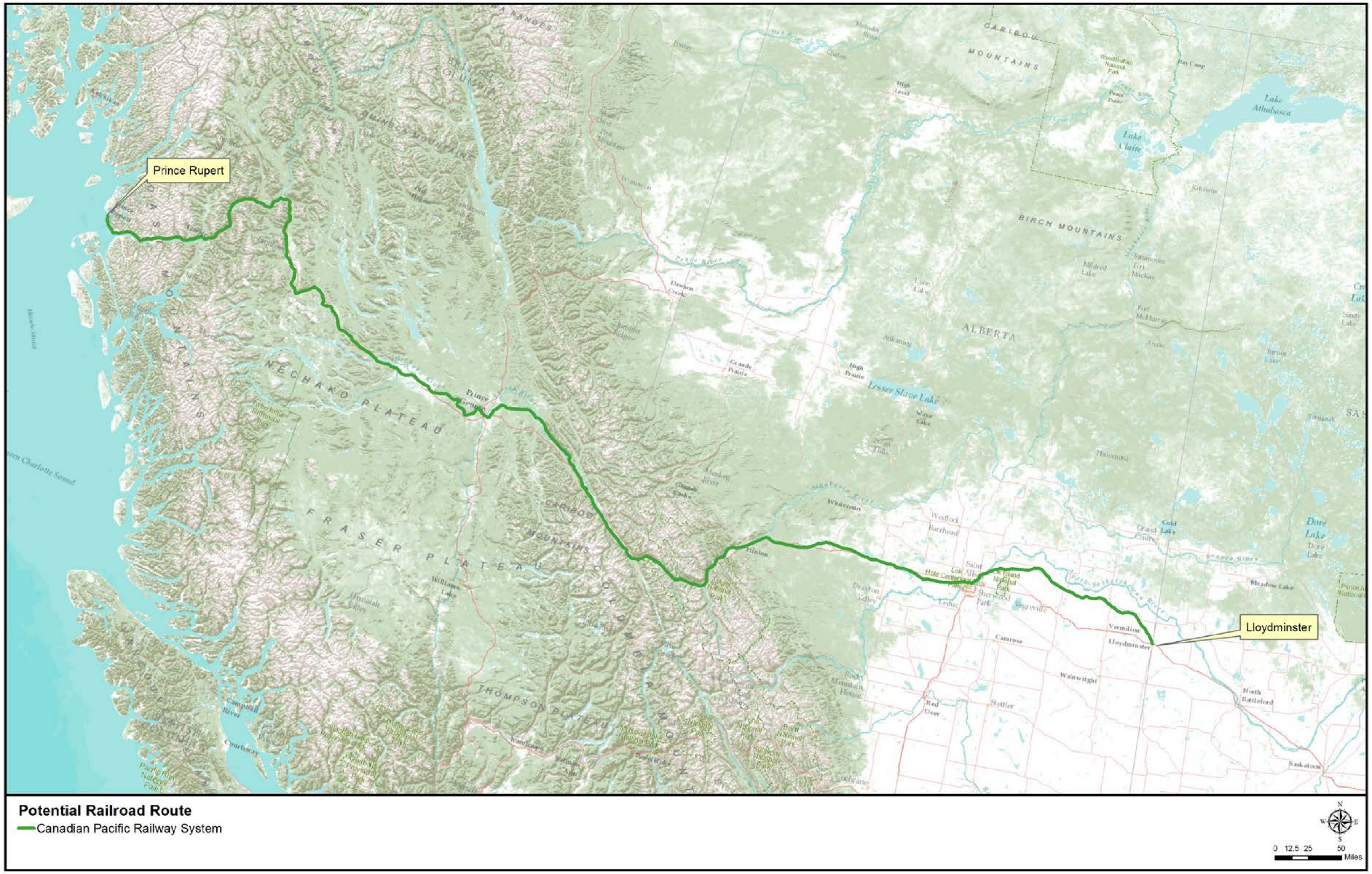

Figure 2.2.3-7 Rail Route from Lloydminster to Prince Rupert

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Table 2.2-4 Crude Oil by Rail to Prince Rupert/Tanker to Gulf Coast Area Scenario: New Construction and Specifications

	Lloydminster, Saskatchewan	**Prince Rupert, British Columbia**	**Epping, North Dakota**	**Stroud and Cushing, Oklahoma**
Throughput (bpd)	Up to 730,000 bpd WCSB	Up to 730,000 bpd WCSB	Up to 100,000 bpd Bakken	Up to 100,000 bpd Bakken
Unit Train Terminal Sites Needed	7 new sites (7 x 500 acres each); 2 trains per day/site	7 new sites; 2 trains per day/site	1 new site; 1-2 trains/day	1 new terminal site (Stroud); 1-2 trains/day
Storage Needs	(4) 75,000 barrel tanks per site	Rail Terminal: (4) 75,000 bbl tanks; Marine terminal: (14) 496,000 bbl tanks; 7 million barrel total storage	(4) 75,000 barrel tanks per site	2 (75,000 barrel tanks)
Number of Trains	13 unit trains per day	13 unit trains/day	1 to 2 unit trains/day	1-2 unit trains/day
Total New Track (within terminals)	175,000 to 210,000 feet for 7 terminals	175,000 to 210,000 feet or 7 terminals	25,000 to 30,000 feet	None
Pipeline Needed	None[a]	15 miles connecting off-loading terminals to marine terminal.	None	17 miles Stroud to Cushing
Total Acreage for New Terminals and Pipelines	**Total: 3,500 acres**	**Marine: 1,200 acres** **Rail Facility: 3,500 acres** **Total: 4,700 acres**	**Terminal: 500 acres**	**Terminal: 500 acres** **Pipeline: 103 acres (permanent)** **227 acres (temporary)**
Total Acres for Scenario		**9,303 acres**		

[a] The locations of these pipelines cannot be determined at this time.

The new facilities in Lloydminster and Prince Rupert would include the following:

- Seven new loading terminals at Lloydminster to load up to 730,000 bpd of WCSB crude. The specifications of these terminals would be the same as those discussed under the Rail/Pipeline Scenario (see Section 2.2.3.2).
- Seven new off-loading rail terminals at Prince Rupert. The specifications of these terminals would be the same as those discussed under the Rail/Pipeline Scenario.
- Storage. The storage tanks at Prince Rupert would total just under 7,000,000 barrels (14 tanks, each with 496,000 barrels of capacity), and would be designed to handle volumes shipped on Suezmax vessels (1 million barrel cargo). Suezmax tankers were used for the analysis because they are the largest vessels that can traverse the Panama Canal.

The proposed Northern Gateway terminal at Kitimat, British Columbia was used as a surrogate to estimate the marine facilities needed at Prince Rupert. The Northern Gateway facility is designed to handle about 525,000 bpd of crude delivered by pipeline for loading on vessels to the West Coast and Asia. In addition, it is designed to receive about 193,000 bpd of diluent (a very light oil obtained from natural gas production) from cargoes arriving by water and discharging into storage at the terminal and moving back to Alberta via a parallel pipeline. The total volume of about 718,000 bpd approximates the volume of WCSB heavy crude oil that would be loaded at Prince Rupert.

New facilities in Prince Rupert would consist of a large rail terminal complex, most likely on the mainland, where off-loaded crude oil would be stored until it could be loaded onto tankers, and an expanded port. The entire facility would cover 4,700 acres, including 3,500 acres for storage and off-loading/on-loading facilities at the rail terminal and approximately 1,200 acres of land at the expanded port (Table 2.2-5).

Table 2.2-5 Terminal Facility Acreage

Project Component	Estimated Area (acres)
Tank terminal	550
Security fence/windbreak area for terminal	650
Total	**1, 200**

The new tank terminal construction would consist of the following:

- Fourteen petroleum storage tanks (11 oil and three condensate);
- A security fence to encompass the tank terminal;
- A 180-foot-wide firebreak area around the outside perimeter of the terminal;
- Electrical supply and distribution (this terminal would be serviced by the Texada Island Reactor substation); and
- Buildings (control center and civil infrastructure including roads).

Prince Rupert Facilities Construction and Operation

The dock portion of the facility would be expanded to accommodate two tanker berths. A utility berth would also be needed to handle large crude oil tankers. Among other things, the following facilities and equipment would be needed:

- A loading platform with gangway tower;
- Access trestles and catwalks;
- Berthing and mooring structures; and
- Spill containment equipment.

The berths would be equipped to load tankers of the size and dimensions specified in Table 2.2-6. Based on using Suezmax vessels through the Panama Canal, the Prince Rupert Marine Loading Facility would expect about 430 vessels per year loading crude oil. These tankers can hold 145,000 deadweight tonnage (DWT) of heavy Canadian crude, or about 986,000 barrels. However, to transit the Panama Canal, they would need to be light-loaded to 130,000 DWT, or about 884,000 barrels. The facility would likely be designed similarly to the proposed Northern Gateway marine terminal in Kitimat, British Columbia (in scale and general design). It may ultimately be desirable to move even greater volumes off the west coast of Canada, or there may be options to load larger or smaller vessels based on world freight market conditions, and that flexibility would likely be in the marine terminal design.

Table 2.2-6 Suezmax Tanker Dimensions and Capacities

Length (meters)	274
Beam (meters)	48
Loaded Draft (meters)	17
Deadweight Tonnage	160,000
Fuels Transport	Oil/Condensate

It was assumed that the entire Marine Loading Facility at Prince Rupert would require 5 megawatts of electric power.

When a large Suezmax vessel arrives off the coast of Houston, it must be loaded onto a smaller vessel that can navigate the Houston Ship Channel and to Port Arthur refinery docks (due to draft restrictions). This process is known in the industry as *lightering*. The charge for lightering is about $200,000. The Panama Canal and lightering charges are the primary additional charges over and above the charter cost charged by the ship owner.

Rail/Tanker Scenarios Cost Assumptions

The estimated cost of the voyage from Prince Rupert to Houston and Port Arthur is estimated at $4.71 per barrel and $4.69 per barrel, respectively, for the Suezmax option (see Table 2.2-7). This analysis also examined fully loading the Suezmax vessel to 986,000 barrels and shipping through the Straits of Magellan (Cape Horn); however, this option is about 66 percent more expensive (about $7.10 per barrel) despite the absence of Panama Canal fees. This is due primarily to a much longer transit time (97 days versus 44).

Table 2.2-7 Rail/Tanker Costs from the Lloydminster, Saskatchewan, to the Gulf Coast Area via the Panama Canal[a]

Activity	Cost $/barrel
Loading railcars at Lloydminster, Saskatchewan	1.50
Rail: Lloydminster- Prince Rupert	7.00-9.00
Railcar lease	0.69
Transfer costs - railcars to storage tanks	1.50
Tanker Cost	4.70
Total	**15.39-17.39[b]**

[a] Does not include Panama Canal Charge or lightering costs.
[b] Does not include costs to ship Bakken crude oil which is estimated at $7.48/barrel. See Table 2.2-3.

This analysis excludes the costs of collecting the crude from the surrounding oil sands fields at Lloydminster to remain consistent to the proposed Project pipeline costs. Given the proximity of production operations to both the pipeline and rail origins, it is reasonable to assume that the collection costs would be similar.

2.2.3.4 Scenarios Considered but Eliminated from Detailed Analysis

The following scenarios under the No Action Alternative were considered, but were not analyzed in detail.

Rail or Pipeline to Vancouver or Kitimat, British Columbia and Tanker to Gulf Coast Area Scenario

Under this option, WCSB would be shipped by existing railways or new pipelines from the Hardisty region to Vancouver or Kitimat, British Columbia for shipment by marine transport through the expanded Panama Canal and delivery to Gulf Coast area refiners. This option considers moving up to 730,000 bpd of heavy crude to the Port of Vancouver and then to the marine docks at the Westridge marine terminal in Vancouver or the port in Kitimat. Under this option, crude oil could move either via rail or by a new pipeline from the Hardisty region.

Currently, Kinder Morgan is planning an expansion of the existing Trans Mountain pipeline originating at Edmonton, increasing its capacity from 300,000 bpd (current) to up to 890,000 bpd (planned for operations in 2017). The Trans Mountain pipeline runs into Vancouver via the existing Burnaby terminal over to the Westridge dock for loading heavy crude onto vessels. The pipeline has sufficient commitment from shippers to proceed with engineering and permitting processes. Kinder Morgan indicates that the project would significantly increase tanker traffic from about 5 to 34 cargoes per month, or up to about 400 cargoes per year (Trans Mountain January 10, 2013). The increased marine traffic is due to increased volume to be shipped, and lack of sufficient channel draft to load larger vessels.

The substantial increase in tanker traffic from the proposed Kinder Morgan expansion has raised safety and environmental concerns. Moving additional volumes of crude oil from the proposed Project into the Vancouver market by either a new pipeline or rail would result in 400 or more additional vessels loading at Vancouver each year and would require considerably more storage to be built than the current Kinder Morgan operations. The expansion of storage capacity, potential rail off-loading facilities and logistics, and increased marine traffic may make this option logistically challenging in a relatively compressed and populated geographical area. Moreover, even if a separate pipeline from Hardisty could be planned, mapped, engineered, designed, and permitted starting today, it would likely not be available as an option until well after the proposed Project's planned start date. As a result of the logistical challenges in increasing the amounts of heavy Canadian grades of crude oil coming into the Vancouver/Burnaby region over and above the volumes from the Kinder Morgan expansion, this option was deemed to be less viable than movements from Kitimat and Prince Rupert and was eliminated from detailed analysis.

Enbridge is proposing to construct the Northern Gateway pipeline, which would transport up to 525,000 bpd of crude oil 1,177 km from Bruderheim, Alberta, to the Port of Kitimat, British Columbia. The port would be improved with two dedicated ship berths and 14 storage tanks for crude oil and condensate. Enbridge intends for the pipeline to be operational around 2017. A regulatory application was submitted in 2010, which is undergoing an independent review process led by the Canadian National Energy Board and the Canadian Environmental Assessment Agency. The pipeline would traverse First Nation traditional lands and important salmon habitat. The project has been controversial and has encountered opposition from some First Nation bands and other organizations. Opposition to the project remains strong as evidenced by media reports of the January 2013 public hearings in Vancouver on the permit application. It remains uncertain at this time if the project would receive permits and be constructed, and therefore the option of moving additional crude to Kitimat was eliminated from detailed analysis.

Rail Directly to the Gulf Coast Area Scenario

Under this option, WCSB crude would be transported by rail directly to refineries or storage facilities in the Port Arthur/Houston region. It is assumed that a network of off-loading facilities that could supply crude to multiple refineries would need to be built to accommodate the amount of WCSB crude oil that would be delivered on a daily basis. This scenario would have the crude directly transported from Hardisty to specific off-loading sites in Texas, rather than using the proposed pipeline system. This scenario faces more logistical challenges that may make it more difficult to scale up to the full capacity of the proposed Project. There is considerable industrial development in this region, in particular, around the refineries along the Houston Ship channel, which are large processors of imported heavy crude (Shell Deer Park, Houston Refining LLC, etc.). Accordingly, it may be a logistical challenge to develop rail unloading facilities for the 13 to 14 daily unit trains of heavy crude oil with connections to storage and refineries.

Nonetheless, the option of direct rail transport of crude oil to Gulf Coast area refineries is viable, and as indicated in Figure 1.4.6-5 there are several unit train off-loading facilities in the Houston/Port Arthur area. Because this option of direct rail transport to the refineries may face several logistical challenges relative to the proposed Rail/Pipeline Scenario, this option was eliminated from further consideration. However, it is important to note that these are simplifying assumptions for this analysis. In reality, and as current trends have indicated, the market is likely to develop multiple solutions (e.g., multiple loading locations, forms of crude oil shipped, train sizes, routes, and destinations). The scenarios presented here are intended to be a reasonable representation of likely rail transport of WCSB crude oil, but do not imply that these scenarios are the only, or necessarily the best, rail options.

Rail/Barge Scenario (Rail from Lloydminster, Saskatchewan to Wood River, Illinois, and Barge to the Gulf Coast Area via the Mississippi River)

Under this option, WCSB crude would be shipped by rail for delivery to the Wood River, Illinois, port facility for transfer to river barges for transit down to the Gulf Coast area. Figure 2.2.3-8 shows the rail route from the Hardisty area to Wood River. There are reports of several companies pursuing rail to barge options for delivery to the U.S. Gulf Coast. This option entails rail costs that are similar to the rail costs to Cushing, but with a much more expensive and logistically challenging subsequent delivery to the Gulf Coast area refiners.

The costs to ship WCSB crude by barge from Wood River, Illinois, to the New Orleans market would be in the $4-$6 per barrel range. The additional cost to move through the Intracoastal Waterway to Port Arthur and Houston could increase this by an additional $1-$2 per barrel, making the increase $5-$8 higher per barrel. On this basis, the cost would appear to be significantly higher relative to pipeline (the cost via pipeline from Cushing would be about $2.35 per barrel compared to much higher barging costs from Wood River, Illinois). Moreover, movement on the Mississippi River can be affected by weather and river conditions. During summer 2012, the river was too shallow due to drought conditions on the lower Mississippi and barge traffic was held up a number of days; at other times, spring floods have affected marine movements. In addition, assuming only the heavy crude (and not the Bakken light crude) is moved by barge, the up to 730,000 bpd would require approximately thirteen 60,000-barrel barges to leave Wood River every day, along with a similar number of empty tows that would head north every day (for an estimated 12 day transit time). Table 2.2-8 shows the rail and barge-related costs of the Rail/Barge Scenario. The rail route to Wood River is shown on Figure 2.2.3-8.

Table 2.2-8 Rail/Barge Costs from Hardisty, Alberta to the Gulf Coast Area

	Approximate Cost $/barrel
Loading railcars at Lloydminster, Saskatchewan	1.00
Rail Lloydminster – Port Arthur, Texas via CPRS – St. Paul Minnesota via Union Pacific	8.50
Railcar lease	1.00
Transfer costs – railcars to barge	1.00
Barge Wood River, Illinois – Port Arthur	5.00-7.00
Total	**16.50-18.50**

Because of these increased costs and logistical challenges, although some companies will employ this option, because of the difficulty in scaling up to the full capacity of the proposed Project and because it would not be an improvement over the Rail/Pipeline Scenario, it was eliminated from detailed analysis discussed in Section 2.2.3.2, Rail/Pipeline Scenario. Other barge options were also considered including the ports of St. Paul, Minnesota; Calumet, Illinois; and Catoosa, Oklahoma, but these all faced the same economic and logistical challenges as Wood River.

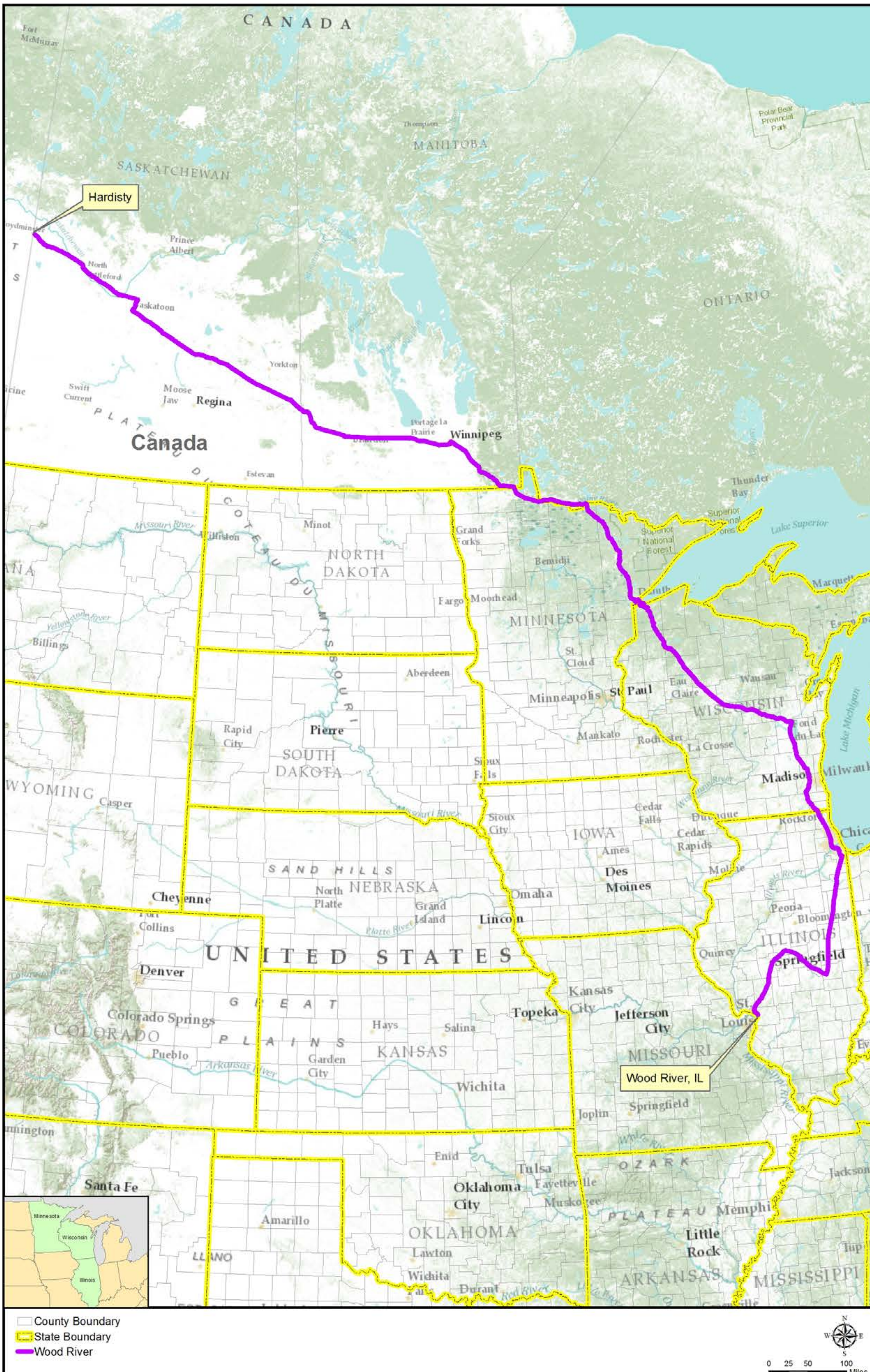

Figure 2.2.3-8 Rail Route from Hardisty Region to Wood River, Illinois

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Trucking Scenario

The option of trucking WCSB to the Gulf Coast area was considered, but was eliminated from detailed analysis for a variety of reasons, including safety (trucking is 87 times more likely to cause fatal injuries than pipelines during transportation of crude oil), it would increase congestion in cities and along highways (there would need to be about 3,300 trucks per day hauling the crude oil from the WCSB), it would emit large amounts of greenhouse gases and other pollutants, and would use significant amounts of fuel.

Existing Transboundary Pipeline Scenario

There are four major pipeline systems that transport Canadian crude oil across the United States border. These include the Kinder Morgan Trans Mountain system (about 300,000 bpd capacity, to both Vancouver and Puget Sound refiners and some export), the Kinder Morgan Express pipeline (282,000 bpd capacity), the existing Keystone pipeline (590,000 bpd capacity), and the large Enbridge system (about 2.5 mmbpd total capacity). The status of each of these lines is described below.

- The existing Trans Mountain pipeline, which can access U.S. Puget Sound refiners in Washington State, operates fully loaded and is typically over-nominated (meaning shippers would transport more if the capacity existed).
- The Kinder Morgan Platte/Express pipeline from Hardisty, Alberta, to Wood River, Illinois. The Express pipeline from Hardisty to Guernsey, Wyoming, has about 282,000 bpd capacity and is underutilized by about 100,000 bpd, but this is because of the capacity limits on the Platte pipeline from Guernsey to Wood River, Illinois. Kinder Morgan is in the process of converting an existing natural gas pipeline and constructing new pipeline segments that would provide pipeline transport capacity for 230,000 bpd from Guernsey to Cushing, Oklahoma. The stated purpose of this project is to accommodate additional production of Bakken crude. But if market conditions warranted it, the new pipeline could also provide a transport pathway for WCSB crude, which could allow the cross-border Express pipeline to be more fully utilized.
- The existing TransCanada Keystone line (not the proposed Project) from Hardisty to Steele City, Nebraska, with pipeline interconnections to both Wood River, Illinois and Cushing, Oklahoma initiated operation in late 2010 with a capacity of 590,000 bpd. Data from the Canadian Association of Petroleum Producers (CAPP 2012) indicate that, as of December 2011, the existing Keystone pipeline was transporting almost 500,000 bpd.
- The Enbridge system is the largest cross-border pipeline system with mainline capacity of 2.5 mmbpd. As noted in the Final EIS, the existing Enbridge system is near its current capacity, and has been increasing both its capacity and throughput to reach United States and Eastern Canadian markets. Enbridge’s existing plans will increase utilization of its mainlines from Edmonton and Hardisty by constructing Eastern Canada pipeline expansions, reversing existing lines (moving primarily Bakken and lighter western Canadian crudes into Sarnia, Ontario and north to Montreal, Quebec), and upgrading existing pipelines (ICC 2012).

As was noted in the Final EIS, there are limited southbound pipeline connections to transfer crude oil from PADD 2 to PADD 3. Currently, only approximately 100,000 bpd of crude oil (originating from the WCSB) are delivered from PADD 2 to PADD 3 via the ExxonMobil

Pegasus pipeline. Similar to other developments in rail transport, new pipeline capacity is being added in response to the new crude oil supplies coming from the WCSB, Bakken, and other new crude oil production areas in North America.

Enbridge is proceeding with expansion, reversal, and upgrading projects, as well as construction of new pipelines that would provide additional capacity to deliver WCSB and Bakken crudes to the Gulf Coast area. Unlike the proposed Project, these are a series of projects on the existing Enbridge system. The status of those projects is described briefly in the following paragraphs and is based on information drawn from press releases, investor materials, and state regulatory filings.

Currently, the Enbridge Mainline/Lakehead system has the capacity to deliver approximately 2.5 mmbpd of crude oil across the border from Canada to Superior, Wisconsin, with pipelines providing onward delivery to the Chicago area, eastward into PADD 2, and back into Eastern Canada. Enbridge is pursuing several projects that would make connections from this pipeline system to the Gulf Coast area.

From Superior, Wisconsin to Flanagan, Illinois, there is line 61 (called the Southern Access project when under construction). This is a 42-inch diameter pipeline with a current capacity of 400,000 bpd, but, according to Enbridge investor materials (Enbridge 2012d), it can be expanded to transport up to 1.2 mmbpd with the addition of more pumping capacity (Enbridge is currently planning an expansion of capacity on Line 61).

From Flanagan, Illinois to Cushing, Oklahoma, Enbridge is seeking regulatory approval[13] to construct a new, 36-inch diameter pipeline in the same ROW as the existing Spearhead pipeline, which has a capacity of 195,000 barrels per day. The new pipeline would have an initial capacity of approximately 600,000 bpd, and could be expanded to approximately 800,000 bpd with the addition of pumping capacity. According to regulatory filings, 70 percent of Enbridge's existing easements for the Spearhead pipeline provide rights to install additional pipelines, which means that Enbridge only needs to negotiate new easements, or seek eminent domain if necessary (and if approved by the Illinois Commerce Commission), along 30 percent of the proposed Flanagan South pipeline route. Enbridge estimates an in-service date of mid-2014.

The final connection from Cushing, Oklahoma to the Gulf Coast area could be made either by the recently reversed Seaway pipeline, and a to-be-constructed Seaway twin pipeline, or (theoretically) by the TransCanada Gulf Coast project. The Seaway pipeline is operated by the Seaway Crude Pipeline Company LLC, a 50/50 joint venture between Enbridge and Enterprise Product Partners L.P. It consists of an existing pipeline that had transported crude oil and petroleum products from Houston to Cushing. Because of the glut of crude oil in Cushing, and the shift in North American crude oil production patterns, the pipeline was substantially underutilized. In response, the owners reversed the flow of the pipeline (its first deliveries of crude oil to Houston occurred in June 2012), and announced they would increase capacity on that existing pipeline, as well as construct another, 30-inch pipeline in the same ROW. Upon completion of these projects, the Seaway pipelines would have the capacity to transport up to

[13] Since the proposed project is an interstate crude oil pipeline that does not cross an international border, there is no general federal permitting authority. Enbridge has applied to the Illinois Commerce Commission for a "Certificate of Good Standing." Such a certificate is necessary for a pipeline company to make use of eminent domain proceedings in Illinois. There are no similar permitting requirements in Missouri, or Oklahoma.

850,000 bpd from Cushing to the Gulf Coast area,[14] with an expected completion date of mid-2014. Enbridge (Enbridge 2012b, 2012c, 2012d) has also stated that the Seaway twin pipeline could be expanded up to 600,000 bpd.

If these various Enbridge projects and joint ventures were completed, those pipelines would have the ultimate capacity (if pumping improvements were implemented) to transport up to approximately 1 mmbpd of additional crude oil from Superior, Wisconsin to the Gulf Coast area. The total transport distance from Hardisty to the Gulf Coast area through the Enbridge projects and joint ventures would be approximately 750 miles longer than through the proposed Project and the Gulf Coast project.[15] However, most of the potential capacity on the Enbridge system is not available for the crude oil with long-term contracts on the proposed Project (over 500,000 bpd for delivery from the WCSB to the Gulf Coast area; 155,000 bpd from the WCSB to Cushing to be transferred from existing Keystone pipeline; and 65,000 bpd from the Bakken) because these projects are supported by their own long-term contractual commitments.

In its regulatory filings and investor materials, Enbridge has made several statements about long-term contractual commitments from shippers for these various projects. It was reported in press reports that for most of 2012 the existing Spearhead pipeline has been at capacity and/or that shippers have wanted to transport crude oil in excess of its capacity (Clark 2012; Campbell 2012). In the Illinois Commerce Commission (ICC 2012) filings for Flanagan South, Enbridge has stated that it had commitments for “about 90 percent of the initial capacity of the Flanagan South Pipeline on terms that range from 10 to 20 years of transport.” They have characterized this as fully contracted, “apart from the mandatory 10 percent minimum required by the Federal Energy Regulatory Commission” (Enbridge 2012b) This would mean that of the 600,000 bpd initial capacity, approximately 540,000 bpd is already committed. Enbridge (Enbridge 2012a) has also stated that for the Seaway pipeline system, it has five and ten year commitments to transport crude originating in Cushing, as well as 10, 15, and 20-year commitments for volumes originating in Flanagan, and that these commitments are for “substantially all of the initial [850,000 bpd] capacity of the Seaway System.”

It is likely that if the proposed Project were not constructed, the shippers that had the long-term contractual commitments would first seek other pipeline transport before resorting to other modes of transportation. Some portion of the volumes committed to the proposed Project could likely be transferred to the Enbridge system if the planned expansions occurred; however, even if the pipelines discussed installed the necessary additional pumping capacity to reach their top-line design capacity, they would not have enough spare capacity to accommodate the volume of crude oil committed under long-term contracts to the proposed Project.

The 2010 Keystone XL Assessment Final Report (EnSys 2010) and the Keystone XL Assessment-No Expansion Update (EnSys 2011) paid considerable attention to export capabilities of existing and proposed pipeline systems. As noted in that report, and detailed above, the existing pipelines TransMountain, Express/Platte, and the existing Keystone have

[14] Enbridge has also announced it will construct a pipeline from Houston to Port Arthur, Texas. This means it would have pipeline connections to the same two main delivery areas (Houston and Port Arthur) that crude oil transported on the proposed project would be subsequently delivered to.

[15] The distance estimate for the Enbridge system and joint venture (total distance approximately 2,627 miles) is based on the company’s Pipeline System Configuration map, and information about the Seaway pipeline project. The distance estimate for TransCanada’s proposed project and Gulf Coast extension (total distance 1,960 miles) is drawn from this document, and the final EIS.

limited capacity to accept additional volumes of crude oil, certainly not in the types of volumes contractually committed to the proposed Project. Each of those three pipelines either does not deliver to Cushing or the Gulf Coast area (TransMountain, Express/Platte), or does not traverse the Bakken in the area of Baker, Montana. Because of these capacity and geographic constraints, none are considered viable alternatives, although, as described in the EnSys report (EnSys 2010) if there were long-term constraints on new pipeline construction, those pipelines may be able to accept some additional volumes of crude oil. EnSys identified the possibility that other pipelines could be constructed to connect PADDs 2 and 3, and that these interstate pipelines face fewer regulatory requirements than cross-border pipelines.

While some additional transboundary and interstate pipeline capacity is available or has recently been proposed, that capacity is being added to meet additional demand for transport, as evidenced by separate long term contractual commitments. The capacity of those additional pipelines that is not committed under long term contractual agreements would not accommodate all of the crude oil contracted to the proposed Project. Given these shortcomings, relying on other projects instead of the proposed Project to meet demand was not considered reasonable and was, therefore, eliminated from detailed analysis in the Supplemental EIS.

Other Recent Crude Oil Transportation Proposals

During the fall 2012, industry spokespeople have announced proposals that would use other options to transport both WCSB and Bakken crude oil to refiners on the Canadian and United States east coast (Financial Post 2012a). Another proposal would include expansion of existing rail capacity and facilities to haul WCSB to Hudson Bay for loading onto oil tankers to ship to refiners (Financial Post 2012b). This proposal, however, would only be operational between July and October due to sea ice in the Arctic Ocean, although its operations could be extended through the use of icebreakers. BNSF Railway announced plans to expand rail capacity to transport Bakken crude oil by 1 mmbpd out of the Williston Basin (Bismarck Tribune 2012). TransCanada is investigating whether to convert an existing natural gas pipeline to transport up to 1 mmbpd of WCSB to refineries on Canada's East Coast (Platts 2012). Finally, BP has applied for an export license from the U.S Department of Commerce to ship Bakken crude oil from North Dakota and Montana to Canadian refiners who would use it instead of more expensive light crude from Europe (Campbell 2012). If implemented, these options would expand takeaway capabilities of WCSB and Bakken crude while requiring little new infrastructure.

Use of Alternative Energy Sources and Energy Conservation

The Final EIS discussed and analyzed alternatives in place of crude oil from the WCSB, including different energy sources and energy conservation. These options were reconsidered in the development of this Supplemental EIS and are incorporated for reference (See Sec. 4.1.1 of the Final EIS).

Many commenters (on the Draft EIS) suggested that the use of alternative sources of energy and conservation of energy would either: (1) eliminate the need for the proposed Project or alternatives to the proposed Project, or (2) reduce the market need for heavy crude oil to the extent that smaller scale projects could meet short- and long-term energy needs.

The market demand for crude oil, including the market demand for heavy crude oil by refineries in PADD 3 (see Section 1.4, Market Analysis, for a discussion of the Petroleum Administration for Defense Districts), is driven primarily by the demand for transportation fuels. Based on

Energy Information Agency (EIA) statistics (EIA 2010a, 2010b), approximately 78 percent of the refined product produced by PADD 3 refineries in 2009 was used for transportation fuel. The percentages of total production from PADD 3 refineries in 2009 for transportation uses in the EIA statistics are listed below:

- Finished motor gasoline—42.9 percent;
- Distillate fuel oil – 24.9 percent (distillate production for all uses was 28 percent of total refinery production. Distillate fuel oil for transportation only was 89 percent of total distillate production, or 24.9 percent of total production);
- Kerosene-type jet fuel—9.3 percent;
- Residual fuel oil—1.0 percent (residual production for all uses was 4.1 percent of total refinery production. Residual fuel oil for transportation only was approximately 25 percent of total residual fuel production, or approximately 1.0 percent of total production); and
- Finished aviation gasoline—0.1 percent.

The remaining 22 percent of PADD 3 refinery production in 2009 consisted primarily of specialized products (e.g., liquefied refinery gases, kerosene, and naphtha for feedstock).

The remainder of this section addresses (1) how the use of alternative fuels and energy conservation would affect market demand for refined products sold by PADD 3 refineries, and therefore addresses the effect on market demand for crude oil by those refineries, and (2) whether or not the use of alternative fuels and energy conservation would result in a sufficient reduction of market demand for crude oil in PADD 3 to justify selection of the No Action Alternative as the preferred alternative. Although most refined products sold by PADD 3 refineries are used in transportation, the assessment of the impact of using alternative fuels and energy conservation was also addressed for refined products that are not used for transportation. Alternative fuels and energy conservation are addressed in the following subsections:

- Use of Alternative Fuels and Energy Conservation in Transportation;
- Use of Alternative Energy Sources in Place of Distillate Fuel Oil for Non-Transportation Uses;
- Use of Alternative Energy Sources in Place of Residual Fuel Oil for Non-Transportation-Related Uses; and
- Use of Alternative Energy Sources in Place of Other Non-Transportation-Related Refined Products.

Use of Alternative Fuel and Energy Conservation in Transportation

Worldwide demand for crude oil is generally projected to grow over the next 25 years unless countries, including developing economies where the majority of the growth is projected to occur, take substantial steps to address climate change. But even if there is a worldwide decline in crude oil consumption, projections indicate that there will be an increase in consumption of crude oil from unconventional sources, primarily from the Canadian oil sands, over the next several decades (EIA 2012; IEA 2012). As discussed in Section 1.4, Market Analysis, in the United States, the overall demand for crude oil is projected to decline over the next 25 years (EIA 2012; IEA 2012).

Two general questions have been raised relevant to the No Action Alternative and adoption of policies that would address climate change by reducing demand for crude oil:

- Would a reduction in United States demand for crude oil eliminate the need for the proposed Project; and
- Would proceeding with the proposed Project alter market conditions such that there would be less rapid adoption of fuel efficiency, alternate fuels, or other measures that would reduce the demand for crude oil?

Outlooks for world and United States demand for crude oil indicate that even if there were a substantial reduction in United States consumption of crude oil (and/or relatively flat world-wide consumption), the market demand in PADD 3 that is driving the development of the proposed Project would likely remain. Also, as explained below, it does not appear that the proposed Project would have enough of an impact on refined fuel prices to alter the market incentives for more widespread adoption of fuel-efficient vehicles, or deployment of alternate fuels (including vehicle electrification).

In early 2010, the U.S. Environmental Protection Agency (EPA 2010) prepared a report examining technically feasible measures that could reduce consumption of crude oil that is refined to produce transportation fuel. The findings of this EPA report were relied upon to construct the low-demand outlook modeled in the EnSys (EnSys 2010) report. The results of the economic modeling were that the low-demand outlook had little impact on the projected demand for oil sands crudes in the United States and little impact on the total production from oil sands throughout the study timeframe. In the EIA, total production in the oil sands was projected to be approximately 4.42 million bpd in 2030, and with the low-demand outlook, the production was projected to be approximately 4.23 million bpd in 2030. Projected Canadian production numbers range from 5.3 to 5.6 million bpd in 2025 in EIA 2012, and 2011. United States projections for total liquids demand are similar in both the EIA 2012 and 2010 low-demand outlook (Figure 1.4.4-1 – U.S. Product Demand Total Liquids, Section 1.4).

As explained in Section 1.4, Market Analysis, there have been several substantial changes to the crude oil market since the EnSys analysis was prepared. In the medium to long-term, the EIA 2012 outlook falls in between the two outlooks modeled in EnSys 2010. The EnSys 2010 analysis indicated that production in the oil sands was not sensitive to reductions in United States crude oil demand. This is broadly consistent with the results of the most recent report from the EIA (see EIA 2013 Memo, Appendix C). This is also broadly consistent with the recent IEA reports, which have not indicated that declining United States demand or increased production would decrease production in the oil sands. In the three most recent IEA reports (2010, 2011, and 2012) United States crude oil demand in 2035 in the New Policies scenario has been in decline in each year: 14.9, 14.5, to 12.6 mmbpd. The decline from 2011 to 2012 is attributable to the new U.S. CAFÉ standards adopted in 2012. Projected production from the oil sands in 2035 has remained relatively constant at 4.2, 4.5, and 4.3 mmbpd through those forecasts, despite declining overall United States demand.

The IEA reports also address energy demand and production in three world-wide policy scenarios. Differences in oil sands production between these different scenarios give an indication of how substantial changes in worldwide policies and energy could impact oil sands production:

- The Current Policies Scenario, which assumed no change from policies in place in mid-2010;
- The New Policies Scenario, which assumed that countries act on their announced policy commitments and plans to address climate change; and
- The 450 Scenario, which sets out an energy pathway with the goal of limiting the global increase in temperature to 2°C by limiting concentration of greenhouse gases in the atmosphere to around 450 parts per million of carbon dioxide (CO_2).

The impact of the three policy scenarios on world-wide crude oil consumption in 2035 is substantial. Compared to the world-wide total oil production (crude oil, natural gas liquids, and unconventional oil) of 83.3 million bpd in 2009, IEA (IEA 2012) projected the following levels of consumption in 2035:

- Current Policies Scenario – 108.5 million bpd;
- New Policies Scenario – 99.7 million bpd; and
- 450 Scenario – 79 million bpd.

The policy scenarios also have a substantial impact on projected consumption of oil-sands-derived crude oil in 2035:

- Current Policies Scenario – 4.8 million bpd;
- New Policies Scenario 4.3 million bpd; and
- 450 Scenario – 3.4 million bpd.

Although the different scenarios had substantial impacts on projections of total oil sands production in 2035, the projected consumption in each of these scenarios represents a substantial increase from 2011 consumption of approximately 1.6 million bpd oil sands-derived crude oil (CAPP 2012). The difference in consumption of the oil sands-derived crude oil among the different scenarios is largely attributable to the differing world oil price in each scenario (the 450 Scenario's substantially reduced demand for crude oil would result in reduced world oil prices), and the additional expense attributed to the oil sands projects that would be necessary to mitigate their relatively higher greenhouse gas emissions (IEA [IEA 2010] assumed a carbon price of $60 per ton in the New Policies Scenario and $120 per ton in the 450 Scenario).

Based on the analysis in Section 1.4, Market Analysis, in the EnSys (EnSys 2010) report and in the analyses of policies and market-drivers that would lead to a reduction in the volume of crude oil refined to produce transportation fuel, it appears unlikely that the proposed Project would have enough of an impact on the prices of refined fuel to impact market drivers related to wider adoption of alternative fuels or more energy efficient vehicles. In a recent report examining economic implications of different policies to reduce CO_2 emissions or petroleum imports, Morrow et al. (Morrow 2010) stated:

> A fundamental insight from this study is that if one wishes to reduce U.S. CO_2 emissions or net petroleum imports from the transportation sector, the costs of driving must be significantly higher than they currently are today. Increasing the cost of driving with higher fuel costs (or other operating fees) will be required to motivate deployment of fuel economy improving technologies in conventional vehicles, accelerate penetration of high-fuel economy vehicles into the existing fleet, and reduce vehicle-miles traveled.

Two of the scenarios examined in Morrow et al. (Morrow 2010) focused on policies that would directly increase the cost of transport fuels. One scenario included carbon pricing in a cap-and-trade plan, which lead to a projected increase of $0.24 in the cost per gallon in 2020 and an increase of $0.46 per gallon in 2030. The second scenario included a direct fuel tax, which led to projected increases to the cost of gasoline of $1.42 per gallon in 2020 and $3.27 per gallon in 2030. The analysis considered how fuel price influenced increases in fuel efficiency (through increased purchases of more fuel efficient vehicles, hybrid vehicles, and electric vehicles) and reducing the projected increases in vehicle miles traveled. The report concluded that the carbon tax scenario had a marginal impact on Green House Gas emissions from transportation. Imposing the transportation tax on fuel stimulated slightly larger improvements in fuel economy of new conventional vehicles than were projected to be achieved through imposition of only corporate average fuel economy (CAFE) standards. In contrast, the EnSys (EnSys 2010) analysis stated the following:

> within each demand outlook, U.S. total [refined] product supply costs are insensitive to pipeline scenario, varying by less than 0.1 percent in any scenario where normal pipeline expansion is allowed.

The scenarios that included the proposed Project resulted in small reductions in product supply costs in PADD 3 (less than $0.10 per barrel), that would amount to approximately a ¼-cent impact on the price of a gallon of gasoline. The scenario with the largest variation in refined product supply costs was the No Expansion Scenario, which led to a 0.6 percent reduction in costs of total refined products in 2030 versus the scenario for the proposed Project because of the artificial discount in crude oil prices obtained from the shut-in of WCSB crude oil supply. As noted in Section 1.4, there is growing evidence that if pipeline capacity is constrained, non-pipeline modes of transport, particularly rail, are capable of economically delivering volumes of WCSB heavy crude oils to the Gulf Coast in excess of the capacity of the propose Project. This indicates, along with the updated analysis of supply and demand in Section 1.4, that whether the proposed Project is constructed is unlikely to have a significant long-term impact on heavy crude supplies on the U.S. Gulf Coast. There is no information indicating that whether WCSB heavy crude oils were delivered to the U.S. Gulf Coast via rail, via other pipelines, or via proposed Project could have a significant enough impact on refined product prices to be in the range of the price increases discussed in the Morrow (Morrow 2010) study.

It is reasonable to infer based market analysis in Section 1.4, when viewed in combination with the results from the Morrow et al. (Morrow 2010) study, that the proposed Project's likely impact on finished transportation fuel prices would not be large enough to influence market behavior in development of more fuel efficient vehicles, alternative transportation fuels (including electrification of the vehicle fleet), or total vehicle miles traveled. The Morrow et al. (Morrow 2010) report concluded that increases in gasoline prices due to a carbon tax would be orders of magnitude greater than likely price impacts of the proposed Project (a $0.42 increase in the cost of a gallon of gasoline in 2030 in the carbon tax scenario) and would only reduce light duty fuel efficiency and light duty total vehicle miles traveled by approximately 1 percent in 2030.

The above factors indicate that even if the United States, and/or countries around the world, adopt more aggressive policies that would reduce the consumption of crude oil (including those necessary to achieve a trajectory towards stabilizing CO_2 concentrations in the atmosphere in line with the 2 degree global goal), there is likely to be a market demand for substantial increases in the volume in crude oil derived from the oil sands over the next 20 to 25 years.

As there would still be a demand for oil sands-derived crude oil, use of alternative energy sources and energy conservation in meeting needs for transportation fuel have not been carried forward for further analysis as an alternative to the proposed Project.

Use of Alternative Energy Sources and Conservation in Place of Distillate Fuel Oil for Non-Transportation-Related Uses

Non-transportation uses of distillate fuel oil include space heating and electrical power generation, and represented approximately 3.1 percent of the production of PADD 3 refineries in 2009 (EIA 2010a, 2010b). The distillate fuel oil was sold for use in the following categories listed by EIA (EIA 2010b):

- Oil company
- Industrial use
- Commercial
- Electrical power
- Residential

For the *oil company* category, it is likely that the distillate fuel oil was used primarily for heating purposes. As a result, natural gas would be a likely alternative fuel in most cases and it is possible that, in the future, many facilities could be retrofitted to accommodate natural gas as a replacement fuel. This category accounted for about 0.2 percent of the total refinery output of PADD 3 refineries. Commercial and industrial use categories were also most likely used primarily for heating purposes. These two categories combined constituted approximately 0.2 percent of the total refinery production from PADD 3. Distillate fuel oil in the residential category would likely be exclusively used for heating, and represents about 0.001 percent of the total production from PADD 3 refineries.

For each of these categories, both natural gas and biofuels (e.g., fuel from municipal solid wastes, wood, and other biomass [e.g., biodiesel from cooking oil]) are potential alternative fuels for heating purposes. However, conversion of heating units to burn natural gas or biofuels would require substantial investments by the users, and it is unlikely that a majority of users would convert their heating units in the near term. In any case, the total volume of distillate fuel oil used for heating was only about 0.4 percent of the total PADD 3 refinery output in 2009. Assuming complete replacement of the distillate fuel oil used for heating by alternative fuels, there would be only a negligible reduction in the market demand for crude oil used by PADD 3 refineries. Similarly, conservation of energy for heating purposes would result in only negligible decreases in refinery output and would have very little effect on the crude oil needs of PADD 3 refineries.

The use of distillate fuel oil produced by PADD 3 refineries for the generation of electrical power represents about 0.01 percent of the total output of PADD 3 refineries. Electrical generation currently fueled by residual fuel from PADD 3 refineries could be generated in a variety of other ways, including natural gas-fired generators, wind farms, solar panels, tidal projects, hydroelectric projects, geothermal sources, nuclear power plants, and energy or fuel from municipal solid wastes, wood, and other biomass. However, use of non-transportation-related residual fuel for electrical power generation in 2009 was a negligible portion of the total output of PADD 3 refineries. With a complete replacement of this distillate fuel oil by alternative fuels to generate electrical power there would therefore be a negligible reduction in the crude oil market demand of PADD 3 refineries and there would be essentially no effect on the current and future crude oil needs of those refineries.

Use of Alternative Energy Sources in Place of Residual Fuel Oil for Non-Transportation-Related Uses

Residual fuel oil is used for the production of electric power, space heating, marine transportation, and various industrial purposes. Approximately 3.1 percent of total PADD 3 refinery production was used for electrical power generation, heating, and industrial uses (EIA 2010a, 2010b). The amount of fuel required for those uses could be reduced with conservation, and for some uses, alternative fuels could replace the residual fuel oil. However, as for distillate fuel oil, the actual volume represents a small portion of the total production of PADD 3 refineries and the use of alternative fuels and conservation would have a negligible effect on the market demand for crude oil in PADD 3.

Use of Alternative Energy Sources in Place of Other Non-Transportation-Related Refined Products

As noted above, approximately 78 percent of the output of refineries in PADD 2 in 2009 was used for transportation purposes. The remaining 22 percent of PADD 3 refinery production consisted primarily of specialized products, including liquefied refinery gases, kerosene, naphtha for feedstock, other oils for feedstock, special naphtha products, lubricants, waxes, petroleum coke, asphalt, road oil, still gas, and miscellaneous products. The three largest production streams, as a percentage of total production, were the following:

- Petroleum coke (5.9 percent) – grades of coke produced in delayed or fluid cokers that may be recovered as relatively pure carbon;
- Liquefied refinery gases (5.2 percent) – this includes ethane/ethylene, propane/propylene, normal butane/butylene, and isobutane/isobutylene; and
- Still gas (4.6 percent) – still gas is used as a refinery fuel and a petrochemical feedstock.

These three categories accounted for nearly 16 percent of total PADD 3 production. For the most part, these three specialty products (as well the other specialty products produced by PADD 3 refineries) cannot be produced using alternative fuels and have not been further considered in this assessment of alternative energy sources. It is possible that conservation could reduce the need for some of these products (e.g., liquefied refinery gases) but that reduction in use would result in a negligible decrease in the market demand for crude oil in PADD 3.

2.2.4 Major Pipeline Route Alternatives

The Department considered potential alternative pipeline routes to assess whether or not there are route alternatives that would avoid or reduce impacts to environmentally sensitive resources as compared to the proposed Project, while also meeting the Project Purpose. Based on a review of practicable routes and comments received from agencies and the public during scoping and the previous EIS process, the route alternatives identified and considered by the Department include:

- Keystone XL 2011 Steele City Segment Alternative (2011 Steele City Alternative)
- I-90 Corridor Alternative
- Express-Platte Alternative
- Steele City Segment - A1A Alternative
- Keystone Corridor Alternative
  - Option 1: Proposed Border Crossing
  - Option 2: Existing Keystone Pipeline Border Crossing
- Western Alternative (To Cushing)

A map showing the major route alternatives considered is presented in Figure 2.2.4-1

In addition to these major route alternatives, options to the proposed Project route in Nebraska have also been assessed. The Nebraska Route Options are relatively short variances (between 12 and 32 miles) of Keystone's proposed route within Nebraska. The primary purpose of these route options is to identify a route that avoids the Nebraska Department of Environmental Quality (NDEQ)-identified Sand Hills Region without an unacceptable increase in other environmental impacts.

These route options have specific objectives separate from the proposed Project Purpose as defined in Section 1.3, Purpose and Need, and were evaluated in detail by Keystone in consultation with the NDEQ. Because the evaluation focus for these route options is somewhat different compared to the major route alternatives, the Nebraska Route Options are discussed separately at the end of the evaluation of the Major Route Variations section.

2.2.4.1 Screening of Reasonable Major Route Alternatives

The subsections below describe the two-phase screening process the Department applied to the major route alternatives considered in this evaluation. The initial screening of major route alternatives considered the following criteria:

- Project Purpose—to be considered reasonable, an alternative must be able to provide reliable transport of up to approximately 730,000 bpd of WCSB crude oil and up to approximately 100,000 bpd of Bakken crude oil;
- Pipeline Length—pipeline length was considered a relative measure of reliability, environmental impact, and construction/operational costs.

As described in detail in Section 4.13, Potential Releases, and Appendix K, Historical Pipeline Incident Analysis, the potential for pipeline incidents is calculated as a function of actual recorded incidents, overall length, and the number of associated facilities or portions of facilities. This relationship between length and associated facilities and incident risk frequency is widely recognized by the pipeline industry (Center for Chemical Process Safety [CCPS] 1989 and International Association of Oil and Gas Producers [OGP] 2010). As stated in: *Guidelines for Chemical Process Quantitative Risk Analysis* (CCPS 1989), "The frequency of each incident is equal to the sum of the failure frequencies of all of the individual components whose failure is included in that representative incident." The OGP (OGP 2010) Risk Assessment Data Directory describes the function of *Parts Count* when conducting risk modeling. The Parts Count is used to calculate the total release frequency of a group of equipment items. These items can include but would not be limited to pumps, flanges, valves, and instrument connections. The release frequency of the group is the sum of the parts.

Phase I Results Summary

Based on the Phase I screening summarized in Table 2.2-9, the following alternatives were eliminated from further consideration:

- Keystone Corridor Alternative
  - Option 1: Proposed Border Crossing
  - Option 2: Existing Keystone Pipeline Border Crossing
- Express-Platte Route Alternative
- Western Alternative

A brief description of each alternative and the rationale for eliminating each of these alternatives is presented below.

Keystone Corridor Alternative

Several commenters have suggested that the proposed Project follow a route that would parallel the entire existing Keystone Oil Pipeline in the United States as a way to reduce potential environmental impacts. In response, the Department investigated two route options that would parallel the existing Keystone pipeline in the United States. These options are discussed below and shown on Figure 2.2.4-1.

Both options assume that the proposed pipeline construction corridor would occupy up to 25 feet of the existing 50-foot Keystone pipeline ROW. New construction impacts would be limited to an area 85 feet outside of the existing ROW (i.e., 85 feet outside of the existing ROW plus 25 feet within the ROW totals to the typical 110-foot-wide pipeline construction easement). Permanent new impacts would be limited to an area 25 feet outside of the existing ROW. The combined new permanent ROW would be 75 feet wide.

Neither route variation would be located near the proposed Bakken Marketlink onramp for domestic crude oil from Williston Basin in North Dakota and Montana. This onramp is where this crude would be delivered into the proposed pipeline and is a condition to Montana's current approval of the proposed route through the state. To satisfy the Project's Purpose and Keystone's current contracts for up to 100,000 bpd of crude from the Bakken, a new way of delivering this crude would need to be combined to either option.

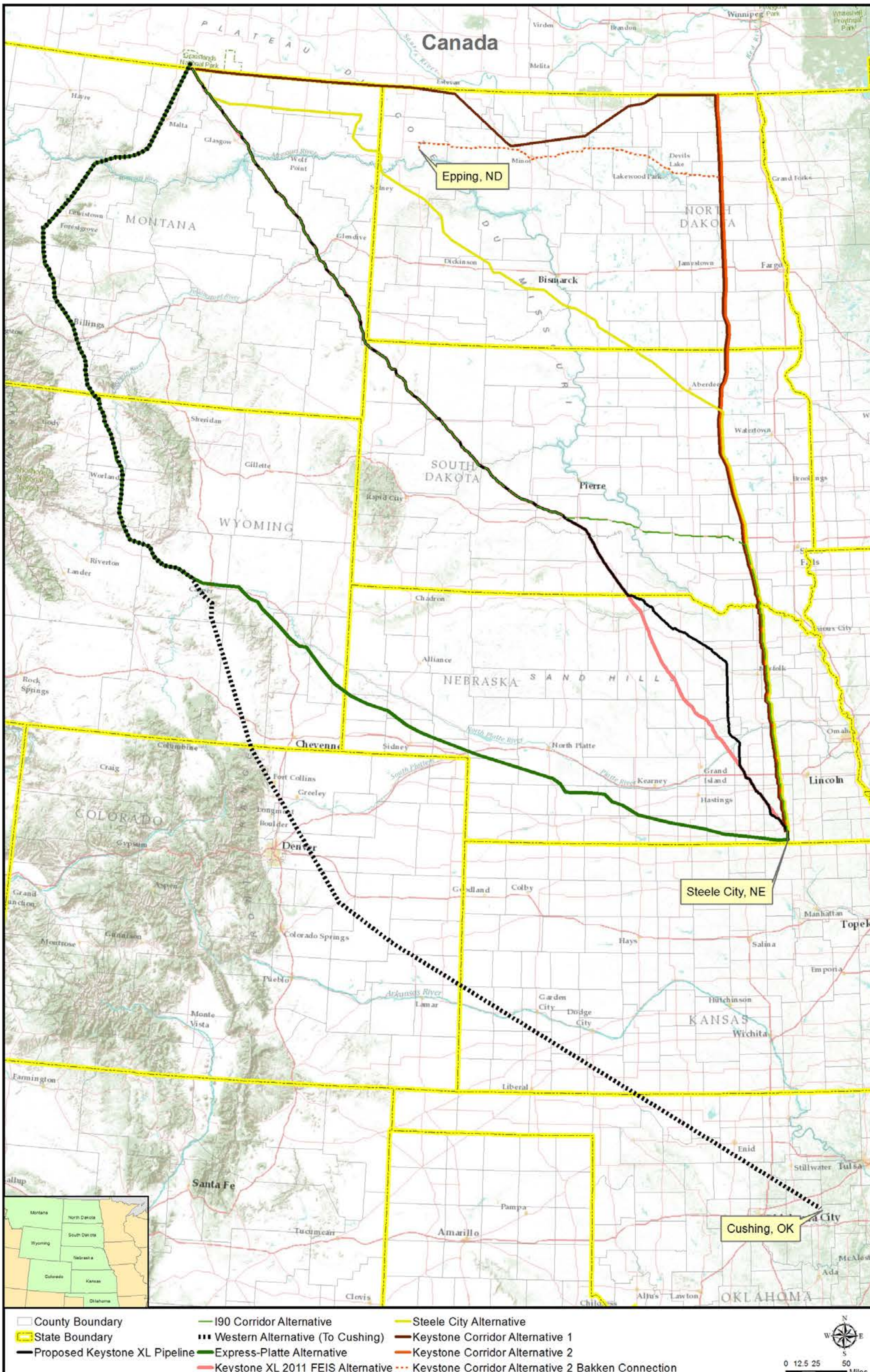

Figure 2.2.4-1 Major Route Alternatives

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Table 2.2-9 Phase I Alternatives Screening

Alternatives[a]	End point	Meets Primary P&N[b]	Meets Secondary P&N[c]	Requires Reroute in Canada (other than proposed border crossing)[d]	Availability	Reliability[g]	Length of Transport (Miles) in U.S.	Total Length U.S. and Canada	Estimated Number of Aboveground Facilities Required (U.S.)[h]	Length Co-located within Existing Corridor (miles)	Affected Land Area (Acres) Construction	Affected Land Area (Acres) Permanent
Route Alternatives												
Keystone's Proposed Project Route August 2012	Steele City NE	Yes	Yes	No	Yes	Yes	875	1,107	59	0	11,667	5,303
Keystone XL 2011 Steele City Segment Alternative	Steele City NE	Yes	Yes	No	Yes	Yes	854	1,086	56	0	11,387	5,176
Western Alternative (to Cushing)	Cushing OK	Yes	No	No	Yes	Yes	1,277	1,509	81	0	17,027	7,739
I-90 Corridor Alternative [e]	Steele City NE	Yes	Yes	No	Yes	Yes	927	1,159	90	254	12,360	4,818*
Express-Platte Alternative [f]	Steele City NE	Yes	No	No	Yes	Yes	1,049	1,281	69	0	13,987	6,358
Steele City Segment - A1A Alternative	Steele City NE	Yes	Yes	No	Yes	Yes	936	1,168	61	368	12,480	4,667*
Keystone Corridor Option 1	Steele City NE	Yes	Yes	No	Yes	Yes	1,092	1,324	72	640	12,621	4,679*
Keystone Corridor Option 2	Steele City NE	Yes	No	Yes	Yes	Yes	640	1,409	42	640	6,594	1,939*

[a] Route alternatives from the international border between Saskatchewan, Canada, and the United States in Phillips County, Montana near the unincorporated community of Morgan to existing Cushing Oil Terminal at Cushing Oklahoma; distribution via existing or under construction pipeline networks to customers in the U.S. Gulf Coast region.
[b] Uninterrupted Transport up to 730,000 bpd of WCSB crude oil across the Canadian border to the existing Cushing Oil Terminal at Cushing Oklahoma through a connection to Keystone's existing Cushing extension pipeline at Steele City, Nebraska. P&N = purpose and need.
[c] Uninterrupted Transport up to 100,000 bpd of transport Bakken crude oil through a connection with the Bakken Marketlink Project at Baker Montana from the Williston Basin in North Dakota and Montana to the Cushing Oil Terminal at Cushing Oklahoma through a connection to Keystone's existing Cushing extension pipeline at Steele City, Nebraska. Alternatives that would not meet this component of the Project Purpose and Need included those alternative routes that were more than 20 miles from existing Williston Basin crude oil infrastructure.
[d] The Canadian government has approved and permitted a route from Hardesty to the proposed border crossing. A new border crossing location would require new routing, approvals, and permits in Canada.
[e] The pipeline for the I-90 Corridor Alternative would not be installed within the existing highway ROW since the South Dakota Department of Transportation does not allow pipelines to be installed longitudinally within the I-90 ROW, although it does allow pipelines to cross the I-90 ROW.
[f] The alternative assumes that the proposed Keystone XL pipeline would be located adjacent to but not within the existing Express-Platte pipeline easement. This corridor is controlled by a different oil transmission company and business and engineering details of the existing corridor are not known. Transmission pipeline easement is often held by companies as potential future expansion, and easement agreements, safety and engineering requirements may not allow co-locating an additional pipeline.
[g] As a baseline for comparison to intermodal alternatives.
[h] Includes pump stations, main line valves and densitometer facilities. Assumes that pig launcher and receiver facilities will be located entirely within pump station facilities. Does not include access roads. Does not include additional pump stations on the existing Cushing Extension pipeline. The number of facilities for the Proposed Project, 2011 Steele City Alternative, and the I-90 Alternative based on preliminary engineering analysis, other alternatives estimated at 0.066 facilities per mile.
*For the purpose of this screening it is assumed that this Alternative could be collocated with the existing Keystone Pipeline. The permanent Corridor (50 feet) ROW would occupy 25 feet of the existing Keystone Pipeline ROW. ((Total Miles of new ROW X 5280 X 50)/43563)+((Total m\Miles of co-located ROW X5280X25 ft of new permanent ROW)/43560)

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Keystone Corridor Alternative Option 1 Proposed Border Crossing

The Keystone Corridor Alternative Option 1 would extend eastward approximately 463 miles across Montana and North Dakota from the proposed border crossing at Morgan, Montana to the existing Keystone pipeline corridor near the Canadian border at Pembina, North Dakota (Figure 2.2.4-1). The eastward leg of Option 1 from Morgan, Montana to the existing Keystone pipeline ROW would divert southeast and northeast along the route to avoid major national wildlife refuges and several smaller refuges as well as the Turtle Mountain Indian Reservation, which are present near the northern border of North Dakota. Near Pembina, Option 1 would turn southward, paralleling the existing Keystone Oil Pipeline for about 640 miles to the proposed Project terminus at Steele City, Nebraska.

The nearest major hub for Bakken crude to Keystone Corridor Alternative Option 1 would be Epping, North Dakota approximately 60 miles south of this alternative route.

As summarized in Table 2.2-9, the Keystone Corridor Alternative Option 1 was removed from further consider for the following reasons:

- The Keystone Corridor Option 1 is approximately 218 miles longer than the proposed route with associated reliability, environmental, and construction/operational cost impacts;
- An additional pipeline with a minimum length of 70 miles would be required to access Bakken crude at Epping, North Dakota, to the south of this alternative; and
- Approximately 72 aboveground facilities would be required to support this alternative compared to 59 for the proposed route.

Keystone Corridor Option 2 Existing Keystone Pipeline Border Crossing

Keystone Corridor Alternative Option 2 would follow the existing Keystone pipeline corridor over its entire length of approximately 1,409 miles from Hardisty, Alberta to Steele City, Nebraska (Figure 2.2.4-1). Option 2 would parallel the approximately 769-mile Canadian portion of the existing Keystone Oil Pipeline from Hardisty, Alberta to the international border crossing near Haskett, Manitoba and Pembina, North Dakota. A new Presidential Permit application would be required for the proposed pipeline to cross the border at this location. This option would then parallel the existing pipeline for 640 miles through North Dakota, South Dakota, and Nebraska.

As currently proposed, the approved pipeline route in Canada from Hardisty, Alberta to Morgan, Montana is approximately 329 miles. Keystone Corridor Alternative Option 2 would require an additional 440 miles of new pipeline in Canada and new permits for the entire 769-mile Canadian portion of Option 2.

As summarized in Table 2.2-9, Keystone Corridor Alternative Option 2 was removed from further consideration for the following reasons:

- This alternative is approximately 303 miles longer than the total length of the proposed route in Canada and the United States (1,106 miles) with associated reliability, environmental, and construction/operational cost impacts;

- An additional pipeline at least 350 miles in length would be required to access Bakken crude at Epping, North Dakota; and
- Approximately 42 aboveground facilities would be required for this alternative compared to 59 for the proposed route.

Express-Platte Alternative

The United States portion of the Express-Platte Alternative would be approximately 1,085 miles long from the proposed border crossing near Morgan, Montana to Steele City, Nebraska. As shown on Figure 2.2.4-1, the Express-Platte Alternative would travel from the border crossing southwest for approximately 200 miles to the existing Express-Platte pipeline ROW. The alternative would then follow parallel and adjacent to the existing Express-Platte pipeline ROW approximately 895 miles to the proposed Project terminus at Steele City, Nebraska. It is assumed that Express-Platte would not allow Keystone to co-locate within any part of its ROW due to liability, maintenance, and future expansion considerations.

The Express-Platte Alternative would not be located near the proposed Bakken Marketlink Project onramp for domestic crude oil from Williston Basin in North Dakota and Montana. This onramp is a condition of Montana’s current approval of Keystone’s proposed route with the state. To satisfy the Purpose and Need and Keystone’s current contracts for up to 100,000 bpd of crude from the Bakken, a new method for delivering this crude would need to be combined with this alternative.

As summarized in Table 2.2-9, the Express-Platte Alternative was removed from further consideration for the following reasons:

- The Express-Platte Alternative would be approximately 211 miles longer in the United States than the proposed route with associated reliability, environmental, and construction/operational cost impacts;
- An additional new pipeline at least 160 miles in length would be required to access Bakken crude at Baker, Montana; and
- Approximately 69 aboveground facilities would be required for this route variation compared to 59 for the proposed route.

Western Route Alternative

The Western Route Alternative would enter the United States at the proposed border crossing near Morgan, Montana and extend through Montana, Wyoming, Colorado, Kansas, and Oklahoma, bypassing the existing Keystone Cushing Extension pipeline and connecting at the Cushing Oil Terminal in Oklahoma (Figure 2.2.4-1). The Western Route Alternative would be approximately 1,277 miles long and would parallel adjacent to the existing Express-Platte System corridor for approximately 350 miles. As noted previously, it is assumed that Express-Platte would not allow Keystone to collocate within any part of its ROW due to liability, maintenance, and future expansion considerations. To satisfy the Purpose and Need and Keystone’s current contracts for up to 100,000 bpd of crude from the Bakken, a new delivery method would need to be connected to this alternative.

As summarized in Table 2.2-9, the Western route variation was removed from further consideration for the following reasons:

- The Western Route Alternative would be approximately 211 miles longer in the United States than the proposed route with associated reliability, environmental, and construction/operational cost impacts;
- An additional pipeline approximately 160 miles in length would be required to access Bakken crude at Baker, Montana; and
- Approximately 81 aboveground facilities would be required for this route variation compared to 59 for the proposed route.

Phase II Screening

The three major route alternatives that remained after the Phase I screening were reviewed through a Phase II screening to identify those alternative routes that warranted consideration as reasonable alternatives as compared to the proposed route (see Table 2.2-10).

The three alternatives that were carried through to Phase II screening include:

- 2011 Steele City Alternative;
- I-90 Corridor Alternative; and
- Steele City Segment - A1A Alternative.

The Phase II screening used a desktop data review of the following conditions and sensitive environmental features to compare these alternatives:

- Length of route (miles);
- Approximate acres affected by construction of the project (typical 110 ft construction ROW)
- Federal lands crossed (miles);
- Principal aquifers crossed (miles);
- Native American lands crossed (miles);
- Total wetlands crossed (miles);
- U.S. Fish and Wildlife Service (USFWS) critical habitat for threatened and endangered species crossed (miles);
- Known cultural resource sites (listed on National Register of Historic Places) within 500 ft of proposed pipeline;
- Number of waterbodies crossed; and
- Soils designated as highly erodible by wind crossed (miles).

In Phase II screening, route alternatives were evaluated to identify those alternatives that have a greater impact to the features identified above or those features that had a greater effect on project constructability when compared to the proposed route. If routes that had these increased impacts did not have some offsetting advantage, they were eliminated from further consideration and not carried forward in the Supplemental EIS.

Table 2.2-10 Phase II Detailed Screening Summary

Feature	Keystone's Proposed Alternative (August 2012)	2011 Steele City Alternative	I-90 Corridor	Steele City Segment-A1A Alternative
Length of route in the United States (miles)	875	854	927	936
Approximate Acres Affected by Construction of the Pipeline Project (acres) [a]	11,667	11,387	12,360	12,480
Approximate Acres Affected by Maintenance of the Permanent Pipeline ROW (acres) [b]	5,303	5,176	4,818*	4,667
Federal Lands Crossed (miles)[c]	50	50	52	32
Principal Aquifers Crossed (miles) (includes glacial)[d]	597	598	565	724
Native American Lands Crossed (miles)[e]	0	0	0	0
Total Wetlands Crossed (miles)[f]	3	8	4	20
FWS Critical Habitat for Threatened & Endangered Species Crossed (miles)[g]	0	0	0	2
Known Cultural Resource Sites (listed on National Historic Database) within 500feet of Proposed Pipeline[h]	0	0	1	0
Number of Waterbodies Crossed[i]	62	60	61	65
Soils Designated as Highly Wind-Erodible Crossed (miles)[i,j]	9	78	2	4

[a] (Length of route (mi)*5280ft*110 ft)/43,560.
[b] (Length of route (mi)*5280ft*50 ft)/43,560.
[c] Lands owned or administered by the government of the United States.
[d] Length of route crossing principal aquifers as defined by U.S. Geological Survey.
[e] Length of route crossing areas with boundaries established by treaty, statute, and (or) executive or court order, recognized by the federal government as territory in which American Indian tribes have primary governmental authority.
[f] Length of route crossing National Wetlands Inventory classes: Freshwater Emergent Wetland, Freshwater Forested/Shrub Wetland, and Other Non-Open Water Wetlands.
[g] USFWS Critical Habitat for Threatened & Endangered Species. The Critical Habitat portal is an online service for information regarding Threatened and Endangered Species final Critical Habitat designation across the United States. Not all of the critical habitat data designated by the USFWS are available.
[h] Google Earth data provided by the National Park Service showing properties listed on the National Register of Historic Places.
[i] U.S. National Atlas Water Feature Areas (2012): aqueducts, canals, dams, intracoastal waterways, rivers, and streams.
[j] Based on soil classification of Wind Erodibility Group (NRCS 2012) values of 1-2 being Highly Erodible (STATSGO soil characteristics for the conterminous United States).
*For the purpose of this screening it is assumed that this Alternative could be collocated with the existing Keystone Pipeline. The permanent Corridor (50 ft) ROW would occupy 25 ft of the existing Keystone Pipeline ROW. ((Total Miles of new ROW X 5280 X 50)/43563)+((Total m\Miles of co-located ROW X5280X25 ft of new permanent ROW)/43560)

Phase II Results Summary

Based on the results of the Phase II screening described above and summarized in Table 2.2-10, the Department selected the 2011 Steele City Alternative and I-90 Corridor Alternative to be carried forward through the Supplemental EIS for analysis (see Figure 2.2.4-2). The Phase II screening eliminated the Steele City Segment-AIA Alternative from further analysis for the reasons discussed below.

2.2.4.2 Steele City Segment-A1A Alternative

The Steele City Segment A1A Alternative is approximately 936 miles long from the border crossing near Morgan, Montana to Steele City, Nebraska. As shown on Figure 2.2.4-1, the Steele City Alternative would be parallel and adjacent to the existing Northern Border Pipeline ROW from the border crossing for approximately 41 miles. At this point, the Steele City Alternative route would divert north away from the Northern Border pipeline to avoid the Fort Peck Indian Reservation in Montana.

The deviation would have a total length of approximately 149 miles. Beginning in central Valley County, Montana the route would extend to the east along a path that would be north of the Standing Rock Indian Reservation. It would then turn south to pass to the east of the Standing Rock Indian Reservation in Sheridan County until crossing into Roosevelt County, Montana, where it would extend to the southeast and cross into Williams County, North Dakota, where it would rejoin the Northern Border Pipeline ROW.

From this location, the Steele City Segment A1A Alternative would travel parallel and adjacent to the Northern Border pipeline ROW for approximately 365 miles to a point where the Northern Border Pipeline intersects with the existing Keystone pipeline. The Steele City Segment A1A Alternative would then turn south and parallel the existing Keystone Pipeline for approximately 381 miles to Steele City, Nebraska. It is assumed that the Northern Border pipeline would not allow Keystone to collocate within any part of its ROW due to liability, maintenance, and future expansion considerations.

The Steele City Segment A1A Alternative would not be located near the proposed Bakken Marketlink Project onramp for domestic crude oil from Williston Basin in North Dakota and Montana. This onramp is a condition of Montana's current approval of Keystone's proposed route with the State. To satisfy the Purpose and Need and Keystone's current contracts to transport up to 100,000 bpd of crude from the Bakken, a new delivery method would need to be combined with this alternative.

As summarized in Table 2.2-10, the Steele City Segment A1A Alternative was removed from further consideration for the following reasons.

- The Steele City Segment A1A Alternative is approximately 80 miles longer than the Proposed Alternative;
- An additional pipeline at least 30 miles in length would be required to access Bakken crude at Epping, North Dakota; and
- Based on the Phase II screening summarized in Table 2.2-10 the Steele City A1A Alternative has no offsetting environmental advantage relative to Keystone's proposed alternative to warrant further assessment.

2.2.4.3 2011 Steele City Alternative

The 2011 Steele City Alternative considered in this Supplemental EIS is identical to the Steele City Segment-B pipeline route that was considered as part of the overall proposed route in the Final EIS. This alternative assumes that Keystone would construct, operate, maintain, inspect, and monitor a single 36-inch pipeline system that would transport crude oil from its existing facilities in Hardisty, Alberta, Canada, and from proposed facilities in Baker, Montana, for delivery to Steele City, Nebraska.

This section provides an overview of the 2011 Steele City Alternative, associated aboveground facilities, connected actions, and a baseline impact comparison to Keystone's proposed route.

In examining the Keystone XL 2011 Steele City Segment, the Department assumed that the typical engineering design specifications, construction procedures, operations, maintenance, and decommissioning would be identical to those presented in the description of the proposed Project in Section 2.1, Overview of the Proposed Project. Specific mitigation or site-specific construction and operation procedures would vary according to differences in the routes and specific conditions on those routes.

The 2011 Steele City Alternative was originally proposed by Keystone as the shortest practical route from the United States/Canada border near Morgan, Montana to existing oil facilities at Steele City, Nebraska with a total pipeline length of approximately 854 miles (see Table 2.2-10). The temporary construction ROW would have a nominal width of 110 feet, and the permanent operating easement would be 50 feet wide. The estimated surface impacts associated with this alternative are presented in Table 2.2-10.

As shown on Figure 2.2.4-2, this alternative would follow Keystone's current proposed Project route from the Canadian border milepost (MP 0) south to approximately MP 204 where it would connect with the proposed Bakken Marketlink Project onramp at the same location as the proposed Project. It would then continue to approximately MP 615 in northern Nebraska near the border with South Dakota. At that location, the 2011 Steele City Alternative would divert from the current proposed Project and would continue southeasterly for another 239 miles to the southern terminus at Steele City, Nebraska. From approximately MP 635 to MP 713, the 2011 Steele City Alternative would cross the NDEQ-identified Sand Hills Region.

Aboveground Facilities

The 2011 Steele City Alternative would require approximately 155 associated aboveground facilities, including 18 pump stations, one densitometer site, 57 intermediate mainline valves (MLVs), and 80 access roads. Pig launchers and receivers, as defined in Section 2.1, Overview of the Proposed Project, would be located completely within the boundaries of the pump stations. The densitometer facility would be located just upstream (north) of the southernmost pump station near Steele City, Nebraska. A summary of these facilities by state is presented in Table 2.2-11.

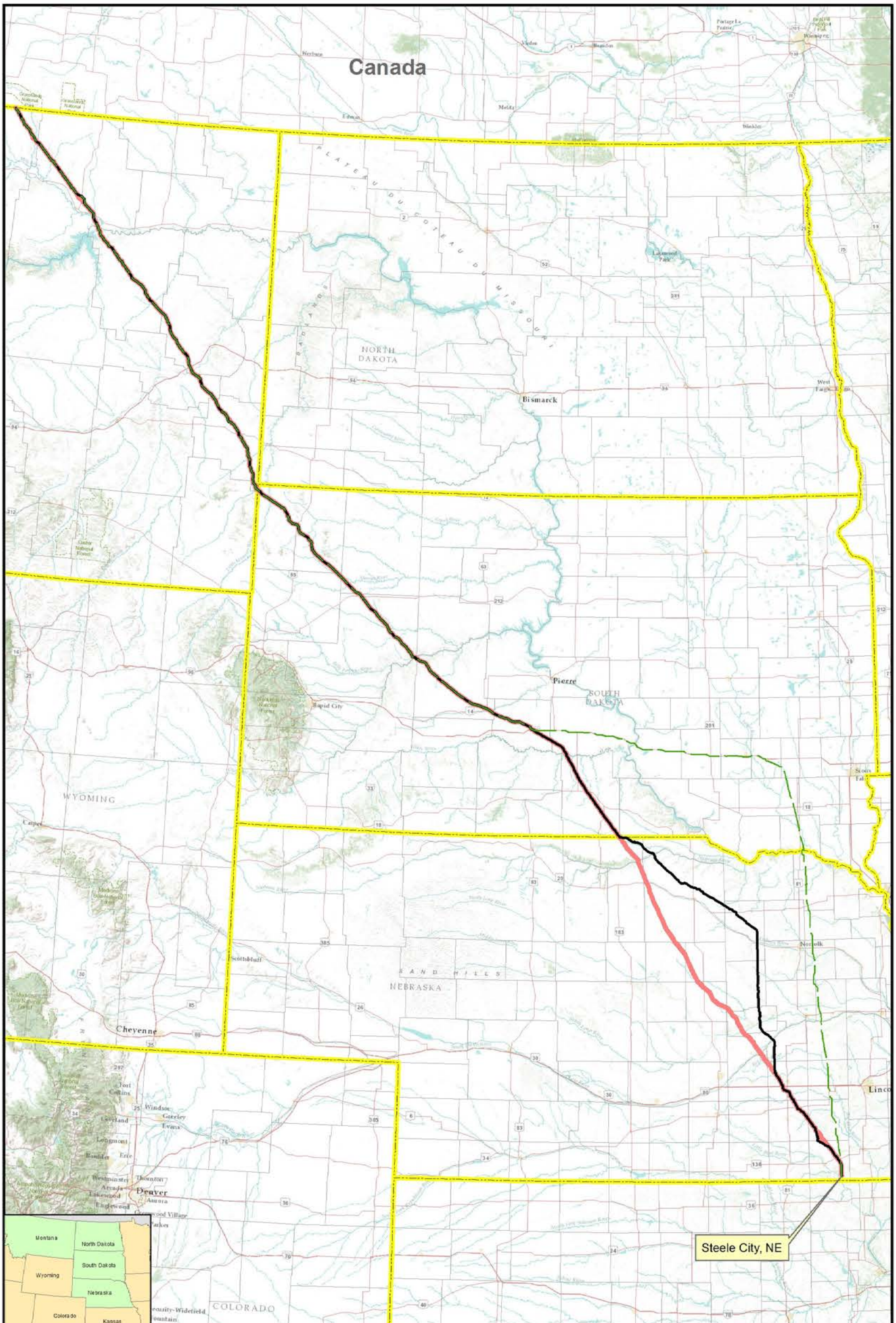

Figure 2.2.4-2 Detailed Screening Alternatives

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Table 2.2-11 Keystone XL 2011 Final EIS Alternate Ancillary Facilities by State

State	Ancillary Facilities
Montana	6 New Pump Stations
	21 MLVs
	50 Access Roads
South Dakota	7 New Pump Stations
	17 Intermediate MLVs
	18 Access Roads
Nebraska	5 New Pump Stations
	19 Intermediate MLVs
	12 Access Roads
	1 Densitometer Facility

Connected Actions

The 2011 Steele City Alternative would require the same three connected actions as the proposed Project:

- Bakken Marketlink Project
- Big Bend to Witten 230-kV Transmission Line
- Electrical Distribution Lines and Substations

2.2.4.4 I-90 Corridor Alternative

This section provides an overview of the I-90 Corridor Alternative pipeline route; associated aboveground facilities; connected actions; and a baseline impact comparison to Keystone's proposed route (see Figure 2.2.4-2). The I-90 Corridor Alternative assumes that Keystone would construct, operate, maintain, inspect, and monitor a single 36-inch pipeline system that would transport up to 830,000 bpd of crude oil from its existing facilities in Hardesty, Alberta, Canada and from proposed facilities in Baker, Montana for delivery to Steele City, Nebraska. In examining the I-90 Corridor Alternative, the Department assumes that the typical engineering design specifications, construction procedures, operations, maintenance, and decommissioning would be identical to those presented in the description of the proposed Project in Section 2.1, Overview of the Proposed Project.

The I-90 Corridor Alternative was identified in the Final EIS for the previous Keystone XL proposed route as an alternative that would avoid crossing the NDEQ-identified Sand Hills Region and would reduce the length of pipeline crossing the Northern High Plains Aquifer (NHPAQ) system, which includes the Ogallala formation. This alternative was developed largely in response to comments received during that EIS process, expressing concerns regarding the risk of spills to the NHPAQ system and suggestions that overall impacts might be reduced by avoiding this formation and using a portion of the existing Keystone pipeline ROW.

The I-90 Corridor Alternative would be approximately 927 miles in length from the United States/Canada border to Steele City, Nebraska. The temporary construction ROW would have a nominal width of 110 feet; the permanent operating easement would be 50 feet wide. As shown on Figure 2.2.4-2, the I-90 Corridor Alternative would follow Keystone's currently proposed Project route from the Canadian Border (MP 0) south through the state of Montana into South Dakota to approximately MP 516, where the proposed pipeline route intersects Interstate 90 (I-90). This alternative pipeline route would divert from the proposed Project route at this location.

In South Dakota, pipelines are allowed to cross the I-90 ROW, but are not allowed to be installed parallel to the roadway within the highway easement (South Dakota Administrative Code 70:04:05.01:01 Construction and Maintenance of Utility Facilities within Interstate Right-of-Way). As a result of this policy, this route alternative would travel eastward, adjacent and parallel to the southern side of the I-90 corridor, for approximately 144 miles (approximately 2 miles west of Alexandria, South Dakota). It is assumed that the I-90 Corridor Alternative would diverge from the I-90 ROW to avoid towns adjacent to I-90, such as Oacoma and Mitchell, South Dakota.

Near Alexandria, South Dakota, the I-90 Corridor Alternative intersects an existing corridor shared by the BNSF railroad line and State Highway 262 (BNSF/262). From this location, the I-90 Corridor Alternative would travel southeast away from I-90, parallel and adjacent to the BNSF/262 corridor for approximately 13 miles to just east of Emery, South Dakota. At this point, the I-90 Corridor Alternative would intersect the existing Keystone Oil Pipeline Project ROW. The I-90 Corridor Alternative would then parallel the west side of the existing Keystone Oil Pipeline Project ROW for approximately 254 miles to Steele City, Nebraska.

The I-90 Corridor Alternative ROW would share up to 25 feet of the existing Keystone easement where these routes are parallel and adjacent for approximately 254 miles. In this segment of the I-90 Corridor Alternative, the 110-foot-wide temporary construction corridor would impact 85 feet outside of Keystone's existing maintained pipeline easement; the new permanent easement would extend 25 feet from the edge of Keystone's existing 50-foot-wide easement.

Just south of the town of Chamberlain, South Dakota, the I-90 Corridor Alternative route crosses Lake Francis Case. This lake is a reservoir along the Missouri River formed by Fort Randall Dam located approximately 90 miles downstream of the potential crossing. The pipeline would remain parallel to the southern side of I-90 for the lake crossing. The lake is approximately 4,100 feet wide at this location. An aerial view of the lake crossing location is shown on Figure 2.2.4-3.

This would be a complex crossing and site-specific studies would be required to validate the feasibility of crossing at this location. Based on a desktop review of the crossing conditions, the proposed crossing would approach the practical limits for horizontal directional drill methods of a 36-inch pipeline (approximately 6,000 feet). As a result, for the purposes of this evaluation, it is assumed that a wet-cut crossing method using barges and bottom dredging may be the preferred method to cross Lake Francis Case at this location.

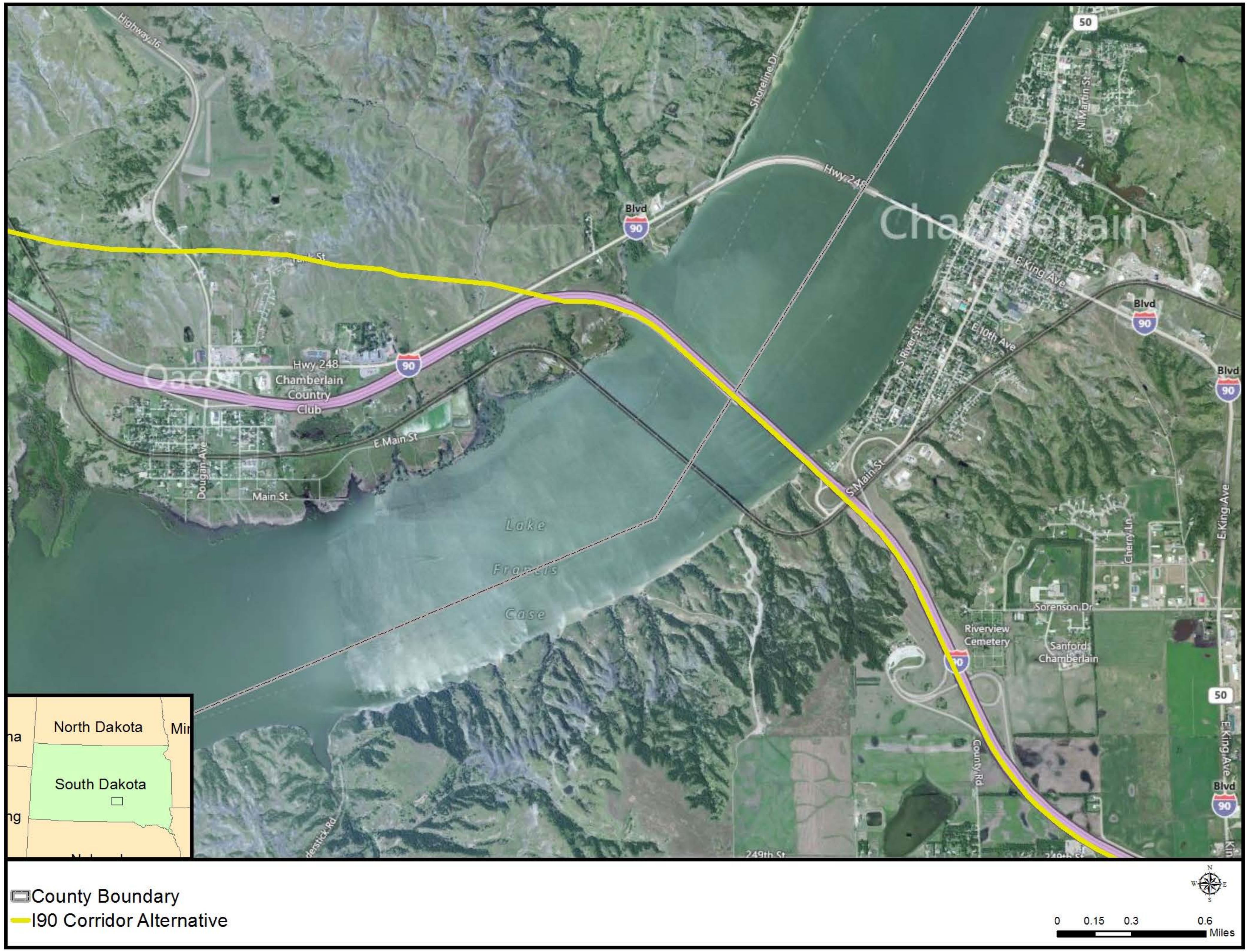

Figure 2.2.4-3 I-90 Corridor Alternative

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Aboveground Facilities

The I-90 Corridor Alternative would require approximately 172 aboveground facilities, including 19 pump stations, one densitometer site, 70 intermediate MLVs, and 82 access roads. Pig launchers and receivers would be located completely within the boundaries of the pump stations or delivery facilities. The densitometer facility would be located just upstream (north) of the southernmost pump station near Steele City, Nebraska. A summary of these facilities by state is presented in Table 2.2-12.

Table 2.2-12 I-90 Corridor Alternative Estimated Aboveground Facilities by State

State	Ancillary Facilities
Montana	6 New Pump Stations 21 Intermediate MLVs 50 Access Roads
South Dakota	9 New Pump Stations 34 Intermediate MLVs 22 Access Roads
Nebraska	4 New Pump Stations 15 Intermediate MLVs 10 Access Roads 1 Densitometer Facility

Connected Actions

The I-90 Corridor Alternative would require the same three connected actions as the proposed action:

- Bakken Marketlink Project
- Big Bend to Witten 230-kV Transmission Line
- Electrical Distribution Lines and Substations

Nebraska Route Options

Concurrent with the draft Supplemental EIS process, the NDEQ is conducting a separate analysis under state law of the newly proposed route in Nebraska. The Department is cooperating with the NDEQ pursuant to a Memorandum of Understanding signed in May 2012.

To specifically address agency and public comments related to the Keystone's proposed 2010 route through the NDEQ-identified Sand Hills Region of Nebraska, NDEQ developed a map identifying the boundaries of the Sand Hill geomorphology within Nebraska (NDEQ 2011). Based on NDEQ's map, Keystone developed eight route options (A-I) through three corridors intended to avoid impacts to the NDEQ-identified Sand Hills Region without an unacceptable increase in other environmental impacts. These route options are relatively short variance routes (between 12 and 32 miles each) that all divert east around the NDEQ-identified Sand Hills Region from the proposed Keystone XL route presented in the Final EIS.

From this analysis, Keystone identified a combination of the proposed segments A, E, and I that together formed the preferred route to avoid the NDEQ-identified Sand Hills Region in Nebraska. Keystone's analysis of these Nebraska route options was documented in an April 2012 report submitted to NDEQ for review (exp Energy Services Inc. 2012). NDEQ requested that Keystone consider revisions to the proposed A-E-I reroute to further avoid highly erodible soils and provide additional aquifer protection. Keystone revised its Nebraska reroute to address the NDEQ comments and submitted a revised report to NDEQ on September 5, 2012, documenting the proposed final route design in Nebraska (exp Energy Services Inc. 2012).

Subsequent to the revised Nebraska route design report submitted to NDEQ, on September 7, 2012, Keystone submitted a detailed environmental resource report to the Department to support the April 2012 Presidential Permit application. The resource report includes the Nebraska reroute as Keystone's proposed route through Nebraska. In addition to the NDEQ-identified Sand Hills Region, the proposed Project route would avoid areas in Keya Paha County identified by the NDEQ that have soil and topographic characteristics similar to the NDEQ-identified Sand Hills Region, and it avoids or moves further away from wellhead protection areas for the Villages of Clarks and Western. The Nebraska reroute as currently proposed will be carried forward for analysis in the Supplemental EIS as a component of Keystone's proposed route, and other Nebraska route options are not carried forward for analysis.

2.2.5 Other Alternatives Considered

2.2.5.1 Route Variations

In addition to major route alternatives, the proposed variations to the proposed Project were reviewed. Variations are relatively short deviations from a proposed route that are developed in response to landowner requests; to avoid or minimize construction impacts to localized, specific resources such as cultural resource sites, wetlands, recreational lands, or residences; or to minimize constructability issues such as shallow bedrock, difficult waterbody crossings, or steep terrain.

Each of the three states crossed by the proposed Project pipeline (Montana, South Dakota, and Nebraska) has incorporated minor route variations into the conditions for its approval of the proposed route. These variations were identified in the TransCanada Keystone XL Pipeline Project, Environmental Report (exp Energy Services Inc. 2012). The variations have been adopted by Keystone and are included in the detailed description of the proposed Project in Section 2.1, Overview of the Proposed Project.

2.2.5.2 Alternative Pipeline Design

In response to public comments, the Department considered two alternative pipeline designs: an aboveground pipeline and an alternative using smaller-diameter pipe. These two alternatives are addressed in the following sections.

Aboveground Pipeline

Although it is technically feasible to construct the proposed Project pipeline aboveground in most areas along the proposed Project route, there are many disadvantages to an aboveground pipeline that need to be considered. An aboveground pipeline is far more vulnerable to damage due to vandalism, sabotage, and the effects of other outside forces, such as vehicle collisions.

Furthermore, there has been increased concern about homeland security over the past decade, and burying the pipeline provides a higher level of security (Government Accountability Office [GAO] 2010).

In addition to safety and security issues, an aboveground pipeline would be more susceptible to the effects of ambient temperature, wind, and other storm events. Construction of an aboveground pipeline would also require exposing the pipeline above rivers (e.g., hung from a bridge or constructed as a special pipeline span) and roadways, where it would be vulnerable during bridge maintenance and accessible to those intent on damaging the pipeline.

Nearly all petroleum transmission pipelines in the United States are buried. As stated in Section 2.1.7, Pipeline System Design and Construction Procedures, the proposed Project would be constructed, operated, maintained, inspected, and monitored consistent with the Pipeline Hazardous Material Safety Administration (PHMSA) requirements presented in 49 CFR 195, relevant industry standards, applicable state standards, and a set of proposed Project-specific Special Conditions developed by PHMSA and incorporated into the proposed Project design, operations, maintenance, and monitoring commitments.

There are examples of successful aboveground pipelines including 466 miles of the Trans-Alaska pipeline. In addition, inspection and leak detection for aboveground pipelines can be more efficient and emergency response more rapid.

Based on review and in consultation with PHMSA, it has been determined that due to the safety and security concerns of an aboveground pipeline, it is not a reasonable alternative for the proposed Project, and it was not considered further in the Supplemental EIS.

Smaller-Diameter Pipe

As noted in Section 2.1, Overview of the Proposed Project, the proposed Project purpose is to transport a maximum capacity of 830,000 bpd of crude oil to satisfy existing commitments and future market demand. A pipeline system with a pipe diameter of less than the Project's proposed 36-inch-diameter would have lower throughput capacities and would not be capable of providing the volume of crude necessary to meet the proposed Project purpose.

The recommended work safety and construction requirements, including the construction ROW width for a small30-inch diameter, long-distance transportation pipelines are the same as those of the proposed 36-inch-diameter pipe (INGAA 1999). The working ROW dimensions of pipeline construction are primarily related to the size of construction vehicles and the need for working space near the pipeline trench.

The proposed pipeline is sized to efficiently meet the contracted volume of crude oil of 500,000 bpd with a maximum capacity of 830,000 bpd with increased pumping capacity. While there are limitations to the ultimate capacity of throughput based on pipeline diameter, the operational throughput is a combined function of pipeline diameter, pipeline operating pressure, and crude oil flow velocity. Therefore, to achieve a throughput that would meet the purpose of the proposed Project, a smaller-diameter pipeline would have to operate at higher pressures and flow velocities, and, for the delivery capacity proposed, the pressures and velocities required for a smaller diameter would not be consistent with PHMSA safety regulations, which limit maximum pipeline pressure.

Even if a special exception would be approved by PHMSA to increase pressure and velocity, it is unlikely that a 30-inch-diameter pipeline would be capable of transporting the volumes proposed for transport in the proposed Project. As of February 2011, Keystone had firm contract commitments to transport 500,000 bpd of crude oil to the oil terminal at Cushing, Oklahoma. If a smaller-diameter pipeline were installed, it would likely be necessary to install an additional pipeline to meet those initial commitments.

As a result of these findings, the Department has determined that the use of a smaller-diameter pipe for the proposed Project is not a reasonable alternative, and installing more than one smaller-diameter pipe to meet the purpose of and need for the proposed Project would not offer an overall environmental advantage over the proposed Project design. Therefore, this alternative was eliminated from further consideration.

2.2.6 Summary

Based on the analysis described above, the Department has identified the following as reasonable alternatives to the proposed Project for inclusion and evaluation in the Supplemental EIS. A preferred alternative will not be put forth in the Draft Supplemental EIS but will be identified if appropriate in the Final Supplemental EIS or the Record of Decision.

- No Action Alternative, including the following options:
  - Status Quo Option (i.e., no change in WCSB or Bakken crude oil production or transport methods);
  - Rail/Pipeline Option:
    - WCSB Crude—Rail from Lloydminster, Saskatchewan to Stroud, Oklahoma; then pipeline to Cushing, Oklahoma for onward delivery to the Gulf Coast area; and
    - Bakken Crude—Rail from Epping, North Dakota to Stroud, Oklahoma; then pipeline to Cushing, Oklahoma for onward delivery to the Gulf Coast area.
  - Rail/Tanker Option:
    - WCSB Crude—Rail from Lloydminster, Saskatchewan to Prince Rupert, British Columbia, then tanker through the Panama Canal to the Gulf Coast area; and
    - Bakken Crude—Rail from Epping, North Dakota to Stroud, Oklahoma; then pipeline to Cushing, Oklahoma for onward delivery to the Gulf Coast area.
- 2011 Steele City Alternative; and
- I-90 Corridor Alternative.

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